

PRIMEWEST ENERGY TRUST

RENEWAL ANNUAL INFORMATION FORM

For the year ended December 31, 2002

March 14, 2003

TABLE OF CONTENTS

ITEM 1: ORGANIZATION.....	1
Trust Structure	2
The Declaration of Trust	2
Unitholder Rights Plan.....	6
Internalization of Management.....	7
Decision Making	8
ITEM 2: GENERAL DEVELOPMENT OF THE BUSINESS.....	8
Developments Since Year-End.....	10
ITEM 3: NARRATIVE DESCRIPTION OF BUSINESS.....	10
The Business of the Trust.....	10
General.....	10
Operatorship.....	11
Acquisitions	11
Risk Management & Marketing.....	11
Reserve Continuity	14
Drilling Activity	14
Capital Expenditures.....	15
Exploration and Development.....	16
Attributes of the Properties	16
Oil and Natural Gas Reserves.....	17
Principal Properties.....	21
Unproved Lands	29
Industry Conditions.....	30
Risks Related to Our Business.....	32
Risks Related to the Trust Structure and the Ownership of Trust Units.....	40
ITEM 4: SELECTED CONSOLIDATED FINANCIAL INFORMATION.....	44
Selected Annual Information.....	44
Selected Quarterly Information	45
Selected Financial and Operational Information	45
ITEM 5: MANAGEMENT'S DISCUSSION AND ANALYSIS.....	48
ITEM 6: MARKET FOR SECURITIES	48
ITEM 7: DIRECTORS AND OFFICERS.....	48
Directors	48
Officers.....	49
Employees.....	50
ITEM 8: ADDITIONAL INFORMATION.....	51
GLOSSARY OF ABBREVIATIONS & TERMS.....	51
Abbreviations	51
Definitions.....	52

SCHEDULE A FINANCIAL STATEMENTS OF CYPRESS ENERGY INC.

NOTE TO READER

The Trust Units were consolidated on a one for four basis on August 16, 2002. Except where otherwise indicated, all amounts relating to the Trust Units contained in this Annual Information Form have been adjusted to give effect to that consolidation.

ITEM 1: ORGANIZATION

PrimeWest Energy Trust (the “**Trust**”) is an open-end investment trust created under the laws of Alberta pursuant to the Declaration of Trust. The undertaking of the Trust is to issue Trust Units to the public and to invest the Trust's funds, directly or indirectly, in petroleum and natural gas properties and assets related thereto. The sole beneficiaries of the Trust are the holders of Trust Units. Computershare Trust Company of Canada is the Trustee of the Trust. The head office and principal place of business of the Trust is 4700, 150 – 6th Avenue S.W., Calgary, Alberta, T2P 3Y7.

PrimeWest Energy Inc. (“**PrimeWest**” or the “**Operating Company**”) was incorporated under the *Business Corporations Act* (Alberta) on March 4, 1996 and was amalgamated with PrimeWest Oil and Gas Corp., PrimeWest Royalty Corp. and PrimeWest Resources Ltd. on January 1, 2002 and continued as PrimeWest Energy Inc. PrimeWest was amalgamated with PrimeWest Management Inc. (the “**Manager**”) and Delgrae Energy Corporation on November 6, 2002 and continued as PrimeWest Energy Inc. The latter amalgamation was completed as part of the “internalization” of the Manager referred to under “Internalization of Management” below.

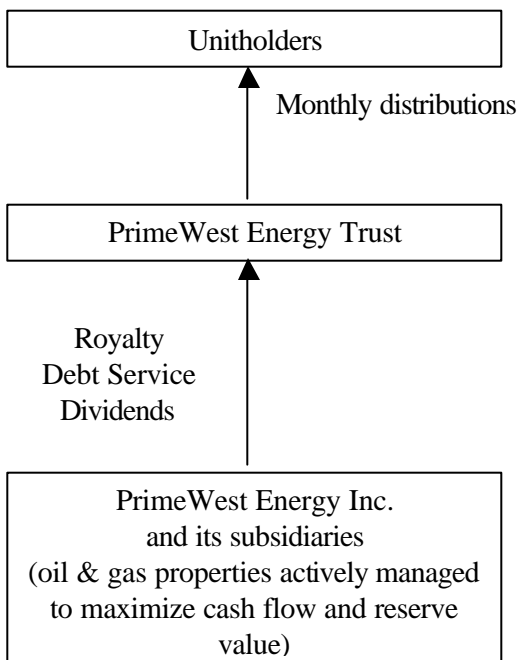
PrimeWest is wholly owned by the Trust. PrimeWest’s business is the acquisition, development, exploitation, production and marketing of petroleum and natural gas properties and granting the Royalty to the Trust.

The principal undertaking of the Trust is to acquire and hold, directly and indirectly, interests in petroleum and natural gas properties. One of the Trust's primary assets is the Royalty granted by PrimeWest pursuant to the Royalty Agreement. The Royalty entitles the Trust to receive 99 percent of the net cash flow generated by the petroleum and natural gas interests held from time to time by PrimeWest, after certain costs and deductions. The balance of such net cash flow may be retained by PrimeWest to fund its working capital and other business and operating requirements, or may be passed on to the Trust to support distributions to Unitholders. The Distributable Income resulting from the Royalty and other amounts received by the Trust is then distributed monthly to Unitholders.

The head, principal and registered office of PrimeWest is 4700, 150 – 6th Avenue S.W., Calgary, Alberta T2P 3Y7.

Trust Structure

The following diagram represents the current structure of the Trust and shows the flow of funds from the petroleum and natural gas properties owned by PrimeWest and the gross overriding royalties owned directly by the Trust, as well as the flow of funds to PrimeWest, and from the Trust to Unitholders:



Note:

1. The Trust also directly owns certain gross overriding royalty interests.

The Declaration of Trust

The Declaration of Trust, among other things, provides for the calling of meetings of Unitholders, the conduct of business at those meetings, notice provisions, the appointment, resignation and removal of the Trustee and the form of Trust Unit certificates. The Declaration of Trust may be amended from time to time. Substantive amendments to the Declaration of Trust, including extension or early termination of the Trust and the sale or transfer of the property of the Trust as an entirety, or substantially as an entirety, requires approval by special resolution of the Unitholders.

The following is a summary of certain provisions of the Declaration of Trust. For a complete description of that indenture, reference should be made to the Declaration of Trust, copies of which may be viewed at the offices of, or obtained from, the Trustee.

Trust Units

An unlimited number of Trust Units may be issued pursuant to the Declaration of Trust, each of which represents an equal fractional undivided beneficial interest in the Trust entitling the holder to receive monthly distributions of Distributable Income.

All Trust Units share equally in all distributions from the Trust, carry equal voting rights at meetings of Unitholders, and have a right of redemption on terms set out in the Declaration of Trust. No Unitholder is liable to pay any further calls or assessments in respect of the Trust Units other than any instalment payment arrangements that are applicable to an offering of Trust Units in respect of which the Unitholder acquired his Trust Units.

The Trust Units are not "deposits" within the meaning of the *Canada Deposit Insurance Corporation Act* (Canada) and are not insured under the provisions of that, or any other, legislation. Furthermore, the Trust is not a trust company and, accordingly, is not registered under any trust and loan company legislation, as it does not carry on or intend to carry on the business of a trust company.

Class A Exchangeable Shares of PrimeWest

An unlimited number of Class A Exchangeable Shares may be issued by the Operating Company, each of which entitles the holder to exchange the Class A Exchangeable Share at any time into a number of Trust Units based on an exchange ratio then in effect. The exchange ratio is determined by reference to the distributions paid on Trust Units in a given month and the current market price of the trust units. On December 31, 2002, each Class A Exchangeable Share was exchangeable for 0.37454 Trust Units.

PrimeWest issued Class A Exchangeable Shares in connection with the acquisitions of the Manager in November 2002, Cypress Energy Inc. in March 2001 and Venator Petroleum Company Ltd. in April 2000. Shareholders of the Manager, Cypress and Venator who received Class A Exchangeable Shares could in certain circumstances defer the tax consequences of that exchange. PrimeWest may issue additional Class A Exchangeable Shares in connection with future acquisitions.

The Class A Exchangeable Shares provide holders with economic terms and voting rights which are, as nearly as practicable, equivalent to those of Trust Units. The Class A Exchangeable Shares are maintained economically equivalent to the Trust Units by the progressive increase in the exchange ratio, incorporating and reflecting the distributions provided to Unitholders in the right to acquire an ever-increasing number of Trust Units per Class A Exchangeable Share. The Class A Exchangeable Shares are provided equivalent voting rights as Unitholders through a voting trust agreement pursuant to which the holders of Class A Exchangeable Shares can direct a trustee to

vote at meetings of Unitholders. The Class A Exchangeable Shares are listed and posted for trading on the TSX under the symbol "PWX".

Trustee

Computershare is the current trustee of the Trust and also acts as the transfer agent for the Trust Units and the Class A Exchangeable Shares. The Trustee is responsible for, among other things: (a) accepting subscriptions for Trust Units and issuing Trust Units pursuant thereto; (b) maintaining the books and records of the Trust and providing timely reports to holders of Trust Units; and (c) paying cash distributions to Unitholders.

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

The current term of the Trustee's appointment expires at the conclusion of the 2005 annual meeting of Unitholders. Thereafter, the Trustee will be reappointed or changed every third annual meeting as may be determined by a majority of the votes cast at a meeting of the Unitholders. The Trustee may also be removed by a majority vote of the Unitholders in that regard. The Trustee may resign on 60 days' notice to PrimeWest. That resignation or removal becomes effective on the appointment of a successor trustee and the acceptance of that appointment and the assumption of the obligations of the Trustee by that successor trustee.

Cash Distributions

Cash distributions of Distributable Income are made on a monthly basis on the Cash Distribution Date following the end of each month, to Unitholders of record on the Record Date in that month.

Redemption Right

Trust Units are redeemable at any time on demand by the holder thereof upon delivery to the Trust of the certificates representing such Trust Units accompanied by a duly completed and properly executed notice requesting redemption. Upon such receipt of the redemption request, all of the Unitholder's rights to and under the Trust Units tendered for redemption are surrendered and the Unitholder becomes entitled to receive a price per Trust Unit as determined by a market price formula, subject to a monthly aggregate cash cap of up to \$100,000. The redemption price payable by the Trust may be satisfied by way of a cash payment, or in certain circumstances, including where such payment would cause the monthly cash cap to be exceeded, by way of an *in specie* distribution.

Meetings and Voting

Annual meetings of the Unitholders commenced in 1997. Special meetings of Unitholders may be called at any time by the Trustee and will be called by the Trustee on the written request of Unitholders holding in aggregate not less than 20 percent of the Trust Units. Notice of all meetings of Unitholders will be given to Unitholders at least 21 days and not more than 50 days prior to the meeting.

Unitholders may attend and vote at all meetings of such Unitholders either in person or by proxy and a proxy holder need not be a holder of Trust Units. At least two persons present in person or represented by proxy and representing in the aggregate not less than five percent of the votes attaching to all outstanding Trust Units constitute a quorum for the transaction of business at all those meetings. Unitholders are entitled to one vote per Trust Unit.

Limitation on Non-Resident Ownership

In order for the Trust to maintain its status as a mutual fund trust under the *Income Tax Act* (Canada), the Trust must not be established or maintained primarily for the benefit of non-residents of Canada within the meaning of the *Income Tax Act* (Canada). Accordingly, the Declaration of Trust provides that at no time may non-residents be the beneficial owners of a majority of the Trust Units. If the Trustee becomes aware that the beneficial owners of 49 percent of the Trust Units then outstanding are or may be non-residents or that situation is imminent, the Trustee may make a public announcement in that regard and will not accept a subscription for Trust Units from or issue or register a transfer of Trust Units to a person unless the person provides a declaration that the person is not a non-resident. Notwithstanding the foregoing, if the Trustee determines that a majority of the Trust Units are beneficially held by non-residents, the Trustee may send a notice to non-resident Unitholders, chosen in inverse order to the order of acquisition or registration or in such other manner as the Trustee may consider equitable and practicable, requiring those non-resident Unitholders to sell their Trust Units or part of them within a specified period of not less than 60 days. If the non-resident Unitholders receiving that notice have not sold the specified number of Trust Units or provided the Trustee with satisfactory evidence that they are not non-residents within that period, the Trustee may on behalf of those Unitholders sell those Trust Units and, in the interim, will suspend the voting and distribution rights attached to those Trust Units. When that sale by the Trustee occurs, the affected Unitholders will cease to be holders of Trust Units and their rights will be limited to receiving the net proceeds of sale on surrender of the certificates representing those Trust Units.

Compulsory Acquisition

The Declaration of Trust provides that if a person within either 120 days of making an offer to purchase all outstanding Trust Units or the time for acceptance

provided in that offer (provided that such offer is open for acceptance for a period of not less than 45 days), whichever period is the shorter, acquires not less than 90 percent of the outstanding Trust Units (other than those held by that person and its affiliates), that person may acquire the Trust Units of the Unitholders who did not accept the offer on the same terms as those offered to those Unitholders who accepted the offer.

Termination of the Trust

The Unitholders may vote to terminate the Trust at any meeting of the Unitholders, provided that the termination must be approved by special resolution of the Unitholders.

Unless the Trust is terminated or extended by vote of the Unitholders earlier, the Trustee will commence to wind-up the affairs of the Trust on December 31, 2095. In the event that the Trust is wound-up, the Trustee will liquidate all the assets of the Trust, pay, retire, discharge or make provision for some or all obligations of the Trust and then distribute the remaining proceeds of the liquidation to Unitholders.

Unitholder Rights Plan

On March 31, 1999, PrimeWest announced that it had adopted a Unitholder Rights Plan. The Rights Plan was approved by Unitholders at the special and annual general meeting of the Unitholders held on May 18, 1999. The Unitholders reconfirmed the Rights Plan at the special and annual general meeting of the Unitholders held on May 21, 2002. The Rights Plan will expire on the date of PrimeWest's Annual general meeting in 2005 unless the Unitholders reconfirm the Rights Plan at that meeting.

Under the terms of the Rights Plan, a prospective bidder would be encouraged to negotiate the terms of a bid with the board of directors of PrimeWest, or to make a "permitted bid", not requiring the approval of the board of directors of PrimeWest but having terms and conditions designed to provide the board of directors of PrimeWest with sufficient time to properly evaluate a take-over bid and its effects, and to seek alternative bidders or to explore other ways of maximizing Unitholder value in the event of an unsolicited take-over bid.

If a Person acquires more than 20 percent of the Trust Units other than by way of a permitted bid, other Unitholders may, at the discretion of the board of directors of PrimeWest, acquire a number of Trust Units at 50 percent of the then prevailing market price, so as to cause significant dilution to the acquiring Person.

The Rights Plan provides that a permitted bid is a take-over bid meeting the following requirements:

- (a) The bid must be made to all Unitholders;

- (b) The bid must be open for a minimum of 45 days following the date of the bid, and no Trust Units may be taken up prior to such time;
- (c) Take-up and payment of Trust Units may not occur unless the bid is accepted by Unitholders holding more than 50 percent of the outstanding Trust Units, excluding Trust Units held by the bidder and its associates;
- (d) Trust Units may be deposited to or withdrawn from the bid at any time prior to the take-up date; and
- (e) If the bid is accepted by Unitholders holding the requisite percentage of Trust Units, the bidder must extend the bid for an additional ten business days to permit other Unitholders to tender into the bid, should they so wish.

Internalization of Management

On September 26, 2002, the Trust announced the planned elimination, effective October 1, 2002, of its external management structure and all related management, acquisition and disposition fees, as well as the acquisition of the right to mandatory quarterly dividends commonly referred to as the "1% retained royalty". The transaction was completed on November 6, 2002.

The transaction resulted in the elimination of a 2.5% management fee on net production revenue, quarterly incentive payments payable in the form of Trust Units, a 1.5% acquisition fee and a 1.25% disposition fee, which resulted in payments to the Manager in 2001 totalling \$21.3 million. In addition, the amount of the 1% retained royalty paid in 2001 was \$3.4 million.

The internalization transaction was achieved through the purchase by PrimeWest of all of the issued and outstanding shares of the Manager for a total consideration of approximately \$26.3 million comprised of a cash payment of \$13.2 million and the issuance of Class A Exchangeable Shares exchangeable, based on an agreed initial exchange ratio, for approximately 491,000 Trust Units and valued at approximately \$13.1 million based on the closing price of the Trust Units on the TSX on September 26, 2002. In addition, PrimeWest agreed to issue Class A Exchangeable Shares valued at \$1.5 million to certain senior managers other than Kent J. MacIntyre (then the Chief Executive Officer of PrimeWest and the Manager) to terminate a management incentive program of the Manager and created a special executive retention plan for those senior managers which provides for long term incentive bonuses in the form of Class A Exchangeable Shares valued, in the aggregate, at \$3.5 million. Class A Exchangeable Shares will be issued pursuant to the retention plan on each of the second, third, fourth and fifth anniversaries of the completion of the internalization transaction. The cash component of the purchase price for the shares of the Manager was funded using PrimeWest's then existing credit facility.

The total consideration payable for the shares of the Manager, in the opinion of the independent directors of PrimeWest, represented a reasonable payment (i) in lieu of fees that would have been payable by PrimeWest to the Manager during the remainder of the initial term of the management agreement among the Trust, PrimeWest and the Manager to October 15, 2003, including management fees, quarterly incentive payments and acquisition and disposition fees, (ii) for the shares of PrimeWest held by the Manager, the holder of which shares is entitled to approximately 1% of net production revenue for the remaining life of the oil and natural gas reserves of PrimeWest, and (iii) for the benefits accruing to Unitholders through continuity of management.

The internalization transaction included the continued commitment of the senior management team at PrimeWest.

Decision Making

Unitholders are entitled to direct the election of directors of PrimeWest, the approval of the financial statements of PrimeWest, and the appointment of its auditors and other matters relating to the business and affairs of PrimeWest and the Trust.

The board of directors of PrimeWest is responsible for making significant decisions with respect to PrimeWest, including all decisions relating to, among other things: (a) the acquisition and disposition of significant petroleum and natural gas properties; (b) the approval of capital expenditure budgets; (c) the approval of risk management activities; and (d) the establishment of credit facilities. In addition, the Trustee has delegated certain matters regarding the Trust to PrimeWest, including all decisions relating to (i) issuances of Trust Units, (ii) the determination of the amount of distributions to be made by the Trust, (iii) approvals required with regard to any proposed amendment to the Declaration of Trust or the royalty agreement and other aspects respecting the relationship between the Trust and PrimeWest, and (iv) responding to unsolicited take-over or merger proposals. The board of directors of PrimeWest holds regularly scheduled meetings to review the business and affairs of PrimeWest and the Trust.

ITEM 2: GENERAL DEVELOPMENT OF THE BUSINESS

On October 16, 1996, the Trust completed an initial public offering of 24,900,000 Trust Units (before giving effect to the Consolidation) on an instalment receipt basis of \$6.00 payable on October 16, 1996 and \$4.00 payable one year later, for total gross proceeds of \$249,000,000. The Trust used the net proceeds of that offering, plus the assignment of the right to be paid the final instalment of \$4.00 per Trust Unit, to purchase the Royalty from PrimeWest. PrimeWest used the net proceeds from the sale of the Royalty to the Trust and debt to acquire certain oil and gas properties.

Since its inception, PrimeWest has been an active acquiror of crude oil and natural gas properties in the Western Canadian Sedimentary Basin. Many of those acquisitions were financed, directly or indirectly, through the issuance of Trust Units and what are now Class A Exchangeable Shares. The following tables summarize the more significant acquisitions and equity financings completed by PrimeWest since January 1, 2000.

Acquisitions

Date	Company/Properties Acquired	Aggregate Purchase Price (currency)	Established Reserves and Production Acquired
April 2000	Venator Petroleum Company Ltd.	\$32.5 million (cash and exchangeable shares)	3.0 mmboe 1,500 boe/d
July 2000	Reserve Royalty Corp.	\$84.0 million (cash and Trust Units)	6.1 mmboe 1,700 boe/d
March 2001	Cypress Energy Inc.	\$820.8 million (cash, Trust Units and exchangeable shares)	57.5 mmboe 15,000 boe/d
December 2002	Caroline/Ells	\$45.6 million (cash)	5.7 mmboe 1,550 boe/d
January 2003	Caroline/Peace River Arch	\$206.1 million (cash)	17.6 mmboe 6,800 boe/d

Public Offerings

Date	No. of Trust Units Issued	Price per Trust Unit	Gross Proceeds
September 2000	1,207,500 ⁽¹⁾	\$33.40 ⁽¹⁾	\$40.3 million
June 2001	2,472,500 ⁽¹⁾	38.40 ⁽¹⁾	94.9 million
November 2001	2,475,000 ⁽¹⁾	28.40 ⁽¹⁾	70.3 million
November 2002	4,200,000	26.20	110.0 million
February 2003	6,000,000	25.75	154.5 million

Note:

- Adjusted to give effect to the Consolidation completed on August 16, 2002.

Other significant developments since January 1, 2000 include the following:

- In the second half of 2001, in a number of separate transactions, PrimeWest disposed of several properties for total proceeds of approximately \$78.2 million. These proceeds were applied to reduce outstanding debt.
- On November 19, 2002, the Trust Units were listed for trading on the New York Stock Exchange under the symbol "PWI".
- On December 23, 2002, the Board of Directors of PrimeWest confirmed the succession of Donald A. Garner to the position of President and Chief Executive Officer, effective January 2, 2003. Kent MacIntyre, the founder of PrimeWest, resigned as Vice-chairman and Chief Executive Officer of PrimeWest effective January 2, 2003, but will remain a member of the Board of Directors of PrimeWest. The Board also appointed Tim Granger, PrimeWest's Vice-president, Operations and Development, as Chief Operating Officer.

Developments Since Year-End

On January 8, 2003, PrimeWest announced the appointment of W. Glen Russell as an independent member of the Board of Directors.

On January 23, 2003, a wholly owned subsidiary of PrimeWest acquired all of the issued and outstanding shares of two private Canadian exploration and production companies for an aggregate purchase price of \$206.1 million, net of adjustments (including working capital), payable in cash. Of the purchase price, \$191.1 million is attributed by PrimeWest to oil and gas reserves and \$15 million is attributed by PrimeWest to certain natural gas processing and midstream assets. The transaction added approximately 17.6 mmboc of Established Reserves, as at July 1, 2002, and approximately 6,800 boc per day of current production. That production is weighted 83% to natural gas and the properties are located primarily in the Caroline and Peace River Arch areas of Alberta.

On February 13, 2003, the Trust closed the issue of 6 million Trust Units at a price of \$25.75 per Trust Unit. The issue was done on a bought-deal basis for gross proceeds of \$154.5 million.

ITEM 3: NARRATIVE DESCRIPTION OF BUSINESS

The Business of the Trust

General

The undertaking of the Trust is to directly and indirectly acquire and hold petroleum and natural gas properties and to distribute the Distributable Income generated therefrom to Unitholders. It is therefore the mandate of PrimeWest to continue to source and acquire petroleum and natural gas properties both for and on behalf of itself and the Trust, and to enhance the production from both acquired and

existing properties in order to increase the amount of Distributable Income distributed to Unitholders.

Operatorship

PrimeWest believes that although operatorship of the properties generally involves higher General and Administrative Costs than would be required for non-operated properties, those higher costs will generally result in more opportunities to enhance value to Unitholders through production enhancement, control of facilities and increased access to acquisition opportunities in core areas.

Currently, PrimeWest operates properties representing approximately 80% of the aggregate daily production.

Acquisitions

Unless PrimeWest and the Trust are able to acquire additional petroleum and natural gas reserves or increase reserves through development activities, production from the currently held properties will continually decline. PrimeWest continually reviews opportunities for the acquisition of producing oil and natural gas properties. When considering the acquisition of any petroleum and natural gas producing property, PrimeWest focuses on long-life properties, with low reservoir risk, that may be operated by either PrimeWest or other acceptable operators and that have the potential to increase Distributable Income and enhance the Trust's value through exploitation of those properties. See "Management Policies and Acquisition Strategy".

Risk Management & Marketing

Prices received for production and associated operating expenses are impacted in varying degrees by factors outside the Trust's control. These include but are not limited to:

- (a) World market forces, including the ability of OPEC to set and maintain production levels and prices for crude oil;
- (b) Potential conditions, including the risk of hostilities in the Middle East;
- (c) Increases or decreases in crude-oil quality differentials, and their implications for prices received by PrimeWest on the portion of oil production that is medium gravity crude;
- (d) To the extent that crude oil prices received by PrimeWest are referenced to WTI oil, which is denominated in U.S. dollars, prices and revenue streams are impacted by changes in value between the Canadian and U.S. dollars.

- (e) North American market forces, most notably shifts in the balance between supply and demand for natural gas and the implications for the price of natural gas;
- (f) Global and domestic economic and weather conditions;
- (g) Price and availability of alternative fuels; and
- (h) The effect of energy conservation measures and government regulations.

Fluctuations in commodity prices, quality differentials and foreign exchange and interest rates, among other factors, are outside the control of PrimeWest and yet can have a significant impact on the level of cash available for distribution to Unitholders. To mitigate a portion of these risks, PrimeWest actively initiates, manages and discloses the effects of hedging activities. PrimeWest evaluates these activities against criteria established under a commodity risk-assessment and management program, which is regularly reviewed by the board of directors of PrimeWest.

As part of PrimeWest's risk-management strategy in 2002, 69% of full-year crude oil production (2001 – 84%) and 71% of full-year natural gas production (2001 – 78%) was hedged, net of royalties. Strategies utilized included both physical and financial instruments with the primary objective of enhancing the stability of cash distributions. No electrical power requirements were hedged in 2002.

The gas hedging instruments are floors, swaps, costless collars, 3-way deals and swaptions. Costless collars involve the simultaneous purchase of a put option and sale of a call option at no cost. 3-way deals are the simultaneous purchase of a near the money put option and the sale of both an out of the money put and an out of the money call all at no cost. Swaptions give PrimeWest the future right to enter into swap transactions for fixed prices and terms. The oil hedging instruments consist of floors, swaps, costless collars and calls.

As at February 28, 2003:

- (a) PrimeWest employed hedging structures using swaps and option-based instruments on approximately 51% of anticipated crude oil production, net of royalties, for 2003 and on none of its anticipated crude oil production, net of royalties, for 2004;
- (b) PrimeWest employed hedging structures using swaps and option-based instruments on approximately 57% of anticipated natural gas production, net of royalties, for 2003 and on approximately 12% of anticipated natural gas production, net of royalties, for 2004;

- (c) PrimeWest employed hedging structures using heat rate instruments (involving the exchange of natural gas production for electrical power) on approximately 42% of anticipated electrical power requirements for 2003 and on approximately 28% of anticipated electrical power requirements for 2004; and
- (d) all 2003 and 2004 hedging contracts mark-to-market represented a net loss of \$54.5 million, as compared to a net loss of \$13.6 million as at December 31, 2002.

Beyond the hedging strategy, PrimeWest also mitigates risk by having a well diversified marketing portfolio for natural gas and by transacting with a number of counterparties to limit exposure to any one counterparty. Approximately 30% of natural gas production is sold to aggregators and approximately 70% of production is sold into the Alberta short-and long-term markets. The contracts that PrimeWest has with aggregators vary in length. They have a blend of domestic and U.S. markets, with fixed and floating prices, which provide price diversification to our revenue stream.

In addition to these noted risk-management practices, while PrimeWest's portfolio of assets is weighted to natural gas, a significant portion of the portfolio consists of crude oil and NGLs reserves. Because oil and gas price cycles do not necessarily coincide, such a balance often provides a natural mitigation of price risk.

For 2002, PrimeWest's commodity mix was approximately 38% oil and NGLs and 62% natural gas, compared to approximately 41% oil and NGLs and 59% natural gas in 2001. PrimeWest realized hedge gains of \$28 million in 2002 and \$39 million in 2001.

Impact of Environmental Protection Requirements

PrimeWest carries out its activities and operations in compliance with all relevant and applicable environmental regulations and good industry practice. At present, PrimeWest believes that it meets all existing environmental standards and regulations. PrimeWest has created a segregated fund devoted to funding future costs for well abandonment and site cleanup. In 2002, PrimeWest contributed \$0.37 per boe of production, totalling \$4.1 million paid into this fund, while \$3.9 million was paid out for active projects completed, leaving a balance of \$0.01 million at the end of the year. The 2003 contribution rate has been set at \$0.50 per boe, which is expected to be sufficient to meet the future funding requirements. In addition, PrimeWest records a provision for site reclamation and abandonment based on cost estimates made by both PrimeWest and external engineers. The provision for 2002 was \$4.0 million compared to \$3.5 million in 2001 and is charged to depletion, depreciation and amortization on a unit of production basis. Expenditures for environmental matters or site restoration are not reported as part of the development capital. Since the environmental standards and regulations to which PrimeWest is subject apply to all participants in the oil and gas

industry, it is not anticipated that PrimeWest's competitive position within the industry will be adversely affected.

Reserve Continuity

Gilbert Laustsen Jung Associates Ltd., independent petroleum consultants, has evaluated the crude oil, natural gas, natural gas liquids and sulphur reserves of PrimeWest and the Trust since their inception in 1996. Gilbert Laustsen Jung Associates Ltd. has prepared the Gilbert Report evaluating the crude oil, natural gas, natural gas liquids and sulphur reserves attributable to properties owned by PrimeWest and the Trust as at January 1, 2003. The following table sets forth the reconciliation of the reserves of PrimeWest and the Trust for the year ended December 31, 2002, using escalated price and cost estimates derived from the Gilbert Report.

	Crude Oil (mmbbls)		Natural Gas (mmcf)		NGLs (mmbbls)		Total (mboe)		Established Reserves (mboe)
	Proved	Probable ⁽¹⁾	Proved	Probable ⁽¹⁾	Proved	Probable ⁽¹⁾	Proved	Probable ⁽¹⁾	
As at January 1, 2002	24,719	7,651	349,310	128,800	7,830	3,432	90,767	32,551	107,043
Additions,									
Extensions	129	(16)	27,035	810	106	33	1,047	153	1,123
Discoveries	53	120	4,875	23,190	690	642	5,249	4,627	7,562
Acquisitions	373	128	23,840	4,940	862	125	5,208	1,075	5,746
Divestments	(512)	(242)	(6,710)	(2,180)	(158)	(55)	(1,789)	(660)	(2,119)
Revision	27	(1,554)	(7,440)	(17,560)	(138)	(697)	(1,351)	(5,177)	(3,940)
2002 Production	(3,372)		(41,440)		(741)		(11,020)		(11,020)
As at January 1, 2003	<u>21,417</u>	<u>6,087</u>	<u>349,470</u>	<u>138,000</u>	<u>8,451</u>	<u>3,480</u>	<u>88,111</u>	<u>32,569</u>	<u>104,395</u>

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. Established Reserves are the sum of Proved Reserves and 50 percent of Probable Reserves.
3. All technical revisions on acquired reserves are included in revisions category.

Drilling Activity

During the Trust's last two financial years, PrimeWest drilled or participated in the drilling of the following wells:

	Year Ended December 31, 2002		Year Ended December 31, 2001	
	Gross	Net	Gross	Net

Natural Gas	55	33.8	45	22.49
Crude Oil	1	0.3	30	24.06
Dry	9	6.5	7	4.50
Total	<u>65</u>	<u>40.6</u>	<u>82</u>	<u>51.05</u>

Capital Expenditures

The ongoing capital expenditures of PrimeWest are financed through the issuance of additional Trust Units, bank borrowing and undistributed net cash flow. The following table summarizes PrimeWest's capital expenditures in the categories and for the periods indicated.

(\$ 000's)	2002				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total for Year
Development drilling and completions	\$15,337	\$207	\$12,052	\$14,369	\$41,965
Plant and facilities	8,002	6,329	3,377	3,474	21,182
Office and other expenditures	1,128	1,187	1,337	2,256	5,908
	<u>24,467</u>	<u>7,723</u>	<u>16,766</u>	<u>20,099</u>	<u>69,055</u>
Acquisitions	291	1,089	25,062	33,164	59,606
Total capital expenditures	<u>24,758</u>	<u>8,812</u>	<u>41,828</u>	<u>53,263</u>	<u>128,661</u>
Property dispositions	(2,066)	(781)	(873)	(809)	(4,529)
Net capital expenditures	<u>\$22,692</u>	<u>\$8,031</u>	<u>\$40,955</u>	<u>\$52,454</u>	<u>\$124,132</u>

(\$ 000's)	2001				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total for Year
Development drilling and completions	\$5,748	\$11,802	\$18,194	\$22,901	\$58,645
Plant and facilities	449	4,330	6,414	10,609	21,802
Office and other expenditures	666	575	609	1,607	3,457
	<u>6,863</u>	<u>16,707</u>	<u>25,217</u>	<u>35,117</u>	<u>83,904</u>
Acquisitions	767,569	4,713	2,894	47,422	822,598
Total capital expenditures	<u>774,432</u>	<u>21,420</u>	<u>28,111</u>	<u>82,539</u>	<u>906,502</u>
Property dispositions	(3,333)	(2,185)	(23,447)	(49,179)	(78,144)
Net capital expenditures	<u>\$771,099</u>	<u>\$19,235</u>	<u>\$4,664</u>	<u>\$33,360</u>	<u>\$828,358</u>

Exploration and Development

The primary focus of PrimeWest is to pursue growth opportunities through the development of existing reserves, the monetization of PrimeWest's exploratory lands and the acquisition of new properties. High risk exploration plays, as well as PrimeWest's 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. PrimeWest will continue its ongoing property rationalization program and any sales proceeds may be used to acquire interests in core areas or new prospects with exploitation opportunities.

Attributes of the Properties

The properties of PrimeWest and the Trust include interests in both unitized and non-unitized oil and natural gas production from several major oil and natural gas fields. The following characteristics, as at December 31, 2002, make the properties suitable for a conventional crude oil and natural gas royalty trust structure:

- (a) **Long Life Reserves:** The properties contain long life, low decline rate reserves that have an Established Reserve Life Index of approximately 10 years;
- (b) **Operated Properties:** Approximately 80% of the total production from the properties is operated by PrimeWest. In respect of these operated properties, PrimeWest is able to exercise management and operating influence to maximize value for the benefit of the Trust;
- (c) **Natural Gas Weighted Portfolio:** For the year ended December 31, 2002 production from the properties is approximately 38 percent crude oil and natural gas liquids and 62 percent natural gas, on a barrel-of-oil-equivalent basis. As at January 1, 2003, Established Reserves for the properties are approximately 34 percent crude oil and natural gas liquids and 66 percent natural gas on a barrel-of-oil-equivalent basis. Crude oil reserves are predominantly light-gravity oil, averaging 31 degree API;
- (d) **Concentrated Portfolio:** While the properties are diversified from a geological and geographic perspective, PrimeWest generally has the largest working interest in these properties; and
- (e) **Upside Potential:** Additional opportunities to enhance the value of the properties have been identified by PrimeWest. These opportunities may not have been included in the valuations provided in the Gilbert Report.

Oil and Natural Gas Reserves

Gilbert has prepared the Gilbert Report evaluating the properties as at January 1, 2003. The Gilbert Report evaluates the crude oil, natural gas, natural gas liquids and sulphur reserves attributable to the properties prior to provision for income taxes, interest costs, general and administrative expenses and management fees, but after providing for estimated royalties, operating costs, other income, future capital expenditures and facility site restoration, well abandonment and well-site restoration costs. Probable additional reserves and the present worth of those reserves as set forth in the tables below have been reduced by 50 percent to reflect the degree of risk associated with recovery of those reserves. It should not be assumed that the discounted future net cash flows estimated by Gilbert represent the fair market value of these reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized in the notes following these tables.

Petroleum and Natural Gas Reserves and Pre-Tax Net Cash Flows										
Escalating Cost and Price Case										
Company Interest Reserves						Estimated Present Worth of Future Pre-Tax Net Cash Flows (\$millions)				
	Crude Oil and Natural Gas Liquids (mmbbls)		Natural Gas (bcf)		Sulphur (mlt)		Undiscounted	Discounted at		
	Gross	Net	Gross	Net	Gross	Net		10%	15%	20%
	Proved									
Producing	26.9	22.9	287	228	588	492	1,254	705	595	521
Non-Producing.	2.9	2.3	62	49	96	80	224	111	88	73
Total Proved	29.8	25.2	349	277	684	572	1,478	816	683	594
Risked Probable.....	4.9	3.9	69	55	128	108	297	107	79	61
Established	34.7	29.1	418	332	812	680	1,775	923	762	655

Petroleum and Natural Gas Reserves and Pre-Tax Net Cash Flows										
Constant Cost and Price Case										
Company Interest Reserves						Estimated Present Worth of Future Pre-Tax Net Cash Flows (\$millions)				
	Crude Oil and Natural Gas Liquids (mmbbls)		Natural Gas (bcf)		Sulphur (mlt)		Undiscounted	Discounted at		
	Gross	Net	Gross	Net	Gross	Net		10%	15%	20%
	Proved									
Producing	28.0	23.7	289	230	591	495	1,773	999	838	728
Non-Producing.	2.8	2.3	63	49	96	80	302	156	125	103
Total Proved	30.8	26.0	352	279	687	575	2,075	1,155	963	831
Risked Probable.....	5.0	4.0	69	55	128	108	385	148	109	86
Established	35.8	30.0	421	334	815	683	2,460	1,303	1,072	917

Notes:

- The following definitions have been used in the Gilbert Report:
 - "Proved Reserves" means those reserves estimated as recoverable with a high degree of certainty under current technology and existing economic conditions, in the case of constant price and cost analyses, and

anticipated economic conditions in the case of escalated cost and price analyses, from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economic and technically successful in the subject reservoir.

- (b) "Probable Reserves" means those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved, but where such analysis suggests the likelihood of their existence and future recovery under current technology and existing or anticipated economic conditions. Probable additional reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above that estimated in the proved category, which can be realistically estimated for the pool on the basis of enhanced recovery processes, which can be reasonably expected to be instituted in the future.
 - (c) "Established Reserves" means those reserves estimated as Proved Reserves plus a portion of the Probable additional reserves, reduced to reflect the risks associated with recovery of those reserves. In the Gilbert Report, Established Reserves have been determined as the sum of 50 percent of Probable Reserves and 100 percent of Proved Reserves.
 - (d) "Producing Reserves" means those reserves that are actually on production and could be recovered from existing wells and facilities or, if facilities have not been installed, that would involve a small investment relative to cash flow to install those facilities. In multi-well pools involving a competitive situation, reserves may be subdivided into producing and non-producing reserves in order to reflect allocation of reserves to specific wells and their respective development status.
 - (e) "Non-Producing Reserves" means those reserves that are not classified as producing.
 - (f) "Gross Reserves" means the total remaining recoverable reserves associated with the acreage of interest.
 - (g) "Company Interest Gross Reserves" means the remaining reserves applicable to the properties, before deduction of any royalties.
 - (h) "Company Interest Net Reserves" means the gross remaining reserves applicable to the properties, less all royalties (but not the Royalty to the Trust) and interests owned by others.
2. The Gilbert Report, the present worth values and quantities of Probable Reserves reported in the Established Reserves category have been reduced by 50 percent to reflect the degree of risk associated with the recovery of those reserves.
 3. All natural gas reserve values are reserves remaining after deducting surface losses due to processing shrinkage and raw gas used as lease fuel.
 4. The \$US/\$Cdn exchange rate is assumed in the Gilbert Report to be \$0.6410 in 2003 and \$0.6467 in 2004, \$0.6500 in 2005, \$0.6533 in 2006, and 0.6567 in 2007.
 5. The Gilbert Report estimates total capital expenditures (net to PrimeWest) to achieve the estimated future pre-tax net cash flows from the Established Reserves based on escalating cost and price assumptions to be \$95.1 million (\$65.3 million if discounted by 12 percent per annum) with \$21.6 million, \$23.5 million and \$11.0 million of those capital expenditures estimated for the calendar years 2003, 2004 and 2005 respectively. The corresponding capital expenditures to achieve the estimated future pre-tax net cash flows from the Established Reserves based on constant cost and price assumptions are \$92.7 million (\$63.5 million if discounted by 12 percent per annum) with \$21.6 million, \$23.1 million and \$10.7 million of these capital expenditures estimated for the calendar years 2003, 2004 and 2005 respectively.
 6. The Gilbert Report estimates total capital expenditures (net to PrimeWest) to achieve the estimated future pre-tax net cash flows from the Total Proved Reserves based on escalating cost and price assumptions to be \$76.6 million (\$50.4 million if discounted by 12 percent per annum) with \$15.5 million, \$16.3 million and \$7.9 million of those capital expenditures estimated for the calendar years 2003, 2004 and 2005, respectively. The corresponding capital expenditures to achieve the estimated future pre-tax net cash flows from the Total Proved Reserves based on constant cost and price assumptions are \$73.4 million (\$48.7 million if discounted by 12 percent per annum) with \$15.5 million, \$16.0 million and \$7.7 million of these capital expenditures estimated for the calendar years 2003, 2004 and 2005, respectively.
 7. The extent and character of the interests of PrimeWest and the Trust evaluated in the Gilbert Report and all factual data supplied to Gilbert were accepted by Gilbert as represented. The crude oil and natural gas reserve calculations and any projections on which the Gilbert Report is based were determined in accordance with generally accepted petroleum engineering evaluation practices.
 8. The constant cost and price evaluation was based on December 31, 2002 reference prices. The prices shown below incorporate oil quality and heating value adjustments, as well as transportation adjustments to a property level:

Average First Year Unit Values

(Cdn.\$)

Crude Oil.....	\$43.69 per bbl
Condensate.....	\$48.00 per bbl
Propane.....	\$32.75 per bbl
Butane.....	\$35.56 per bbl
Ethane.....	\$18.40 per bbl
Natural Gas.....	\$5.85 per mcf
Sulphur.....	\$9.94 per lt

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

9. In respect of the escalated cost and price valuation for the Gilbert Report, average yearly general product prices, which are referred to in these reports as the industry consensus as at January 1, 2003 for natural gas, crude oil, natural gas liquids and sulphur, are outlined in the following table. The figures in the following table were calculated as of that date as the arithmetic average of the then current price forecasts of Gilbert, Sproule Associates Limited, and McDaniel & Associates Consultants Ltd.

Consultant's Average (Escalated)

	Light Crude Oil		Natural Gas Liquids at Edmonton			Natural Gas			Sulphur \$/lt
	WTI Cushing Oklahoma* \$/bbl	Edmonton Par price 40° API \$/bbl	Propane \$/bbl	Butane \$/bbl	Pentanes Plus \$/bbl	Henry Hub \$/MMBTU	Alberta Spot AECO-C \$/MMBTU	BC Direct \$/MMBTU	
2003.....	25.83	38.84	23.46	25.90	39.49	4.22	5.61	5.46	7.75
2004.....	23.20	34.41	20.82	22.42	34.85	3.89	5.13	5.03	8.56
2005.....	21.84	32.14	19.85	21.04	32.57	3.61	4.76	4.66	9.40
2006.....	21.92	32.09	19.89	21.02	32.52	3.54	4.70	4.59	15.85
2007.....	22.28	32.53	20.10	21.29	32.97	3.60	4.76	4.65	19.21
2008.....	22.72	33.11	20.41	21.74	33.55	3.65	4.79	4.70	20.08
2009.....	23.09	33.89	20.96	22.28	34.35	3.71	4.89	4.79	20.95
2010.....	23.45	34.48	21.28	22.73	34.93	3.79	4.97	4.87	21.83
2011.....	23.82	35.06	21.63	23.15	35.52	3.85	5.05	4.95	22.95
2012.....	24.27	35.65	21.99	23.60	36.12	3.91	5.15	5.05	23.83
2013.....	24.64	36.28	22.43	24.06	36.75	3.97	5.23	5.13	24.71
2014.....	25.01	36.87	22.76	24.43	37.35	4.03	5.33	5.21	25.09
2015.....	25.39	37.47	23.11	24.77	37.95	4.09	5.42	5.29	25.47
2016.....	25.76	38.06	23.44	25.14	38.55	4.15	5.52	5.38	25.85
2017.....	26.17	38.69	23.80	25.52	39.18	4.22	5.62	5.48	26.24
2018.....	26.61	39.34	24.20	25.95	39.83	4.29	5.72	5.57	26.68
2019.....	27.05	39.99	24.60	26.38	40.50	4.36	5.82	5.66	27.12
Thereafter	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%

Notes:

- Operating and capital costs have been escalated at 1.67 percent annually for 16 years and 1 percent thereafter.
- Price forecasts used to generate the above price projections:
 Gilbert Lautsen Jung Associates Ltd. – Effective January 1, 2003
 Sproule Associates Limited - Effective January 1, 2003
 McDaniel & Associates Consultants Ltd. - Effective January 1, 2003

Estimated Pre-Tax Net Cash Flows
Established Reserves of the Properties
Escalating Cost and Price Case (Consultant's Average)
(Smillions except for production)

	Annual Production (mboe)	Company Interest Revenue ⁽¹⁾ (MMS)	Royalty Burdens ⁽²⁾ (MMS)	Net Revenue After Royalty Burdens (MMS)	Alberta Royalty Tax Credit (MMS)	Operating Expenses ⁽³⁾ (MMS)	Other Net Income ⁽⁴⁾ (MMS)	Abandonmen t Costs (MMS)	Net Capital Investment (MMS)	Net Cash Flow Before Income Taxes ⁽⁵⁾⁽⁶⁾ (MMS)
2003.....	10,862	358.1	74.3	283.7	0.5	57.2	4.2	3.3	21.6	206.5
2004.....	10,203	304.7	61.3	243.4	0.5	56.4	5.1	4.0	23.5	165.1
2005.....	9,074	251.3	48.6	202.8	0.5	53.1	5.1	4.0	11.0	140.3
2006.....	7,958	218.7	40.8	177.9	0.5	49.6	4.7	3.5	6.7	123.3
2007.....	6,942	193.3	34.9	158.4	0.5	46.7	4.4	3.7	4.1	108.8
2008.....	6,044	170.5	30.0	140.5	0.5	44.0	4.0	1.6	3.9	95.3
2009.....	5,267	152.2	26.1	126.1	0.5	40.6	3.6	2.3	2.2	85.0
2010.....	4,631	136.2	23.0	113.2	0.4	37.3	3.2	2.4	3.1	74.0
2011.....	4,036	121.1	20.1	101.0	0.4	33.4	2.9	1.2	3.2	66.4
2012.....	3,591	109.9	17.9	92.0	0.4	31.0	2.6	1.6	3.9	58.5
2013.....	3,223	100.4	16.1	84.2	0.4	28.7	2.5	1.3	2.9	54.3
2014.....	2,912	92.2	14.6	77.6	0.3	27.5	2.3	1.1	2.3	49.3
Remainder	29,652	1,085.6	156.7	928.8	2.5	370.5	18.8	24.6	6.5	548.4
TOTAL....	104,395	3,294.0	564.5	2,729.5	7.9	876.0	63.3	54.7	95.1	1,775.0

Total net cash flow before income taxes discounted at:

10 percent: \$923 million

15 percent: \$762 million

20 percent: \$655 million

Notes:

1. Includes working-interest revenue and royalty-interest revenue.
2. Includes royalties net of gas processing allowances.
3. Includes other expenses, capital taxes and certain third party processing income.
4. Includes other income less net profits interest payments and mineral taxes.
5. Undiscounted.
6. Net cash flow before income taxes is stated prior to interest, general and administrative expenses and management fees.
7. Columns may not add due to rounding.

**Estimated Pre-Tax Net Cash Flows
Established Reserves of the Properties
Constant Cost and Price Case
(Millions except for production)**

	Annual Production	Company Interest Revenue ⁽¹⁾	Royalty Burdens ⁽²⁾	Net Revenue After Royalty Burdens	Alberta Royalty Tax Credit	Operating Expenses ⁽³⁾	Other Net Income ⁽⁴⁾	Abandonmen t Costs	Net Capital Investment	Net Cash Flow Before Income Taxes ⁽⁵⁾⁽⁶⁾
	(mboe)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)
2003.....	10,869	412.4	86.1	326.3	0.5	57.2	3.9	2.7	21.6	249.2
2004.....	10,233	388.0	79.7	308.4	0.5	56.0	4.4	3.4	23.1	230.8
2005.....	9,134	345.8	68.9	276.9	0.5	52.7	4.5	3.8	10.7	214.7
2006.....	8,014	303.1	58.3	244.8	0.5	48.7	4.3	3.4	6.3	191.1
2007.....	6,990	264.3	49.2	215.1	0.5	45.1	4.0	3.6	3.8	167.1
2008.....	6,087	230.3	41.6	188.7	0.5	41.8	3.6	1.5	3.6	145.9
2009.....	5,323	201.5	35.6	165.9	0.5	38.2	3.5	1.6	2.0	127.9
2010.....	4,690	177.5	30.8	146.7	0.5	34.8	3.0	1.6	2.8	111.0
2011.....	4,145	157.0	26.7	130.3	0.4	31.9	2.8	1.3	2.8	97.6
2012.....	3,677	139.3	23.3	115.9	0.4	29.0	2.6	1.5	3.4	85.0
2013.....	3,299	124.8	20.6	104.3	0.4	26.3	2.5	1.5	2.6	76.8
2014	2,969	112.4	18.3	94.1	0.4	24.5	2.2	0.9	2.0	69.3
Remainder..	30,543	1,161.0	173.7	987.3	2.9	290.7	20.0	18.2	7.9	693.5
TOTAL.....	105,975	4,017.4	712.7	3,304.6	8.5	777.0	61.3	45.0	92.7	2,459.9

Total net cash flow before income taxes discounted at:

10 percent: \$1,303 million

15 percent: \$1,072 million

20 percent: \$917 million

Notes:

1. Includes working-interest revenue and royalty-interest revenue.
2. Includes royalties net of gas processing allowances.
3. Includes other expenses, capital taxes and certain third party processing income.
4. Includes other income less net profits interest payments and mineral taxes.
5. Undiscounted.
6. Net cash flow before income taxes is stated prior to interest, general and administrative expenses and management fees.
7. Columns may not add due to rounding.

Principal Properties

The following is a description of the average daily production for the year ending December 31, 2002 and reserves as of January 1, 2003 associated with the significant properties owned by PrimeWest as of January 1, 2003. Remaining Established Reserves, ultimate recovery estimates and working interests contained in the following property descriptions are derived from the Gilbert Report. The term "net" used in the following property descriptions refers to the working interest of PrimeWest in the properties.

Daily Production Volumes by Commodity and Significant Property

	Natural Gas (mcf/d)	Crude Oil (bbls/d)	Natural Gas Liquids (bbls/d)	Total (boe/d)
Dawson				
Dawson	17,841	1,082	—	4,056
Stowe	11,813	287	—	2,256
NorthWest				
NW Alberta	661	—	—	105
NE Alberta	847	—	—	141
Laprise	8,468	—	192	1,603
Boundary Lake	108	1,202	7	1,227
Kaybob	477	374	17	471
Grande Prairie	1,979	75	96	501
Meekwap	304	455	15	521
Central				
Thunder	4,945	46	98	968
Thorsby	21,865	384	794	4,822
Crossfield / Lone Pine Creek	10,336	82	202	2,007
Caroline	5,878	208	275	1,463
SouthEast				
Brant Farrow	8,764	163	13	1,636
Dinosaur/ MedHat	4,944	1	—	825
Grand Forks	2,206	2,999	38	3,404
Jumping Pound / Whiskey Creek	2,691	—	107	555
Saskatchewan	468	562	3	643
Others	4,162	513	74	1,290
Royalties	4,743	806	99	1,695
Total	113,500	9,239	2,030	30,189

Reserves by Commodity and Significant Property

Property	Proved			Probable ⁽¹⁾			Established			Total (mboe)
	Crude Oil (mbbls)	Natural Gas (mmcf)	NGLs (mbbls)	Crude Oil (mbbls)	Natural Gas (mmcf)	NGLs (mbbls)	Crude Oil (mbbls)	Natural Gas (mmcf)	NGLs (mbbls)	
Dawson										
Dawson	808	17,800	—	326	6,280	—	971	20,940	—	4,461
Stowe	717	21,761	—	318	6,673	—	876	25,098	—	5,059
Northwest										
NW Alberta	2	1,896	2	—	516	—	2	2,154	2	363
NE Alberta	—	10,452	—	—	1,573	—	—	11,238	—	1,873
Laprise	—	35,923	833	—	10,028	232	—	40,937	949	7,772
Boundary Lake	5,671	484	35	768	94	6	6,055	531	38	6,182
Kaybob	1,015	568	67	322	186	18	1,176	661	76	1,362
Grande Prairie	274	2,792	162	178	929	64	363	3,257	194	1,100
Meekwap	703	467	22	704	382	17	1,055	658	30	1,195
North Other	582	1,906	46	130	2,232	5	647	3,022	48	1,199
Central										
Thunder	161	8,368	161	36	4,038	80	179	10,387	201	2,111
Thorsby	1,021	73,696	2,595	358	15,303	540	1,200	81,347	2,865	17,623
Crossfield/Lone										
Pine Creek	224	41,720	580	116	23,800	276	282	53,620	718	9,937
Others	130	4,323	89	37	1,329	30	147	4,988	104	1,084
Caroline	1,168	37,140	2,306	238	27,835	1,626	1,287	51,058	3,119	12,916
Southeast										
Brant Farrow	146	17,547	46	86	15,151	29	189	25,122	61	4,437
Dinosaur/Med Hat	—	29,204	—	—	7,309	—	—	32,858	—	5,476
Grand Forks	5,512	3,421	79	1,848	1,337	24	6,436	4,089	91	7,209
Jumping Pound/Whiskey Creek	—	25,410	1,220	—	9,504	492	—	30,162	1,466	6,493
Saskatchewan	1,580	2,094	13	356	1,544	2	1,758	2,866	14	2,250
Others	129	127	—	14	11	—	138	133	—	158
Royalties	1,573	12,371	195	252	1,946	40	1,699	13,344	215	4,138
										104,39
Total	<u>21,416</u>	<u>349,470</u>	<u>8,451</u>	<u>6,087</u>	<u>138,000</u>	<u>3,481</u>	<u>24,460</u>	<u>418,470</u>	<u>10,191</u>	<u>6</u>

Notes:

- 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.
- Based on escalated prices and costs derived from the Gilbert Report.

Oil and Natural Gas Wells

The following table summarizes, as at December 31, 2002, PrimeWest's interests in producing and shut-in wells which it believes are capable of production.

	Producing Wells				Shut-in Wells ⁽¹⁾			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross ⁽²⁾	Net ⁽³⁾	Gross ⁽²⁾	Net ⁽³⁾	Gross ⁽²⁾	Net ⁽³⁾	Gross ⁽²⁾	Net ⁽³⁾
Alberta	1,602	578	1,134	634	658	331	533	348
British Columbia	168	43	27	19	23	13	11	10
Saskatchewan	432	77	120	120	94	32	2	2
Total	<u>2,202</u>	<u>698</u>	<u>1,281</u>	<u>773</u>	<u>775</u>	<u>376</u>	<u>546</u>	<u>360</u>

Notes:

1. "Shut-In" wells means wells which are not producing but which may be capable of production. Shut-in wells in which PrimeWest has an interest are located no further than 10 kilometres from gathering systems, pipelines or other means of transportation.
2. "Gross" wells and acres are defined as the total number of wells and acres in which PrimeWest 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 PrimeWest's percentage working interest therein.

Dawson

The Dawson area consists of extensive land holdings from Twps. 75 to 81 and Ranges 14 to 23W5M, approximately 80 miles northeast of Grande Prairie, Alberta. PrimeWest generally holds a 50 percent working interest in the majority of lands. The lands are located in the Normandville, Dawson, Roxana, Lalby, Fahler, Seal, Stowe and Kimiwan fields. The Dawson area is characterised by natural gas reservoirs located in multiple shallow depth horizons such as the Notekiwen, Fahler, BlueSky, Shunda and Debolt formations. The deep oil production originates in the Beaverhill Lake and Slave Point formations.

PrimeWest operates the majority of its activities in this area. PrimeWest operates three gas processing plants, which have 20 mmcf/d of capacity, net to PrimeWest.

Northwest

PrimeWest's significant holdings in the Northwest Alberta area are located in Twps. 90 to 97, Range 21W5 to Range 3W6M, approximately 100 miles southeast of Rainbow Lake, Alberta. The lands are located in the Hotchkiss, Naylor, Sutton and Keg River Post fields. The Northwest Alberta area is characterized by oil and natural gas reservoirs located in multiple, shallow to medium depth horizons. The area produces oil and natural gas from the Gilwood formation, as well as natural gas from the Bluesky, Gething, Debolt, Shunda and Slave Point formations. PrimeWest's current focus in this area is the development of natural gas reserves in the shallow Cretaceous formations. PrimeWest operates a gas processing plant in the area that has 22 mmcf/d of capacity.

Included in the NorthWest are Meekwap, NE B.C., Kaybob, and Grande Prairie.

Meekwap

Meekwap is comprised of the Nisku D2A unitized waterflood with a 48% PrimeWest working interest. PrimeWest operates this property.

Northeast B.C.

Northeast B.C. is comprised of Boundary Lake and Laprise.

The Boundary Lake area is located approximately 25 miles east of Fort St. John, British Columbia on the British Columbia/Alberta border. The Boundary Lake Field was discovered in 1955. The productive horizon is the Boundary Lake member of the Triassic Charlie Lake Formation at a depth of approximately 4,200 feet, which produces a 35-degree API light-gravity crude oil and solution gas. PrimeWest operates and PrimeWest has a 100 percent working interest in both Boundary Lake Project No. 1, and Boundary Lake Project No. 2 (both projects are located in British Columbia), varying working interests averaging 4.2 percent in three producing oil wells operated by Imperial Oil Limited in the British Columbia portion of the field and a 25 percent working interest in a producing oil well operated by PrimeWest in the Alberta portion of the field. PrimeWest also has a 2.1 percent working interest in the Boundary Lake Unit No. 1.

The Laprise Creek area is located in northeast British Columbia, approximately 110 miles northwest of Fort St. John, British Columbia. Gas is produced from the Baldonnel Formation at a depth of approximately 4,200 feet. The Laprise Creek Baldonnel "A" Pool is one of British Columbia's largest natural gas pools, having original gas-in-place of 880 bcf. PrimeWest has a 75.6 percent working interest in the Laprise Creek Baldonnel Unit No. 1, which is operated by PrimeWest. The Unit consists of 20 (15.1 net) producing natural gas wells and one (0.76 net) suspended well. In addition, PrimeWest has a 100 percent interest in one producing non-unit gas well.

Kaybob

The Kaybob South area is located approximately 150 miles northwest of Edmonton, Alberta and consists of oil and solution gas production from the Kaybob South Triassic "A" Pool at a depth of approximately 7,000 feet. PrimeWest has a 42.5 percent working interest in the Kaybob South Triassic Unit No. 1 and a 20.1 percent working interest in the Kaybob South Triassic Unit No. 2, both of which are operated by PrimeWest.

Caroline

The Caroline area is located approximately 60 miles northwest of Calgary, Alberta. Production in the area is obtained from the Cardium, Viking and Manville formations. PrimeWest owns a high working interest and is the operator of this predominantly gas producing area.

The properties include working interests ranging from gross overriding royalty interests to 100%. Average net daily production in 2001 was 2,344 boe/d and in September 2002 was 2,810 boe/d.

On January 23, 2003, PrimeWest acquired additional reserves and production at Caroline, consistent with the Trust's strategy of consolidating interests in an existing core area where a competitive advantage exists and resident technical skills can be

leveraged. Caroline is now the Trust's largest core operating area with production of 5,500 boe/d.

Effective December 18, 2001, the East Caroline portion of the Caroline properties were sold.

At Caroline, the Trust acquired, effective January 1, 2003, a 100% interest in the 25 mmcf/d Sundre Gas Plant and related gas gathering infrastructure in addition to liquids rich natural gas production and reserves. PrimeWest plans to process certain of the Trust's preacquisition volumes as well as new development production through this plant at lower processing costs, relative to what it has previously incurred in this area.

Future reserve growth in this area will be enhanced by a significant farm-in opportunity on undeveloped lands, including the right to purchase the farmor's share of developed reserves at a future date. Furthermore, an area of mutual interest has been established focused on low risk, high impact gas development drilling activities.

Central

The Central area encompasses properties at Thorsby, Thunder and Crossfield/Lone Pine Creek. These properties are located between Calgary and Edmonton.

Crossfield / Lone Pine Creek

The Crossfield/Lone Pine Creek area is located 20 miles north of Calgary, Alberta and was discovered in 1960. Production of natural gas and natural gas liquids occurs from the Elkton, Wabamun (Crossfield), Leduc, Viking and Nisku Formations.

All operated natural gas production is processed at the East Crossfield Sour Gas Processing Facility. The East Crossfield gas processing facility has a throughput capacity of 74 mmcf/d. Originally, PrimeWest had a 20 percent interest in the facility. Effective January 5, 2000, PrimeWest acquired Amoco's 34.6 percent interest and became operator of the facility. In May 2000, PrimeWest sold a 25.8 percent interest to a third party for cash and a dedication of the third party gas reserves and adjacent levels to the plant on a life reserves basis. After this sale, PrimeWest's ownership in the facility is 28.8 percent. All of PrimeWest's natural gas produced from this area is processed on a plant operating-cost basis. During 2002, plant utilization was approximately 50 percent. Other major facilities owned by PrimeWest in respect of this property include the Lone Pine Creek Central Gathering and Compression Facility (42.8 percent interest), the Lone Pine Creek Waukesha Compressors (50.1 percent interest), the Lone Pine Creek D-1 Unit Booster Compressor (68.4 percent interest) and the Lone Pine Creek to East Crossfield Amalgamation Pipeline (40.2 percent interest).

PrimeWest has no ownership interest in the Sulphur Block or any liability related to future clean-up costs.

Thorsby

The Thorsby property is located in Twps. 47 to 50, Ranges 27 W4 to Range 2 W5M, approximately 35 miles southwest of Edmonton, Alberta. The lands are located in the Pembina, Thorsby, Holburn, Wizard Lake and Bonnie Glen fields. PrimeWest holds an average 83 percent working interest in this natural gas and crude oil producing area.

The majority of the production is derived from regionally extensive Glauconitic Sandstone.

SouthEast

Brant/Farrow

The Brant/Farrow property is located in Twps. 18 to 21, Ranges 23 to 26 W4M, approximately 40 miles southeast of Calgary. The lands are located in the Brant, Farrow, Mossleigh and Herronton fields. Gas is the major product constituting approximately 95 percent of the total production volumes. The Brant/Farrow area is characterised by shallow to medium depth natural gas and oil reservoirs. The area produces from the Mississippian, Basal Quartz, Glauconite, Belly River, and Medicine Hat formations.

When acquired, the majority of production was from deep, high decline formations. Since the acquisitions, PrimeWest has redirected development to low risk, shallow drilling in the Belly River and Medicine Hat Formations. For the year ended December 31, 2002 PrimeWest drilled 12 gross (9 net) wells in the area. This area is a high activity development area and further drilling is expected.

PrimeWest operates two gas-processing plants in the area, which have 15 mmcf/d of capacity.

Dinosaur/Medicine Hat

The Dinosaur area is located approximately 110 miles east of Calgary. PrimeWest owns a 51 percent operated interest in both the Patricia Gas Unit #1 and the Dinosaur Gas Unit #1. There are currently 69 producing gross (35.2 net) wells in the Patricia Unit and 25 producing gross (12.75 net) wells in the Dinosaur Unit.

The Medicine Hat property covers a 25 mile radius around Medicine Hat, Alberta. PrimeWest is working interest owner and operator of the Medicine Hat Consolidated Unit #2, which is located 25 miles northeast of Medicine Hat. Gas is produced from the Medicine Hat "A", "C", "D", Lower Colorado and Milk River

Zones". In 2002, the Medicine Hat Consolidated Owners installed their own compression which helped alleviate the custom processing charges previously paid.

Both the Dinosaur and Medicine Hat properties are shallow gas plays with low operating costs, stable production, and long reserve life indexes.

Grand Forks

The Grand Forks property is located 45 miles west of Medicine Hat, Alberta. Crude oil reserves are found predominantly in the Sawtooth and Arcs (Nisku) formations at an average depth of 3,100 feet. PrimeWest has an average 73 percent working interest in 190 (138.7 net) producing oil wells and a 94 percent working interest in 10 (9.4 net) producing gas wells.

Jumping Pound West / Whiskey Creek

PrimeWest has a 14.6 percent interest in the Jumping Pound West Unit No. 2 operated by Shell Canada Limited and located 30 miles west of Calgary. The unitized zone is in the Rundle Formation. Production from the unit commenced in 1972 and is currently coming from 12 natural gas wells. Production is processed at the adjacent Jumping Pound Unit No. 1 plant facilities on a custom-processing-fee basis. The production is slightly sour and liquids rich, yielding 40 bbls of liquids per mmcf of natural gas.

Whiskey Creek is a non-operated property that has one well on production and tied-in with another well completed and currently waiting to be tied in. The third well is currently being drilled.

Both the Jumping Pound and Whiskey Creek properties have deep thrustured Mississippian reservoirs characterized with long-life, stable production and long reserve life indexes.

Early in 2002, the joint venture partners experienced a pipeline failure which halted production. The well resumed production in February 2003.

Gross Overriding Royalty (GORR) Interests

These interests, principally acquired from Reserve Royalty Corp. in July 2000, entitle PrimeWest to a share of the gross sales price on production from the underlying properties generally without deduction for royalties and operating expenses. As well, as the owner of the GORR interest, PrimeWest is not generally responsible for any capital costs or abandonment and restoration costs associated with any exploration or development activities undertaken by the underlying working interest owner of the lands subject to the GORR.

Unproved Lands

PrimeWest has an interest in approximately 1,286,883 (938,683 net) acres of unproved lands at December 31, 2002. PrimeWest is currently reviewing available seismic and other data, and developing an exploitation plan for these properties. Capital expenditures, farmouts and/or dispositions may result in future revenues from these undeveloped lands. The province and value of the unproved lands is as follows:

	<u>Gross Acres</u>	<u>Net Acres</u>	<u>Gross Royalty Acres</u>	<u>Total Net Acres</u>	<u>Value of Net Acres</u>
Alberta	1,062,147	724,567	165,723	890,290	\$43,467,422
B.C.	13,482	4,202	0	4,202	350,820
Sask	6,463	5,123	39,068	44,191	416,498
Total	1,082,092	733,892	204,791	938,683	\$44,234,740

	<u>2002</u>		<u>Net Value</u>	<u>2001</u>		<u>Net Value</u>
	<u>Acres</u>	<u>Acres</u>		<u>Acres</u>	<u>Acres</u>	
	<u>Gross</u>	<u>Net</u>	<u>(\$)</u>	<u>Gross</u>	<u>Net</u>	<u>(\$)</u>
UNPROVED LANDS						
Dawson						
Dawson	236,488	144,647	\$11,571,760	247,608	156,229	\$14,129,465
Stowe	218,571	201,885	9,084,825	8,256	4,992	8,884,822
Other	6,880	4,160	270,400	158,467	144,842	697,859
Northwest						
NW Alberta	28,000	19,554	586,620	32,699	22,835	685,050
NE B.C.	13,482	4,202	350,820	14,830	4,622	323,540
Kaybob	7,200	1,420	78,100	7,920	1,562	109,340
Meekwap	7,040	3,166	221,620	8,096	3,640	254,800
GP	20,347	15,840	633,600	23,399	18,216	1,275,120
Other	81,574	41,249	2,580,545	71,731	35,065	3,895,369
Caroline						
Caroline	49,362	35,802	2,506,140	47,489	35,063	1,402,550
Central						
Thorsby	62,048	48,775	2,194,875	56,931	49,011	3,430,770
Crossfield / Lone Pine Creek	45,178	23,866	2,413,575	46,468	35,781	2,504,670
Thunder	53,920	24,987	1,124,415	67,680	33,813	2,366,910
Other	36,168	11,854	766,000	44,439	21,224	2,307,444
Southeast						
Brant Farrow	116,888	88,090	5,285,400	78,609	60,414	4,228,980
Dinosaur/Medicine Hat	13,907	9,618	376,950	15,530	13,779	543,127
Grand Forks	43,732	20,328	813,120	48,835	29,122	1,971,582
Jumping Pound / Whiskey Creek	5,438	4,095	163,800	6,073	5,867	236,011
Saskatchewan	6,463	5,123	237,425	7,109	5,635	394,450
Other	29,406	25,231	926,840	32,466	26,754	2,344,729
Total Working Interest Acres	1,082,092	733,892	42,186,830	1,024,635	708,466	51,986,588
Gross Royalty Acres	204,791	204,791	2,047,910	244,961	244,961	3,674,415
Total	1,286,883	938,683	\$44,234,740	1,269,596	953,427	\$55,661,003

Industry Conditions

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 PrimeWest or the Trust in a manner materially different than they would affect other oil and gas companies and trusts of similar size. All current legislation is a matter of public record, and PrimeWest is unable to predict what additional legislation or amendments may be enacted.

Pricing and Marketing – Natural Gas

In Canada, the price of natural gas sold intraprovincially, interprovincially or to the United States is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the NEB and the government of Canada. Natural gas exports for a term of less than two years requires a general short term export license while terms greater than two years require a specific license for the particular gas sold (in quantities of not more than 30,000 cubic metres per day). Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issue of such a licence requires the approval of the Governor in Council.

The 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 on such factors as reserve availability, transportation arrangements and market considerations.

Pricing and Marketing – Oil

In Canada, producers of oil negotiate sales contracts directly with oil purchasers. Oil prices are primarily based on worldwide supply and demand. The specific price paid 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 NEB. Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issue of such a licence requires the approval of the Governor in Council.

The North American Free Trade Agreement

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

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

Royalties and Incentives

In addition to federal regulation, each province has legislation and regulations, which govern land tenure, royalties, production rates, environmental protection and other matters. In all Canadian jurisdictions, producers of oil and natural gas are required to pay annual rental payments in respect of Crown leases and royalties and freehold production taxes in respect of oil and natural gas produced from Crown and freehold lands, respectively. 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 governmental 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. These programs reduce the amount of Crown royalties otherwise payable.

Environmental Regulation

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. Environmental legislation provides for

restrictions and prohibitions on releases or emissions of various substances produced 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 facilities sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of that legislation may result in the imposition of fines or issuance of clean-up orders.

PrimeWest is committed to meeting its responsibilities to protect the environment wherever it operates, and anticipates making increased expenditures of both a capital and expense nature as a result of the increasingly stringent laws relating to the protection of the environment. PrimeWest's internal procedures are designed to ensure that the environmental aspects of new developments are taken into account prior to proceeding. PrimeWest believes that it is in material compliance with applicable environmental laws and regulations properties.

Kyoto Protocol

In December of 2002, Canada became a signatory to the Kyoto Protocol. The implementation of this plan has not been fully defined by the federal government. Until an implementation plan is developed it is impossible to assess the impact on specific industries and individual businesses within an industry. It is generally believed that the oil and gas industry, as a major producer of carbon dioxide as a necessary by-product and emission of hydrocarbon production, will bear a disproportionately large share of the anticipated cost of implementation.

Risks Related to Our Business

Volatility in oil and natural gas prices could have a material adverse effect on results of operations and financial condition which, in turn, could affect the market price of the Trust Units and the amount of distributions to Unitholders.

Results of operations and financial condition are dependent on the prices received for the oil and natural gas that the Trust sells. Historically, the markets for oil and natural gas have been volatile and are likely to continue to be volatile in the future. Oil and natural gas prices may fluctuate widely on a daily basis in response to a variety of factors beyond the Trust's control, including:

- global energy policy, including the ability of OPEC to set and maintain production levels and prices for oil;
- political conditions, including the risk of hostilities in the Middle East;
- global and domestic economic conditions;
- weather conditions;

- the supply and price of imported oil and liquified natural gas;
- the production and storage levels of North American natural gas;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the proximity of reserves to, and capacity of, transportation facilities;
- the effect of worldwide energy conservation measures; and
- government regulations.

Any decline in crude oil or natural gas prices may have a material adverse effect on PrimeWest's operations, financial condition, borrowing ability, reserves and the level of expenditures for the development of oil and natural gas reserves. Any resulting decline in PrimeWest's cash flow could reduce distributions.

PrimeWest uses financial derivative instruments and other hedging mechanisms to try to limit a portion of the adverse effects resulting from changes in natural gas and oil commodity prices. To the extent PrimeWest hedges its commodity price exposure, it foregoes the benefits it would otherwise experience if commodity prices were to increase. In addition, its commodity hedging activities could expose PrimeWest to losses. Such losses could occur under various circumstances, including if the other party to a hedge does not perform its obligations under the hedge agreement, the hedge is imperfect or PrimeWest's hedging policies and procedures are not followed. Furthermore, PrimeWest cannot guarantee that its hedging transactions will fully offset the risks of changes in commodities prices.

An increase in operating costs or a decline in PrimeWest's production level could have a material adverse effect on our results of operations and financial conditions and, therefore, could reduce distributions to Unitholders.

Higher operating costs for the underlying properties of the Operating Company will directly decrease the amount of cash flow received by the Trust and, therefore, may reduce distributions to our unitholders. Electricity, chemicals, supplies, reclamation and abandonment and labour costs are a few of the operating costs that are susceptible to material fluctuation.

The level of production from existing properties may decline at rates greater than anticipated due to unforeseen circumstances, many of which are beyond PrimeWest's control. A significant decline in production could result in materially lower revenues and cash flow and, therefore, could reduce the amount available for distributions to Unitholders.

Distributions may be reduced during periods in which PrimeWest makes capital expenditures or debt repayments using cash flow.

To the extent that PrimeWest uses cash flow to finance acquisitions, development costs and other significant expenditures, the net cash flow that the Trust receives from PrimeWest will be reduced. Hence, the timing and amount of capital expenditures may affect the amount of net cash flow received by the Trust and, as a consequence, the amount of cash available to distribute to Unitholders. Therefore, distributions may be reduced, or even eliminated, at times when significant capital or other expenditures are made.

The board of directors of PrimeWest has the discretion to determine the extent to which cash flow from PrimeWest will be allocated to the payment of debt service charges as well as the repayment of outstanding debt, including under the credit facility. Funds used for such purposes will not be payable to the Trust. As a consequence, the amount of funds retained by PrimeWest to pay debt services charges or reduce debt will reduce the amount of cash distributed to Unitholders during those periods in which funds are so retained.

A decline in PrimeWest's ability to market its oil and natural gas production could have a material adverse effect on production levels or on the price that it received for production which, in turn, could reduce distributions to Unitholders.

PrimeWest's business depends in part upon the availability, proximity and capacity of gas gathering systems, pipelines and processing facilities. Canadian federal and provincial, as well as United States federal and state, regulation of oil and gas production, processing and transportation, tax and energy policies, general economic conditions, and changes in supply and demand could adversely affect PrimeWest's ability to produce and market oil and natural gas. If market factors change and inhibit the marketing of PrimeWest's production, overall production or realized prices may decline, which could reduce distributions to our unitholders.

Fluctuations in foreign currency exchange rates could adversely affect PrimeWest's business.

The price that PrimeWest receives for a majority of its oil and natural gas is based on United States dollar denominated benchmarks, and therefore the price that PrimeWest receives in Canadian dollars is affected by the exchange rate between the two currencies. A material increase in the value of the Canadian dollar relative to the United States dollar may negatively impact net production revenue by decreasing the Canadian dollars received for a given United States dollar price. To the extent that PrimeWest has engaged, or in the future engages, in risk management activities related to foreign exchange rates, through entry into forward foreign exchange contracts or otherwise, PrimeWest will be subject to unfavourable price changes.

If PrimeWest is unable to acquire additional reserves, the value of the Trust Units and distributions to Unitholders may decline.

The Trust and PrimeWest do not explore for oil and natural gas reserves. Instead, PrimeWest adds to its oil and natural gas reserves primarily through acquisitions. As a result, future oil and natural gas reserves are highly dependent on PrimeWest's success in exploiting existing properties and acquiring additional reserves. PrimeWest also distributes the majority of its net cash flow to Unitholders rather than reinvesting it in reserve additions. Accordingly, if external sources of capital, including the issuance of additional Trust Units, become limited or unavailable on commercially reasonable terms, PrimeWest's ability to make the necessary capital investments to maintain or expand its oil and natural gas reserves will be impaired. To the extent that PrimeWest is required to use cash flow to finance capital expenditures or property acquisitions, the level of cash flow available for distribution to Unitholders will be reduced. Additionally, PrimeWest cannot guarantee that it will be successful in developing additional reserves or acquiring additional reserves on terms that meet its investment objectives. Without these reserve additions, PrimeWest's reserves will deplete and as a consequence, either production from, or the average reserve life of, its properties will decline. Either decline may result in a reduction in the value of Trust Units and in a reduction in cash available for distributions to Unitholders.

Actual reserves will vary from reserve estimates, and those variations could be material.

The value of the Trust Units depends upon, among other things, the reserves attributable to PrimeWest's properties. Estimating reserves is inherently uncertain. Ultimately, actual reserves attributable to PrimeWest's properties will vary from estimates, and those variations may be material. The reserve information contained herein are only estimates. A number of factors are considered and a number of assumptions are made when estimating reserves. These factors and assumptions include, among others:

- historical production in the area compared with production rates from similar producing areas;
- future commodity prices, production and development costs, royalties and capital expenditures;
- initial production rates;
- production decline rates;
- ultimate recovery of reserves;
- success of future development activities;

- marketability of production;
- effects of government regulation; and
- other government levies that may be imposed over the producing life of reserves.

Reserve estimates are based on the relevant factors, assumptions and prices on the date the relevant evaluations were prepared. Many of these factors are subject to change and are beyond PrimeWest's control. If these factors, assumptions and prices prove to be inaccurate, actual results may vary materially from reserve estimates.

If PrimeWest expands its operations beyond oil and natural gas production in western Canada, it may face new challenges and risks. If PrimeWest is unsuccessful in managing these challenges and risks, its results of operations and financial condition could be adversely affected.

PrimeWest's operations and expertise are currently focused on conventional oil and gas production and development in the Western Canadian Sedimentary Basin. In the future, it may acquire oil and gas properties outside this geographic area. In addition, the Declaration of Trust does not limit the activities to oil and gas production and development, and PrimeWest could acquire other energy related assets, such as oil and natural gas processing plants or pipelines. Expansion of PrimeWest's activities into new areas may present challenges and risks that it has not faced in the past. If PrimeWest does not manage these challenges and risks successfully, its results of operations and financial condition could be adversely affected.

In determining the purchase price of acquisitions, PrimeWest relies on assessments relating to estimates of reserves that may prove to be inaccurate.

The price PrimeWest is willing to pay for reserve acquisitions is based largely on estimates of the reserves to be acquired. Actual reserves could vary materially from these estimates. Consequently, the reserves PrimeWest acquires may be less than expected, which could adversely impact cash flows and distributions to Unitholders.

An initial assessment of an acquisition may be based on a report by engineers or firms of engineers that have different evaluation methods and approaches than those of PrimeWest's engineers, and these initial assessments may differ significantly from PrimeWest's subsequent assessments.

Some of PrimeWest's properties are not operated by PrimeWest and, therefore, results of operations may be adversely affected by the failure of third-party operators.

The continuing production from a property, and to some extent the marketing of that production, is dependent upon the ability of the operators of those properties. At

December 31, 2002, approximately 20% of PrimeWest's daily production was from properties operated by third parties. To the extent a third-party operator fails to perform its functions efficiently or becomes insolvent, PrimeWest's revenue may be reduced. Third party operators also make estimates of future capital expenditures more difficult.

Further, the operating agreements which govern the properties not operated by PrimeWest typically require the operator to conduct operations in a good and "workmanlike" manner. These operating agreements generally provide, however, that the operator has no liability to the other non-operating working interest owners, such as Unitholders, for losses sustained or liabilities incurred, except for liabilities that may result from gross negligence or wilful misconduct.

Delays in business operations could adversely affect distributions to Unitholders.

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of PrimeWest's properties, and the delays of those operators in remitting payment to PrimeWest, payments between any of these parties may also be delayed by:

- restrictions imposed by lenders;
- accounting delays;
- delays in the sale or delivery of products;
- delays in the connection of wells to a gathering system;
- blowouts or other accidents;
- adjustments for prior periods;
- recovery by the operator of expenses incurred in the operation of the properties;
or
- the establishment by the operator of reserves for these expenses.

Any of these delays could reduce the amount of cash available for distribution to Unitholders in a given period and expose PrimeWest to additional third party credit risks.

The Trust and PrimeWest's indebtedness may limit the timing or amount of the distributions that are paid to Unitholders.

The payments of interest and principal, and other costs, expenses and disbursements to the providers of the Trust and PrimeWest's credit facility reduces

amounts available for distribution to Unitholders. Variations in interest rates and scheduled principal repayments could result in significant changes to the amount of the cash flow required to be applied to the debt before payment of any amounts to the Unitholders. The credit facility provides that if the Trust or PrimeWest are in default under the credit facility, exceed certain borrowing thresholds or fail to comply with certain covenants, the ability to make distributions to Unitholders may be restricted.

The lenders under the credit facility have been provided with a security interest in substantially all of the Trust's and PrimeWest's assets. If the Trust and PrimeWest are unable to pay the debt service charges or otherwise commit an event of default, such as bankruptcy, these lenders may foreclose on and sell the properties. The proceeds of any sale would be applied to satisfy amounts owed to the creditors. Only after the proceeds of that sale were applied towards the debt would the remainder, if any, be available for distribution to Unitholders.

The current credit facility and any replacement credit facility may not provide sufficient liquidity.

The amounts available under the existing credit facility may not be sufficient for future operations, or the Trust and PrimeWest may not be able to obtain additional financing on economic terms attractive to them, if at all. The existing credit facility is available on a one year revolving basis. If the lenders do not extend the facility at the end of the annual revolving period, the loan will convert to a term basis with 60% of the aggregate principal amount of the loan repayable on the date which is 366 days after that conversion date and the remaining 40% of the aggregate principal amount outstanding repayable on the date which is 365 days after the initial term repayment date. If this occurs, the Trust and PrimeWest may need to obtain alternate financing. Any failure to obtain suitable replacement financing may have a material adverse effect on the business, and distributions to Unitholders may be materially reduced.

The Trust may be unable to successfully compete with other organizations in the Trust's industry.

The oil and natural gas industry is highly competitive. The Trust competes for capital, acquisitions of reserves, undeveloped lands, skilled personnel, access to drilling rigs, service rigs and other equipment, access to processing facilities, pipeline and refining capacity and in many other respects with a substantial number of other organizations, many of which may have greater technical and financial resources than the Trust. Some of these organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market oil and other products on a worldwide basis. As a result of these complementary activities, some of the Trust's competitors may have greater and more diverse competitive resources to draw on than the Trust does.

The industry in which PrimeWest operates exposes the Trust and PrimeWest to potential liabilities that may not be covered by insurance.

PrimeWest's operations are subject to all of the risks associated with the operation and development of oil and natural gas properties, including the drilling of oil and natural gas wells, and the production and transportation of oil and natural gas. These risks and hazards include encountering unexpected formations or pressures, blow-outs, craterings and fires, all of which could result in personal injury, loss of life, or environmental and other damage to PrimeWest's property and the property of others. PrimeWest cannot fully protect against all of these risks, nor are all of these risks insurable. PrimeWest may become liable for damages arising from these events against which PrimeWest cannot insure or against which PrimeWest may elect not to insure because of high premium costs or other reasons. Any costs incurred to repair these damages or pay these liabilities would reduce funds available for distribution to Unitholders.

The operation of oil and natural gas wells could subject PrimeWest to environmental claims and liability.

The oil and natural gas industry is subject to extensive environmental regulation pursuant to local, provincial and federal legislation. A breach of that legislation may result in the imposition of fines or the issuance of "clean up" orders. Legislation regulating the oil and natural gas industry may be changed to impose higher standards and potentially more costly obligations. For example, the 1997 Kyoto Protocol to the United Nation's Framework Convention on Climate Change, known as the Kyoto Protocol, was ratified by the Canadian government in December, 2002 and will require, among other things, significant reductions in greenhouse gases. The impact of the Kyoto Protocol on PrimeWest is uncertain and may result in significant additional costs (future) for PrimeWest's operations. Although PrimeWest has established a reclamation fund for the purpose of funding our estimated future environmental and reclamation obligations based on PrimeWest's current knowledge and expectations, PrimeWest cannot guarantee that it will be able to satisfy its actual future environmental and reclamation obligations.

PrimeWest is not fully insured against certain environmental risks, either because such insurance is not available or because of high premium costs. In particular, insurance against risks from environmental pollution occurring over time (as opposed to sudden and catastrophic damages) is not available on economically reasonable terms. Accordingly, PrimeWest's properties may be subject to liability due to hazards that cannot be insured against, or that have not been insured against due to prohibitive premium costs or for other reasons.

Any site reclamation or abandonment costs actually incurred in the ordinary course of business in a specific period will be funded out of cash flow and, therefore,

will reduce the amounts available for distribution to Unitholders. Should PrimeWest be unable to fully fund the cost of remedying an environmental problem, PrimeWest might be required to suspend operations or enter into interim compliance measures pending completion of the required remedy.

Lower oil and gas prices increase the risk of write-downs of PrimeWest's oil and gas property investments.

Under Canadian accounting rules, the net capitalized cost of oil and gas properties may not exceed a “ceiling limit” that is based, in part, upon estimated future net cash flows from reserves. If the net capitalized costs exceed this limit, PrimeWest must charge the amount of the excess against earnings. If oil and natural gas prices decline, PrimeWest's net capitalized cost may exceed this cost ceiling, ultimately resulting in a charge against PrimeWest's earnings. Under United States GAAP, the cost ceiling is generally lower than under Canadian GAAP because the future net cash flows used in the United States ceiling test are discounted to a present value. Accordingly, PrimeWest would have more risk of a ceiling test write-down in a declining price environment if PrimeWest reported under United States GAAP. While these write-downs would not affect cash flow, the charge against earnings could be viewed unfavourably in the market.

Unforeseen title defects may result in a loss of entitlement to production and reserves.

PrimeWest conducts title reviews in accordance with industry practice prior to any purchase of resource assets. However, these reviews do not guarantee that an unforeseen defect in the chain of title will not arise and defeat PrimeWest's title to the purchased assets. If such a defect were to occur, PrimeWest's entitlement to the production from such purchased assets could be jeopardized and, as a result, distributions to Unitholders may be reduced.

The economic impact on PrimeWest of claims of aboriginal title is unknown.

Aboriginal people have claimed aboriginal title and rights to a substantial portion of western Canada. PrimeWest is not aware that any claims of aboriginal title have been made in respect of its property and assets, and PrimeWest is unable to assess the effect, if any, that any such claim would have on its business and operations.

Risks Related to the Trust Structure and the Ownership of Trust Units

Changes in tax and other laws may adversely affect Unitholders.

Income tax laws, other laws or government incentive programs relating to the oil and gas industry, such as the treatment of mutual fund trusts and resource allowance, may in the future be changed or interpreted in a manner that adversely affects the Trust and Unitholders. Tax authorities having jurisdiction over the Trust or the Unitholders may disagree with how the Trust calculates its income for tax purposes or could change

their administrative practices to the Trust's detriment or the detriment of its Unitholders.

There would be material adverse tax consequences if the Trust lost its status as a mutual fund trust under Canadian tax laws.

It is intended that the Trust continue to qualify as a mutual fund trust for purposes of the *Income Tax Act* (Canada). The Trust may not, however, always be able to satisfy any future requirements for the maintenance of mutual fund trust status. Should the status of the Trust as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise for the Trust and Unitholders. Some of the significant consequences of losing mutual fund trust status are as follows:

- The Trust would be taxed on certain types of income distributed to Unitholders, including income generated by the royalties held by the Trust. Payment of this tax may have adverse consequences for some Unitholders, particularly Unitholders that are not residents of Canada and residents of Canada that are otherwise exempt from Canadian income tax.
- The Trust would cease to be eligible for the capital gains refund mechanism available under Canadian tax laws if it ceased to be a mutual fund trust.
- Trust units held by Unitholders that are not residents of Canada would become taxable Canadian property. These non-resident holders would be subject to Canadian income tax on any gains realized on a disposition of Trust Units held by them.
- The Trust Units would not constitute qualified investments for Registered Retirement Savings Plans, or "RRSPs," Registered Retirement Income Funds, or "RRIFs," Registered Education Savings Plans, or "RESPs," or Deferred Profit Sharing Plans, or "DPSPs." If, at the end of any month, one of these exempt plans holds Trust Units that are not qualified investments, the plan must pay a tax equal to 1% of the fair market value of the Trust Units at the time the Trust Units were acquired by the exempt plan. An RRSP or RRIF holding non-qualified Trust Units would be subject to taxation on income attributable to the Trust Units. If an RESP holds non-qualified Trust Units, it may have its registration revoked by the Canada Customs and Revenue Agency.

In addition, the Trust may take certain measures in the future to the extent the Trust believes them necessary to ensure that the Trust maintains its status as a mutual fund trust. These measures could be adverse to certain holders of Trust Units.

Rights as a Unitholder differ from those associated with other types of investments.

The Trust Units do not represent a traditional investment in the oil and natural gas sector and should not be viewed by investors as shares in the Trust or PrimeWest. The Trust Units represent an equal fractional beneficial interest in the Trust and, as such, the ownership of the Trust Units does not provide Unitholders with the statutory rights normally associated with ownership of shares of a corporation, including, for example, the right to bring “oppression” or “derivative” actions. The unavailability of these statutory rights may also reduce the ability of Unitholders to seek legal remedies against other parties on PrimeWest's behalf.

The Trust Units are also unlike conventional debt instruments in that there is no principal amount owing to Unitholders. The Trust Units will have minimal value when reserves from PrimeWest's properties can no longer be economically produced or marketed. Unitholders will only be able to obtain a return of the capital they invested during the period when reserves may be economically recovered and sold. Accordingly, the distributions received over the life of the investment may not meet or exceed the initial capital investment.

Changes in market-based factors may adversely affect the trading price of Trust Units.

The market price of the Trust's Trust Units is primarily a function of anticipated distributions to Unitholders and the value of the properties owned by PrimeWest and the Trust. The market price of the Trust's Trust Units is therefore sensitive to a variety of market based factors, including, but not limited to, interest rates and the comparability of the Trust Units to other yield oriented securities. Any changes in these market-based factors may adversely affect the trading price of the Trust Units.

The operation of the Trust is entirely independent from the Unitholders and loss of key management and other personnel could impact the business.

Unitholders are entirely dependent on the management of the Trust with respect to the acquisition of oil and gas properties and assets, the development and acquisition of additional reserves, the management and administration of all matters relating to the properties and the administration of the Trust. The loss of the services of key individuals who currently comprise the management team could have a detrimental effect on the Trust. Investors should carefully consider whether they are willing to rely on the existing management before investing in the Trust Units.

There may be future dilution.

One of the Trust's objectives is to continually add to its resource reserves through acquisitions and through development. Because the Trust does not reinvest its cash flow, its success is, in part, dependent on its ability to raise capital from time to time by selling Trust Units. Unitholders will suffer dilution as a result of these offerings

if, for example, the cash flow, production or reserves from the acquired assets do not reflect the additional number of trust units issued to acquire those assets. Unitholders may also suffer dilution in connection with future issuances of Trust Units to effect acquisitions.

The Trust Units have a short prior trading history in the United States and an active trading market has not yet developed and may not develop.

The Trust is a reporting issuer in Alberta, Canada under the *Securities Act* (Alberta) and a reporting issuer or the equivalent in the other provinces of Canada under similar legislation. The Trust Units are currently listed on the Toronto Stock Exchange and the New York Stock Exchange. The Trust Units only began trading on the New York Stock Exchange on November 19, 2002 and, accordingly, prior to the date of this Annual Information Form, there has been only a short period in which a public market for the Trust Units in the United States has had the opportunity to develop. The Trust therefore cannot guarantee that an active trading market will develop or be sustained in the United States. Furthermore, there can be no assurance that an active trading market will be sustained in Canada.

The limited liability of Unitholders is uncertain.

Because of uncertainties in the law relating to investment trusts, there is a risk that a Unitholder could be held personally liable for obligations of the Trust in respect of contracts or undertakings which the Trust enters into and for certain liabilities arising otherwise than out of contracts including claims in tort, claims for taxes and possibly certain other statutory liabilities. Although every written contract or commitment of the Trust must contain an express disavowal of liability of the Unitholders and a limitation of liability to Trust property, such protective provisions may not operate to avoid Unitholder liability. Notwithstanding attempts to limit Unitholder liability, Unitholders may not be protected from liabilities of the Trust to the same extent that a shareholder is protected from the liabilities of a corporation. Further, although the Trust has agreed to indemnify and hold harmless each Unitholder from any costs, damages, liabilities, expenses, charges and losses suffered by the Unitholder resulting from or arising out of that Unitholder not having limited liability, the Trust cannot guarantee that any assets would be available in these circumstances to reimburse Unitholders for any such liability.

The Trust has adopted a Unitholders' rights plan that may discourage a takeover attempt.

Provisions contained in the Trust's Unitholders' rights plan could make it more difficult for a third party to acquire the Trust, even if doing so might be beneficial to Unitholders. The rights plan imposes various procedural and other requirements on a potential bidder, including a requirement that a potential bidder keep the bid open for a period of at least 45 days and that the bid be approved by Unitholders holding at

least 50% of the Trust Units, other than the Trust Units held by the potential bidder. In addition, if a Unitholder acquires more than 20% of the outstanding Trust Units, other Unitholders may, at the discretion of the board of PrimeWest, acquire a number of Trust Units at 50% of the then prevailing market price, causing significant dilution to the 20% Unitholder. These rights may have the effect of delaying or deterring a change of control of the Trust, and could limit the price that investors might be willing to pay in the future for Trust Units.

The redemption rights of Unitholders is limited.

Unitholders have a limited right to require the Trust to repurchase their Trust Units, which is referred to as a redemption right. It is anticipated that the redemption right will not be the primary mechanism for Unitholders to liquidate their investment. The Trust's ability to pay cash in connection with a redemption is subject to limitations. Any securities which may be distributed *in specie* to Unitholders in connection with a redemption may not be listed on any stock exchange and a market may not develop for such securities. In addition, there may be resale restrictions imposed by law upon the recipients of the securities pursuant to the redemption right.

ITEM 4: SELECTED CONSOLIDATED FINANCIAL INFORMATION

Reference is made to the consolidated financial statements of the Trust contained in the Annual Report, which financial statements are hereby incorporated into this Annual Information Form by reference.

Selected Annual Information

	For the Year Ended December 31				
(\$000's except per Trust Unit)	2002	2001	2000	1999	1998
Earnings Information					
Total Revenue, net of royalties	264,248	306,515	156,561	83,063	66,057
Expenses, including D, D & A and taxes	263,628	226,979	100,949	77,078	79,604
Net Income (Loss)	620	79,536	55,612	5,985	(13,547)
Net Income (Loss) per Trust Unit (\$)					
Basic	0.02	3.12	5.00	0.72	(1.72)
Diluted	0.02	3.08	4.84	0.72	(1.72)
Cash Distribution Information					
Cash Available for Distribution	159,546	236,834	79,832	37,728	26,030
Cash Distribution to Trust Unitholders	157,951	234,465	79,033	37,351	25,769
Cash Distribution per Trust Unit (\$)	4.80	9.24	7.08	4.40	3.28
Balance Sheet Information					
Total Assets	1,502,252	1,522,310	441,573	320,210	316,140
Long Term Debt, including current portion	225,000	195,067	79,046	92,286	73,112
Average Trust Units Outstanding (000's)	34,134	25,633	11,162	8,491	7,857

Selected Quarterly Information

(\$000's except per Trust Unit)

	For the Quarters Ended - 2002			
	March 31	June 30	September 30	December 31
Total Revenue, net of royalties	69,442	62,198	63,814	68,794
Expenses including D, D & A and taxes	63,466	68,392	55,636	76,134
Net Income (Loss)	5,976	(6,194)	8,178	(7,340)
Net Income (Loss) per Trust Unit				
Basic	0.05	(0.05)	0.24	(0.19)
Diluted	0.04	(0.05)	0.24	(0.19)

	For the Quarters Ended - 2001			
	March 31	June 30	September 30	December 31
Total Revenue, net of royalties	56,990	87,974	83,105	78,446
Expenses including D, D & A and taxes	32,800	53,742	59,255	81,182
Net Income	24,190	34,232	23,850	(2,736)
Net Income per Unit				
Basic	1.80	1.32	0.80	(0.08)
Diluted	1.76	1.32	0.80	(0.08)

In addition, applicable securities laws require the Trust to provide certain historical financial statements of Cypress in connection with any offering of Trust Units. Those financial statements are attached to this Annual Information Form as Schedule A.

Selected Financial and Operational Information

The information in the tables below sets forth certain quarterly comparative financial and operations data which is intended to supplement the financial and operations results otherwise set forth herein and in the documents incorporated by reference herein.

Average Daily Production Volume (before royalties)

	For the Quarters Ended - 2002			
	March 31	June 30	September 30	December 31
Crude Oil (bbls/d)	10,244	8,990	8,975	8,766
Natural Gas Liquids (bbls/d)	2,240	2,055	1,950	1,878
Natural Gas (mmcf/d)	113.3	111.1	115.5	114.2

	For the Quarters Ended - 2001			
	March 31	June 30	September 30	December 31
Crude Oil (bbls/d)	6,988	11,453	11,216	10,425
Natural Gas Liquids (bbls/d)	1,613	2,614	2,414	2,441
Natural Gas (mmcf/d)	49.6	127.7	121.3	119.7

Average Margins - Crude Oil and NGLs (per bbl)

	For the Quarters Ended - 2002			
	March 31	June 30	September 30	December 31

Average net product price	32.07	31.62	34.57	33.12
Royalties	4.40	4.89	6.36	6.81
Operating expenses ⁽¹⁾	5.10	5.44	5.38	6.16
Margin received	20.58	21.29	22.83	20.15

For the Quarters Ended - 2001

	<u>March 31</u>	<u>June 30</u>	<u>September 30</u>	<u>December 31</u>
Average net product price	33.05	35.35	32.37	28.98
Royalties	5.78	6.42	6.24	4.32
Operating expenses ⁽¹⁾	5.49	4.80	6.08	5.69
Margin received	21.78	24.13	20.05	18.97

Note:

1. Operating expenses have been allocated to crude oil and NGLs produced based on the relative production of crude oil and NGLs as compared to production of natural gas.

Average Margins – Natural Gas (per mcf)

	For the Quarters Ended – 2002			
	March 31	June 30	September 30	December 31
Average net product price	4.38	4.47	4.07	5.09
Royalties	0.57	0.97	0.73	1.02
Operating expenses ⁽¹⁾	0.85	0.91	0.90	1.03
Margin received	3.15	2.60	2.45	3.04

	For the Quarters Ended – 2001			
	March 31	June 30	September 30	December 31
Average net product price	10.38	6.21	5.32	5.16
Royalties	2.50	1.70	0.75	0.67
Operating expenses ⁽¹⁾	0.92	0.81	0.91	0.95
Margin received	6.96	3.70	3.66	3.54

Note:

- Operating expenses have been allocated to natural gas produced based on the relative production of natural gas as compared to production of crude oil and NGLs.

Capital Expenditures (in thousands)

	For the Quarters Ended – 2002			
	March 31	June 30	September 30	December 31
Property acquisitions	291	1,089	25,062	33,164
Exploration, including drilling	-	-	-	-
Development, including facilities	23,339	6,536	15,429	17,843
Other ⁽¹⁾	1,128	1,187	1,337	2,256

	For the Quarters Ended – 2001			
	March 31	June 30	September 30	December 31
Property acquisitions	\$ 767,569	\$ 4,713	\$ 2,894	\$ 47,422
Exploration, including drilling	-	-	-	-
Development, including facilities	6,197	16,132	24,608	33,510
Other ⁽¹⁾	666	575	609	1,607

Note:

- Other capital expenditures include capitalized general and administrative expenses and other corporate expenditures.

ITEM 5: MANAGEMENT'S DISCUSSION AND ANALYSIS

Reference is made to the information under the heading "Management's Discussion and Analysis" in the Annual Report, which information is hereby incorporated into this Annual Information Form by reference.

ITEM 6: MARKET FOR SECURITIES

The outstanding Trust Units of the Trust are listed for trading on the Toronto Stock Exchange under the symbol PWI.UN and on the New York Stock Exchange under the symbol PWI. The outstanding Class A Exchangeable Shares of PrimeWest are listed for trading on the Toronto Stock Exchange under the symbol PWX.

ITEM 7: DIRECTORS AND OFFICERS

The Trust has no directors or officers. The following information pertains to the board of directors of PrimeWest and the officers of PrimeWest.

Directors

The Trust has the right to nominate and elect a majority of the board of directors of PrimeWest to serve until the next annual meeting of Unitholders. The names of the nominees for election as directors, their municipalities of residence, principal occupations, year in which each became a director of PrimeWest and numbers of Trust Units beneficially owned or over which control or direction is exercised by such persons, as at December 31, 2002, are as follows:

Name and Present Principal Occupation or Employment	Director of PrimeWest Since	Municipality of Residence	Trust Units Beneficially Owned or over which Control or Discretion is Exercised as at December 31, 2002
HAROLD P. MILAVSKY ⁽¹⁾⁽²⁾⁽³⁾ Chairman Quantico Capital Corp.	1996	Calgary, Alberta	19,152
BARRY E. EMES ⁽³⁾ Partner Stikeman Elliott LLP	1996	Calgary, Alberta	2,250
HAROLD N. KVISLE ⁽¹⁾⁽²⁾⁽³⁾ President TransCanada PipeLines Limited	1996	Calgary, Alberta	10,911
KENT J. MACINTYRE Independent Businessman	1996	Calgary, Alberta	696,940 ⁽⁴⁾
MICHAEL W. O'BRIEN ⁽¹⁾⁽²⁾⁽³⁾ Corporate Director	2000	Canmore, Alberta	2,500
W. GLEN RUSSELL ⁽¹⁾⁽²⁾⁽³⁾ Management Consultant	2003	Calgary, Alberta	Nil

Notes:

1. Member of the Audit and Reserves Committee.
2. Member of the Compensation Committee.
3. Member of the Corporate Governance and Nominating Committee.
4. Includes Trust Units and 1,032,030 Class A Exchangeable Shares (which, at December 31, 2002, were exchangeable into 386,537 Trust Units), of which 250,158 Trust Units and all Class A Exchangeable Shares were held by Canadian Income Fund Group Inc., a corporation wholly-owned by Mr. MacIntyre.

Each of the foregoing persons has been engaged in the occupation set forth above or similar occupations with the same employer for the five preceding years, other than: (a) Mr. Kvisle who prior to May 2001 was Senior Vice President, Energy Operations of TransCanada Pipelines Limited (October 1999 to May 2001) and prior to October 1999 was President of Fletcher Challenge Energy Canada Inc.; (b) Mr. MacIntyre who prior to January 2003 was Vice-Chairman and Chief Executive Officer of PrimeWest; (c) Mr. O'Brien who prior to June 2002 was Executive Vice President, Corporate Development and Chief Financial Officer of Suncor Energy Inc. (December 1999 to June 2002) and prior to December 1999 was Executive Vice-President of Sunoco Inc., a wholly-owned subsidiary of Suncor Energy Inc.; and (d) Mr. Russell who prior to January 1998 was President and Chief Operating Officer of Chauvco Resources Ltd.

Officers

The name, municipality of residence, position held and holdings of Trust Units by each officer of PrimeWest on the date hereof are set out below:

Name and Municipality	Principal Occupation	Trust Units Beneficially Owned or over which Control or Discretion is Exercised as at December 31, 2002⁽¹⁾
Donald A. Garner Calgary, Alberta	President and Chief Executive Officer Since January 2003	5,303
Timothy S. Granger Calgary, Alberta	Chief Operating Officer Since January 2003	900
Ronald J. Ambrozy Calgary, Alberta	Vice-President, Business Development Since October 1997	11,915
Dennis G. Feuchuk Calgary, Alberta	Vice-President, Finance and Chief Financial Officer Since October 2001	11,875
James T. Bruvall Calgary, Alberta	Partner, Stikeman Elliott LLP (Secretary of PrimeWest since October 1996)	18,787

Note:

1. Includes holdings of Class A Exchangeable Shares.

Donald A. Garner, President and Chief Executive Officer

Mr. Garner joined PrimeWest in June 2001 and has overall responsibility for leading and overseeing the business direction of the day-to-day business and operations. He has more than 24 years experience in the oil and gas industry. He was

President and Chief Operating Officer of Northstar Energy Corporation from January 1998 to February 2001. Prior to that Mr. Garner spent a good portion of his career at Imperial Oil Limited in various capacities, including executive responsibility for the Oilsands Business Unit.

An engineering graduate of the University of Saskatchewan, Mr. Garner has undertaken postgraduate studies through the Wharton School, The American Graduate School of International Management and University of Calgary.

Timothy S. Granger, Chief Operating Officer

Mr. Granger joined PrimeWest in June 1999 and has overall responsibility for the day-to-day business and operations of PrimeWest. Mr. Granger has more than 22 years of extensive experience in exploitation, production operations and asset management. From 1996 to 1999, Mr. Granger held various managerial positions at Pogo Canada Ltd. and Petro-Canada, including production engineering and upstream and corporate information technology. Prior to 1996, Mr. Granger held various management positions at Amerada Hess. From 1980 to 1991, Mr. Granger held various engineering positions at Dynex Petroleum, Canterra Energy and Dome Petroleum. Mr. Granger holds a P.Eng. (Mechanical) from Carlton University.

Ronald J. Ambrozy, Vice-President, Business Development

Mr. Ambrozy has over 28 years of experience in the petroleum and natural gas industry. Prior to joining PrimeWest in 1997, Mr. Ambrozy held progressively more senior positions at Gulf Canada Resources Limited, as well as manager of Gulf's asset management group. Mr. Ambrozy has a Bachelor of Science in Engineering from the University of Manitoba.

Dennis G. Feuchuk, Vice-President, Finance and Chief Financial Officer

Mr. Feuchuk joined PrimeWest in October 2001 and is responsible for the general financial operations of PrimeWest including tax and accounting matters. Mr. Feuchuk has over 27 years of experience in finance, accounting, audit and income tax in the oil and natural gas industry. He was Vice President, Controller of Gulf Canada Resources from February 1995 to February 2001. Mr. Feuchuk also was Vice President and Treasurer of Athabasca Oil Sands Trust from inception in December 1995 to February 2001. Mr. Feuchuk has a Bachelor of Business Management from Ryerson University and has completed the Richard Ivey School of Business Executive Development Program and is a Certified Management Accountant.

Employees

As of December 31, 2002, PrimeWest had 144 employees.

Potential Conflicts of Interest

Mr. Emes, a director of PrimeWest, and Mr. Bruvall, the Secretary of PrimeWest, are partners in a law firm which provides services to PrimeWest.

The Board of Directors of PrimeWest does not believe that any of the activities set forth above and undertaken by such individuals interferes in any way with their ability to act in their respective capacities for PrimeWest and with a view to the best interests of PrimeWest.

ITEM 8: ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Trust's securities, interests of insiders in material transactions and the compensation of the Manager, where applicable, is contained in the Circular. Additional financial information is provided in the Trust's consolidated comparative financial statements for the year ended December 31, 2002, contained in the Annual Report.

Upon request to the Secretary of PrimeWest, the Trust will provide one copy of this Annual Information Form, together with one copy of any document incorporated herein by reference, one copy of the Annual Report (including the consolidated comparative financial statements of the Trust for the year ended December 31, 2002 and accompanying report of the auditors), one copy of any interim financial statements subsequent to the consolidated financial statements for the year ended December 31, 2002 and a copy of the Circular dated April 1, 2003.

When securities of the Trust are in the course of a distribution pursuant to a short-form prospectus, or a preliminary short form prospectus has been filed in respect of a distribution of the Trust's securities, copies of the foregoing documents and any other documents that are incorporated by reference into the short form prospectus or preliminary short-form prospectus may also be obtained from the Secretary of PrimeWest.

GLOSSARY OF ABBREVIATIONS & TERMS

Abbreviations

In this Annual Information Form measurements are given in standard Imperial or metric units only. The following table sets forth certain standard conversions:

bbls	Barrels	mcf/d	1,000 cubic feet per day
mbbls	1,000 barrels	bcf	1,000,000,000 cubic feet
mmbbls	1,000,000 barrels	m	1000 cubic metres
bbls/d	Barrels per day	boe	barrels of oil equivalent
mcf	1,000 cubic feet	mboe	1,000 barrels of oil

mmcf	1,000,000 cubic feet	boe/d	equivalent barrels of oil equivalent per day
mlt	1,000 long tons	mmboe	millions of barrels of oil equivalent

For purposes of this document, 6 mcf of natural gas and 1 bbl of NGLs each equal 1 bbl of oil. This conversion rate is not based on price or energy content.

Definitions

In this Annual Information Form, the capitalized terms set forth below have the following meanings:

Annual Report means the 2002 Annual Report of PrimeWest Energy Trust filed on SEDAR at www.sedar.com.

ARTC means Alberta royalty tax credit.

Cash Distribution Date means the date Distributable Income is paid to Unitholders, currently being the 15th day following any Record Date.

Circular means the Management Proxy Circular of PrimeWest Energy Trust, to be dated on or about April 1, 2003.

Class A Exchangeable Shares means class A exchangeable shares in the capital of PrimeWest.

Computershare means Computershare Trust Company of Canada.

Consolidation means the consolidation of the Trust Units on a one for four basis, effective August 16, 2002.

Credit Facility means a bank syndication of Canadian chartered banks offering a maximum borrowing capability of \$490 million.

Cypress means Cypress Energy Inc.

Declaration of Trust means the declaration of trust dated August 2, 1996 among the Trustee, PrimeWest and the Initial Unitholder (as therein defined), as amended and restated as of October 26, 2001, as amended from time to time.

Distributable Income means all amounts received by the Trust in respect of the Royalty, ARTC and other income, less certain expenses and other deductions.

DRIP means the Distribution Reinvestment Plan of the Trust.

Established Reserves, Proved Reserves and **Probable Reserves** have the meanings given to those terms in this Annual Information Form under the heading "Oil and Natural Gas Reserves".

General and Administrative Costs means the amount in aggregate representing all expenditures and costs incurred by or in respect of PrimeWest, the Trust or the Royalty or in the management and administration of PrimeWest, the Trust or the Royalty.

Gilbert means Gilbert Laustsen Jung Associates Ltd.

Gilbert Report means the reserve report prepared by Gilbert evaluating the crude oil, natural gas, natural gas liquids and sulphur reserves attributable to properties owned by PrimeWest and the Trust as at January 1, 2003.

Manager means PrimeWest Management Inc.

NEB means National Energy Board.

Net Production Revenue in respect of any period for which Net Production Revenue is calculated means the aggregate of:

- (a) the amount received or receivable by PrimeWest in respect of the sale of its interest in all Petroleum Substances produced from the properties;
- (b) Crown royalties and other Crown charges which are not deductible for income tax purposes to the extent those royalties are not included in the amounts described in paragraph (a);
- (c) PrimeWest's share of all other revenues which accrue in respect of the properties including, without limitation,
 - (i) fees and similar payments made by third parties for the processing, transportation, gathering or treatment of their Petroleum Substances in facilities that are part of the properties,
 - (ii) proceeds from the sale or licensing of seismic and similar data,
 - (iii) incentives, rebates and credits in respect of production costs or in respect of capital expenditures,
 - (iv) overhead and other cost recoveries,
 - (v) royalties and similar income; and
- (d) ARTC applicable to the properties;

less

- (e) the amount of non-capital operating costs paid or payable by or on behalf of PrimeWest in respect of operating the properties including, without limitation, the costs of gathering, compressing, processing, transporting and marketing all Petroleum Substances produced therefrom and all other amounts paid to third parties which are calculated with reference to production from the properties including, without limitation, gross overriding royalties and lessors' royalties, but excluding Crown royalties and other Crown charges and any site reclamation and abandonment costs.

Oil & Gas means PrimeWest Oil and Gas Corp.

Person means an individual, a body corporate, a partnership (limited or general), a joint venture, a trust, a pension fund, a union, a government and a governmental agency.

Petroleum Substances means petroleum, natural gas and related hydrocarbons (except coal) including, without limitation, all liquid hydrocarbons, and all other substances, including sulphur, whether gaseous, liquid or solid and whether hydrocarbon or not, produced in association with those petroleum, natural gas or related hydrocarbons.

PrimeWest means PrimeWest Energy Inc., a wholly-owned subsidiary of the Trust.

PrimeWest Royalty means PrimeWest Royalty Corp.

Record Date means the last day in each month.

Reserve Life Index means the amount obtained by dividing the quantity of reserves by the production of Petroleum Substances from those reserves for the year ending December 31, 2002.

Resources means PrimeWest Resources Ltd.

Rights Plan means the Unitholder Rights Plan of the Trust which is embodied in the Unitholder Rights Plan Agreement dated as of March 31, 1999 between the Trust and the Trust Company of Bank of Montreal as rights agent, as amended and restated as of April 5, 2002 between the Trust and Computershare.

Royalty means the royalty payable by PrimeWest to the Trust pursuant to the Royalty Agreement, which royalty equals 99 percent of Royalty Income.

Royalty Agreement means the amended and restated royalty agreement dated January 1, 2002 between PrimeWest and the Trustee as trustee for and on behalf of the Trust, as amended from time to time, regarding the creation and sale of the Royalty.

Royalty Income in respect of any period for which Royalty Income is calculated means Net Production Revenue less the aggregate of:

- (a) the Debt Service Charges, General and Administrative Costs and taxes (other than Crown royalties but including any capital taxes) payable by PrimeWest or the Trust;
- (b) capital expenditures intended to improve or maintain production from the properties or to acquire additional properties, in excess of amounts borrowed or designated as a deferred purchase price obligation pursuant to the Royalty Agreement, provided that the amount of capital expenditures that can be deducted will not be in excess of 10 percent of the annual net cash flow from the properties in the year before the year in which the determination is made;
- (c) net contributions to PrimeWest's reclamation fund; and
- (d) ARTC applicable to the properties.

Any income derived from properties which are not working, royalty or other interests in Canadian resource properties or which do not relate to production from working, royalty or other interests in Canadian resource properties, will not be included as Royalty Income and will be used to defray other expenses, capital expenditures of PrimeWest and Debt Service Charges.

Trust means PrimeWest Energy Trust.

Trust Units means the units of the Trust, each unit representing an equal undivided beneficial interest in the Trust.

Trustee means Computershare, or its successor as trustee of the Trust.

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

Venator means Venator Petroleum Company Ltd.

SCHEDULE A

FINANCIAL STATEMENTS OF CYPRESS ENERGY INC.

AUDITORS' REPORT

TO: The Shareholders of Cypress Energy Inc.

We have audited the consolidated balance sheets of Cypress Energy Inc. as at December 31, 2000, 1999 and 1998 and the consolidated statements of income and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2000, 1999 and 1998 and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in Canada.

Calgary, Canada
April 16, 2001

(signed) Ernst & Young LLP
Chartered Accountants

CYPRESS ENERGY INC.
CONSOLIDATED BALANCE SHEETS

As at December 31
(in thousands of dollars)

	2000		1999		1998
Assets					
Current assets (note 6)					
Accounts receivable	\$ 31,813	\$	17,112	\$	9,531
Deposits, prepaids and other	2,531		2,452		542
Assets held for resale (note 3)	-		5,395		-
	34,344		24,949		10,073
Property and equipment (note 4)	368,479		270,572		136,489
	\$ 402,823	\$	295,531	\$	146,562
Liabilities and Shareholders' Equity					
Current Liabilities					
Accounts payable and accrued liabilities	\$ 47,870	\$	25,511	\$	10,392
Long-term debt (note 6)	113,889		92,760		34,559
Deferred rental obligation	532		772		-
Future income taxes (note 8)	61,743		8,017		518
Provision for future site restoration	3,972		2,043		618
	180,136		103,592		35,695
Shareholders' Equity					
Share capital (note 7)	149,747		155,478		96,921
Retained earnings	25,070		10,950		3,554
	174,817		166,428		100,475
	\$ 402,823	\$	295,531	\$	146,562
Commitments and contingencies (notes 6 and 10)					
See accompanying notes					

CYPRESS ENERGY INC.

**CONSOLIDATED STATEMENTS OF INCOME
AND RETAINED EARNINGS**

**Years ended December 31
(in thousands of dollars except per share amounts)**

	2000	1999	1998
Revenue			
Petroleum and natural gas sales	\$ 186,763	\$ 78,168	\$ 34,124
Royalties, net of ARTC	(45,180)	(17,270)	(7,098)
	141,583	60,898	27,026
Expenses			
Production	18,394	11,983	6,235
General and administrative	4,453	3,508	1,894
Interest	7,785	3,758	1,281
Depletion, depreciation and site restoration	41,912	26,417	14,332
	72,544	45,666	23,742
Income before income taxes	69,039	15,232	3,284
Income taxes			
Capital taxes	1,178	746	165
Future income taxes (note 8)	29,363	7,049	1,527
	30,541	7,795	1,692
Net income for the year	38,498	7,437	1,592
Retained earnings, beginning of year	10,950	3,554	1,962
Adjustment to reflect adoption of new income tax accounting policy (note 11)	(20,195)	-	-
Acquisition of shares in excess of carrying value	(4,183)	(41)	-
Retained earnings, end of year	\$ 25,070	\$ 10,950	\$ 3,554
Earnings per common share (note 9)			
Basic Class A and Class B shares	\$ 0.90	\$ 0.20	\$ 0.06
Fully diluted	\$ 0.84	\$ 0.20	\$ 0.06

See accompanying notes

CYPRESS ENERGY INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
Years ended December 31
(in thousands of dollars except per share amounts)

	2000	1999	1998
Cash provided by (used in):			
Operating Activities			
Net income for the year	\$ 38,498	\$ 7,437	\$ 1,592
Non-cash items			
Depletion, depreciation and site restoration	41,912	26,417	14,332
Future income taxes	29,363	7,049	1,527
Cash flow from operations	109,773	40,903	17,451
Net change in non-cash working capital items	12,734	1,561	2,525
	122,507	42,464	19,976
Funding Activities			
Increase in long-term debt	21,129	31,373	7,043
Issue of Class A flow-through shares	-	3,731	1,995
Issue of Special Warrants	-	-	20,600
Issue of Class A shares on exercise of stock options	1,378	991	688
Repurchase of Class A shares	(9,577)	(129)	(3)
Share issue and repurchase costs (note 7)	(47)	(1,724)	(1,157)
	12,883	34,242	29,166
Investing Activities			
Additions to property and equipment	(135,096)	(79,732)	(48,917)
Cash expenditures on acquisitions (note 5)	-	(3,682)	-
Cash acquired on acquisition (note 5)	-	6,905	-
Site restoration and abandonment expenditures	(294)	(197)	(225)
	(135,390)	(76,706)	(49,142)
Change in cash and cash, beginning and end of year	-	-	-
Cash flow from operations per common share (note 9)			
Basic Class A and Class B shares	\$ 2.56	\$ 1.09	\$ 0.68
Fully diluted	\$ 2.39	\$ 1.04	\$ 0.60

See accompanying notes

CYPRESS ENERGY INC

Notes to the Consolidated Financial Statements

December 31, 2000, 1999 and 1998

(thousands of dollars except per share amounts)

1. DESCRIPTION OF THE BUSINESS

Cypress Energy Inc. ("Cypress" or the "Company") was incorporated under the laws of the Province of Alberta on November 16, 1995. The Company's business is related to the acquisition of petroleum and natural gas rights and the exploration for, and the development, exploitation and production of, petroleum and natural gas in Canada.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles which, in management's opinion, have been properly prepared within reasonable limits of materiality and within the framework of the accounting policies summarized below.

Property and Equipment

Capitalized Costs

The Company follows the full cost method of accounting in accordance with the guidelines issued by the Canadian Institute of Chartered Accountants whereby all costs associated with the exploration for and development of petroleum and natural gas reserves, whether productive or unproductive, are capitalized and charged to income as set out below. Such costs include lease acquisition, drilling, geological and geophysical, equipment costs, staff costs and certain overhead expenses directly related to exploration and development activities. Costs of acquiring and evaluating unproved properties are excluded from depletion calculations until it is determined whether or not proved reserves are attributable to the properties or when impairment occurs.

Gains or losses are not recognized upon disposition of petroleum and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the rate of depletion of 20 percent or more.

Depletion and Depreciation

Depletion of petroleum and natural gas properties and depreciation of production equipment is provided on accumulated costs using the unit of production method based on estimated proven petroleum and natural gas reserves, before royalties, as

determined by independent engineers. For purposes of the depletion calculation natural gas reserves and production are converted to equivalent barrels of oil using the relative energy content of six thousand cubic feet of natural gas to one barrel of oil. Depreciation of gas plants and related equipment is provided for on a straight-line basis over fifteen years.

The depletion and depreciation cost base includes total capitalized costs, less costs of unproved properties, plus a provision for future development costs of proven undeveloped reserves.

Ceiling Test

The Company applies a ceiling test to capitalized costs to ensure that such costs do not exceed the aggregate of estimated future net revenues from production of proven reserves and the costs of unproved properties, net of impairment allowances, less estimated future production costs, general and administrative costs, financing costs, site restoration and abandonment costs, and income taxes. Future net revenues are estimated using year-end prices and costs without escalation or discounting, and the income tax and Alberta Royalty Tax Credit legislation in effect at the year end.

Office furniture and equipment

Office furniture and equipment are carried at cost and are depreciated on a straight-line basis over the estimated useful lives of the assets at rates varying between 15 percent and 20 percent.

Future site restoration and abandonment costs

The estimated cost of future site restoration and abandonment is based on the current cost and the anticipated method and extent of site restoration and abandonment in accordance with existing legislation and industry practice. The annual charge, provided for on a unit of production basis, is accounted for as part of depletion, depreciation and site restoration expense. Site restoration expenditures are charged to the accumulated provision account as incurred.

Measurement uncertainty

The amounts recorded for depletion and depreciation of property and equipment and the provision for future site restoration and abandonment costs are based on estimates. The ceiling test calculation is based on estimates of proven reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the consolidated financial statements of changes in such estimates in future years could be significant.

Joint operations

Substantially all of the Company's exploration and development activities are conducted jointly with others, and accordingly the consolidated financial statements reflect only the Company's proportionate interest in such activities.

Future Income Taxes

The Company follows the liability method in accounting for income taxes. Under this method future tax assets and liabilities are determined based on differences between financial reporting and income tax bases of assets and liabilities, and are measured using enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in net income in the period in which the change occurs.

Flow-through shares

A portion of the Company's exploration and development activities is financed through proceeds received from the issue of flow-through shares. Under the terms of the flow-through share issues, the tax attributes of the related expenditures are renounced to the share subscribers. To recognize the foregone tax benefits to Cypress, the flow-through shares issued are recorded net of the tax benefits renounced as the expenditures are incurred and renounced with a corresponding future tax liability recorded.

Financial Instruments

Financial instruments of the Company consist mainly of accounts receivable, accounts payable and accrued liabilities and long-term debt. As at December 31, 2000, 1999 and 1998 there are no significant differences between the carrying amounts reported on the balance sheet and the estimated fair values of the financial instruments.

The Company also from time to time employs financial instruments to manage exposures related to interest rates, Canada/U.S. exchange rates and commodity prices. These instruments are not used for speculative trading purposes.

Gains and losses on exchange rate and commodity price hedges are included in revenues upon the sale of the related production provided there is reasonable assurance that the hedge is and will continue to be effective. Amounts received or paid under interest rate swaps are recognized in interest expense on an accrual basis.

Stock Based Compensation Plan

The Company follows the intrinsic value method of accounting for stock-based compensation plans. Consideration paid by employees, consultants or directors on the

exercise of stock options is credited to share capital. Options are issued at current market value, consequently no compensation expense is recorded.

3. ASSETS HELD FOR RESALE

On November 1, 1999 the Company acquired assets in the Thorsby area for \$5.5 million. The Company has granted a third party an irrevocable option, exercisable through May 14, 2000, to purchase these assets for a purchase price equal to the original acquisition cost of \$5.5 million subject to adjustments relating to operations from November 1, 1999 to the option exercise date. Assets held for resale has been shown net of revenue attributable to the property during the option period to date of \$0.1 million. On March 3, 2000 the option was exercised and the properties were sold to the option holder.

4. PROPERTY AND EQUIPMENT

		2000		1999		1998
Petroleum and natural gas properties	\$	449,895	\$	312,624	\$	153,392
Office furniture and equipment		1,170		845		497
		451,065		313,469		153,889
Accumulated depletion and depreciation		(82,586)		(42,897)		(17,400)
Net property and equipment	\$	368,479	\$	270,572	\$	136,489

At December 31, 2000 the Company estimates its liability for future site restoration and abandonment to be \$12.6 million (net of the year-end accumulated provision) (1999 - \$7.8 million; 1998 - \$3.3 million).

At December 31, 2000 \$34.5 million (1999 - \$31.4 million; 1998 - \$9.5 million) of costs associated with unproved properties have been excluded from costs subject to depletion.

5. ACQUISITIONS

(a) Acquisition of Canadian Conquest Exploration Inc.

In May, 1999, the Company acquired all of the common shares of Canadian Conquest Exploration Inc. ("Canadian Conquest"). Canadian Conquest was amalgamated with Cypress effective September 1, 1999. The acquisition was accounted for by the purchase method and the purchase price was allocated as follows:

Net working capital	\$	1,140
Property and equipment		75,396
Long-term debt		(26,828)
Rent obligation		(1,207)
Provision for deferred taxes		(1,215)
Provision for future site restoration		(702)
Total Consideration	\$	46,584
Consideration was comprised of		
Cash	\$	3,619
Issue of 10,479,200 Class A shares at \$4.10 per share		42,965
Total Consideration	\$	46,584

1) Acquisition of Gardiner Exploration Limited

In July, 1999, the Company acquired all of the common shares of Gardiner Exploration Limited ("Gardiner"). Gardiner was amalgamated with Cypress effective September 1, 1999. The acquisition was accounted for by the purchase method and the purchase price was allocated as follows:

Cash	\$	6,905
Net non-cash working capital		623
Property and equipment		8,280
Total Consideration	\$	15,808
Consideration was comprised of		
Cash	\$	63
Issue of 2,581,200 Class A shares at \$6.10 per share		15,745
Total Consideration	\$	15,808

6. LONG-TERM DEBT

At December 31, 2000, the Company had a \$180.0 million syndicated revolving term credit facility, which was subsequently increased to \$200.0 million. The loan facility provides that advances may be made by way of direct advances, bankers acceptances or U.S. dollar LIBOR advances which bear interest at the applicable bankers' acceptances or LIBOR rates plus an applicable bank fee per annum or the bank's prime lending rate depending on the nature of the advance. The authorized limit is subject to an annual review and redetermination of the Company's borrowing base by the bank.

The effective interest rate on the amounts outstanding under the facility at December 31, 2000 was 6.8 percent (1999 - 5.7 percent; 1998 - 5.9 percent).

Cash interest paid for the years ended December 31, 2000, 1999 and 1998 approximated interest expense.

Collateral pledged for the facility consists of a fixed and floating charge demand debenture in the principal amount of \$300.0 million conveying a floating charge on all of the property and assets of the Company.

While the credit facility is demand in nature, the bank has stated that it is not its intention to call for repayment before December 31, 2001 provided that there is no adverse change in the Company's financial position. Accordingly, the loan advances are classified as long-term.

At December 31, 2000, the Company was party to a contract to fix the interest rate on \$9.0 million of its loan advances at approximately 6.8 percent until March 11, 2002. In addition, the counterpart to the contract has an option to extend the contract at its expiry to March 11, 2004 at the same rate and for the same notional amount. If the Company were required to settle this contract at December 31, 2000, a cash payment of approximately \$0.2 million would be required.

7. SHARE CAPITAL

Authorized:

Unlimited number of Class A and Class B common voting shares

Issued:

	2000		1999		1998	
	Number of Shares (000s)	Amount	Number of Shares (000s)	Amount	Number of Shares (000s)	Amount
Class A Shares						
Outstanding, beginning of year	42,521	\$ 161,211	28,256	\$ 97,867	23,408	\$ 74,587
On acquisition of Canadian Conquest (see note 5)	-	-	10,479	42,965	-	-
On acquisition of Gardiner (see note 5)	-	-	2,581	15,745	-	-
Private Placement (a)	-	-	746	3,731	547	1,995
Adjustment to reflect adoption of new income tax accounting policy (see note 11)	-	(1,668)	-	-	-	-
Special Warrants financings (b)	-	-	-	-	4,000	20,600
Repurchase of Class A Shares	(1,438)	(5,394)	(24)	(88)	(1)	(3)
Exercised stock options	410	1,378	483	991	302	688
Class A Shares						
Outstanding, end of year	41,493	155,527	42,521	161,211	28,256	97,867
Class B Shares (c)						
Outstanding, beginning and end of year	558	5,580	558	5,580	558	5,580
		161,107		166,791		103,447
Share issue costs (d)		(4,179)		(4,132)		(3,173)
Tax benefits renounced (a)		(7,181)		(7,181)		(3,353)
Total Share Capital		\$ 149,747		\$ 155,478		\$ 96,921

- (a) On December 31, 1999 Cypress issued 746,263 (1998 - 546,574) flow-through shares at \$5.00 (1998 - \$3.65) per share resulting in gross proceeds of \$3.7 million (1998 - \$2.0 million).

During 2000, in accordance with the terms of the flow-through share offering and pursuant to certain provisions of the Income Tax Act (Canada), Cypress incurred aggregate exploration expenditures of \$3.7 million and renounced the tax benefits to the purchasers of its flow-through shares.

- (b) On March 30, 1998, Cypress completed a Special Warrants financing consisting of 4,000,000 Special Warrants at \$5.15 per Special Warrant for gross proceeds of \$20.5 million. The Special Warrants were converted in April, 1998 into 4,000,000 Class A shares for no additional consideration.
- (c) The Class B shares are convertible at the option of Cypress into Class A shares at any time after March 1, 2000 and before March 1, 2002. After March 1, 2002 the Class B shares are convertible at the option of the shareholder until June 30, 2002 when all remaining Class B shares will be deemed to be converted. The number of Class A shares to be issued on conversion of each Class B share will be equal to \$10.00 divided by the greater of \$1.00 or the current market price of the Class A shares at the conversion date.
- (d) The total share issue costs incurred related to the 2000, 1999 and 1998 share issues were \$0.05 million, \$1.7 million and \$1.2 million respectively. A charge to share capital of \$0.05 million (1999 - \$1.0 million; 1998 - \$0.6 million) was recorded to reflect these costs, with no associated estimated future tax benefit in 2000 (1999 - estimated deferred tax benefit of \$0.7 million; 1998 - \$0.6 million).

Stock options

The Company has established a stock option plan whereby options may be granted to its directors, officers and employees. The exercise price of each option equals the market price of the Company's stock on the date of the grant and an option's maximum term is five years. The stock options are exercisable over a five-year period from the date of grant. The options are exercisable on a cumulative basis of 20 percent immediately and 20 percent per year for each of the first four years of the plan. No compensation expense is recognized for the plan when stock options are issued or exercised. The following is a continuity of stock options outstanding for which shares have been reserved:

	2000		1999		1998	
	Shares (000s)	Weighted Average Exercise Price (\$)	Shares (000s)	Weighted Average Exercise Price (\$)	Shares (000s)	Weighted Average Exercise Price
Balance, beginning of year	3,582	3.96	2,181	3.06	1,456	2.51
Granted	1,009	6.82	1,925	4.48	1,119	3.55
Exercised	(410)	3.39	(483)	2.05	(302)	2.05
Cancelled	(43)	3.53	(41)	3.37	(92)	2.99
Balance, end of year	4,138	4.71	3,582	3.96	2,181	3.06

The following summarizes information about stock options outstanding at December 31, 2000:

Range of Exercise Prices	Number Outstanding at 12/31/00 (000s)	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Number Exercisable at 12/31/00 (000s)	Weighted Average Exercise Price
\$ 1.78 to \$ 2.75	212	1.1	\$ 2.21	181	\$ 2.12
\$ 3.15 to \$ 3.75	1,065	2.6	\$ 3.48	492	\$ 3.52
\$ 4.10 to \$ 4.95	1,805	3.5	\$ 4.53	709	\$ 4.52
\$ 5.45 to \$ 6.00	397	4.3	\$ 5.94	81	\$ 5.96
\$ 6.85 to \$ 7.30	659	4.9	\$ 7.29	132	\$ 7.29
	4,138	3.4	\$ 4.71	1,595	\$ 4.24

8. FUTURE INCOME TAXES

The liability for future income taxes is primarily due to the excess carrying value of property plant and equipment over the associated tax basis.

The effective tax rate used in the financial statements differs from the statutory income tax rate due to the following:

	2000	1999	1998
Statutory tax rate	44.7%	45.0%	45.0%
Calculated income tax expense	\$ 30,840	\$ 6,796	\$ 1,478
Increase (decrease) in income tax resulting from:			
Non-deductible Crown payments (net of ARTC)	15,007	4,757	1,174
Resource allowance	(16,103)	(6,321)	(2,445)
Other	(381)	1,817	1,320
Total future income tax	29,363	7,049	1,527
Large corporation and capital tax	1,178	746	165
Income tax provision	\$ 30,541	\$ 7,795	\$ 1,692

As at December 31, 2000, the Company has exploration and development costs, undepreciated capital costs and unamortized share issue costs and loss carryforwards available for deduction against future taxable income in aggregate of approximately \$209.2 million (1999 - \$185.5 million; 1998 - \$106.5 million).

Cash tax paid for the years ended December 31, 2000, 1999 and 1998 approximated the amounts reported above for large corporation and capital taxes for each of the years.

9. PER SHARE AMOUNTS

The calculations of "earnings per common share-basic" and "cash flow from operations per common share - basic" are based on the weighted average number of Class A shares outstanding during the year ended December 31, 2000 of 42.9 million (1999 - 36.5 million; 1998 - 24.3 million). The "fully diluted" weighted average number of shares outstanding during the year ended December 31, 2000 is 46.5 million (1999 - 39.9 million; 1998 - 29.7 million). The number of shares for the calculation of "Class A and Class B" and "fully diluted" assumes that the Class B shares were deemed to be converted into Class A shares based on the conversion formula described in note 7(c) using the trading price of the Class A shares as at December 31, 2000 which was \$9.75 (1999 - \$6.10; 1998 - \$3.85). The fully diluted number of shares also includes the effects of exercising outstanding stock options.

Cash flow from operations per share is based on cash flow from operations before changes in non-cash working capital items.

10. COMMODITY MARKETING ARRANGEMENTS

As at December 31, 2000, physical delivery contracts were in effect to deliver a total of 5,201 gigajoules ("GJ") per day at prices as set out in the following table:

Sales Volume (GJ/day)	Terms	Contract Expiry Dates
2,740	AECO Daily Spot less \$0.075/GJ	October 31, 2002
2,461	AECO Monthly plus variable premium, less 3% marketing fee	September 30, 2003

The balance of 2000 gas sales was split between aggregator sales (approximately 13.5 mmcf/d) and spot gas sales. All liquids are sold on a spot basis.

At December 31, 2000, the Company had no financial natural gas contracts or swaps outstanding.

11. CHANGE IN ACCOUNTING POLICY - FUTURE INCOME TAX

Effective January 1, 2000, Cypress adopted the Canadian Institute of Chartered Accountants' new accounting recommendations with respect to income taxes. The new recommendations were applied retroactively without restatement of prior year financial statements. The application of the new liability method for income taxes resulted in a change against retained earnings of \$20.2 million (largely as a result of prior years' corporate acquisitions). There was a corresponding increase to the Company's liability for future income taxes of \$24.4 million, an increase to property plant and equipment of \$2.5 million and a reduction to share capital of \$1.7 million.

Prior to the adoption of the new recommendation, the Company followed the deferral method of accounting for income taxes. Under this method, the Company provided for deferred income taxes to the extent that income taxes otherwise payable were reduced by exploration and development costs and capital cost allowances in excess of the depletion and depreciation provisions recorded in the accounts.

12. SUBSEQUENT EVENTS

On February 28, 2001 the Company announced that it had mailed to the registered shareholders of Rancho Energy Inc. ("Rancho") its Offer to Purchase ("Offer") all of the outstanding Class A shares of Rancho ("Rancho shares") on the basis of, for each Rancho share, \$1.68 in cash or 0.1723 of a Class A share of Cypress, subject to an aggregate maximum of 1,076,900 Class A shares of Cypress and subject to pro-ration. On March 23, 2001 the Company announced that all of the conditions to the Offer were satisfied.

On February 16, 2001 PrimeWest Energy Trust ("PrimeWest") and Cypress jointly announced that they had entered into an agreement whereby PrimeWest offered to purchase all of the issued and outstanding common shares of Cypress. The offer consisted of cash of \$14.00 per Cypress share up to a maximum of \$60.0 million, or, at the option of the Cypress shareholder, 1.45 PrimeWest Trust Units or 1.45 exchangeable shares of a subsidiary of PrimeWest (subject to a maximum of 5.44 million exchangeable shares). On March 29, 2001, PrimeWest announced that all of the conditions to the Offer were satisfied.