Enerplus Resources Fund

RENEWAL ANNUAL INFORMATION FORM

For the year ended December 31, 2001

April 10, 2002

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GLOSSARY OF TERMS

Unless the context otherwise requires, in this Renewal Annual Information Form, the following terms and abbreviations have the meanings set forth below.

"Economic Life" means, with respect to an oil and gas property, the time remaining before production of petroleum substances from the property is forecast to be uneconomic;

"EGEM" means Enerplus Global Energy Management Company, a private company, which acts as manager of Enerplus pursuant to the Management Agreement;

"EnerMark" means EnerMark Inc., a corporation amalgamated under the *Business Corporations Act* (Alberta) and a wholly owned subsidiary of the Fund;

"Enerplus" means Enerplus Resources Fund and its subsidiaries, taken as a whole;

"ERC" means Enerplus Resources Corporation, a corporation amalgamated under the *Business Corporations Act* (Alberta) and a wholly owned subsidiary of EnerMark;

"Established Reserves" means Proven Reserves plus 50% of Probable Reserves;

"Fund" means Enerplus Resources Fund;

"Governance Agreement" means the governance agreement dated June 21, 2001 among the Fund, EnerMark, ERC, the Trustee and EGEM, as may be amended, restated or supplemented from time to time;

"Management Agreement" means the Amended and Restated Management, Advisory and Administrative Agreement dated June 21, 2001, as amended December 31, 2001, made among the Fund, EnerMark, ERC, the Trustee and EGEM, as may be amended, supplemented or restated from time to time;

"Merger" means the merger of Enerplus Resources Fund and EnerMark Income Fund effective June 21, 2001, pursuant to which such entities continued as "Enerplus Resources Fund";

"Proven Reserves" and **"Probable Reserves"** have the meanings given to those terms in the notes under "Oil and Gas Reserves";

"Reserve Life Index" or **"RLI"** is an index reflecting the theoretical production life of a property if the remaining reserves were to be produced out at current production rates. The index is calculated by dividing the reserves in the selected reserve category at a certain date by the estimated production for the following 12 month period;

"Sproule" means Sproule Associates Limited, independent petroleum consultants;

"Sproule Report" means the independent engineering evaluations of Enerplus' oil, NGLs and natural gas interests prepared by Sproule dated March 4, 2002 and effective January 1, 2002, utilizing commodity price forecasts of Sproule dated January 1, 2002;

"Termination Costs" means all costs, expenses or obligations which are incurred by EGEM or its affiliates within 90 days following the effective date of termination of the Management Agreement (the "**Termination Date**") as a direct or indirect result of:

(i) any termination, retirement or severance of any officers, employees or consultants of EGEM or its affiliates to the extent that the provision of services by any such officer, employee or consultant is allocable (based on the prior calendar year) to the provision of the services of EGEM under the Management Agreement prior to its termination ("**Terminated Personnel**");

(ii) the termination or cancellation of any agreement, contract, lease or other commitment applicable to the services provided under this Agreement that pre-existed the Management Agreement (a "**Terminated Pre-Existing Contract**"); and

(iii) the termination or cancellation of any agreement, contract, lease or other commitment applicable to the services provided under this Agreement that was entered into on or after the date of the Management Agreement (a "**Terminated Post-Merger Contract**"),

provided, however, that: (A) no cost, expense or obligation shall be included as a "Termination Cost" if it is applicable to a Terminated Post-Merger Contract: (i) having a term extending more than 36 months after the Termination Date of the Management Agreement; or (ii) involving aggregate costs, expenses or obligations of $2,000,000 or more, unless such Terminated Post-Merger Contract was approved by the board of directors of EnerMark at any time prior to the Termination Date; and (B) the costs, expenses or obligations applicable to termination, retirement or severance of Terminated Personnel shall not exceed, in the aggregate, the sum of: (i) all amounts payable pursuant to any written agreement with Terminated Personnel which was approved by the board of directors of EnerMark at any time prior to the Termination Date (an "**Approved Employment Agreement**"); and (ii) the aggregate of the annual remuneration (including salary, bonuses, benefits, any rights or entitlements to options or incentives under corporate plans or other employment compensation) of all Terminated Personnel, other than those whose payments are made pursuant to an Approved Employment Agreement, for the last fiscal year of the Fund ending prior to the Termination Date, provided, however that there shall be no duplication of any amounts under terms (B)(i) and (B)(ii) above;

"Termination Fees" means an amount equal to the annualized average of the base management fee paid to EGEM in each of the trailing eight quarters ending immediately prior to the quarter in which notice of termination of the Management Agreement is provided to EGEM;

"Trust Indenture" means the Amended and Restated Trust Indenture dated June 21, 2001 among EnerMark, ERC and the Trustee, as may be amended, supplemented or restated from time to time;

"Trust Units" means the trust units of the Fund, each representing an equal undivided beneficial interest in the Fund; and

"Trustee" means CIBC Mellon Trust Company, or its successor as trustee of the Fund.

In this Renewal Annual Information Form, unless otherwise indicated, all dollar amounts are in Canadian dollars and all references to "**$**" are to Canadian dollars.

ABBREVIATIONS

Oil and Natural Gas Liquids

Bbls - barrels

Mbbls - thousand barrels

BOPD - barrels of oil per day

Bbls/d - barrels per day

MMbbls - million barrels

NGLs - natural gas liquids

Natural Gas

GJ - gigajoules

GJ/d - gigajoules per day

Mcf - thousand cubic feet

MMcf - million cubic feet

Bcf - billion cubic feet

Mcf/d - thousand cubic feet per day

MMcf/d - million cubic feet per day

MMBTU - million British Thermal Units

Other

AECO means Alberta Energy Company interconnect with the NOVA System.

BOE means barrel of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one barrel of oil. The conversation factor used to convert natural gas to oil equivalent is not necessarily based upon either energy or price equivalents at this time.

BOE/d means BOE per day.

MBOE means thousand barrel of oil equivalent.

W.I. means working interest

WTI West Texas Intermediate at Cushing, Oklahoma, the benchmark crude oil for pricing purposes.

CONVERSION

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

To Convert from	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
Bbls	cubic metres	0.159
cubic metres	Bbls	6.293
Feet	Metres	0.305
metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471
GJ	MMBTU	0.950

ENERPLUS RESOURCES FUND

Renewal Annual Information Form
For the year ended December 31, 2001

NOTE TO READER

On June 21, 2001, Enerplus Resources Fund and EnerMark Income Fund merged and continued as Enerplus Resources Fund. The nature of the business combination was such that, as the former unitholders of EnerMark Income Fund held approximately 69% of the outstanding Trust Units of the combined Enerplus Resources Fund at the date of the Merger, the Merger has been accounted for using the reverse take-over form of the purchase method of accounting for business combinations.

Accordingly, unless otherwise noted, all historical financial, operational and oil and natural gas reserve information contained in this Renewal Annual Information Form, together with the management's discussion and analysis of financial condition and results of operations incorporated by reference in this Renewal Annual Information Form, is based on the historical financial and operational results of EnerMark Income Fund, and where applicable, historical per Trust Unit information has been restated to reflect the exchange ratio of 0.173 of an Enerplus Trust Unit for each trust unit of EnerMark Income Fund effective under the Merger. ***The production and operational information relating to the pre-Merger Enerplus Resources Fund has been included in the information for the current Enerplus Resources Fund since June 21, 2001, the effective date of the Merger, and the reserve information as of January 1, 2002 includes all reserves of Enerplus as of that date, including those acquired pursuant to the Merger.***

STRUCTURE OF ENERPLUS RESOURCES FUND

Enerplus Resources Fund

Enerplus Resources Fund is an energy investment trust created under the laws of the Province of Alberta in 1986 and currently governed by the Trust Indenture. The Fund's assets currently consist of all of the issued and outstanding shares of EnerMark (which owns all of the issued and outstanding shares of ERC), an unsecured note issued by EnerMark to the Fund and 95% and 99% royalties on the crude oil and natural gas property interests of EnerMark and ERC, respectively. The head, principal and registered office of Enerplus is located at 1900, 700 - 9th Avenue S.W., Calgary, Alberta T2P 3V4 until June 1, 2002, when it will be relocated to 3000, 333 - 7th Avenue S.W., Calgary, Alberta T2P 2Z1. The Trustee of the Fund is CIBC Mellon Trust Company located at 600 The Dome Tower, 333 – 7th Avenue S.W., Calgary, Alberta T2P 2Z1. The Fund is managed by EGEM pursuant to the Management Agreement.

The Fund's primary focus is to maintain and enhance cash distributions to its unitholders through the development of EnerMark's and ERC's existing crude oil and natural gas properties, acquisition of new producing properties and monetization, by the way of sale or farm out, of EnerMark's and ERC's undeveloped lands. Development efforts are concentrated on optimizing production from existing and new crude oil and natural gas reserves.

EnerMark Inc. and Enerplus Resources Corporation

Each of EnerMark and ERC are corporations organized under the *Business Corporations Act* (Alberta). All of the issued and outstanding shares of EnerMark are owned by the Fund, and all of the issued and outstanding shares of ERC are owned by EnerMark. EnerMark and ERC are managed by EGEM pursuant to the Management Agreement. Pursuant to the Governance Agreement, EGEM is entitled to nominate three members to the board of directors of EnerMark (the entity responsible for the governance of Enerplus), with the balance, which must constitute a majority of the directors of EnerMark, to be nominated pursuant to a vote by the unitholders of the Fund.

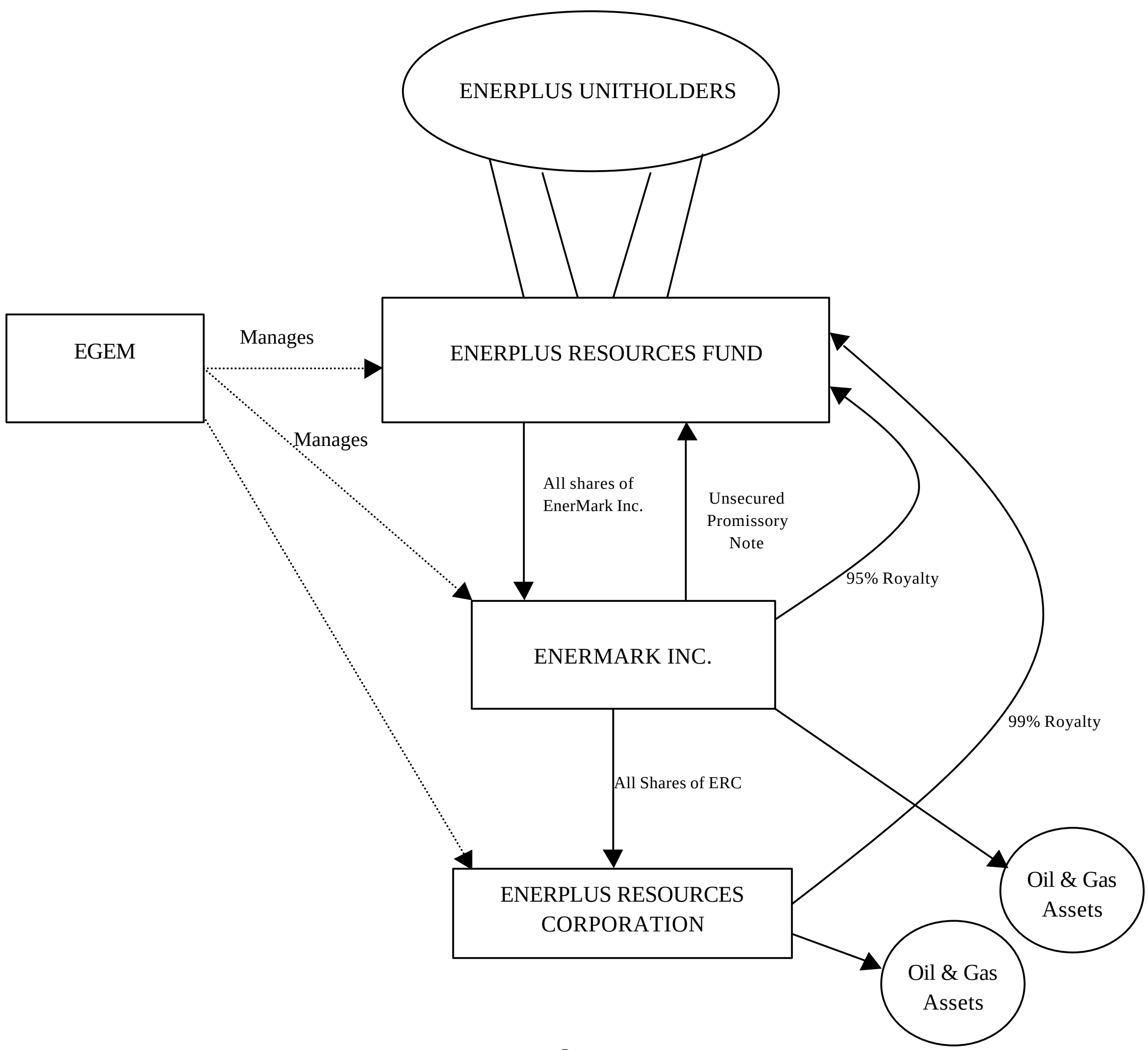
EnerMark and ERC acquire, exploit and operate crude oil and natural gas assets in western Canada for the benefit of the Fund. See "Operational Information" and "Oil and Natural Gas Reserves" for information regarding the operations and oil and natural gas reserves of Enerplus.

Enerplus Global Energy Management Company

EGEM is a corporation organized under the *Companies Act* (Nova Scotia) and is an indirect wholly owned subsidiary of El Paso Corporation of Houston, Texas. EGEM manages the Fund and its subsidiaries pursuant to the Management Agreement. The board of directors of EnerMark, as the body which oversees the business and affairs of Enerplus, has retained EGEM to provide comprehensive management services, administer and regulate the day-to-day operations and make executive decisions in respect of Enerplus which conform to general policies and principles established by the board of directors of EnerMark. For these services, EGEM receives a management fee, incentive fees based on the performance of Enerplus and reimbursement of its general and administrative expenses. See "Information Respecting Enerplus Resources Fund - Governance of Enerplus and the Management Agreement".

Organization Chart

The structure of Enerplus and the flows of cash from EnerMark and ERC to the Fund and from the Fund to its unitholders are set forth below:



GENERAL DEVELOPMENT OF ENERPLUS RESOURCES FUND

Historical Overview

Enerplus was formed in 1986 and was the first issuer in Canada to offer trust units to the public and to list its trust units on a stock exchange. Enerplus was historically one of a group of royalty trusts, income funds and other entities managed by the Enerplus Group of Companies, and in recent years has grown significantly as a result of consolidation of many of those entities, as discussed below.

Merger with Westrock Energy Income Fund I and Westrock Energy Income Fund II

On June 8, 2000, unitholders of each of Enerplus, Westrock Energy Income Fund I ("Westrock I") and Westrock Energy Income Fund II ("Westrock II") approved the merger of those issuers, which was completed the same day. Enerplus issued an aggregate of approximately 8,911,667 Trust Units (after giving effect to one for six consolidation of the Trust Units that occurred concurrently with the merger) to former unitholders of Westrock I and Westrock II in connection with the merger. Following this transaction, a total of approximately 15,473,000 Trust Units were issued and outstanding. Enerplus, Westrock I and Westrock II were managed by affiliated management companies which were part of the Enerplus Group of Companies (and each of which was a predecessor of EGEM). The transaction was negotiated on an arm's length basis on behalf of each of Enerplus, Westrock I and Westrock II by an independent special committee of the board of directors responsible for each respective entity.

Strategic Affiliation with El Paso Corporation

On August 3, 2000, Enerplus announced that it had formed a strategic affiliation with El Paso Corporation ("El Paso") of Houston, Texas through the sale of the management companies responsible for the management of Enerplus' various public and private funds, including the manager of Enerplus. El Paso has operations in natural gas transmission, merchant energy services, power generation, international project development, natural gas gathering and oil and natural gas production.

Listing on the New York Stock Exchange

On November 17, 2000, the Trust Units were listed and posted for trading on the New York Stock Exchange (the "NYSE") under the trading symbol "ERF". Enerplus was the first Canadian royalty trust to have its securities trade on the NYSE.

Acquisition of EPRC III

On December 19, 2000, Enerplus completed the acquisition of all of the outstanding shares of Enerplus Pension Resource Corporation ("EPRC III"), a private Canadian pension resource corporation that owned producing oil and natural gas properties in western Canada, for consideration of $90 million plus the assumption of bank debt and working capital balances. The effective date of the transaction was November 30, 2000. EPRC III was managed by a predecessor of EGEM. The transaction was negotiated on an arm's length basis on behalf of Enerplus by an independent special committee of the board of directors of ERC (the entity responsible for the governance of Enerplus at that time) with the independent directors and shareholders of EPRC III. The acquisition was funded through a combination of cash from existing credit facilities and the assumption of debt, which together represented 75% of the purchase price, and the issuance of 1,145,375 Trust Units which represented the remaining 25% of the purchase price. EPRC III was amalgamated with ERC on December 29, 2000 and continued as "Enerplus Resources Corporation".

Merger with EnerMark Income Fund

On June 21, 2001, Enerplus and EnerMark Income Fund completed the Merger pursuant to which each trust unit of EnerMark Income Fund (an "EIF Unit") was exchanged for 0.173 of a Trust Unit of Enerplus, and each outstanding warrant to purchase an EnerMark Income Fund Unit was substituted with 0.173 of a warrant to purchase a Trust Unit of Enerplus (an "Enerplus Warrant"). Each whole Enerplus Warrant was exercisable into a Trust Unit at an exercise price of $26.53 on or before December 17, 2001. A total of approximately 43,525,961 Trust Units of the Fund and 2,507,330 Enerplus Warrants were issued to former holders of EnerMark Income Fund Units and warrants, respectively. Immediately following the Merger, there were approximately 64,388,336 Trust Units and 2,507,330 Enerplus Warrants issued and outstanding.

Enerplus and EnerMark were managed by affiliated management companies which were part of the Enerplus Group of Companies (and each of which was a subsidiary of EGEM). Although it was concluded that the Merger was not subject to the provisions governing "related party transactions" within the meaning of certain Canadian securities laws, due to the common management of the two funds, the Merger was effectively treated as a related party transaction by the funds and their respective boards in order to avoid the perception of any conflict of interest or any informational disadvantage arising from the Merger, including complying with certain valuation, disclosure and minority approval requirements. The transaction was negotiated on an arm's length basis on behalf of Enerplus and EnerMark Income Fund by an independent special committee of the board responsible for each respective entity.

EnerMark Income Fund was created on April 3, 1996 as a result of a corporate reorganization of Mark Resources Inc. by way of a plan of arrangement. From 1997 through 2000, EnerMark Income Fund made several corporate and asset acquisitions, including the acquisitions of Quest Oil & Gas Inc. in 1997, Derrick Energy Corporation in 1999 and Western Star Exploration Ltd., Pursuit Resources Corp., EBOC Energy Ltd. and Cabre Exploration Ltd., in addition to an asset acquisition in the Hanna, Alberta area, in 2000. Additional details regarding the corporate acquisitions made in 1999 and 2000 are contained in Note 7 of Enerplus' audited annual consolidated financial statements for the year ended December 31, 2001.

Attached as Appendix "A" to this Renewal Annual Information Form are certain unaudited pro forma consolidated financial statements of Enerplus for the year ended December 31, 2001 which give effect to the Merger as if it had occurred on January 1, 2001.

Property Acquisitions and Dispositions in 2001

In 2001, Enerplus made several property acquisitions for an aggregate cost of approximately $77 million. The most significant of these acquisitions were made in the Kaybob, Ferrier, Joarcam, Medicine Hat and Hanna Garden areas of Alberta and the Gleaneath area of Saskatchewan. Production from the acquired properties, at the time of their respective acquisitions, was approximately 1,113 Bbls/d of crude oil and NGLs and 10.5 MMcf/d of natural gas.

Additionally, Enerplus undertook a property rationalization program in 2001 which was designed to enable it to focus its activities on high yield properties. Under the program, over 40 non-core properties were sold. Proceeds from the sales totalled approximately $68 million, and daily production from these properties, at the time of their respective sales, was approximately 1,266 Bbls/d of crude oil and NGLs and 4.8 MMcf/d of natural gas.

Recent Developments Since Fiscal Year-End

Commodity Price Risk Management Program

On January 8, 2002, Enerplus entered into a three-way financial option structure for 1,500 Bbls/d of crude oil from April 2002 to December 2003. Under the terms of this structure, Enerplus purchased a WTI put at US$19.50/Bbl, sold a WTI call at US$27.00/Bbl and sold a WTI put at $US17.00/Bbl. On this same date, Enerplus also entered into a three-way option structure on 9,480 Mcf/d of natural gas for the period from April 2002 to October 2002, selling an AECO call at $4.22/Mcf, purchasing an AECO put at $3.29/Mcf and selling an AECO put at $2.37/Mcf, and additionally, Enerplus sold an AECO call at $6.33/Mcf on 9,480 Mcf/d of natural gas for the period from November 2002 to March 2003.

On March 6, 2002, Enerplus entered into two additional three-way financial option structures. One structure comprised 1,500 Bbls/d of crude oil from April 2002 to December 2003 wherein Enerplus purchased a WTI put at US$20.10/Bbl, sold a WTI call at US$28.00/Bbl and sold a WTI put at US$17.00/Bbl. The other structure comprised 1,500/Bbls/d of crude for all of calendar 2003 wherein Enerplus purchased a WTI put at US$20.15/Bbl, sold a WTI call at US$28.00/Bbl and sold a WTI put at US$17.00/Bbl

OPERATIONAL INFORMATION

As mentioned in the "Note to Reader" on page 1, all historical operational and reserve information in this Renewal Annual Information Form is based on the historical operational results of EnerMark Income Fund. The production and operational information relating to the pre-Merger Enerplus Resources Fund has been included in the information for the current Enerplus Resources Fund since June 21, 2001, the effective date of the Merger, and the reserve information as of January 1, 2002 includes all reserves of Enerplus as of that date, including those acquired pursuant to the Merger.

Description of Principal Properties

All of Enerplus' oil and natural gas property interests are located in western Canada in the provinces of Alberta, British Columbia and Saskatchewan (with a minimal interest in the province of Manitoba). Production volumes from Enerplus' properties are approximately 45% crude oil and NGLs and 55% natural gas on a BOE basis. During the year ended December 31, 2001, Enerplus' oil and natural gas property interests yielded average production of 20,592 Bbls/d of crude oil, 3,978 Bbls/d of NGLs and 176.7 MMcf/d of natural gas for a total of 54,015 BOE/d, compared to 12,089 Bbls/d of crude oil, 2,111 Bbls/d of NGLs and 101.5 MMcf/d of natural gas for a total of 31,112 BOE/d during 2000. For the last six months of 2001, following the Merger, Enerplus' property interests yielded average production of 22,765 Bbls/d of crude oil, 4,415 Bbls/d of NGLs and 202.1 MMcf/d of natural gas, for a total of 60,871 BOE/d. As at January 1, 2002 the oil and natural gas property interests held by Enerplus are estimated to contain Established Reserves of 132.1 MMbbls of crude oil and NGLs and 1,081.5 Bcf of natural gas. See "Oil and Natural Gas Reserves".

The following paragraphs discuss the principal producing properties of Enerplus including, where applicable, the additional properties or working interests acquired through the Merger with EnerMark Income Fund effective June 21, 2001. All production information represents the net working interest of Enerplus in such property before deduction of royalty interests owned by others, and production figures for the year ended December 31, 2001 only include, where applicable, net average production attributable to the acquired pre-Merger Enerplus Resources Fund interests for the period from June 21, 2001 to December 31, 2001. All references to reserve volumes contained in each property are based upon the estimated volumes contained within the Sproule Report applicable to Enerplus' gross working interest in the property.

Joarcam, Alberta

Enerplus has varying working interests averaging 80% in the Joarcam area of central Alberta located 300 kilometres northeast of Calgary, Alberta. The Joarcam area, which Enerplus operates, produces crude oil, solution gas and gas cap natural gas from the Viking formation as well as non-associated natural gas from the Mannville formations. Production from this area in December 2001 was 2,177 Bbls/d of crude oil, 149 Bbls/d of NGLs and 8.0 MMcf/d of natural gas for a total of 3,640 BOE/d. All crude oil and gas produced from this property is processed at Enerplus operated facilities. Plans for 2002 include the drilling of up to 18 infill Viking crude oil wells, 6 non-associated gas wells, and on-going re-completions, tie-ins and facility optimizations. As at January 1, 2002, Enerplus' property interests in this area contained 12,337 MBOE of Established Reserves. Production from this property is sold at the prevailing spot price under short-term contracts.

Medicine Hat Region

The Medicine Hat region of southern Alberta is primarily a natural gas producing region which Enerplus operates and in which Enerplus has an average working interest of 95%. In 2001, production from this region averaged 17.0 MMcf/d of natural gas net to Enerplus from four core properties. A significant portion of Enerplus' property interests in this region was acquired from the pre-Merger Enerplus Resources Fund. This area was one of Enerplus' most active areas with a total of 156 (135 net) natural gas wells drilled during the year. The majority of the wells were drilled and brought on-stream in the fourth quarter, and as a result natural gas sales averaged 32.9 MMcf/d in December 2001. As at January 1, 2002, the interests of Enerplus in the Medicine Hat region contained 46,354 MBOE of Established Reserves. Further information regarding each of the four properties in this area is contained below.

Bantry, Alberta

Enerplus owns an average 95% working interest in the Bantry Field located approximately 200 kilometres southeast of Calgary near Brooks, Alberta. Natural gas from this property, which Enerplus operates, is primarily produced from the Milk River and Medicine Hat formations. During the second and fourth quarters of 2001, Enerplus installed additional compression and drilled an additional 98 shallow natural gas infill wells. As a result, December 2001 production averaged 12.1 MMcf/d and 38 drilled wells were brought on-stream in the first quarter of 2002. Plans for 2002 include additional drilling of up to 25 wells to further develop the pool on an 80 acre spacing and to keep the compression facilities running at capacity. As at January 1, 2002, Enerplus' interests in the Bantry property contained 16,267 MBOE of Established Reserves. A total of 3.8 MMcf/d of production from this property is sold under a fixed price arrangement at $2.64/Mcf which expires on October 31, 2002. The remainder of production from this property is sold at the prevailing spot price under short-term contracts.

Fox Valley, Saskatchewan

Enerplus has a 96.8% working interest in the Fox Valley property located approximately 400 kilometres southeast of Calgary in the shallow natural gas producing region of southwestern Saskatchewan. The natural gas from this property, which Enerplus operates, is produced from the Milk River formation. In December 2001, this property averaged production of approximately 4.2 MMcf/d of natural gas from 152 (147 net) natural gas wells. Plans are to drill up to 25 infill natural gas wells in 2002. As at January 1, 2002, Enerplus' Fox Valley property interests contained 4,349 MBOE of Established Reserves. A total of 2.8 MMcf/d of natural gas produced from this property has been sold under a fixed price arrangement at $2.64/Mcf which expires on October 31, 2003. The remainder of production from this property is sold at the prevailing spot price under short-term contracts.

Medicine Hat, Alberta

Enerplus owns various working interests ranging from 20% to 100% in this Medicine Hat shallow natural gas field located 300 kilometres southeast of Calgary. The natural gas from this property, which Enerplus operates, is produced from the Medicine Hat and Milk River formations. As a result of successful restimulation and infill drilling programs in the third and fourth quarters of 2001, this property averaged production of approximately 9.9 MMcf/d of natural gas at the end of 2001. In 2002, Enerplus' plans for this property include installing additional compression, restimulating existing wells and reducing the well spacing by infill drilling 75 additional shallow natural gas wells. As at January 1, 2002, Enerplus' property interest in the Medicine Hat property contained 15,239 MBOE of Established Reserves. A significant portion of these reserves are dedicated under long term contracts to major netback priced pool aggregators. The remainder of the natural gas production from this area is sold at the prevailing spot price under short-term contracts.

Verger, Alberta

Enerplus owns various working interests in the Verger area located approximately 100 kilometres southeast of Calgary. Enerplus operates the majority of the production and owns an average 80% working interest in 175 natural gas wells. Enerplus' production from this property in December 2001 averaged 6.5 MMcf/d, primarily from the Milk River and Medicine Hat formations. An additional 20 operated wells were brought on-stream in the first quarter of

2002 and plans are to drill 29 shallow gas infill wells later in 2002. As at January 1, 2002, Enerplus' Verger property interests contained 10,499 MBOE of Established Reserves. The production from this property is sold at the prevailing spot price under short-term contracts.

Deep Basin, Alberta

Enerplus has an average working interest of 8% in the non-operated Deep Basin property which encompasses the Elmworth, Karr, Wapiti, and South Wapiti producing fields which are located approximately 500 kilometres northwest of Calgary, Alberta. In 2001, this property produced 2,103 BOE/d comprised of 9.5 MMcf/d of natural gas and 519 Bbls/d of NGLs. Enerplus owns sufficient capacity in compressor stations, natural gas gathering systems and natural gas processing plants to process its production from the 320 wells in which it has a working interest. As at January 1, 2002, Enerplus' property interest contained 8,201 MBOE of Established Reserves. Natural gas production from this property is marketed under a long-term contract to a major netback priced pool operator.

Progress, Alberta

Enerplus has a 100% working interest in the operated portion of the Progress area located approximately 600 kilometres northwest of Calgary, Alberta, which produces crude oil and solution gas from the Boundary Lake formation. Enerplus also has a 27% working interest in the partner-operated Progress Halfway Gas Unit which produces non-associated gas from the Halfway formation. In 2001, production from this property averaged 784 Bbls/d of crude oil, 107 Bbls/d of NGLs and 6.9 MMcf/d of natural gas for a total of 2,043 BOE/d. As at January 1, 2002, Enerplus' total property interests in this area contained 4,307 MBOE of Established Reserves. Crude oil and NGLs production is marketed at the prevailing market price under short-term contracts. Natural gas production is sold under a variety of contracts including major netback priced pool aggregators and short-term contracts at the prevailing spot price, and is marketed in the U.S. midwest via Enerplus' natural gas pipeline commitments.

Hanna Garden Plains, Alberta

Enerplus has various working interests in the Hanna Garden Plains field and owns an average 80% working interest in 258 wells. This property, which is operated by Enerplus, is located approximately 200 kilometres northeast of Calgary, Alberta. The primary producing zone is the Second White Specks, which averaged production of 10.9 MMcf/d in 2001. In 2001, Enerplus drilled 92 Second White Specks natural gas wells and expanded the two field compressor sites, and as a result, production in December 2001 was 13.8 MMcf/d. Plans for the property in 2002 are to drill up to 75 additional natural gas wells, the majority of which will complete development of the lands on 320-acre spacing. As at January 1, 2002, Enerplus' property interest in this area contained 29,118 MBOE of Established Reserves. The natural gas produced from this area is marketed under a variety of contracts including major net priced pool aggregators and short-term contracts at the prevailing spot price.

Benjamin, Alberta

Enerplus has an average working interest of 20% in the 7 producing natural gas wells in this area which is located in the foothills approximately 80 kilometres northwest of Calgary, Alberta. These wells produce from the Turner Valley formation. This property produced 10.0 MMcf/d of natural gas for the year 2001. Several follow-up development drilling locations have been identified with the first one drilled in mid-2001 in conjunction with Enerplus' participation in a compression and pipeline project, which will ensure plant processing capacity will be available for Enerplus' needs. The well commenced production in November 2001 and produced 3.9 MMcf/d of sales natural gas net to Enerplus through the end of 2001. As at January 1, 2002, Enerplus' property interest contained 13,947 MBOE of Established Reserves. Production from this property is sold both to a major netback priced pool aggregator and at the prevailing spot price under short-term contracts.

Giltedge, Alberta

Enerplus has a 100% working interest in and operates the Giltedge field located 350 kilometres northeast of Calgary, Alberta. In December 2001, production averaged 1,661 Bbls/d of crude oil and 643 Mcf/d of natural gas, for a total of

1,769 BOE/d, from this Lloydminster zone waterflood. A horizontal oil well and four vertical oil wells are planned for this pool in 2002. As at January 1, 2002, Enerplus' property interests in this area contained 10,827 MBOE of Established Reserves. Production from this property is sold at the prevailing spot price under short-term contracts.

Valhalla, Alberta

Enerplus has varying working interests averaging 80% in the Valhalla area located approximately 500 kilometres northwest of Calgary, Alberta. The Valhalla area, which Enerplus operates, produces crude oil and natural gas from the Doe Creek, Bluesky, Boundary Lake and Halfway formations. During 2001, Enerplus' production from this area averaged 1,453 BOE/d consisting of 377 Bbls/d of crude oil, 5.9 MMcf/d of natural gas and 86 Bbls/d of NGLs. Crude oil and natural gas is either processed at Enerplus owned and operated facilities or at non-operated facilities. Plans for 2002 include additions to and optimization of existing compression at the operated facilities. Enerplus also intends to drill several infill Halfway crude oil wells in 2002 to optimize both crude oil and natural gas recovery from the existing pool. As at January 1, 2002, Enerplus' property interests in this area contained 5,293 MBOE of Established Reserves. Crude oil and NGLs production is marketed at the prevailing market price under short-term contracts. Natural gas production is sold under a variety of contracts including major netback priced pool aggregators and short-term contracts at the prevailing spot price, and is marketed in the U.S. midwest via Enerplus' natural gas pipeline commitments.

Pembina Five-Way / South Buck Lake, Alberta

Enerplus acquired from the pre-Merger Enerplus Resources Fund working interests of up to 100% in certain lands in the Pembina Five-Way area and a 100% working interest in the South Buck Lake Cardium Unit No. 1, located approximately 300 kilometres north of Calgary, with 304 (217 net) wells in this area. Enerplus operates this area, and the crude oil produced from the Cardium zone in this area is of high quality and is supported by long-life, low decline reserves. The majority of the production is under secondary recovery schemes designed to maximize the recoverable reserves. In December 2001, production averaged 2,215 Bbls/d of crude oil, 108 Bbls/d of NGLs and 1.4 MMcf/d of natural gas, for a total of 2,550 BOE/d. As at January 1, 2002, this property contained 28,251 MBOE of Established Reserves net to Enerplus. Crude oil produced from this area is marketed under a 30 day evergreen contract with either an end use refinery or intermediary. The natural gas produced from this property is marketed at the prevailing spot price under short-term contracts.

Bashaw, Alberta

Enerplus has varying working interests ranging from 50% to 100% in the Bashaw area located approximately 130 kilometres northeast of Calgary, Alberta. This Enerplus-operated area produces natural gas primarily from the Belly River and Mannville formations. In December 2001, production from this area averaged 6.8 MMcf/d of natural gas and 66 Bbls/d of NGLs for a total of 1,199 BOE/d. The natural gas is compressed and processed through Enerplus owned and operated infrastructure as well as third party gas processing plants. Plans for 2002 include field compression optimization and uphole gas re-completions. As at January 1, 2002, Enerplus' property interests in this area contained 942 MBOE of Established Reserves. Production from this property is sold at the prevailing spot price under short-term contracts.

Pine Creek, Alberta

Enerplus has both operated and non-operated production in working interests ranging from 50% to 100% in the Pine Creek area located approximately 500 kilometres northwest of Calgary, Alberta. The Pine Creek area produces liquids rich natural gas from the Bluesky, Gething and Ostracod formations. In December 2001, production averaged 5.8 MMcf/d of natural gas and 225 Bbls/d of NGLs for a total of 1,192 BOE/d. The majority of production from this area is compressed and processed through Enerplus-owned infrastructure with a portion of the natural gas handled through third party gas plants. As at January 1, 2002, Enerplus' property interests in this area contained 9,955 MBOE of Established Reserves. Production from this property is sold at the prevailing spot price under short-term contracts.

Kaybob, Alberta

Enerplus has both operated and non-operated production in working interests ranging from 50% to 100% in the Kaybob area located approximately 300 kilometres north of Calgary, Alberta. In June 2001, additional working interests in this area were acquired for approximately $25 million. The Kaybob area produces liquids rich natural gas from the Bluesky, Gething, Viking and Notikewin formations. In 2001, production averaged 3.9 MMcf/d of natural gas and 419 Bbls/d of NGLs for a total of 1,066 BOE/d. As at January 1, 2002, Enerplus' interests in this property contained 7,884 MBOE of Established Reserves. NGLs production from this property is marketed at the prevailing market price under short-term contracts. natural gas production is sold under a variety of contracts including major netback priced pool aggregators and short-term contracts at the prevailing spot price, and is marketed in the U.S. midwest via Enerplus' natural gas pipeline commitments.

Auburndale, Alberta

Enerplus has an average 80% working interest in and operates the Auburndale field located 350 kilometres northeast of Calgary, Alberta. There are 21 producing crude oil wells and 4 producing natural gas wells on this property that averaged production of 752 Bbls/d of crude oil and 800 Mcf/d of natural gas, for a total of 885 BOE/d, in 2001. Plans for 2002 are to drill three infill wells in the Sparky formation and complete the development of the pool on 20 acre spacing. As at January 1, 2002, Enerplus' property interests in this area contained 1,161 MBOE of Established Reserves. Production from this property is sold at the prevailing spot price under short-term contracts.

Medicine Hat Glauconitic C Pool, Alberta

Enerplus has various working interests which average 71% in this large crude oil pool which Enerplus operates and which is located approximately 350 kilometres southeast of Calgary near Medicine Hat, Alberta. In 2001, a portion of this pool was unitized and a waterflood scheme was implemented to enhance crude oil recovery. Full-scale injection into the pool commenced in June, 2001. Additional working interests in the pool were acquired in the fourth quarter of 2001. Enerplus owns a 44% working interest in the unitized lands that encompass 5,040 acres. As a result of production improvements experienced due to the waterflood and the additional working interest acquired, production averaged 800 Bbls/d of crude oil and 1.0 MMcf/d of natural gas in December 2001 for a total of 967 BOE/d. As at January 1, 2002, this property contained 7,649 MBOE of Established Reserves. Both crude oil and natural gas produced from this property are marketed at the prevailing spot price under short-term contracts.

Sylvan Lake, Alberta

Enerplus acquired from the pre-Merger Enerplus Resources Fund both operated and non-operated working interests in this area located approximately 130 kilometres northwest of Calgary. Enerplus has an 85% working interest in and operates a Pekisko crude oil pool with 18 gross (15.3 net) producing oil wells on 1,280 (1,088 net) acres. The Pekisko zone in this area has been under development by the pre-Merger Enerplus Resources Fund since 1996 with 8 successful gross (7.2 net) oil wells drilled in the last three years. The production is treated at the operated battery facilities located in this area. Enerplus also has a 19% working interest in 32,640 acres in the non-operated Sylvan Lake Gas Unit No. 1 which consists of 20 gross (3.8 net) producing natural gas wells producing from the Glauconitic, Basal Quartz, Ostracod, Jurassic, Elkton-Shunda and Pekisko formations.

During the last six months of 2001, production from this area averaged 527 Bbls/d of crude oil, 3.2 MMcf/d of natural gas and 184 Bbls/d of NGLs for a total of 1,250 BOE/d. As at January 1, 2002, Enerplus' total Sylvan Lake property interests contained 4,927 MBOE of Established Reserves. Crude oil production is marketed under a 30 day evergreen contract with either an end use refinery or an intermediary. The natural gas production from the Sylvan Lake Unit is sold under a long-term contract to a major netback priced pool aggregator. The remainder of production from this property is sold at the prevailing spot price under short-term contracts.

Summary of Production Locations

During the year ended December 31, 2001, 84% of Enerplus' crude oil and NGLs production and 91% of Enerplus' natural gas production came from Alberta, 2% of Enerplus' crude oil and NGLs production and 5% of Enerplus' natural gas production came from British Columbia, and 14% of Enerplus' crude oil and NGLs production and 4% of Enerplus' natural gas production came from Saskatchewan. The following table sets out the geographical areas of Enerplus' production from its major properties in 2001 and the average daily production from such properties during the year ended December 31, 2001:

Location	Crude Oil (Bbls/d)	NGLs (Bbls/d)	Natural Gas (Mcf/d)	Total (BOE/d) (6 Mcf/d = 1 BOE/d)
Alberta				
Joarcam	1,999	141	7,703	3,424
Medicine Hat Region	3	-	17,011	2,838
Deep Basin	-	519	9,501	2,103
Progress	784	107	6,909	2,043
Hanna Garden	-	1	10,898	1,817
Benjamin	-	11	9,988	1,676
Giltedge	1,546	-	597	1,646
Valhalla	377	86	5,938	1,453
Pembina Five-Way / South Buck Lake	1,166	60	732	1,348
Bashaw	-	66	6,708	1,184
Pine Creek	11	263	4,895	1,090
Kaybob	-	419	3,884	1,066
Auburndale	752	-	800	885
Medicine Hat Glauconite C Pool	585	-	844	726
Sylvan Lake	280	97	1,717	663
Other	9,337	2,109	72,474	23,524
Total Alberta	**16,840**	**3,879**	**160,599**	**47,486**
Total British Columbia	**300**	**95**	**9,291**	**1,943**
Total Saskatchewan	**3,446**	**4**	**6,781**	**4,580**
Total Manitoba	**6**	**-**	**-**	**6**
TOTAL	**20,592**	**3,978**	**176,671**	**54,015**

Location of Facilities

The following tables describe the location, type of facility, working interest of Enerplus and, where applicable, the total processing or treating capacity and the processing or treating capacity attributable to Enerplus' working interests in each of the facilities that are material to Enerplus' operations.

Crude Oil Production Facilities

Area Name	Type of Facility	W.I. %	Gross Treating Capacity (Bbls/d)	W.I. Treating Capacity (Bbls/d)
Auburndale (1)	Emulsion Treating & Water Disposal	100%	2,000	2,000
Battle Creek (1)	Emulsion Treating & Water Disposal	100%	6,000	6,000

Crude Oil Production Facilities

Area Name	Type of Facility	W.I. %	Gross Treating Capacity (Bbls/d)	W.I. Treating Capacity (Bbls/d)
Butte Unit	Emulsion Treating & Water Injection	25%	7,200	1,800
Cadogan (1)	Emulsion Treating & Water Disposal	100%	9,000	9,000
Chauvin (1)	Emulsion Treating & Water Disposal	95%	28,000	26,600
Chauvin South (1)	Emulsion Treating & Water Disposal	100%	5,000	5,000
David (1)	Emulsion Treating & Water Disposal	100%	30,000	30,000
Freda Lake	Emulsion Treating & Water Injection	30%	4,000	1,200
Gift	Emulsion Treating	24%	11,300	2,720
Giltedge (1)	Emulsion Treating & Water Disposal, Refrigeration, Compression	100%	30,000	30,000
Gleneath (1)	Emulsion Treating & Water Disposal	47%	3,000	1,398
Hayter	Emulsion Treating & Water Disposal	2%	110,800	2,560
Hayter	Emulsion Treating & Water Disposal	11%	83,100	8,970
Heward (1)	Emulsion Treating & Water Disposal	100%	18,000	18,000
Jenner	Emulsion Treating, Water Disposal & Solution Gas Compressing	15%	25,000	3,750
Joarcam (1)	Emulsion Treating & Water Injection	95%	2,800	2,660
Joarcam (1)	Emulsion Treating & Water Injection	82%	10,000	8,200
Kessler (1)	Emulsion Treating & Water Disposal	100%	6,000	6,000
Little Horse (1)	Emulsion Treating & Water Disposal	65%	13,775	8,954
Medicine Hat (1)	Emulsion Treating & Water Injection	44%	8,000	3,520
Medicine Hat (1)	Emulsion Treating & Water Injection	44%	4,000	1,760
Medicine River (1)	Emulsion Treating & Water Disposal	56%	2,000	1,120
Pembina Five-Way (1)	Emulsion Treating & Water Injection	100%	7,500	7,500
	Emulsion Treating & Water Injection	100%	1,250	1,250
	Emulsion Treating & Water Injection	100%	2,500	2,500
Pouce Coupe (1)	Emulsion Treating & Water Injection	49%	2,500	1,225
Progress (1)	Emulsion Treating & Water Injection	100%	2,000	2,000
Shorncliffe (1)	Emulsion Treating & Water Injection	66%	38,000	24,928
South Buck Lake (1)	Emulsion Treating & Water Injection	100%	1,800	1,800
Sylvan Lake (1)	Emulsion Treating & Water Disposal	100%	2,500	2,500
Valhalla (1)	Emulsion Treating & Water Disposal	86%	4,600	3,956

Note:
(1) Operated by Enerplus.

Natural Gas Production Facilities

Area Name	Type of Facility	W.I. %	Gross Processing Capacity (MMcf/d)	W.I. Processing Capacity (MMcf/d)
Bantry (1)	Compression & dehydration	92%	20.0	18.3
Bashaw (1)	Compression, dehydration & processing	27%	12.0	3.2
Botha Facility	Compression, refrigeration & dehydration	10%	16.7	1.7
Burnt Timber Gas Plant	Refrigeration, sweetening, sulphur recovery & stabilization/storage for pentanes plus	3%	128.1	4.2
Carson Creek	Sweetening & refrigeration	5%	87.0	4.2
Elmworth Gas Plant	Turboexpansion & ethane extraction	6%	575.0	34.9
Ferrier	Compression & refrigeration	29%	9.1	2.7
Ferrier (1)	Compression & dehydration	64%	6.0	3.8
Fox Valley (1)	Compression & dehydration	97%	8.0	7.7
Gilby	Sweetening, absorption & refrigeration	9%	71.0	6.4
Hanna Garden (1)	Compression & dehydration	84%	11.0	10.0
Hanna Garden (1)	Compression & dehydration	100%	11.0	11.0

Natural Gas Production Facilities

Area Name	Type of Facility	W.I. %	Gross Processing Capacity (MMcf/d)	W.I. Processing Capacity (MMcf/d)
Joarcam [(1)]	Compression, dehydration & processing	99%	5.5	5.4
Joarcam [(1)]	Compression, dehydration & processing	93%	10.0	9.3
Joarcam [(1)]	Compression, dehydration & processing	86%	9.5	8.2
Karr Gas Processing Plant	Turboexpansion & ethane extraction	2%	110.0	2.1
Komie [(1)]	Compression & dehydration	45%	6.0	2.7
Leo Gas Plant	Compression & refrigeration	21%	25.2	5.4
Medicine Hat [(1)]	Compression & dehydration	100%	8.0	8.0
Medicine Hat [(1)]	Compression & dehydration	100%	4.0	4.0
Medicine River [(1)]	Compression & dehydration	49%	3.5	1.7
Minnehik Buck Lake	Sweetening & absorption	8%	159.5	12.9
Pine Creek Gas Plant	Compression, refrigeration & dehydration	40%	16.0	6.4
Pine Creek [(1)]	Compression & dehydration	73%	12.0	8.8
Progress Gas Plant	Compression, sweetening, refrigeration & dehydration	10%	140.3	14.1
Ram River	Sweetening & refrigeration	2%	630.0	10.1
South Wapiti Gas Plant (Shallow Cut)	Compression, refrigeration & dehydration	1%	300.0	4.0
Sylvan Lake	Sweetening, refrigeration & absorption	14%	69.0	9.7
Sylvan Lake [(1)]	Compression & dehydration	100%	3.0	3.0
Valhalla [(1)]	Compression & dehydration	86%	6.0	5.2
Valhalla [(1)]	Compression, dehydration & processing	35%	6.0	2.1
Valhalla Burnt River Gas Processing	Compression, refrigeration & dehydration	11%	32.0	3.4
Verger [(1)]	Compression & dehydration	100%	12.0	12.0
Wapiti Deep Cut Plant	Turboexpansion & ethane extraction	3%	355.8	11.1
Wapiti Gas Plant (Shallow Cut)	Compression, refrigeration & dehydration	3%	120.0	3.5

Note:
(1) Operated by Enerplus.

Drilling Activities and Results

During 2001, Enerplus participated in the drilling of 546 gross wells (321.6 net wells) with a 99% net well success rate. The following table summarizes the number and type of wells that Enerplus drilled or participated in drilling for the years ended December 31, 2001 and 2000. Enerplus did not participate in drilling any exploratory wells in any such period. Other than wells designated as "Dry" in the table below, all wells described in the table are capable of production.

	Year Ended December 31,			
	2001		2000	
Development Wells	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]
Oil	104	37.7	103	33.5
Natural Gas	429	279.4	184	53.9
Dry	13	4.5	15	3.4
Total working interest wells [(3)]	546	321.6	302	90.8

Notes:
(1) "Gross" means the number of wells in which Enerplus has an interest.
(2) "Net" means the product of the total number of gross wells multiplied by Enerplus' percentage interest therein.
(3) In 2001, the pre-Merger Enerplus Resources Fund participated in the drilling of 14.6 net oil wells and 13.4 net natural gas wells, for a total of 28.0 net working interest wells, which are not included in the above table.

Oil and Natural Gas Wells and Lease Holdings

The following table summarizes, as at December 31, 2001, Enerplus' interests in producing and shut-in wells which it believes are capable of production, along with Enerplus' interests in undeveloped oil and natural gas leases and rights:

	Producing Wells				Shut-in Wells[1]				Acres	
	Oil		Natural Gas		Oil		Natural Gas		(000's)	
Area	**Gross[2]**	**Net[3]**	**Gross[2]**	**Net[3]**	**Gross[2]**	**Net[3]**	**Gross[2]**	**Net[3]**	**Gross[2]**	**Net[3]**
Alberta	2,642	1,131	3,732	1,725	489	162	306	97	820.0	408.6
British Columbia	34	12	87	19	11	3	44	13	118.7	51.5
Saskatchewan	2,325	478	305	211	376	103	8	1	36.6	25.6
Total	5,001	1,621	4,124	1,955	876	268	358	111	975.3	485.7

Notes:

(1) "Shut-In" wells means wells which are not producing but which may be capable of production. Shut-in wells in which Enerplus has an interest are located no further than 10 kilometres from gathering systems, pipelines or other means of transportation. See "Description of Principal Properties".

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

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

Reserves Reconciliation

The table below reconciles the oil and natural gas reserves of Enerplus from December 31, 2000 (being the reserves of EnerMark Income Fund at such time) to December 31, 2001.

	Crude Oil (Mbbls)		Natural Gas (MMcf)		NGLs (Mbbls)		Total (MBOE)		Established Reserves (MBOE)
	Proven	Probable[1]	Proven	Probable[1]	Proven	Probable[1]	Proven	Probable[1]	
Opening reserves as of December 31, 2000	57,221	31,036	655,416	183,532	11,399	3,062	177,856	64,687	210,199
Production	(7,516)	0	(64,485)	0	(1,452)	0	(19,716)	0	(19,716)
Acquisitions[2]	46,858	11,400	307,763	84,441	5,582	417	103,734	25,891	116,680
Divestments	(4,163)	(1,616)	(16,977)	(6,540)	(344)	(64)	(7,337)	(2,770)	(8,722)
Drilling, Development and Revisions	2,447	(3,177)	69,416	(744)	929	1,259	14,945	(2,043)	13,924
Year-end reserves as at December 31, 2001	94,847	37,643	951,133	260,689	16,114	4,674	269,482	85,765	312,365

Notes:

(1) No discount factor has been applied to the Probable Reserves to account for the risk associated with the probability of obtaining production from such reserves.

(2) Includes reserve acquisitions attributable to the Merger.

Historical Production Revenues

Gross production revenues (before deduction of royalties payable to others) for each of Enerplus' products during the years ended December 31, 2001 and 2000 are as follows:

	2001		2000	
	$ Million	**% of Total Revenue**	**$ Million**	**% of Total Revenue**
Crude Oil	$234.5	37%	$149.0	44%
NGLs	45.2	7%	25.0	7%
Natural gas	359.7	56%	169.2	49%
Total	$639.4	100%	$343.2	100%

Quarterly Production History

The following tables show Enerplus' average working interest sales volumes (before deduction of royalties payable to others) for each of the last eight fiscal quarters and the years then ended.

Average Daily Production

	2001				
	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total for Year**
Crude oil					
Light/medium (Bbls/d)	14,273	13,425	16,535	17,468	**15,437**
Heavy (Bbls/d)	4,513	4,561	5,933	5,593	**5,155**
Total crude oil (Bbls/d)	18,786	17,986	22,468	23,061	**20,592**
NGLs (Bbls/d)	3,127	3,936	4,559	4,272	**3,978**
Total liquids (Bbls/d)	21,913	21,922	27,027	27,333	**24,570**
Natural gas (Mcf/d)	152,367	149,201	199,823	204,467	**176,671**
Total (BOE/d)	47,308	46,789	60,331	61,411	**54,015**

	2000				
	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total for Year**
Crude oil					
Light/medium (Bbls/d)	6,236	7,558	7,762	8,610	**7,546**
Heavy (Bbls/d)	4,470	4,929	4,812	3,966	**4,543**
Total crude oil (Bbls/d)	10,706	12,487	12,574	12,576	**12,089**
NGLs (Bbls/d)	1,695	2,101	1,856	2,790	**2,111**
Total liquids (Bbls/d)	12,401	14,588	14,430	15,366	**14,200**
Natural gas (Mcf/d)	81,153	93,444	104,045	126,943	**101,473**
Total (BOE/d)	25,927	30,162	31,771	36,523	**31,112**

Quarterly Netback History

The following tables show Enerplus' average netbacks received for each of the last eight fiscal quarters and the years then ended.

Crude oil and NGLs Netbacks ($ per Bbl)

	Year Ended December 31, 2001				
	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total for Year**
Sales price	$35.13	$33.58	$33.62	$21.63	**$30.58**
Hedging gains (costs)	-	(0.78)	(0.63)	3.41	**0.61**
Royalties	(6.98)	(6.70)	(6.45)	(3.89)	**(5.91)**
Operating costs[1]	(5.90)	(6.49)	(7.89)	(8.28)	**(7.25)**
Netback	$22.25	$19.61	$18.65	$12.87	**$18.03**
Average selling price					
Crude oil					
Light/medium	$37.10	$36.86	$37.95	$24.04	**$33.55**
Heavy	$20.93	$22.34	$27.20	$14.39	**$21.27**
Total crude oil	$33.22	$33.18	$35.11	$21.70	**$30.48**
NGLs	$46.61	$35.44	$26.29	$21.23	**$31.12**

	Year Ended December 31, 2000				
	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total for Year**
Sales price	$34.81	$34.79	$38.90	$32.90	**$35.33**
Hedging gains (costs)	(1.57)	(1.58)	(2.10)	(2.13)	**(1.86)**
Royalties	(7.38)	(7.21)	(7.97)	(6.62)	**(7.28)**
Operating costs[1]	(4.74)	(6.05)	(6.33)	(6.53)	**(5.97)**
Netback	$21.12	$19.95	$22.50	$17.62	**$20.22**
Average selling price					
Crude oil					
Light/medium	$38.67	$37.36	$41.06	$36.49	**$38.34**
Heavy	$32.31	$32.32	$35.53	$25.79	**$31.74**
Total crude oil	$36.01	$35.37	$38.95	$33.11	**$35.86**
NGLs	$27.22	$31.37	$38.60	$31.95	**$32.33**

Natural Gas Netbacks ($ per Mcf)

	Year Ended December 31, 2001				
	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total for Year**
Sales price	$8.59	$5.81	$3.43	$3.01	**$4.91**
Hedging gains (costs)	(0.21)	0.01	1.03	1.51	**0.69**
Royalties	(2.46)	(1.60)	(0.92)	(0.39)	**(1.24)**
Operating costs[1]	(0.77)	(0.83)	(0.82)	(0.96)	**(0.85)**
Netback	$5.15	$3.39	$2.72	$3.17	**$3.51**

	Year Ended December 31, 2000				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total for Year
Sales price	$2.56	$3.18	$4.43	$6.81	**$4.52**
Hedging gains (costs)	0.08	(0.02)	(0.01)	0.10	**0.04**
Royalties	(0.69)	(0.69)	(1.25)	(1.73)	**(1.16)**
Operating costs[(1)]	(0.65)	(0.56)	(0.71)	(0.66)	**(0.65)**
Netback	$1.30	$1.91	$2.46	$4.52	**$2.75**

Note:

(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.

Quarterly Capital Expenditures

The ongoing capital expenditures of Enerplus are financed through the issuance of additional Trust Units, bank borrowing, the withholdings of amounts from cash distributions to unitholders and the use of working capital. The following table summarizes Enerplus' capital expenditures in the categories and for the periods indicated.

	2001				
($ 000's)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total for Year**
Development drilling and completions	$ 8,529	$19,218	$25,941	$29,316	**$ 83,004**
Plant and facilities	14,006	6,981	15,190	17,417	**53,594**
Office and other expenditures	1,448	2,899	771	1,564	**6,682**
	23,983	29,098	41,902	48,297	**143,280**
Producing property acquisitions	367	2,388	57,214	17,463	**77,432**
Total capital expenditures	24,350	31,486	99,116	65,760	**220,712**
Property dispositions	(9,427)	(10,548)	(34,826)	(13,695)	**(68,496)**
Net capital expenditures	$14,923	$20,938	$64,290	$52,065	**$152,216**

	2000				
($ 000's)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total for Year**
Development drilling and completions	$ 9,306	$ 3,803	$ 4,731	$ 9,262	**$27,102**
Plant and facilities	1,189	5,417	1,730	3,525	**11,861**
Office and other expenditures	461	140	221	211	**1,033**
	10,956	9,360	6,682	12,998	**39,996**
Producing property acquisitions	37,168	3,196	7,659	3,086	**51,109**
Total capital expenditures	48,124	12,556	14,341	16,084	**91,105**
Property dispositions	(481)	(5,121)	(7,385)	(12,274)	**(25,261)**
Net capital expenditures	$47,643	$7,435	$6,956	$3,810	**$65,844**

Exploration and Development

The primary focus of Enerplus is to pursue growth opportunities through the development of existing reserves, the monetization of Enerplus' exploratory lands and the acquisition of new properties. High risk exploration plays, as well as Enerplus' undeveloped acreage, will continue to be farmed out, sold, or exchanged for producing properties with upside potential. Development efforts will be concentrated on optimizing production from existing and new reserves, and developing new properties in a cost effective manner. Enerplus will continue its ongoing property rationalization program and any sale proceeds may be used to acquire interests in core areas or new prospects with exploitation opportunities.

Marketing Arrangements

No individual customer accounts for more than 10% of Enerplus' crude oil, NGLs or natural gas production.

Crude oil and NGLs

Enerplus' crude oil and NGLs production are marketed to a diverse portfolio of intermediaries and end users. Enerplus received an average price before hedging of $30.48/Bbl for its crude oil and $31.12/Bbl for its NGLs for the year ended December 31, 2001, compared to $35.86/Bbl for crude oil and $32.33/Bbl of NGLs for the year ended December 31, 2000.

Natural Gas

In marketing its natural gas production, Enerplus' efforts are directed to achieve a mix of contracts, customers and geographic markets. Enerplus' percentage of revenues attributable to natural gas has risen over the past five years from 30% in 1997 to 56% in 2001. The average price received by Enerplus, before hedging, for its natural gas in 2001 was $4.91/Mcf compared to $4.52/Mcf in the year ended December 31, 2000.

Future Commitments

Enerplus uses various types of financial instruments and fixed price physical sales contracts to manage the risk related to fluctuating commodity prices. Absent such hedging activities, the crude oil, NGLs and natural gas production of Enerplus is sold into the open market at prevailing spot prices, which exposes Enerplus to the risks associated with commodity price fluctuations. See "Risk Factors - Oil and Natural Gas Prices". Information regarding Enerplus' financial instruments is contained in Note 8 to Enerplus' audited annual consolidated financial statements for the year ended December 31, 2001 and under the heading "Pricing and Price Risk Management" in the Fund's management discussion and analysis for the year ended December 31, 2001 and which is contained on page 36 of the Fund's 2001 Annual Report, both of which are incorporated herein by reference.

Enerplus has firm commitments for gathering, processing and transmission services that require Enerplus to deliver certain minimum quantities of crude oil and NGLs and natural gas to third parties or pay the corresponding tariffs. With respect to natural gas, Enerplus has contracted to transport 10 MMcf/day of natural gas into Chicago on the Foothills and Northern Border pipelines until October 31, 2008. It has also agreed to transport 5 MMcf/day to Marshfield, Illinois on the TransCanada and Viking pipelines until October 31, 2008. In addition, Enerplus has pipeline commitments to transport 5 MMcf/day into Chicago on the Alliance Pipeline until October 31, 2015.

Impact of Environmental Protection Requirements

Enerplus carries out its activities and operations in compliance with all relevant and applicable environmental regulations and good industry practice. See "Information Respecting Enerplus Resources Fund - Operations of Enerplus - Environmental Obligations". At present, Enerplus believes that it meets all existing environmental standards and regulations and has included appropriate amounts in it capital expenditure budget to continue to meet environmental protection requirements. The costs incurred by Enerplus for compliance with environmental matters and site restoration costs amounted to approximately 2% of the total development expenditures incurred by Enerplus in 2001. Since the environmental standards and regulations to which Enerplus is subject apply to all participants in the oil and gas industry, it is not anticipated that Enerplus' competitive position within the industry will be adversely affected. See "Risk Factors - Environmental Concerns".

OIL AND NATURAL GAS RESERVES

Sproule Associates Limited, a firm of independent petroleum engineers, has evaluated Enerplus' "major" properties which comprise approximately 86% of Enerplus' proven developed producing crude oil and gas reserve value discounted at 12%, and 83% of Enerplus' proven plus probable oil and gas reserves value discounted at 12%.

Enerplus has evaluated the balance of the properties using similar evaluation parameters, including the same escalated price forecasts utilized by Sproule and are included as "minor" properties in the Sproule Report. The constant price cases contained herein were extracted from a separate report prepared by Sproule dated March 7, 2002 which was based upon the escalated case Sproule Report.

In preparing its report, Sproule obtained basic information from Enerplus, which included land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans. Other engineering, geological or economic data required to conduct the evaluation and upon which the Sproule Report is based, was obtained from public records, other operators and from Sproule's non-confidential files. Information concerning the extent and character of ownership of Enerplus' interests and the accuracy of all factual data supplied to Sproule by third parties was accepted by Sproule as represented and neither title searches nor field inspections were conducted.

Enerplus follows the Canadian practice of reporting gross production and reserve volumes, which are prior to the deduction of royalties and similar payments. In the United States, production and reserve volumes are reported after deducting these amounts. The Canadian practice of using escalating prices and costs when estimating the quantities of reserves is also followed by Enerplus. In the United States, reserve estimates are calculated using prices and costs held constant at amounts in effect at the date of the reserve report. Enerplus also follows the Canadian practice of using "Established Reserves", which include proved reserves and the probable reserves portion that has been reduced by a risk factor of 50%. As a consequence, our production volumes and reserve estimates may not be comparable to those made by United States companies.

The following is a summary, as at January 1, 2002, of Enerplus' crude oil, NGLs and natural gas reserves attributable to Enerplus' properties and the present worth value of the estimated future net cash flows associated with such reserves, based on escalated and constant price and cost assumptions. The tables summarize the data contained in the evaluations and as a result may contain slightly different numbers than the evaluations due to rounding. **All future cash flows are stated prior to provision for income taxes, interest, general and administrative expenses and management fees and indirect costs and after deduction of royalties and estimated future capital expenditures. It should not be assumed that the present worth of estimated future cash flows shown below is representative of the fair market value of the reserves. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of Enerplus' crude oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein. The probable additional reserve volumes and the present value of estimated future cash flows from such reserves as shown in the tables have been reduced by a factor of 50% to account for risk.**

Oil and Natural Gas Reserves and Present Value of Estimated Future Cash Flows Including ARTC Based on Escalated Price Assumptions(11)

	Working Interest Reserves(1)						Present Value of Estimated Future Net Cash Flow, $000 Discounted at Rates of:			
	Gross			Net						
	Oil Mbbls	Gas MMcf	NGLs Mbbls	Oil Mbbls	Gas MMcf	NGLs Mbbls	0%	10%	15%	20%
Proven Reserves(2)										
Developed Producing(3)(4)	86,770	722,692	13,685	78,085	570,157	9,567	2,992,588	1,376,940	1,116,058	946,568
Developed Non-Producing(3)(5)	620	58,791	512	540	47,233	352	157,757	78,807	63,970	54,201
Undeveloped (6)	7,457	169,650	1,917	6,311	142,109	1,347	401,713	170,532	118,996	84,367
Total Proven Reserves	94,847	951,133	16,114	84,936	759,499	11,266	3,552,058	1,626,279	1,299,024	1,085,136
Probable Reserves at 50% (7)	18,821	130,345	2,337	15,830	106,940	1,657	644,955	159,099	106,027	75,323
Established Reserves	113,668	1,081,478	18,451	100,766	866,439	12,923	4,197,013	1,785,378	1,405,051	1,160,459

Oil and Natural Gas Reserves and Present Value of Estimated Future Cash Flows Including ARTC Based on Constant Price Assumptions[12]

	Working Interest Reserves[1]						Present Value of Estimated Future Net Cash Flow, $000 Discounted at Rates of:			
	Gross			Net						
	Oil Mbbls	Gas MMcf	NGLs Mbbls	Oil Mbbls	Gas MMcf	NGLs Mbbls	0%	10%	15%	20%
Proven Reserves[2]										
Developed Producing[3][4]	81,222	708,955	13,485	73,302	558,990	9,432	2,040,855	1,088,148	904,741	781,039
Developed Non-Producing[3][5]	604	57,899	508	527	46,461	349	110,681	62,525	52,084	44,929
Undeveloped [6]	7,397	166,003	1,730	6,320	139,485	1,218	265,004	111,269	74,803	49,828
Total Proven Reserves	89,223	932,857	15,723	80,149	744,936	10,999	2,416,540	1,261,942	1,031,628	875,796
Probable Reserves at 50%[7]	16,662	129,770	2,334	14,138	106,548	1,656	336,976	100,586	67,464	47,619
Established Reserves	105,885	1,062,627	18,057	94,287	851,484	12,655	2,753,516	1,362,528	1,099,092	923,415

Notes:

(1) "Gross Reserves" are the remaining reserves owned by Enerplus, before deduction of any royalties. "Net Reserves" are the gross remaining reserves of the properties in which Enerplus has an interest, less all royalties and interests owned by others.

(2) "Proven Reserves" are those quantities of oil, natural gas and natural gas by-products, which, upon analysis of geologic and engineering data, appear with a high degree of certainty to be recoverable at commercial rates in the future from known oil and natural gas reservoirs under current economic and operating conditions for reserves based on constant price and cost assumptions, and presently anticipated economic and operating conditions for the reserves based on escalated price and cost assumptions. There is relatively little risk with these reserves.

(3) "Proven Developed Reserves" are Proven Reserves which can be expected to be recovered through existing wells with existing equipment and operating methods.

(4) "Proven Developed Producing Reserves" are Proven Reserves which are presently being produced from completion intervals open for production in existing wells. As at January 1, 2002, these reserves were on production and represent approximately 76% of Enerplus' total proven and risked probable oil and NGLs reserves and 67% of Enerplus' total proven and risked probable natural gas reserves.

(5) "Proven Developed Non-producing Reserves" are Proven Reserves which are currently not being produced but do exist in completed intervals but not producing in existing wells, behind casing in existing wells or at minor depths below the present bottom of existing wells. These Proven Reserves are expected to be produced through the existing wells in the predictable future. These reserves are classified as Proven Developed Reserves since the cost of making such reserves available for production is relatively small compared to the cost of a new well.

(6) "Proven Undeveloped Reserves" are Proven Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where relatively major expenditures are required for the completion of these wells or for the installation of processing and gathering facilities prior to the production of these reserves. Reserves on undrilled acreage are limited to those drilling units offsetting productive wells that are reasonably certain of production when drilled.

(7) "Probable Reserves" are those reserves which may be recoverable as a result of the beneficial effects which may be derived from the future institution of some form of pressure maintenance or other secondary recovery method, or as a result of a more favourable performance of the existing recovery mechanism than that which would be deemed proven at the present time, or those reserves which may reasonably be assumed to exist because of geophysical or geological indications and drilling done in regions which contain proven reserves. **Probable reserve values for the petroleum and natural gas properties and the future net cash flow from probable reserves have been discounted by a factor of 50% to account for the risk associated with the probability of obtaining production from such reserves**.

(8) Includes the ARTC based on current legislation in place on January 1, 2002.

(9) Natural gas reserves are reported at a base pressure of 14.65 pounds per square inch and a base temperature of 60º F.

(10) Prices for oil F.O.B. Edmonton are based upon 40º API oil having less than 0.4% sulphur. Prices for natural gas are based upon a base pressure of 14.65 pounds per square inch and base temperature of 60ºF. The wellhead oil prices were adjusted for quality and transportation to reflect the actual price to be received. The natural gas prices were adjusted, where necessary, only for heating values and the differing costs of service applied by various purchasers. The natural gas liquids prices were adjusted to reflect current prices received.

(11) The escalated price and cost case assumes the continuance of current laws and regulations, and any increase in selling prices also takes inflation into account. The product price forecasts used are as follows:

Year	WTI Cushing Oklahoma (US$/bbl)	Edmonton Par Price 40° API ($/bbl)	Natural Gas Liquids: Plant Gate Ethane ($/bbl)	Natural Gas Liquids: Edmonton Propane ($bbl)	Natural Gas Liquids: Edmonton Butane ($/bbl)	Natural Gas Liquids: Edmonton Pentanes ($/bbl)	Natural Gas Plant Gate: Alberta ($/MMBTU)	Natural Gas Plant Gate: Sask. ($/MMBTU)	Natural Gas Plant Gate: B.C. ($/MMBTU)
2002	19.90	29.86	10.54	16.73	17.81	30.59	3.63	3.70	3.75
2003	20.64	30.96	12.04	17.34	18.46	31.71	4.18	4.25	4.30
2004	21.12	31.67	12.08	17.74	18.88	32.43	4.19	4.26	4.26
2005	21.44	32.15	12.08	18.01	19.17	32.93	4.18	4.26	4.26
2006	21.76	32.65	12.29	18.29	19.47	33.44	4.25	4.34	4.34
2007	22.08	33.14	12.51	18.56	19.76	33.94	4.32	4.41	4.41
2008	22.42	33.65	12.73	18.85	20.06	34.46	4.40	4.49	4.49
2009	22.75	34.16	12.95	19.13	20.37	34.98	4.48	4.57	4.57
2010	23.09	34.68	13.18	19.42	20.68	35.51	4.57	4.66	4.66
2011	23.44	35.20	13.41	19.72	20.99	36.05	4.65	4.74	4.74
2012	23.79	35.74	13.64	20.02	21.31	36.60	4.73	4.82	4.82
2013	24.15	36.28	13.87	20.32	21.63	37.15	4.82	4.91	4.91

Escalation Rate of 1.5% thereafter

(12) The constant price and cost case assumes the continuance of product prices at December 31, 2001 and operating costs projected for 2002, and the continuance of current laws and regulations. Product prices have not been escalated beyond this date nor have operating and capital costs been increased on an inflationary basis. The annual revenue to be received from the production of the reserves was based on the following prices:

Oil	Edmonton Par Price 40° API ($/bbl)	$30.35
Natural Gas:	Alberta ($/MMBTU)	$3.58
	Saskatchewan ($/MMBTU)	$3.80
	British Columbia ($/MMBTU)	$3.90
Natural Gas Liquids:	Ethane ($/bbl)	$9.91
	Propane ($/bbl)	$13.34
	Butane ($/bbl)	$15.47
	Pentanes ($/bbl)	$30.14

(13) Capital expenditures required to achieve the future net revenue attributable to Proven Reserves in the escalated price and cost case were estimated to be $256.6 million, of which $94.7 million is required in 2002 and $33.2 million is required in 2003. Capital expenditures required to achieve the future net revenue attributable to Probable Reserves in the escalated price and cost case are estimated to be $146.2 million, of which $23.3 million is required in 2002 and $24.8 million is required in 2003.

(14) Capital expenditures required to achieve the future net revenue attributable to Proven Reserves in the constant price and cost case are estimated to be $210.4 million of which $93.6 million is required in 2002 and $31.5 million is required in 2003. Capital expenditures required to achieve the future net revenue attributable to Probable Reserves in the constant price and cost case are estimated to be $125.9 million, of which $18.3 million is required in 2002 and $24.9 million is required in 2003.

(15) "Estimated Future Net Production Revenue" has been calculated before deduction of income tax. **The present worth of estimated Future Net Production Revenue is not to be construed as fair market value.**

Estimated Future Net Pre-Tax Cash Flows Established Reserves[1]
Escalating Cost and Price Case
($000's except for production)

Year	Annual Production (MBOE)	Company Interest Revenue[2]	Royalty Burdens	Net Revenue After Royalty Burdens	Operating Expenses	Net Production Revenue[3]	Net Capital Investment	Net Cash Flow Before Income Taxes[4][5]
2002	24,399	514,970	104,457	410,513	125,938	284,575	106,359	178,216
2003	24,692	589,474	119,780	469,694	132,208	337,486	45,588	291,899
2004	22,876	561,889	109,335	452,555	131,308	321,247	43,511	277,736
2005	20,683	513,592	97,039	416,553	127,491	289,062	14,198	274,864
2006	18,491	470,253	86,801	383,452	122,915	260,537	2,201	258,336
2007	16,430	426,571	77,405	349,166	117,344	231,822	3,010	228,813
2008	14,553	386,389	68,896	317,493	110,064	207,429	2,849	204,581
2009	12,984	351,184	61,297	289,887	104,026	185,861	3,315	182,547
2010	11.717	322,868	55,542	267,326	99,092	168,234	2,578	165,657
2011	10,747	299,798	51,358	248,440	92,323	156,118	2,445	153,673
Remaining	134,793	5,179,032	686,554	4,492,477	2,408,114	2,084,362	103,666	1,980,691
TOTAL:	312,365	9,616,020	1,518,464	8,097,556	3,570,823	4,526,733	329,720	4,197,013

Cash Flow Before Income Taxes Discounted to January[5] 1, 2002 at:

10%: $1,785,378
15%: $1,405,051
20%: $1,160,459

Notes:

(1) Proven Reserves plus 50% Probable Reserves.
(2) Includes working interest revenue, royalty interest revenue and third party processing and other income.
(3) Company interest revenue less royalty burdens and operating expenses.
(4) Undiscounted.
(5) Cash flow before income taxes is stated prior to interest, general and administrative expenses and management fees.

Estimated Future Net Pre-Tax Cash Flows Established Reserves[1]
Constant Cost and Price Case
($000's except for production)

Year	Annual Production (MBOE)	Company Interest Revenue[2]	Royalty Burdens	Net Revenue After Royalty Burdens	Operating Expenses	Net Production Revenue[3]	Net Capital Investment	Net Cash Flow Before Income Taxes[4][5]
2002	24,345	510,297	105,267	405,030	125,170	279,861	102,709	177,152
2003	24,396	514,492	105,493	408,999	127,671	281,328	44,010	237,318
2004	22,584	477,030	93,116	383,914	124,712	259,202	41,109	218,093
2005	20,353	429,537	80,889	348,648	118,143	230,505	14,379	216,126
2006	18,018	382,047	69,835	312,212	109,646	202,566	3,677	198,890
2007	15,928	338,224	60,552	277,672	101,625	176,047	3,228	172,819
2008	14,091	299,450	52,471	246,979	93,447	153,533	2,215	151,318
2009	12,619	268,541	45,939	222,602	87,928	134,675	1,969	132,706
2010	11,370	242,054	40,793	201,261	82,404	118,857	2,022	116,835
2011	10,445	221,358	37,027	184,331	75,908	108,424	2,335	106,089
Remaining	126,898	2,815,009	375,708	2,439,301	1,357,476	1,081,821	55,650	1,026,170
TOTAL:	301,047	6,498,039	1,067,090	5,430,949	2,404,130	3,026,819	273,303	2,753,516

Cash Flow Before Income Taxes Discounted[5] to January 1, 2002 at:

10%: $1,362,528
15%: $1,099,092
20%: $923,415

Notes:

(1) Proven Reserves plus 50% Probable Reserves.
(2) Includes working interest revenue, royalty interest revenue and third party processing and other income.
(3) Company interest revenue less royalty burdens and operating expenses.
(4) Undiscounted.
(5) Cash flow before income taxes is stated prior to interest, general and administrative expenses and management fees.

INFORMATION RESPECTING ENERPLUS RESOURCES FUND

Operations of Enerplus

Management Policies and Acquisition Strategy

EGEM manages the Fund, EnerMark, Enerplus and any other of the Fund's subsidiaries pursuant to the Management Agreement. The board of directors of EnerMark, as the publicly-elected body which oversees the business and affairs of Enerplus, has retained EGEM to provide comprehensive management services and has delegated certain authority to EGEM to administer and regulate the day-to-day operations of Enerplus and to make executive decisions which conform to general policies and general principles established by the board of directors of EnerMark. The Management Agreement also provides that EGEM is to undertake all matters pertaining to the properties on behalf of Enerplus' operating subsidiaries. All activities undertaken by EGEM are directed towards maximizing distributable income to the unitholders while at the same time striving for long-term growth in the value of the assets of Enerplus. These two objectives are fundamental to the operation of Enerplus and are balanced to maximize benefit to the unitholders. Enerplus ensures that EGEM utilizes its extensive experience and employs prudent oil and gas business practices to increase the value of the assets of Enerplus through the acquisition of producing oil and gas properties.

Enerplus selectively acquires producing oil and natural gas properties with development opportunities that are considered to be of a low risk nature in the oil and gas industry. Credit facilities are maintained which enable Enerplus to pursue the purchase of additional properties as opportunities arise.

EGEM may present Enerplus with opportunities to acquire properties and assets which Enerplus may be interested in acquiring and which are consistent with the guidelines for acquisitions which may be established from time to time by the board of directors of EnerMark. In addition, as part of the services provided by EGEM to Enerplus, EGEM may recommend that Enerplus enter into agreements to dispose of oil and natural gas properties and make farmouts and other dispositions of such properties. Any asset or property acquisition or disposition with a value of greater than $10 million requires the approval of the directors of EnerMark.

Enerplus ensures that the strategy employed by EGEM maximizes the level of sustainable production of oil and natural gas from Enerplus' existing properties and supplements production by reserve acquisitions and development. Capital expenditures are focused on development activity as opposed to exploration. Certain exploration properties may be sold, farmed out or developed emphasizing the use of third party resources.

Distributable Income

Unitholders of record on a distribution record date, currently established by Enerplus as the 10th of each calendar month (with the exception of January, for which the distribution record date is December 31st of the prior year), will be entitled to receive distributions which are paid by Enerplus to those unitholders on the corresponding distribution payment date, currently established as the 20th of each calendar month. Each unitholder's share of the income distributed by the Fund is equal to the proportionate share per Trust Unit multiplied by the number of Trust Units owned of record by the unitholder on that distribution record date. Distributable income consists of both the net income of the Fund (being all royalty, interest, dividend and other income received by the Fund from its operating subsidiaries less all expenses of the Fund (including the general and administrative expenses of the Fund) chargeable against that income) and the net realized capital gains of the Fund. Enerplus may, on or before any distribution record date, declare payable to the unitholders on that distribution record date, all or any part of the net income and net realized capital gains of the Fund to the extent not previously declared payable, for that period ending on the distribution record date. On December 31 of each fiscal year, an amount equal to the net income of the Fund for such fiscal year determined in accordance with the *Income Tax Act* (Canada) (other than paragraph 82(1)(b) thereof) plus any net realized capital gains of the Fund, to the extent that either is not previously declared payable by Enerplus to its unitholders in such fiscal year, shall be payable to unitholders immediately prior to the end of that fiscal year. Notwithstanding the foregoing, the amount of net income and net realized capital gains of the Fund that is determined to be required to be retained by the Fund in order to pay any tax liability of the Fund shall not be payable by the Fund to unitholders.

See "Distributions to Unitholders" for the past cash distributions made or declared to unitholders of Enerplus.

Environmental Obligations

Enerplus emphasizes the importance of creating and maintaining a safe and environmentally sound operation by focusing on proper training of field operators, continuous and thorough review of operating procedures and policies conducted by the field operations staff and management and by monitoring and ensuring compliance with safety and environmental regulations.

Enerplus regularly conducts safety and environment training for the field foremen and operations staff, who then implement this training in the field with employees and other operators. Production optimization, operator training and development, and orientation programs are held which include such topics as emergency response, media relations, first aid and CPR, and oil spill training. Occupational health and safety, environmental regulations, site remediation and waste handling training are also included to continually improve the knowledge and expertise of the personnel employed by EGEM to oversee the operations of Enerplus.

Acquisition Due Diligence

Enerplus conducts thorough due diligence on all prospective acquisitions. Site inspections, file reviews and soil and ground-water sampling, if required, are conducted by environmental consultants and/or an internal team from Enerplus. Potential contamination and operational issues are identified at this stage to help protect Enerplus from purchasing properties with significant environmental liabilities.

Site Inspections Program

As part of its regular due diligence program, Enerplus conducts both internal and third party site inspections at selected facilities each year. In addition, in 2001 Enerplus implemented an inspection program for construction and drilling projects. These inspections review issues relating to environment and safety regulations, industry practices and company and operational practices.

Spill and Incident Control

Enerplus field staff are required to report all spills, incidents and near misses to the Environment and Safety department for review. The review of such incidents allows Enerplus to determine the factors responsible and assist in the identification of other similar situations prior to any incidents occurring. Overall, Enerplus is confident that the program will reduce the occurrence of spills and prevent future losses.

Air Emissions - Flaring and Benzene

The Alberta Energy and Utilities Board (the "EUB") released flaring guidelines which require that companies work to reduce and improve the efficiency of solution gas flaring and consult with residents, especially those living within 500 metres of solution gas flare installations at crude oil or crude bitumen batteries. Enerplus has been actively reviewing all its flare sites and is confident that it will meet the EUB guidelines as required by the end of 2002.

Enerplus implemented monitoring of its glycol dehydrators as part of the voluntary program for addressing benzene emissions in its operations. Enerplus had previously begun the inventory and calculation of benzene emissions, however, due to new acquisitions in 2000 and 2001, additional properties required investigation. Information has been collected on all glycol dehydrators and those that do not meet the guidelines will require additional investigation by a third party consultant, towards retrofitting them to bring them into compliance in 2002. Others will continue to be monitored to ensure they remain within compliance of the guidelines.

Insurance

Enerplus carries insurance coverage to protect its assets at or above the standards applied within the oil and natural gas industry. Coverages are determined and placed by Enerplus subsequent to giving consideration to the perceived risk of loss, limit of coverage determined appropriate and the cost of coverages. Coverages currently in place include protection against third party liability, property damage or loss, and, for certain properties, business interruption. In addition, director and officer liability coverage is also carried for directors and officers acting in good faith in these capacities on behalf of Enerplus.

Borrowing

The Fund may, provided that the approval of the board of directors of EnerMark has been obtained, borrow, incur indebtedness, give any guarantee or enter into any subordination agreement on behalf of the Fund or of any other person, or pledge or provide any security interest or encumbrance on any property of the Fund. At present, all indebtedness of Enerplus is incurred directly by its primary operating entity, EnerMark. Details of these banking arrangements are contained in Note 3 of Enerplus' audited annual consolidated financial statements for the year ended December 31, 2001 and under the heading "Liquidity and Capital Resources" in Enerplus' management discussion and analysis, contained on page 45 of the Fund's 2001 Annual Report, each of which sections is incorporated herein by reference.

Records

EGEM, on behalf of the Trustee, keeps such books and records as are necessary for the proper recording of the business transactions of the Fund. These records are, as nearly as practicable, in accordance with those required to be maintained by a distributing corporation incorporated under the *Business Corporations Act* (Alberta). Unitholders shall at all times have access to such records to the same extent as though they were shareholders of such a corporation. All such records are kept by EGEM at its office in Calgary, Alberta.

Personnel

As at December 31, 2001, Enerplus (including the personnel of EGEM who devote a significant portion of their time to the affairs of Enerplus) employed a total of 391 persons.

<u>Description of the Trust Units and the Trust Indenture</u>

General

The Fund is authorized to issue an unlimited number of Trust Units pursuant to the Trust Indenture. The Trust Units represent equal undivided beneficial interests in the Fund. All Trust Units share equally in all distributions from the Fund and all Trust Units carry equal voting rights at meetings of unitholders. No unitholder will be liable to pay any further calls or assessments in respect of the Trust Units. No conversion or pre-emptive rights attach to the Trust Units.

The Trust Indenture provides that the directors of EnerMark may from time to time authorize the creation and issuance of rights, warrants or options to subscribe for Trust Units or other securities convertible or exchangeable into Trust Units, on the terms and conditions as the directors of EnerMark may determine. A right, warrant, option or other security is not considered to be a Trust Unit and a holder of such securities is not considered to be a unitholder of Enerplus. Additionally, the directors of EnerMark may authorize the creation and issuance of debentures, notes and other evidences of indebtedness of the Fund on such terms and conditions as the directors of EnerMark may determine.

The Trust Indenture, among other things, provides for the investment of the Fund's assets, the calculation and payment of distributions to unitholders, the calling of and conduct of business at meetings of unitholders, the appointment and removal of the Trustee, redemptions of Trust Units and the payment of distributions by the Fund to its unitholders. Among other things, material amendments to the Trust Indenture, the early termination of the Fund and the sale or transfer of all or substantially all of the property of the Fund require the approval by extraordinary resolution (i.e., 66 2/3% of the votes cast) of the unitholders. See "Meetings and Voting" and "Amendments to the Trust Indenture" below.

The following is a summary of certain provisions of the Trust Indenture. For a complete description, reference should be made to the Trust Indenture, copies of which may be viewed at the offices of, or obtained from, the Trustee. See "Reporting to Unitholders".

The Trustee

CIBC Mellon Trust Company is the trustee of the Fund. The Trustee possesses and may exercise all rights, powers and privileges pertaining to the ownership of the Fund's assets to the same extent as an individual or beneficial owner might. Additionally, the Trustee is responsible for, among other things, (i) effecting payment of distributions to the Fund's unitholders; (ii) maintaining records and providing timely reports to unitholders, and (iii) performing functions related to supervision and activities of the Fund. The Trustee may also delegate any or all of its management or administrative powers and, pursuant to the Trust Indenture and the Management Agreement, has retained EGEM to effect the actual administration of its duties under the Trust Indenture. However, the Trustee continues to ultimately be responsible for the performance of these duties.

The Trustee shall be removed by notice in writing delivered by EnerMark to the Trustee if the Trustee fails to meet certain criteria stated within the Trust Indenture or with the approval of at least 66 2/3% of the votes cast at a meeting of unitholders duly called for that purpose. The Trustee or any successor may resign upon 60 days notice to EnerMark. Such resignation or removal shall become effective upon the acceptance of appointment by a successor trustee. If the Trustee is removed by EnerMark, EnerMark shall promptly appoint a successor trustee. If the Trustee resigns or is removed by unitholders, its successor must be approved by unitholders. If a successor trustee does not accept its appointment as trustee, a court may appoint the successor trustee.

The Trust Indenture provides that the Trustee shall exercise the powers and discharge the duties of its office honestly, in good faith and in the best interests of the Fund and its unitholders and shall exercise the degree of care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.

The Trustee will not be liable for any action taken in good faith in reliance on *prima facie* properly executed documents or for the disposition of monies or securities, nor shall it be liable or responsible in any way for depreciation or loss incurred by reason of the sale of any security or for any inaccuracy in any advice or action of EGEM or any authorized delegate. These provisions, however, shall not protect the Trustee in cases of wilful misfeasance, bad faith, negligence or disregard of its obligations and duties nor shall it protect the Trustee in any case where the Trustee fails to act in accordance with the standard of care described above. The Trustee may retain an expert or advisor in connection with the performance of its duties under the Trust Indenture and may act or refuse to act on the advice of any such expert or advisor without liability. The Trustee, where it has met its standard of care, shall be indemnified out of the assets of the Fund for any taxes or other governmental charges imposed upon the Trustee in consequence of its performance of its duties but shall have no additional recourse against the Fund's unitholders. In addition, the Trust Indenture contains other customary provisions limiting the liability of the Trustee.

Investments of the Fund

The Fund is a limited purpose trust which is restricted to investing in investments or properties described in Section 132(6)(b) of the *Income Tax Act* (Canada) including, without limitation, any investments or property acquired directly or indirectly from the issue of Trust Units. However, the Fund cannot hold property or investments which would result in the Fund not being either a "unit trust" or a "mutual fund trust", or which would cause the Trust Units to be foreign property, for the purposes of the *Income Tax Act* (Canada). At present, the sole assets of the Fund are all of the outstanding shares of EnerMark (which owns all of the shares of ERC), unsecured indebtedness issued to the Fund by EnerMark and the 95% and 99% royalty interests issued to the Fund by EnerMark and ERC, respectively. The Fund may invest cash which is not being used immediately for the purposes required in the Trust Indenture in short term financial instruments guaranteed by a Canadian chartered bank or the federal or a provincial government of Canada.

Distributions of Distributable Income

The Fund's distributable income is distributed to the unitholders by EGEM on behalf of the Fund on the date which is either on or within 30 days after (and in the same calendar year as) the corresponding distribution record date. The Fund has established the 10th day of each calendar month as a distribution record date and the 20th day of such month as the corresponding distribution payment date, with the exception of the January 20th payment date which is preceded by a record date of December 31st. See "Information Respecting Enerplus Resources Fund – Operations of Enerplus - Distributable Income" and "Distributions to Unitholders". In certain circumstances, including where the Fund does not have sufficient cash to pay the full distribution to be made on a distribution payment date, the distribution payable to unitholders may, at the option of the Trustee, include a distribution of Trust Units having a value equal to the cash shortfall.

Meetings and Voting

At all meetings of the Fund's unitholders, each holder is entitled to one vote in respect of each Trust Unit held. Meetings of the unitholders may be called on not less than 21 days and not more than 50 days notice and may be called at any time by the Trustee and shall be called by the Trustee and held annually or upon written request of unitholders holding in the aggregate not less than 20% of the Trust Units. All activities necessary to organize any such meeting will be undertaken by EGEM on behalf of the Trustee.

Unitholders may attend and vote at all meetings of the unitholders either in person or by proxy, and a proxy holder does not have to be a unitholder. Two persons present in person or represented by proxy and representing no less than 5% of the votes attached to all outstanding Trust Units will constitute a quorum for the transaction of business at such meetings. If a quorum is not present at any such meeting, the meeting shall stand adjourned until at least one day later and to such place and time as the chairman of the meeting determines, and the unitholders present in person or by proxy at such adjourned meeting shall constitute a quorum for the transaction of any business which might have been dealt with at the original meeting in accordance with the notice calling the original meeting.

Under the Trust Indenture and other material agreements of Enerplus, the Fund's unitholders are entitled to nominate all but three of the directors of EnerMark and to nominate the auditors of the Fund. Certain matters, such as the removal or appointment of the Trustee, making material amendments to the Trust Indenture, the termination of the Fund or the sale of all or substantially all of the property of the Fund, must be approved by at least 66 2/3% of the votes cast at a duly called meeting of unitholders. Provided due and proper notice to unitholders is given in accordance with the Trust Indenture, a resolution executed by unitholders holding the requisite number of the outstanding Trust Units entitled to vote shall have the same effect as if it had been passed by that percentage of votes cast at a duly called meeting of unitholders.

Redemption Right

Each unitholder is entitled to require the Fund to redeem at any time or from time to time, at the demand of the unitholder, all or any part of the Trust Units registered in the name of the unitholder at a price per Trust Unit equal to the lesser of:

(a) 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 day trading period commencing immediately after the date on which the Trust Units were tendered to the Fund for redemption; and

(b) the closing market price on the principal market on which the Trust Units are quoted for trading, on the date that the Trust Units were so tendered for redemption.

Management of the Fund

The Trust Indenture provides the Trustee with certain powers and authorities with respect to the Fund and its assets. See "Description of the Trust Units and The Trust Indenture - The Trustee" above. Additionally, the Trust Indenture provides that the Trustee may grant or delegate such authority as the Trustee may in its sole discretion deem necessary or advisable to effect the actual administration of the Fund. The Trustee has delegated to the directors of EnerMark the supervision of the management and affairs of the Fund, including the responsibility for significant administrative and operational decisions. In particular, the Trustee has delegated to the board of directors of EnerMark the responsibility for, among other things, all issuances and offerings of Trust Units, merger and acquisition activity relating to Enerplus, the amendment of material contracts to which the Fund is a party, borrowings by Enerplus, voting of securities held by the Fund and approval of the Fund's financial statements. Additionally, EGEM has been retained by the Fund and its subsidiaries to manage and administer the business and affairs of the Fund and manage the operations, business and affairs of the Fund's subsidiaries, subject to the supervision of the directors of EnerMark. See "Information Respecting Enerplus Resources Fund - Governance of Enerplus and the Management Agreement".

Termination of the Fund

The unitholders may vote by extraordinary resolution (i.e., 66 2/3% of the votes cast) to terminate the Fund at any meeting of unitholders duly called for that purpose, upon which the Trustee shall commence to wind up the affairs of the Fund, provided that such a vote may be held only if requested in writing by the holders of at least 25% of the Trust Units or if called by the Trustee following the refusal of the Trustee to redeem Trust Units. The quorum requirement for such a meeting is at least 20% of the issued and outstanding Trust Units represented in person or by proxy.

Upon being required to commence to wind up the affairs of the Fund, the Trustee shall give notice to the unitholders designating the time at which unitholders may surrender their Trust Units for cancellation and the date at which the register of the Fund shall be closed.

After the date on which the Trustee is required to commence to wind up the affairs of the Fund, the Trustee shall generally carry on no activities except for the purpose of winding up the affairs of the Fund and, for this purpose, the Trustee shall continue to be vested with and may exercise all or any of the powers conferred upon the Trustee under the Trust Indenture.

Reporting to Unitholders

The accounts of the Fund are audited at least annually by an independent recognized firm of chartered accountants selected by the unitholders and the financial statements of the Fund, together with the report of such auditors, are mailed by the Fund to unitholders within appropriate regulatory time periods in each calendar year. The fiscal year-end of the Fund is December 31.

The Trust Indenture provides that a unitholder has the right, upon payment of reasonable production costs, to obtain a copy of the Trust Indenture and the right to inspect and, on payment of the reasonable charges of the registrar therefor, to obtain a list of the registered holders of the Trust Units for purposes connected with the Fund.

Auditors

The Trust Indenture currently states that the appointment or removal of the Fund's auditors (as well as the appointment of a new auditor upon such removal) must be approved by the Fund's unitholders. At Enerplus' annual general and special meeting of unitholders to be held on April 25, 2002, unitholders will be asked to pass an extraordinary resolution to amend the provisions of the Trust Indenture to remove the uncertainty surrounding certain auditor-related matters and provide the board of directors of EnerMark with more flexibility to deal with the appointment of the Fund's auditors in the case of an auditors' resignation or, in certain circumstances, removal.

Enerplus proposes to amend the Trust Indenture so that it will generally mirror certain provisions of the *Business Corporations Act* (Alberta) regarding the appointment, removal and resignation of auditors. In particular, Enerplus proposes that, if the Fund's auditors resign or are removed by the unitholders without a successor properly appointed, the board of directors of EnerMark would have the power to appoint new auditors to fill the vacancy created by the resignation or removal. The new auditors would hold office until the next annual meeting of the Fund's unitholders. The proposed amendments do not change the basic concept that, in the absence of extraordinary events, the unitholders are to appoint the Fund's auditors.

Amendments to the Trust Indenture

The Trust Indenture may be amended from time to time by the Trustee, EnerMark and ERC. Material amendments to the Trust Indenture require approval by at least 66 2/3% of the votes cast at a meeting of the unitholders called for that purpose. However, the Trustee, EnerMark and ERC may, without the approval of the unitholders, make amendments to the Trust Indenture for the purposes of:

(a) ensuring that the Fund will comply with any applicable laws or requirements of any governmental agency or authority of Canada or of any province;

(b) ensuring that the Fund will maintain its status as a "unit trust" or "mutual fund trust", and not become foreign property, pursuant to the *Income Tax Act* (Canada);

(c) ensuring that such additional protection is provided for the interests of unitholders as the Trustee or the board of directors of EnerMark may consider expedient;

(d) removing any conflicts or inconsistencies between the provisions of the Trust Indenture or any supplemental indenture and any prospectus filed with any regulatory or governmental body with respect to the Fund, or any applicable law or regulation of any jurisdiction, if, in the opinion of the Trustee, such an amendment will not be detrimental to the interests of the unitholders;

(e) adding to the provisions of the Trust Indenture such additional covenants and enforcement provisions as, in the opinion of counsel, are necessary or advisable, or making such provisions not inconsistent with the Trust Indenture as may be necessary or desirable with respect to matters or questions arising under the Trust Indenture, provided that the same are not, in the opinion of the Trustee, prejudicial to the interests of the unitholders;

(f) modifying any of the provisions of the Trust Indenture, including relieving EnerMark from any of its obligations, conditions or restrictions, provided that such modification or relief shall be or become operative or effective only if, in the opinion of the Trustee, such modification or relief in no way prejudices any of the rights of the unitholders or the Trustee; and

(g) for any other purpose not inconsistent with the terms of the Trust Indenture, including the correction or rectification of any ambiguities, defective or inconsistent provisions, errors, mistakes or omissions therein, provided that in the opinion of the Trustee the rights of the Trustee and of the unitholders are not prejudiced thereby.

Royalty Agreements

Pursuant to separate royalty agreements between the Fund and each of EnerMark and ERC, EnerMark and ERC have granted to the Fund a 95% and 99% royalty, respectively, on the income from their respective oil and natural gas properties and operations. The Fund is entitled to be paid monthly the amount payable in respect of such royalties on or about the 20th day of the second month following the month to which such income relates. The income received by the Fund from EnerMark and ERC is the gross production revenue from their oil and natural gas operations, less certain permitted deductions (generally being operating costs, general and administrative expenses, management fees, debt service charges, taxes on the properties and site restoration and abandonment costs). Unitholders may also receive distributions of the net proceeds received from the sale of properties, although it is anticipated that such proceeds will generally be used to repay debt or purchase additional properties and assets.

The royalty from ERC is paid to the Fund as payments on royalty units issued by ERC to the Fund pursuant to an amended and restated royalty indenture dated June 21, 2001 between ERC and the Trustee. The royalty units are held by the Trustee on behalf of the Fund.

Governance of Enerplus and the Management Agreement

General

Pursuant to the Trust Indenture, the Trustee has delegated to the directors of EnerMark the supervision of the business and affairs of the Fund, including the supervision of EGEM in carrying out the duties delegated to it under the Trust Indenture and the Management Agreement. Among other things, the board of directors of EnerMark maintain responsibility for all matters relating to an offering or repurchase of securities of the Fund or to a take-over bid or similar transaction involving the Fund or its subsidiaries, the terms and execution of material contracts on behalf of the Fund, the voting of securities held by the Fund, the responsibility for borrowings and acquisitions by the Fund and its subsidiaries and the approval of the public disclosure documents of the Fund.

Pursuant to the Trust Indenture and in accordance with the Management Agreement, EGEM has agreed to act as manager of the Fund and its subsidiaries. The Trustee and the board of directors of EnerMark have retained EGEM to provide comprehensive management services and have delegated certain authority to EGEM to administer and regulate the day-to-day operations of the Fund and its subsidiaries, subject to the supervision of the board of directors of EnerMark, and to make executive decisions which conform to general policies and general principles established by the board of directors of EnerMark. The EGEM officers and employees who are involved in the management of the business and operations of Enerplus perform essentially the same services as they would if they were officers or employees of Enerplus. The officers provided by EGEM to Enerplus may divide their time between the management of Enerplus and other management obligations and interests, including those of affiliates of EGEM. See "Management Agreement - Conflicts" below, "Risk Factors - Potential Conflicts of Interest" and "Directors and Officers".

Management Agreement

Responsibilities

As discussed above, EGEM provides certain management, advisory and administrative services to the Fund and its subsidiaries pursuant to the Management Agreement. EGEM has been engaged by Enerplus to, among other things:

(a) manage the business and affairs of EnerMark, ERC and any other subsidiary of the Fund, including the acquisition, exploration, development, operation (or the monitoring of third party operators) and disposition of oil and natural gas properties and assets and the marketing and dealing of the petroleum substances produced from such properties;

(b) make available the office space, equipment and staff necessary for the proper administration and operation of Enerplus and its assets, including keeping necessary records and accounts relating to those operations;

(c) arrange for, negotiate and administer all borrowings and credit facilities required by Enerplus (subject to the approval of the board of directors of EnerMark) and ensure compliance by Enerplus with applicable legal and disclosure obligations; and

(d) manage and administer all matters relating to the Fund and the Trust Units, including (i) determining the total distributions owing to unitholders, (ii) providing investor relations services to the Fund; (iii) providing unitholders with financial reports and tax information relating to the Fund; (iv) subject to the approval of the board of directors of EnerMark, calling, holding and distributing materials in respect of meetings of unitholders; and (v) subject to the approval of the board of directors of EnerMark, determining the timing and terms of future offerings, issuances and repurchases of Trust Units or other securities of the Fund.

Notwithstanding the above, the board of directors of EnerMark supervises the management of the business and affairs of Enerplus generally and, without limitation and in addition to those matters described under "Governance of Enerplus and Management Agreement - General" above, the following matters require the approval of the board of directors of EnerMark (or the relevant operating subsidiary):

(a) the acquisition and disposition of oil and natural gas properties, assets or entities for a purchase price in excess of $10,000,000 (or such greater amount as the board may determine);

(b) the responsibility for approving capital expenditure and operational budgets of Enerplus; and

(c) the yearly review of EGEM's performance under the Management Agreement and the extension of the term of the Management Agreement (as discussed below); and

(d) the approval of any amendment to the constating documents and material contracts of the Fund on behalf of the Fund or its subsidiaries.

Term

The Management Agreement is in effect for continuous three year terms. Upon the approval of the board of directors of EnerMark prior to March 31 of each year, each three year term will be extended for an additional year. As the term was extended by the directors of EnerMark on March 7, 2002, the current term of the Management Agreement continues to June 30, 2005.

Compensation and Fees

At the time of the Merger of Enerplus and EnerMark Income Fund on June 21, 2001, the manner in which EGEM receives fees in consideration for its services provided to Enerplus under the Management Agreement was significantly revised to better align the interests of EGEM with the Fund's unitholders. Under the new Management Agreement, base management fees are set at 2.75% of Enerplus' total operating income (compared to pre-June 21, 2001 rates of 2.2% for EnerMark Income Fund and 3.5% for Enerplus). In addition, acquisition and divestment fees were eliminated and were replaced by performance fees based on both the total return of the Fund, and its relative performance as compared to other senior oil and gas trusts. The performance fees can range between 0% and 4% of the operating income of Enerplus. In addition, EGEM is reimbursed for all general and administrative costs incurred by it in performing its duties under the Management Agreement. In connection with the merger, EGEM was guaranteed a minimum performance fee of $5 million in 2001, which was capitalized as part of the Merger cost.

As described above, there are two types of incremental performance fees which can range, in the aggregate, from 0% to 4% of Enerplus' operating income for the relevant period and which are based on the performance of the Fund in any calendar year (and initially for the period from May 10, 2001 to December 31, 2001):

(a) *Total Return Performance Fee* (minimum 0%, maximum 2% of the Fund's operating income).

  (i) If the total return of the Trust Units in the period (i.e., the amount of distributions paid and appreciation in Trust Unit price) is less than the yield on 10-year Government of Canada bonds plus 5%, then no Total Return Performance Fee will be paid (subject to the minimum payment described in (iv) below).

(ii) If the total return of the Trust Units in the period exceeds the yield on 10-year Government of Canada bonds plus 15%, then the Total Return Performance Fee will be 2% of the operating income of the Fund for that period.

(iii) If the total return of the Trust Units is between the yield on 10-year Government of Canada bonds plus a factor of 5% to 15%, then a sliding scale calculation, ranging from 0% to 2% of the operating income of the Fund (subject to the minimum payment described in (iv) below), will be used.

(iv) Notwithstanding the above, if the total return of the Trust Units in the period exceeds 11%, then the Total Return Performance Fee will be a minimum of 0.5% of the Fund's operating income for the period.

(b) *Relative Performance Fee* (minimum 0%, maximum 2% of the Fund's operating income).

The relative performance of Enerplus as compared to eight other qualifying conventional oil and gas trusts in the relevant period will be ranked based on distributions paid and unit price appreciation in that period. The Relative Performance Fee will be calculated using a percentage equal to 2% divided by the number of trusts in the top half of the rankings which Enerplus is below the number one ranking, and subtracting the product obtained thereby from 2%. If the resulting value obtained is less than zero, then no Relative Performance Fee will be paid. Otherwise the Relative Performance Fee will be the amount obtained by multiplying the resulting percentage (not to exceed 2% of the Fund's operating income) by the operating income of the Fund. In effect, Enerplus must rank at least fourth out of the eight largest trusts (including Enerplus) before any Relative Performance Fee is payable.

The fee arrangements under the Management Agreement will be reviewed annually with the board of directors of EnerMark.

The Management Fee is calculated at the end of each quarter or portion thereof and paid on the last business day of the second month following such quarter. The Total Return Performance Fee and the Relative Performance Fee are estimated by EGEM and presented to the board of directors of EnerMark and paid on the last business day of the second month following such quarter. Annually, EGEM presents the board of directors with a final calculation of the actual Total Return Performance Fee and Relative Performance Fee to be paid to EGEM in respect of such period. EGEM then reconciles such amount to all quarterly payments of such fees received by EGEM in respect of the applicable period and adjusts them accordingly based on the reconciliation.

The Management Agreement also provides for the payment of certain fees to EGEM in most instances of termination. See "Termination Provisions" below.

Termination Provisions

The Management Agreement may be terminated by the Fund, its subsidiaries or any other entity managed by EGEM pursuant to the Management Agreement at any time without the payment of compensation to EGEM if EGEM institutes bankruptcy proceedings, seeks relief under bankruptcy law, consents to the appointment of a receiver, voluntarily suspends transaction of its usual asset management business, is declared bankrupt or insolvent, if a receiver is appointed in respect of EGEM or if EGEM fails to carry out its material obligations under the Management Agreement and does not cure such failure in accordance with the terms of the Management Agreement.

The Management Agreement may be terminated pursuant to an extraordinary resolution of Enerplus unitholders or, alternatively, by the board of directors of EnerMark upon twelve months' notice to EGEM, in which cases the fees described below shall be payable to EGEM. EGEM may terminate the Management Agreement upon twelve months notice to Enerplus.

Notwithstanding the remaining term of the Management Agreement, if the agreement is terminated pursuant to an extraordinary resolution of Enerplus unitholders, in connection with the winding-up of the Fund, as a result of the

Fund selling all or all or substantially all of its assets or in any other manner which is not permitted under the Management Agreement, and EGEM is not provided with a twelve month notice period in respect of such termination, EGEM is entitled to all fees and compensation owing to EGEM at the time of termination. Additionally, EGEM is entitled to be reimbursed for all Termination Costs plus an amount equal to either: (i) $40 million if the effective date of such termination is prior to December 31, 2003; or (ii) the Termination Fees multiplied by three.

Alternatively, the Management Agreement may be terminated by the board of directors of EnerMark upon twelve months written notice to EGEM, during which time EGEM shall continue to receive all fees and compensation pursuant to the Management Agreement, followed by the payment of an amount equal to either: (i) $40 million if the proposed effective date of such termination is on or prior to December 31, 2003; or (ii) the Termination Fees multiplied by two, plus reimbursement of all Termination Costs. The Management Agreement also provides that any failure to annually extend such agreement shall be deemed to be a termination thereof and that upon such an occurrence EGEM is entitled to receive the aforementioned fees and compensation which would be payable to EGEM if the Management Agreement were terminated with notice.

The Management Agreement also provides that, if any person announces a proposed transaction which, if completed, would result in such person acquiring in excess of 20% of the issued and outstanding Trust Units, acquiring all or substantially all of the Fund's assets or would result in the winding-up or liquidating of the Fund, or any similar transaction which in the reasonable opinion of EGEM might result in the termination of the Management Agreement, then the Termination Fees which would be payable to EGEM if the Management Agreement were terminated without notice, plus the maximum allowable amount of Termination Costs which would be payable to EGEM, shall be paid forthwith upon termination.

Conflicts

EGEM is one of the Enerplus Group of companies, which may manage other private and public entities which are involved in the oil and natural gas business and which may employ management, operational, exploitation and development strategies similar to that employed by Enerplus. As a result, certain directors, officers and employees of EGEM, and certain consultants retained by EGEM from time to time, are also directors, officers and employees of affiliates of EGEM, or may be consultants retained by affiliates of EGEM engaged in substantially the same business. The Management Agreement contains provisions which require EGEM to make disclosure to the board of directors of EnerMark of the fact and substance of any particular conflict of interest in a matter which will treat Enerplus, as the case may be, and the other interested party in an even handed manner taking into account all of the circumstances of Enerplus, and such interested party and to act honestly and in good faith in resolving such matters. See "Risk Factors - Potential Conflicts of Interest" and "Directors and Officers".

Other Matters

The Management Agreement may be assigned by any party only with 30 days prior written notice and the prior written consent of the other parties, except that EGEM can assign the agreement to an affiliate of EGEM (subject to the approval of the EnerMark board of directors). The Management Agreement may only be amended in writing by the parties thereto, provided that the Trustee shall act in accordance with the direction of the board of directors of EnerMark with respect to any proposed amendment. The Management Agreement contains provisions which state that EGEM must act honestly, in good faith and with a view to the best interests of Enerplus and its unitholders in carrying out its duties and exercising its powers under the Management Agreement, and EGEM shall exercise that degree of care, diligence and skill that a reasonably prudent advisor and manager of petroleum and natural gas properties in western Canada would exercise in comparable circumstances. Provided that EGEM acts in accordance with such standard of care, EGEM is indemnified by Enerplus against any liabilities or expenses it may incur in carrying out its duties and obligations under the Management Agreement.

Governance Agreement

The Governance Agreement provides for certain matters respecting the governance of Enerplus and its subsidiaries, including the right of EGEM to nominate three members of the board of directors of EnerMark, which is to consist of a minimum of seven and a maximum of eleven members, with the balance of the directors of EnerMark to be nominated pursuant to a vote of the Fund's unitholders. The unitholders will always be entitled to nominate a majority of the EnerMark directors. Following the nomination of the directors by the unitholders and EGEM, the Fund, as the sole shareholder of EnerMark, will vote its shares to elect those nominees to the board of directors. The Governance Agreement also states that the board of directors of ERC, which is a wholly owned subsidiary of EnerMark, is to be comprised of the same persons as the board of directors of EnerMark.

The Governance Agreement states, except where expressly prohibited in the Trust Indenture and other material agreements of Enerplus, the Fund and EnerMark can vote their shares of EnerMark and ERC, respectively. Under the Trust Indenture, the ability to vote the EnerMark shares has been delegated, except in certain circumstances, to the board of directors of EnerMark.

The Governance Agreement states, that the full amount of any dividends paid from ERC to EnerMark must immediately be paid by EnerMark to the Fund.

Any person who subsequently becomes an owner of any shares of EnerMark or ERC shall be bound by the provisions of the Governance Agreement, and the Governance Agreement may only be terminated, cancelled or amended in writing by the parties to the agreement. The Trustee is to act in accordance with the direction of the board of directors of EnerMark with respect to such matters.

Unitholder Rights Plan

On March 5, 1999, the Fund entered into a Unitholder Rights Plan Agreement (the "Rights Plan") with CIBC Mellon Trust Company, as Rights Agent, which was approved by Enerplus' unitholders on April 23, 1999. The Rights Plan generally provides that following any person or entity acquiring 20% or more of the issued and outstanding Trust Units (except pursuant to certain permitted or excepted transactions) and upon the occurrence of certain other events, each holder of Trust Units, other than such person or entity, shall be entitled to acquire Trust Units at a discounted price. The Rights Plan is similar to other shareholder or unitholder rights plans adopted in the energy sector at such time. The Rights Plan is proposed to be renewed for another three years by the Enerplus unitholders at the annual general and special meeting of unitholders to be held on April 25, 2002.

DISTRIBUTIONS TO UNITHOLDERS

Cash Distribution Policy

Unitholders of record on a distribution record date are entitled to receive distributions which are paid by Enerplus to its unitholders on the corresponding distribution payment date. Enerplus has established the 10th day of each calendar month as a distribution record date with the 20th day of such month being the corresponding distribution payment date, with the exception of the January 20th payment date which is preceded by a distribution record date of December 31 of the prior year.

The following cash distributions were paid by each of Enerplus Resources Fund and EnerMark Income Fund to their respective unitholders prior to the Merger. The following amounts are stated before giving effect to the Merger and therefore are not reflected on a combined basis.

Month of Record and Payment Date	Amount per Trust Unit	
	Enerplus Resources Fund	EnerMark Income Fund
July, 2000	$0.30	$0.06
August, 2000	0.43	0.09
September, 2000	0.30	0.06
October, 2000	0.30	0.06
November, 2000	0.75	0.12
December, 2000	0.40	0.08
January, 2001(1)	0.40	0.08
February, 2001	0.65	0.13
March, 2001	0.45	0.09
April, 2001	0.45	0.09
May, 2001	0.90	0.17
June, 2001	0.52	0.09

The following cash distributions have been paid by Enerplus to its unitholders following completion of the Merger.

Month of Record and Payment Date	Amount Per Trust Unit
July, 2001	$0.48
August, 2001	$0.50
September, 2001	$0.45
October, 2001	$0.40
November, 2001	$0.40
December, 2001	$0.35
January, 2002(1)	$0.30
February, 2002	$0.25
March, 2002	$0.20
April, 2002 (declared)	$0.20

Note:

(1) The record date for the distribution was December 31 of the prior year.

The historical distribution payments described above may not be reflective of future distribution payments, which will be subject to review by the board of directors of EnerMark Inc. taking into account the prevailing financial circumstances of the Fund at the relevant time. See "Risk Factors".

INDUSTRY CONDITIONS

Canadian Government Regulation

The oil and natural gas industry is subject to extensive controls and regulations imposed by various levels of government. It is not expected that any of these controls or regulations will affect the operations of the Fund and ERC in a manner materially different than they would affect other oil and natural gas corporations of similar size.

Pricing and Marketing - Oil

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

Pricing and Marketing - Natural Gas

In Canada the price of natural gas sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. The price received by a natural gas producer depends, in part, on the price of competing natural gas and other fuels, type of natural gas produced, access to downstream transportation, length of contract term, weather conditions and the supply/demand balance.

The governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas which may be removed from those provinces for consumption elsewhere based, mainly in the case of removals exceeding two years, on such factors as reserve availability, transportation arrangements, and market considerations.

Exports from Canada

In order to export oil or natural gas from Canada, certain approvals are required from the NEB and the Government of Canada. The approval(s) required are dependent on the hydrocarbon substance being exported and the length of the proposed export arrangement.

Royalties and Incentives

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by government regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced.

From time to time the governments of Canada, Alberta, British Columbia and Saskatchewan have established incentive programs which have included royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced planning projects, although the trend is toward eliminating these types of programs in favour of long-term programs which enhance predictability for producers. Oil and natural gas royalty holidays and reductions for specific wells will reduce the amount of Crown royalties paid by Enerplus to the provincial governments.

Canadian Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulation pursuant to provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced or utilized in association with certain oil and natural gas industry operations and can affect the location of wells and facilities and the extent to which exploration and development is permitted. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in the imposition of fines and penalties, the suspension or revocation of necessary licenses and authorizations, restrictions on the transfer of well and facility sites and civil liability for pollution damage. In Alberta, environmental compliance has been governed by the Alberta Environmental Protection and Enhancement Act ("AEPEA") since September 1, 1993. In addition to replacing a variety of older statutes which related to environmental matters, the AEPEA also imposes certain new environmental compliance, reporting and monitoring responsibilities and stricter environmental standards on oil and natural gas operators in Alberta and in certain instances also imposes greater fines and penalties for violations. As well, the AEPEA permits greater public involvement in environmental assessment and enforcement.

RISK FACTORS

The following are certain risk factors relating to the business of Enerplus which prospective investors should carefully consider before deciding whether to purchase Trust Units. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this Renewal Annual Information Form.

Limited Purpose Trust

The Fund is a limited purpose trust which is entirely dependent upon the operations and assets of its subsidiaries through the Fund's ownership of the securities of, and royalties and debt instruments issued by, those subsidiaries. Enerplus' income will be received from the production of crude oil and natural gas from its resource properties and will be susceptible to the risks and uncertainties associated with the oil and natural gas industry generally. Since the primary focus is to pursue growth opportunities through the development of existing reserves and acquisition of new properties, Enerplus' involvement in the exploration for oil and natural gas is minimal. As a result, if the oil and natural gas reserves associated with Enerplus' resource properties are not supplemented through additional development or the acquisition of additional oil and natural gas properties, the ability of Enerplus to continue to generate cash flow for distribution to unitholders may be adversely affected.

Exploitation and Development

Exploitation and development risks arise due to the uncertain results of searching for and producing oil and natural gas using imperfect scientific methods. These risks are mitigated by using highly skilled staff, focusing exploitation efforts in areas in which Enerplus has existing knowledge and expertise or access to such expertise, using up-to-date technology to enhance methods and controlling costs to maximize returns. Advanced oil and natural gas related technologies such as three dimensional seismography, reservoir simulation studies and horizontal drilling will be used by Enerplus to improve its ability to find, develop and produce oil and natural gas.

Operations

Enerplus' operations are subject to all of the risks normally incident to the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells, including encountering unexpected formations or pressures, blow-outs, craterings and fires, all of which could result in personal injuries, loss of life and damage to property of Enerplus and others. Enerplus has both safety and environmental policies in place to protect its operators and employees, as well as to meet the regulatory requirements in those areas where they operate. In addition, Enerplus has liability insurance policies in place in such amounts as it considers adequate, however, it will not be fully insured against all of these risks, nor are all such risks insurable. Business interruption insurance may also be purchased for selected facilities, to the extent that such insurance is available. Enerplus may become liable for damages arising from such events against which it cannot insure or against which it may elect not to insure because of high premium costs or other reasons. Costs incurred to repair such damage or pay such liabilities will reduce payments made by the operating subsidiaries to the Fund.

Continuing production from a property, and to some extent the marketing of production therefrom, are largely dependent upon the ability of the operator of the property. To the extent the operator fails to perform these functions properly, revenue may be reduced. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent. Although satisfactory title reviews are to be conducted in accordance with industry standards, such reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat the claim of Enerplus to certain properties. A reduction of the payments made by the operating subsidiaries to the Fund could result in such circumstances.

Oil and Natural Gas Prices

Enerplus' results of operations and financial condition, and therefore the amounts paid to the Fund by its subsidiaries, are dependent on the prices received for their oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions as well as conditions in other oil producing regions, which are beyond the control of Enerplus. Any decline in oil and natural gas prices could have a material adverse effect on Enerplus' operations, financial condition, the value of their reserves and the level of expenditures for the development of its oil and natural gas reserves. 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 Enerplus' net production revenue. Enerplus and EGEM may manage the risk associated with changes in commodity prices and foreign exchanges rates by causing Enerplus to, from time to time, enter into oil or natural gas price hedges and forward foreign exchange contracts. To the extent that Enerplus engages in risk management activities related to commodity prices and foreign exchange rates, it will be subject to credit risks associated with counterparties with which it contracts.

Capital Investment

The timing and amount of capital expenditures will directly affect the amount of income for distribution to unitholders. Distributions may be reduced, or even eliminated, at times when significant capital or other expenditures are made. To the extent that external sources of capital, including the issuance of additional Trust Units, become limited or unavailable, Enerplus' ability to make the necessary capital investments to maintain or expand their oil and gas reserves and to invest in assets, as the case may be, will be impaired. To the extent that Enerplus is required to use distributable cash flow to finance capital expenditures, property acquisitions or asset acquisitions, as the case may be, the level of its distributable income will be reduced.

Debt Service

Enerplus has unsecured credit facilities. Variations in interest rates and scheduled principal repayments, if required under the terms of the banking agreements, could result in significant changes in the amount required to be applied to debt service before payment of any amounts by the operating subsidiaries to the Fund. Certain covenants in the agreements with the lenders may also limit payments by the operating subsidiaries to the Fund. Although it is believed that the bank lines of credit are sufficient there can be no assurance that the amount will be adequate for the financial obligations of Enerplus or that additional funds can be obtained.

If Enerplus becomes unable to pay its debt service charges or otherwise commits an event of default, such as bankruptcy, the lenders may rank senior to securities or royalties of the operating subsidiaries which are held by the Fund.

Delay in Cash Distributions

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

Reserves

Although Sproule and EGEM have prepared Enerplus' reserve figures using methods of estimating reserves consistent with those commonly followed in the industry and believe that those methods have been verified by operating experience, such figures are estimates and no assurance can be given that the indicated levels of reserves will be produced. Probable reserves estimated for properties may require revision based on the actual development strategies employed to prove such reserves. Estimated reserves may also be affected by changes in oil and natural gas prices. Declines in Enerplus' reserves which are not offset by the acquisition or development of additional reserves may reduce the underlying value of Trust Units to unitholders.

The reserve reports under the heading "Oil and Natural Gas Reserves" have been prepared using certain commodity price assumptions which are described in the notes to the reserve tables. If lower prices for crude oil, NGLs and natural gas are realized by Enerplus and substituted for the prices assumptions utilized in those reserve reports, the present value of estimated future net cash flows for Enerplus' reserves would be reduced and the reduction could be significant, particularly based on the constant price case assumptions.

Investment Eligibility

If Enerplus ceases to qualify as a mutual fund trust, the Trust Units will cease to be qualified investments for RRSPs, RRIFs, RESPs and DPSPs (collectively, "Exempt Plans"). Where at the end of any month an Exempt Plan holds Trust Units that are not qualified investments, the Exempt Plan must, in respect of that month, pay a tax under Part XI.1 of the *Income Tax Act* (Canada) equal to 1% of the fair market value of the Trust Units at the time those Trust Units were acquired by the Exempt Plan. In addition, where a trust governed by an RRSP or RRIF holds Trust Units that are not qualified investments, the trust will become taxable on its 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.

If Enerplus ceases to qualify as a mutual fund trust, it will be required to pay a tax under Part XII.2 of the *Income Tax Act* (Canada). The payment of Part XII.2 tax by Enerplus may have adverse income tax consequences for certain unitholders including non-resident persons and Exempt Plans that acquire an interest in Enerplus directly or indirectly from another unitholder.

Environmental Concerns

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines or issuance of clean up orders in respect of Enerplus or its properties. Such legislation may be changed to impose higher standards and potentially more costly obligations on Enerplus, and there can be no assurance that Enerplus will be able to satisfy its actual future environmental and reclamation obligations. Additionally, the potential impact on Enerplus' operations and business of the December 1997 Kyoto treaty with respect to instituting reductions of greenhouse gases is difficult to quantify at this time as specific measures for meeting Canada's commitments have not been developed and the treaty itself may be modified or nullified.

Actual site reclamation or abandonment costs incurred in the ordinary course in a specific period are deducted for purposes of calculating income paid to the Fund by its subsidiaries and will reduce the amount of distributable income available for distribution to unitholders.

Reliance on Management

Unitholders will be dependent on the management of Enerplus and EGEM in respect of the administration and management of all matters relating to Enerplus and its operations and administration. The loss of the services of key individuals or termination of the Management Agreement could have a detrimental effect on Enerplus. Enerplus currently operates approximately 65% of its total daily production. Investors who are not willing to rely on the management of Enerplus and EGEM should not invest in the Trust Units.

Depletion of Reserves

Enerplus has certain unique attributes which differentiate it from other oil and gas industry participants. Distributions of income from crude oil and natural gas production, absent commodity price increases or cost effective acquisition and development activities, will decline over time in a manner consistent with declining production from typical oil, natural gas and natural gas liquids reserves. Enerplus will not be reinvesting cash flow in the same manner as other industry participants. Accordingly, absent capital injections, Enerplus' initial production levels and reserves will decline.

The future oil and natural gas reserves and production of Enerplus, and therefore its cash flows, will be highly dependent on its success in exploiting its reserve base and acquiring additional reserves. Without reserve additions through acquisition or development activities, Enerplus' 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 ability of Enerplus to make the necessary capital investments to maintain or expand its oil and natural gas reserves will be impaired. To the extent that Enerplus is required to use cash flow to finance capital expenditures or property acquisitions, the level of distributable income will be reduced.

There can be no assurance that Enerplus and EGEM will be successful in developing or acquiring additional reserves on terms that meet Enerplus' investment objectives.

Additional Financing

To the extent that external sources of capital, including the issuance of additional Trust Units, become limited or unavailable, Enerplus' ability to make the necessary capital investments to maintain or expand its oil and gas reserves will be impaired. To the extent that Enerplus is required to use cash flow to finance capital expenditures or property acquisitions, the level of distributable income will be reduced.

Competition

There is strong competition relating to all aspects of the oil and gas industry. Enerplus and EGEM will actively compete for capital, skilled personnel, undeveloped lands, reserves acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity and in all other aspects of its operations with a substantial number of other organizations, many of which may have greater technical and financial resources than Enerplus and EGEM. Some of those organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a world wide basis and as such have greater and more diverse resources on which to draw.

Return of Capital

Trust Units will have no value when reserves from Enerplus' 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. Unitholders 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.

Potential Conflicts of Interest

There may be circumstances in which the interests of EGEM, its affiliates or entities managed by them will conflict with those of Enerplus and its unitholders. EGEM or its affiliates may acquire oil and gas properties or entities on its own behalf or on behalf of persons other than Enerplus and may manage and administer those additional properties or entities, as well as enter into other types of energy-related management, advisory and investment activities. Neither EGEM, nor its management or affiliates, carry on their full-time activities on behalf of Enerplus and, when acting on their own behalf or on behalf of others, may at times act in competition with the interests of Enerplus and its unitholders.

In the event of such conflicts, decisions will be made on a basis consistent with the objectives and financial resources of each group of interested parties, the time limitations on investment of such financial resources, and on the basis of operating efficiencies having regard to the then current holdings of properties of each group of interested parties consistent with the duties of EGEM to each such group of persons. EGEM will use all reasonable efforts to resolve such conflicts of interest in a manner which will treat Enerplus and the other interested party fairly taking into account all of the circumstances of Enerplus and such interested party and to act honestly and in good faith in resolving such matters.

Circumstances may also arise where members of the board of directors of EnerMark or EGEM are directors or officers of corporations or other entities involved in the oil and gas industry which are in competition to the interests of Enerplus. No assurances can be given that opportunities identified by such board members will be provided to Enerplus.

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 Enerplus' operating subsidiaries. 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 Fund. As holders of Trust Units, unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring "oppression" or "derivative" actions. The Fund's assets are the shares of, royalties granted by, and certain unsecured debt instruments of its operating subsidiaries, and may also include certain other investments permitted under the Trust Indenture. The price per Trust Unit is a function of anticipated distributable income, the oil and natural gas properties acquired by Enerplus and the ability to effect long-term growth in the value of Enerplus. 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 Enerplus to acquire suitable oil and natural gas properties. Changes in market conditions may adversely affect the trading price of the Trust Units.

Unitholder Limited Liability

The Trust Indenture provides that no unitholder will be subject to any personal liability in connection with the Fund or its obligations and affairs, and the satisfaction of claims of any nature arising out of or in connection therewith is only to be made out of the Fund's assets. Additionally, the Trust Indenture states that no unitholder is liable to indemnify or reimburse the Trustee for any liabilities incurred by the Trustee with respect to any taxes payable by or liabilities incurred by the Fund or the Trustee, and all such liabilities will be enforceable only against, and will be satisfied only out of, the Fund's assets. Notwithstanding the foregoing statements in the Trust Indenture, because of uncertainties in the law relating to investment trusts such as the Fund, there is a risk that a unitholder could be held personally liable for obligations of the Fund to the extent that claims are not satisfied by the Fund. It is intended that the operations of the Fund will be conducted, upon the advice of counsel, in such a way and in such jurisdictions as to avoid as far as possible any material risk of liability on the unitholders for claims against the Fund. In any event, it is considered that the risk of any personal liability of unitholders in Canada is minimal, particularly where the beneficiaries are not controlling the day-to-day activities of the trust and there is no direct contact between the beneficiaries of the trust and parties who contract with the trust, each of which conditions is satisfied in the case of Enerplus and its unitholders.

Changes in Legislation

There can be no assurances that income tax laws and government incentive programs relating to the oil and gas industry, such as the status of mutual fund trusts and the resource allowance, will not be changed in a manner which adversely affects Enerplus and its unitholders. There can be no assurance that the Canada Customs and Revenue Agency or the Internal Revenue Service will agree with how Enerplus calculates its income for tax purposes or that the Canada Customs and Revenue Agency or the Internal Revenue Service will not change their administrative practices to the detriment of Enerplus or its unitholders.

Retraction Right

It is anticipated that the retraction right will not be the primary mechanism for unitholders to liquidate their investment. Cash distributions are subject to limitations and any securities 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 for such securities. In addition, there may be resale restrictions imposed by law upon the recipients of the securities pursuant to the retraction right.

SELECTED CONSOLIDATED FINANCIAL INFORMATION

The following tables set forth selected consolidated financial information of Enerplus for the past three years.

Three Year Detailed Statistical Review

	Year Ended December 31,		
($thousands, except per Trust Unit amounts)	**2001**	**2000**	**1999**
Financial			
Gross oil and gas sales	$ 639,397	$ 343,182	$ 169,541
Funds flow from operations	340,246	176,366	80,965
Per Trust Unit	6.20	6.57	3.94
Net income	180,269	82,150	25,754
Per Trust Unit – Basic	3.28	3.06	1.25
Per Trust Unit – Diluted	3.28	3.05	1.25
Capital expenditures (net)	152,216	65,844	12,136
Total assets	2,284,253	1,567,952	576,901
Long term debt	412,589	275,944	131,315
Cash available for distribution			
Funds flow from operations	340,246	176,366	80,965
Site restoration and abandonment costs incurred	2,628	1,471	1,124
Cash withheld for debt reduction	(48,850)	(11,746)	(3,900)
Enerplus Resources Fund (pre-Merger) cash flows	16,870	-	-
Accruals	5,560	-	-
Pursuit Resources Corp. operating cash flows net of cash withheld for debt reduction	-	2,090	-
Cash available for distribution	$ 316,454	$ 168,181	$ 78,189
Per Trust Unit	$ 5.67	$ 5.49	$ 3.70

The above financial data has been taken from the audited consolidated financial statements of Enerplus for the years ended December 31, 2001, 2000 and 1999. The audited consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles. See Note 2 to Enerplus' audited annual consolidated financial statements of the year ended December 31, 2001 for a description of the significant accounting policies of Enerplus.

Cash Distributions to Unitholders

Reference is made to the information under the heading "Distributions to Unitholders" in this Renewal Annual Information Form.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management's discussion and analysis of financial condition and results of operations for the year ended December 31, 2001, as contained on pages 33 to 50 of the Fund's Annual Report for the year ended December 31, 2001, is incorporated by reference in this Renewal Annual Information Form.

MARKET FOR SECURITIES

The Trust Units are listed and posted for trading on The Toronto Stock Exchange and the New York Stock Exchange. The trading symbol for the Trust Units on the TSE is "ERF.UN" and on the NYSE is "ERF".

DIRECTORS AND OFFICERS

Directors of EnerMark

With the exception of three directors of EnerMark who, pursuant to the Governance Agreement, are nominated by EGEM, the directors of EnerMark are nominated by the unitholders of the Fund at each annual meeting of unitholders. All directors serve until the next annual meeting or until a successor is elected or appointed. See "Governance Agreement". The name, municipality of residence, principal occupation for the past five years and year of appointment as a director of EnerMark for each director of EnerMark are set forth below:

Name and Municipality of Residence	Director Since	Principal Occupation for Past Five Years
André Bineau [2] Montréal, Québec	February, 1996	Vice President of Association de bienfaisance et de retraite des policiers et policières de la Ville de Montréal (a municipal pension plan)
Derek J.M. Fortune [4][5][6] Ottawa, Ontario	June, 2001	Secretary/Manager, City of Ottawa Superannuation Fund (a municipal pension plan)
Gordon J. Kerr [5][7][10] Calgary, Alberta	May, 2001	President and Chief Executive Officer of EGEM since May, 2001 (and Chief Financial Officer of EGEM until December 2001). Executive Vice President and Chief Financial Officer of EGEM since January, 2001. Prior thereto, Senior Vice President, Financial Services of EGEM since September, 2000. Prior thereto, Vice President, Finance and Chief Financial Officer of EGEM since 1998. Prior thereto, Strategic Development Consultant to EGEM since 1996.
Douglas R. Martin [1][4][5][8] Calgary, Alberta	July, 2000	President of Charles Avenue Capital Corp. (a private merchant banking company) since April, 2000. Prior thereto, Chairman of the Board of Pursuit Resources Corp. (an oil and natural gas exploration and production company)
Arne Nielsen [3][6] Calgary, Alberta	June, 2001	Chairman of Shiningbank Energy Management Inc. (manager of an energy investment trust)

Name and Municipality of Residence	Director Since	Principal Occupation for Past Five Years
Robert Normand[(2)(4)(6)] Montréal, Québec	June, 2001	Businessman
Eric P. Tremblay[(3)(7)(10)] Calgary, Alberta	January, 2001	Senior Vice President, Capital Markets of EGEM since September, 2000. Prior thereto, Senior Vice President, Corporate Development of EGEM since January, 2000. Prior thereto, Vice President, Corporate Development of EGEM since 1996.
Harry B. Wheeler[(2)(3)] Calgary, Alberta	January, 2001	President of Colchester Investments Ltd. (a private investment firm) since January 2001. Prior thereto, Chairman of the Board of Cabre Exploration Ltd. (an oil and natural gas exploration and production company)
Robert L. Zorich[(7)(9)] Houston, Texas	January, 2001	Managing Director of EnCap Investments L.L.C. (a wholly owned subsidiary of El Paso Corporation, which provides private equity financing to the oil and gas industry)

Notes:

(1) Chairman of the Board of Directors.
(2) The Audit and Risk Management Committee is comprised of Robert Normand as Chairman, André Bineau and Harry B. Wheeler.
(3) The Environment, Safety and Reserves Committee is comprised of Harry B. Wheeler as Chairman, Arne Nielsen and Eric P. Tremblay.
(4) The Corporate Governance Committee is comprised of Douglas R. Martin as Chairman, Robert Normand and Derek J. M. Fortune.
(5) The Compensation and Human Resources Committee is comprised of Derek J. M. Fortune as Chairman, Douglas R. Martin and Gordon J. Kerr.
(6) Prior to the merger of Enerplus and EnerMark Income Fund on June 21, 2001, each of Derek J.M. Fortune, Arne Nielsen and Robert Normand was a director of Enerplus Resources Corporation ("ERC"), the entity responsible for governance of Enerplus prior to the merger. Mr. Fortune was a director of ERC since June, 1992, Mr. Nielsen was a director of ERC since June, 2000 and Mr. Normand was a director of ERC since March, 1998.
(7) Nominee of EGEM pursuant to the Management Agreement
(8) From 1991 to 2000, Mr. Martin was director of Coho Energy, Inc. ("Coho"), an oil and natural gas corporation that was listed on the TSE and NASDAQ. In 1999, Coho filed for protection under United States federal bankruptcy law, from which it was released in April, 2000. The directors of Coho were not held responsible for any actions. Mr. Martin resigned as a director of Coho in April of 2000.
(9) In late 1997, Mr. Zorich was appointed to the board of directors of Benz Energy Inc. ("Benz"), a Vancouver Stock Exchange listed company at the time, as a representative of Mr. Zorich's employer, EnCap Investments L.L.C., which had provided certain financing to Benz. On November 8, 2000, Benz, together with its wholly-owned subsidiary, Texstar Petroleum Inc., jointly filed a petition for protection under United States federal bankruptcy law, and on January 19, 2001, the shares of Benz were made subject to a cease trade order by the Alberta Securities Commission and suspended from trading on the Canadian Venture Exchange Inc. for failing to file required financial information.
(10) Prior to June 21, 2001, EGEM's role as the principal management company of Enerplus Resources Fund was performed by Enerplus Energy Services Ltd. ("EES"), a private company which was owned by EGEM. All references to EGEM in the above table prior to June 21, 2001 should be construed as references to EES, but for simplicity, EGEM has been utilized throughout the above table.

Officers of EnerMark and EGEM

The name, municipality of residence, position held and principal occupation for the past five years for each officer of EnerMark and EGEM are set out below:

Name and Municipality of Residence	Position with EnerMark	Position with EGEM	Principal Occupation for Past Five Years[1]
Gordon J. Kerr Calgary, Alberta	President and Chief Executive Officer	President and Chief Executive Officer	President and Chief Executive Officer of EGEM since May, 2001 (and Chief Financial Officer of EGEM until December 2001). Prior thereto, Executive Vice President and Chief Financial Officer of EGEM since January, 2001. Prior thereto, Senior Vice President, Financial Services of EGEM since September, 2000. Prior thereto, Vice President, Finance and Chief Financial Officer of EGEM since 1998. Prior thereto, Strategic Development Consultant to EGEM since 1996.
Heather J. Culbert Calgary, Alberta	Senior Vice President, Corporate Services	Senior Vice President, Corporate Services	Senior Vice President, Corporate Services of EGEM since March 2001. Prior thereto, Vice President, Management Information Systems & Administration of EGEM since 1996.
Garry A. Tanner Calgary, Alberta	N/A	Senior Vice President, New Business Development	Senior Vice President, New Business Development of EGEM since August, 2001 (in addition to Senior Vice President of El Paso Merchant Energy (a merchant trading company) since October, 2000). Prior thereto, Senior Vice President of EnCap Investments L.L.C. (a wholly owned subsidiary of El Paso Corporation which provides private equity financing to the oil and gas industry) since 1997.
Eric P. Tremblay Calgary, Alberta	Senior Vice President, Capital Markets	Senior Vice President, Capital Markets	Senior Vice President, Capital Markets of EGEM since September, 2000. Prior thereto, Senior Vice President, Corporate Development of EGEM since January, 2000. Prior thereto, Vice President, Corporate Development of EGEM since 1996.
Robert J. Waters Calgary, Alberta	Senior Vice President and Chief Financial Officer	Senior Vice President and Chief Financial Officer	Senior Vice President and Chief Financial Officer of EGEM since December, 2001. Prior thereto, Vice President, Finance and Chief Financial Officer of Pengrowth Corporation since June, 1998. Prior thereto, Treasurer of Norcen Energy Resources Limited (an oil and gas exploration and production company) since 1988.
Jo-Anne M. Caza Calgary, Alberta	Vice President, Investor Relations	N/A	Vice President of Investor Relations of Enerplus since January, 2000. Prior thereto, Manager, Investor Relations of Enerplus since 1998. Prior thereto, Investor Relations Supervisor of Enerplus since 1996.

Name and Municipality of Residence	Position with EnerMark	Position with EGEM	Principal Occupation for Past Five Years[1]
Daryl W. Cook Calgary, Alberta	Vice President, Operations	N/A	Vice President, Operations of Enerplus since 1997. Prior thereto, Vice President, Exploitation and Land of Enerplus.
Dorothy J. Else Calgary, Alberta	Vice President, Land	N/A	Vice President, Land of Enerplus since 1998. Prior thereto, Manager of Land of Enerplus.
Wayne T. Foch Calgary, Alberta	Vice President, Finance	N/A	Vice President, Finance of Enerplus since February, 2001. Prior thereto, Treasurer of EMR Resource Management Ltd. (the management company of EnerMark Income Fund) since April, 1996.
I. Laura Pierrot Calgary, Alberta	Vice President and Treasurer	N/A	Vice President and Treasurer of Enerplus since February, 2001. Prior thereto, Treasurer of Enerplus.
Darrell Shaw Calgary, Alberta	Vice President, Exploitation	N/A	Vice President, Exploitation of Enerplus since 1998. Prior thereto, General Manager, Exploitation of Enerplus.
Gerald F. Stevenson Calgary, Alberta	Vice President, Acquisitions	N/A	Vice President, Acquisitions of Enerplus since October, 2001. Prior thereto, consultant with Waterous & Co. (a financial advisory firm to the oil and gas industry) since February, 2000. Prior thereto, advisor to Hurricane Hydrocarbons Ltd. ("HHC") (an oil and gas exploration and production company) from April, 1999 to December, 1999. Prior thereto, Interim President and Chief Executive Officer of HHC from October, 1998. Prior thereto, Vice President Production of HHC from April, 1998. Prior thereto, a consultant to Mercantile Latin America an oil and gas company) from September, 1997 to February, 1998. Prior thereto, Associate with Waterous & Co. since July, 1993.
Wayne Ford Calgary, Alberta	Controller	N/A	Controller of Enerplus since August, 2001. Prior thereto, Controller of Argonauts Group Ltd. (an oil and gas exploration and production company) since January, 2000. Prior thereto, Operations Accounting Consultants with Enerplus since September, 1998. Prior thereto, Client Service Manager with Applied Terravision Systems Inc. (a software company) since October, 1996.
Ian Dundas Calgary, Alberta	N/A	Vice President	Vice President, EGEM since August, 2001. Prior thereto, Chief Financial Officer of Medmira Inc., (a public biotechnology company) since 1999. Prior thereto, Director of Enron Canada Corp. merchant banking group since 1996.

Name and Municipality of Residence	Position with EnerMark	Position with EGEM	Principal Occupation for Past Five Years[1]
Larry Titley Calgary, Alberta	N/A	Treasurer	Treasurer of EGEM since January, 1998. Prior thereto, Manager of Financial Reporting and Accounting of EGEM since June, 1996.
Christina S. Meeuwsen Calgary, Alberta	Corporate Secretary	Corporate Secretary	Corporate Secretary of EGEM since 1996.
Joanne Danyschuk Calgary, Alberta	Assistant Corporate Secretary	Assistant Corporate Secretary	Assistant Corporate Secretary of EGEM since 1997. Prior thereto, Corporate Law Clerk at Blake, Cassels & Graydon LLP (law firm).

Note:

(1) Those persons whose principal occupations are designated as officers of Enerplus are not officers of EGEM but are only officers of EnerMark. However, prior to June 21, 2001, EGEM's role as the principal management company of Enerplus Resources Fund was performed by Enerplus Energy Services Ltd. ("EES"), a private company which was owned by EGEM, and the principal employer of such persons prior to such time was EES. Therefore, all references to EGEM or to Enerplus (with respect to those officers who are not officers of EGEM) prior to June 21, 2001 should be construed as references to EES, but for simplicity, EGEM and Enerplus, as applicable, have been utilized throughout the above table.

The directors and officers named above beneficially own, directly or indirectly, an aggregate of 462,427 Trust Units, representing approximately 0.66% of the Trust Units outstanding on March 31, 2002.

Certain of the directors and officers named above may be directors or officers of issuers which are in competition to Enerplus, and as such may encounter conflicts of interests in the administration of their duties with respect to Enerplus. See "Management Agreement - Conflicts" and "Risk Factors - Potential Conflicts of Interest".

ADDITIONAL INFORMATION

Enerplus will provide to any person, upon request to the Corporate Secretary of EGEM:

(a) when the securities of Enerplus are in the course of a distribution under a preliminary short form prospectus or a short form prospectus:

 (i) one copy of this Renewal Annual Information Form, together with one copy of any document, or the pertinent pages of any document, incorporated by reference in this Renewal Annual Information Form;

 (ii) one copy of Enerplus' comparative financial statements for its most recently completed financial year for which financial statements have been filed together with the accompanying report of the auditors and one copy of the most recent interim financial statements of Enerplus that have been filed, if any, for any period after the end of its most recently completed financial year;

 (iii) one copy of the information circular of Enerplus in respect of its most recent annual meeting of unitholders that involved the election of directors of EnerMark or one copy of any annual filing prepared instead of that information circular, as appropriate; and

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

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

Additional information regarding directors' and certain officers' remuneration and indebtedness, remuneration of EGEM pursuant to the Management Agreement, principal holders of Trust Units, options to purchase Trust Units and interests of insiders in material transactions is contained in Enerplus' information circular for its most recent annual meeting of unitholders that involved the election of directors of EnerMark. Additional information is provided in Enerplus' comparative consolidated financial statements for the year ended December 31, 2001.

APPENDIX "A"

UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS

COMPILATION REPORT

TO: The Directors of EnerMark Inc.

We have reviewed, as to compilation only, the accompanying unaudited pro forma consolidated statements of income and cash available for distribution of Enerplus Resources Fund (the "Fund") for the year ended December 31, 2001. These pro forma consolidated financial statements have been prepared for inclusion in the Renewal Annual Information Form of the Fund dated April 10, 2002. In our opinion, the unaudited pro forma consolidated statements of income and cash available for distribution have been properly compiled to give effect to the proposed transaction and the assumptions described in the notes thereto.

Calgary, Alberta	*"Arthur Andersen LLP"*
April 10, 2002.	Chartered Accountants

Enerplus Resources Fund
Pro Forma Consolidated Statement of Income
For the year ended December 31, 2001
(Unaudited)

($ thousands except per Trust Unit amounts)

	Enerplus	Enerplus (pre-acquisition) 171 days	Adjustments		Pro Forma Consolidated
Revenues					
Oil and gas sales	$639,379	$122,343	$ -		$761,722
Crown royalties	(101,114)	(18,951)	(236)	(2a)	(120,301)
Freehold and other royalties	(31,546)	(7,149)	682	(2c)	(38,013)
	506,719	96,243	446		603,408
Interest and other income	858	177	-		1,035
	507,577	96,420	446		604,443
Expenses					
Operating	120,082	18,136	-		138,218
General and administrative	12,971	1,969	-		14,940
Management fee	9,323	2,743	412	(2b)	12,478
Interest	17,605	2,717	-		20,322
Depletion, depreciation and amortization	194,080	15,441	8,336	(2d)	217,857
	354,061	41,006	8,748		403,815
Income before taxes	153,516	55,414	(8,302)		200,628
Capital taxes	4,722	526	-		5,248
Future income tax provision (recovery)	(31,475)	274	-		(31,201)
Net income	$180,269	$54,614	$(8,302)		$226,581
Net income per Trust Unit					
Basic	$3.28				$3.50
Diluted	$3.28				$3.50

Enerplus Resources Fund
Pro Forma Consolidated Statement of Cash Available for Distribution
For the year ended December 31, 2001
(Unaudited)

($ thousands except per Trust Unit amounts)

	Enerplus	Enerplus (pre-acquisition) 171 days	Adjustments	Pro Forma Consolidated
Net income	$180,269	$54,614	$(8,302)	$226,581
Depletion, depreciation and amortization	194,080	15,441	8,336	217,857
Future income tax provision (recovery)	(31,475)	274	-	(31,201)
Site restoration and abandonment costs incurred	(2,628)	(633)	-	(3,261)
Funds flow from operations	340,246	69,696	34	409,976
Debt repayments related to capital expenditures	(48,850)	(8,150)	-	(57,000)
Enerplus cash flows	16,870	(16,870)	-	-
Site restoration and abandonment costs incurred	2,628	(633)	-	(3,261)
Accruals	5,560	2,249	-	7,809
ARTC received	-	567	-	567
Cash available for distribution	$316,454	$48,125	$34	$364,613
Cash available for distribution per Trust Unit	$5.67			$5.61

ENERPLUS RESOURCES FUND
NOTES TO THE PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2001
(unaudited)

1. BASIS OF PRESENTATION

The accompanying unaudited pro forma consolidated financial statements (the "Pro Forma Statements") of Enerplus Resources Fund ("Enerplus") have been prepared by management of Enerplus in accordance with Canadian generally accepted accounting principles for inclusion in the Renewal Annual Information Form of Enerplus dated April 10, 2002.

Effective June 21, 2001, Enerplus acquired all of the outstanding trust units of EnerMark Income Fund ("EnerMark") in exchange for 43,525,961 Trust Units of Enerplus, and all of the outstanding warrants to acquire EnerMark trust units were exchanged for 2,507,330 warrants to acquire Trust Units of Enerplus (the "Merger"). As a result of this exchange, the Unitholders of EnerMark became the controlling Unitholders of Enerplus. Accordingly, the Merger was accounted for as a reverse take-over. Under this form of purchase accounting, the net assets of Enerplus, rather than of EnerMark, are deemed to have been acquired.

The Pro Forma Statements of income and cash available for distribution have been prepared from the audited consolidated statements of income and cash available for distribution of Enerplus for the year ended December 31, 2001 and the financial records of Enerplus for the period from January 1, 2001 to June 21, 2001. The Pro Forma Statements should be read in conjunction with the audited consolidated financial statements of Enerplus for the year ended December 31, 2001. Other information which was available at the time of preparation of the Pro Forma Statements has also been considered. In the opinion of management, these Pro Forma Statements include all material adjustments necessary for a fair presentation.

The Pro Forma Statements are not necessarily indicative of the results of operations which would have occurred for the year ended December 31, 2001 had the Merger been effected on January 1, 2001 and, therefore, may not be representative of the operating results of future periods.

In preparing the Pro Forma Statements, no adjustments have been made to recognize any operating efficiencies or general and administrative cost savings which would be expected to occur as a result of combining the operations of Enerplus and EnerMark.

2. PRO FORMA ASSUMPTIONS AND ADJUSTMENTS

The pro forma consolidated statements of income and cash available for distribution for the year ended December 31, 2001 give effect to the Merger if it had occurred on January 1, 2001.

The accounting policies used in preparing the Pro Forma Statements are in accordance with those disclosed in the audited consolidated financial statements for Enerplus for the fiscal year ended December 31, 2001.

The Pro Forma Statements give effect to the following assumptions and adjustments:

(a) Enerplus' Alberta Royalty Tax Credit ("ARTC") for the period from January 1, 2001 to June 21, 2001 has been eliminated.

(b) Management fees have been adjusted to reflect the change in the management agreement between Enerplus and Enerplus Global Energy Management Company and have been provided for at 2.75% of oil and gas revenues plus ARTC, net of Crown, freehold and other royalties and operating expenses in accordance with the new management agreement.

(c) Freehold and other royalties have been adjusted to reflect the acquisition of Enerplus Energy Services Ltd.'s residual royalty interest of 1% by EnerMark Inc.

(d) The provision for depletion, depreciation and amortization has been adjusted as a result of the increase in property, plant and equipment.

Enerplus Resources Fund

Prior to June 1, 2002

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Following June 1, 2002

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