

***PRIMEWEST ENERGY TRUST***

**RENEWAL ANNUAL INFORMATION FORM**

**For the year ended December 31, 1998**

**April 2, 1999**

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## **ITEM 1: INCORPORATION**

### **PrimeWest Energy Trust**

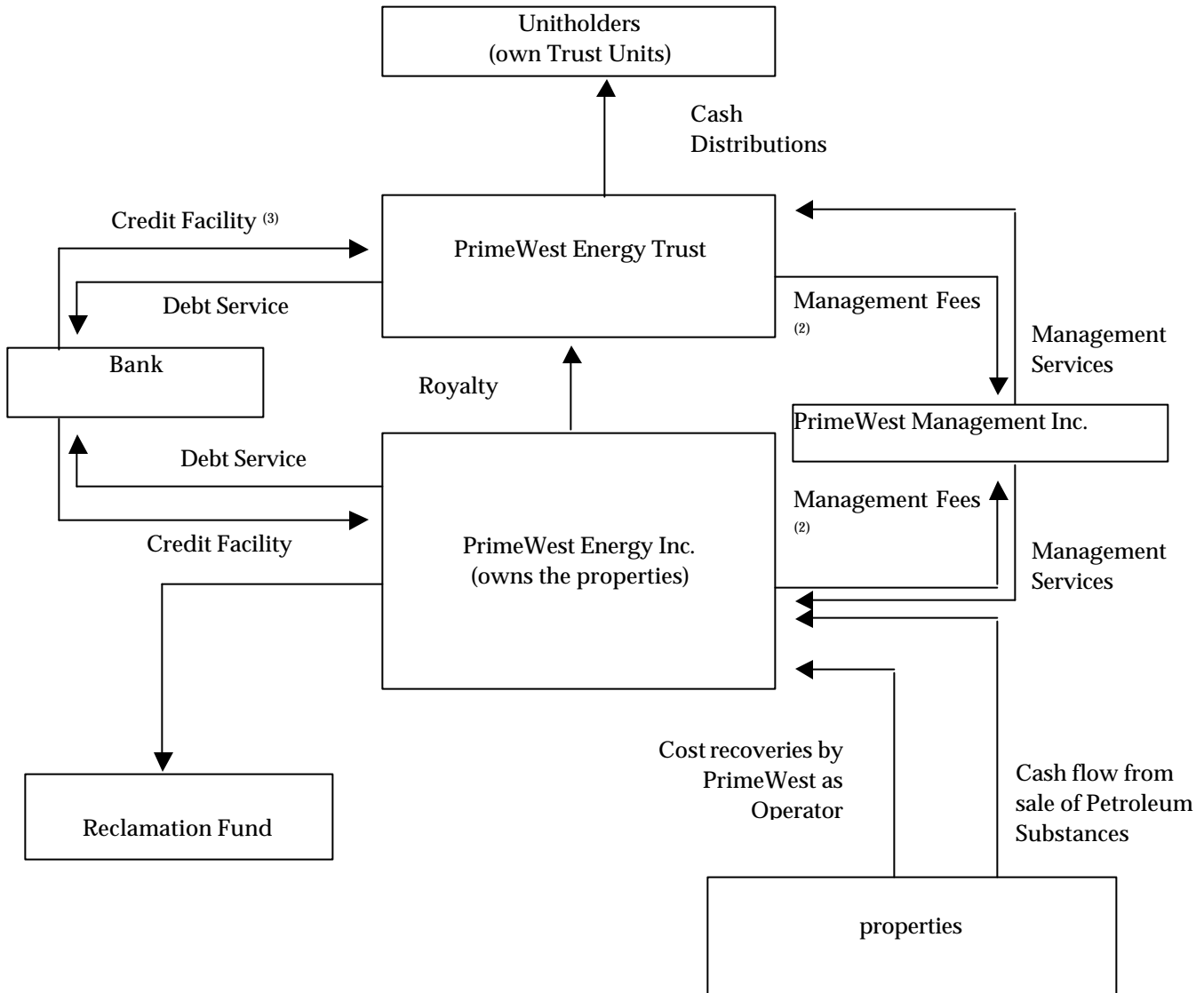
The Trust is an open-end investment trust created under the laws of Alberta pursuant to the Declaration of Trust dated August 2, 1996 and as amended on October 15, 1996 and on June 30, 1998. The undertaking of the Trust is to issue Trust Units to the public and to invest the Trust's funds, directly or indirectly, in petroleum and natural gas properties and assets related thereto. The sole beneficiaries of the Trust are the holders of Trust Units. Montreal Trust Company of Canada is currently the trustee of the Trust. The head office and principal place of business of the Trust is 1600, 530 – 8<sup>th</sup> Avenue S.W., Calgary, Alberta T2P 3S8. The initial term of Montreal Trust Company of Canada, as the trustee of the Trust expires at the conclusion of the third annual meeting of Unitholders set for May 18, 1999. The Manager has proposed a resolution of Unitholders to appoint The Trust Company of the Bank of Montreal as a successor trustee to Montreal Trust Company of Canada. Accordingly, it is expected that following the May 18, 1999 Annual Meeting of Unitholders, The Trust Company of the Bank of Montreal will be the trustee of the Trust.

PrimeWest was incorporated under the *Business Corporations Act* (Alberta) on March 4, 1996. PrimeWest's business is the acquisition, development, exploitation, production and marketing of petroleum and natural gas properties and granting the Royalty to the Trust. All of the issued and outstanding shares of PrimeWest are held by the Manager.

The Manager was incorporated on March 4, 1996 under the *Business Corporations Act* (Alberta). The head, principal and registered office of PrimeWest and the Manager is 1600, 530 – 8<sup>th</sup> Avenue S.W., Calgary, Alberta T2P 3S8.

## Trust Structure

The following diagram represents the current structure of the Trust<sup>(1)</sup> and the flow of funds from the petroleum and natural gas properties owned by PrimeWest to PrimeWest, the Manager and the Trust, and from the Trust to Unitholders:



Note:

- (1) The Declaration of Trust amendments approved by Unitholders at the Special and Annual General Meeting of Unitholders held May 21, 1998 allow the Trust to directly acquire and hold petroleum and natural gas properties, as well as the securities of any issuer holding such assets. To date, no petroleum and natural gas assets are held directly by the Trust.
- (2) The Manager is also reimbursed for general and administrative costs.
- (3) PrimeWest provides a guarantee on any advances by the Trust under the credit facility

## **Organization and Structure of PrimeWest Energy Trust**

The principal undertaking of the Trust is to acquire and hold, directly and indirectly, interests in petroleum and natural gas properties. The Trust's primary asset is currently the Royalty granted, 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 Distributable Income generated by the Royalty is then distributed monthly to Unitholders.

## **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 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 Act 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.

## ***Trustee***

Montreal Trust Company of Canada is the current trustee of the Trust and also acts as the transfer agent for the Trust Units. 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 initial term of the Trustee's appointment is until the conclusion of the third 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.

The initial term of Montreal Trust Company of Canada, as the trustee of the Trust expires at the conclusion of the third annual meeting of Unitholders set for May 18, 1999. The Manager has proposed a resolution of Unitholders to appoint The Trust Company of the Bank of Montreal as a successor trustee to Montreal Trust Company of Canada. Accordingly, it is expected that following the May 18, 1999 Annual Meeting of Unitholders, The Trust Company of the Bank of Montreal will be the trustee of the Trust.

## ***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 ("non-residents") 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.

### **The Manager**

#### ***Business***

The principal business of the Manager is to provide administrative services to the Trust and to carry out the management of the business and affairs of PrimeWest, including managing the operation (where PrimeWest has been appointed operator) and administration of the petroleum and natural gas properties owned by PrimeWest.

#### ***Manager Compensation***

The Manager is compensated for its services to PrimeWest and the Trust as follows:

- (a) a management fee equal to 2.5 percent of the net production revenue generated by the petroleum and natural gas interests held by PrimeWest or otherwise held directly or indirectly by the Trust, plus Alberta royalty tax credit, after certain adjustments for hedging activities, Crown royalties

and other Crown charges, third-party processing and other income and certain non-capital operating costs;

- (b) quarterly incentive payments of Trust Units. The first quarterly incentive payment was 12,500 Trust Units and subsequent payments have increased in proportion to the number of additional Trust Units issued by the Trust. The most recent quarterly incentive payment was 16,589 Trust Units for the quarter ended March 31, 1999;
- (c) an acquisition fee equal to 1.5 percent of the purchase price of any properties acquired by PrimeWest or the Trust or of the enterprise value of the Person which owns petroleum and natural gas rights or interests in the event of the acquisition of that Person by PrimeWest or the Trust, and a disposition fee equal to 1.25 percent of the sale price of any properties sold by PrimeWest, the Trust or any Person acquired by PrimeWest or the Trust;
- (d) reimbursement for general and administrative costs based on time spent and direct costs incurred in providing management and administrative services to PrimeWest and the Trust; and
- (e) one percent of the net cash flow generated by the petroleum and natural gas interests held by PrimeWest, the Trust or any Person acquired by PrimeWest or the Trust (without duplication), after certain costs, expenditures and deductions.

### **Management Policies and Acquisition Strategy**

Activities undertaken by the Manager in overseeing the operations and administration of PrimeWest are directed toward achieving stable long-term growth in Distributable Income paid to the Unitholders and in the value of the properties owned by PrimeWest and the Trust. These two objectives are fundamental to the operation of the Trust and are balanced to enhance benefits to the Unitholders.

Unless PrimeWest is able to acquire additional petroleum and natural gas reserves or increase reserves through development activities, production from the properties owned by it will eventually decline. Accordingly, the Manager presents proposals to PrimeWest and the Trust to acquire producing properties or to participate in development activities that are considered to be of a low-risk nature in the oil and natural gas industry. When considering the acquisition of any petroleum and natural gas producing property, the Manager focuses on long-life properties with low reservoir risk. The properties may be operated either by PrimeWest or by other acceptable operators and must have the potential to increase Distributable Income and enhance the Trust's value through exploitation of those properties.

The Manager's acquisition strategy uses the following procedures and targets individual properties, or groups of properties, that generally comply with the following guidelines:

- (a) a property, or group of properties, acquired, directly or indirectly, pursuant to an acquisition will provide a forecast internal rate of return that is greater than 400 basis points above the yield of long-term (ten-year) Government of Canada bonds over the life of the reserves associated with that property or group of properties, after deducting general and administrative expenses and management fees and incorporating the impact of debt financing, but before income taxes;
- (b) properties where PrimeWest will become the operator are preferred;
- (c) commodity price and exchange rate assumptions used in acquisition evaluations will be from a major independent petroleum engineering firm;
- (d) each acquisition having a purchase price of \$5,000,000 or more will be based on an independent petroleum engineering report, the results of which report may be modified to incorporate the Manager's view of the engineering analysis contained in that report;
- (e) at no time will more than 25 percent of the total reserve value of the properties owned by PrimeWest or the Trust be attributable to a single property; and
- (f) the expected economic life of a property, or group of properties, acquired in a single transaction will not be less than 20 years.

The board of directors of PrimeWest may at its discretion approve acquisitions that do not conform to these guidelines, based on the board's consideration of other qualitative aspects of the subject properties including risk profile, technical upside, reserve life and asset quality.

### **Decision Making**

PrimeWest, the Manager and the Trust are parties to a unanimous shareholder agreement which provides that Unitholders will be entitled to notice of and to attend all meetings of shareholders of PrimeWest and except as set forth below, to direct the manner in which the Manager will vote its shares in PrimeWest at all of those meetings. Accordingly, the Unitholders are entitled to direct the Manager as to the election of directors of PrimeWest (other than the two nominees of the Manager), the approval of the financial statements of PrimeWest and the appointment of its auditors. The unanimous shareholder agreement also provides that the board of directors of PrimeWest will, subject to complying with applicable laws regarding the declaration of

dividends, declare and pay dividends to the Manager in an amount representing one percent of its net cash flow, as more fully described above.

The board of directors of PrimeWest is responsible for making significant decisions with respect to PrimeWest, including all decisions relating to (a) the acquisition, directly or indirectly, of petroleum and natural gas properties at a cost in excess of \$5,000,000 and the disposition of petroleum and natural gas properties for a sale price or proceeds in excess of \$2,000,000; (b) the approval of capital expenditure budgets; (c) the approval of risk management activities proposed to be undertaken by the Manager; 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, and (iii) approvals required with regard to any proposed amendment to the Declaration of Trust, the management agreement, the royalty agreement or the unanimous shareholder agreement respecting the relationships among the Trust, PrimeWest and the Manager. 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 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 in the amount of \$12,071,000 to acquire certain oil and gas properties. By December 31, 1996, PrimeWest had completed additional minor property acquisitions for consideration totalling \$1,300,000.

During the year ended December 31, 1997, PrimeWest completed the acquisition of additional petroleum and natural gas reserves having an aggregate acquisition cost of approximately \$35 million. The most significant acquisition by PrimeWest during 1997 was completed in March 1997, of just over 3.9 mboe of Established Reserves for a purchase price of approximately \$6.47 per boe plus an amount for associated undeveloped land and processing revenues.

On February 25, 1998, PrimeWest implemented a Distribution Reinvestment Plan (the "DRIP") and Optional Trust Unit Purchase Plan of the Trust. The DRIP allows Unitholders to elect to reinvest cash distributions to purchase additional Trust Units from the Trust.

In March 1998, the Trust completed two acquisitions of petroleum and natural gas reserves in the Grand Forks and Medicine Hat areas of Alberta. Pursuant to those

acquisitions, PrimeWest acquired approximately 9.7 mboe of Established Reserves at \$5.19 per boe, plus an amount for interests in certain facilities, for an aggregate purchase price of approximately \$60.2 million. The acquired properties had production of approximately 4,050 boe/d to PrimeWest at the time of acquisition. Substantially all of the purchase price was financed by an equity offering of 8,000,000 Trust Units at \$7.80 per unit, for net proceeds of \$59,280,000.

On May 21, 1998, the Trust held a Special and Annual General Meeting of Unitholders at which the Unitholders authorized the reorganization of the Trust from a closed-end investment trust to an open-end investment trust. This change was made in order to add flexibility to the investments that the Trust is allowed to make. As a closed-end trust, the Trust was restricted to owning certain types of assets, principally royalty interests. As an open-end trust, the Trust is able to invest in shares of other corporations and in other types of income producing assets.

On July 29, 1998, the Trust received approval from the Toronto Stock Exchange to make a normal course issuer bid. The bid commenced on July 31, 1998 and will terminate on July 30, 1999 or such earlier time as the bid is complete. The Trust has not purchased any Trust Units pursuant to the normal course issuer bid as of the date of this Annual Information Form.

During 1998, PrimeWest entered into agreements to dispose of 2.9 mmboe of Established Reserves for total proceeds of \$19.8 million. These non-core assets consisted of 12 properties, 11 of which were non-operated.

On December 21, 1998 the Trust launched two take-over bids for Starcor Energy Royalty Fund ("Starcor") and Orion Energy Trust ("Orion"), two conventional oil and gas royalty trusts. The proposed acquisitions were intended to create a combined entity with increased economies of scale and scope, and improved liquidity for the trading of trust units. The initial offers were to expire on January 12, 1999, but were subsequently amended by Notices of Extension and Variation dated January 11, 1999, and Notices of Extension dated January 14, 1999 and January 29, 1999. The Offer for Orion was allowed to expire on February 4, 1999, after Orion entered into a business combination with a third party. A further Notice of Extension and Variation dated February 4, 1999 was issued for Starcor but was subsequently allowed to expire on February 16, 1999, after Starcor entered into an enhanced business combination with a third party.

## **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 and the Manager to continue to source and acquire petroleum and natural gas properties both for and on behalf of PrimeWest 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**

The Manager, on behalf of PrimeWest, manages the operation of those properties in respect of which PrimeWest is the operator.

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.

#### **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 eventually decline. The Manager, on behalf of PrimeWest and the Trust, 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, the Manager 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 "PrimeWest Energy Trust - Management Policies and Acquisition Strategy".

#### **Marketing Arrangements**

Effective September 1, 1996, PrimeWest and Amoco entered into an agreement whereby Amoco agreed to market the crude oil and natural gas liquids production from the properties initially purchased from Amoco, on behalf of PrimeWest for a period of five years. During this period, PrimeWest has the right to solicit proposals from other parties to market all or any part of that crude oil and natural gas liquids production. Amoco is entitled to match the price and terms of any of these proposals.

PrimeWest may decontract the quantities of crude oil and natural gas liquids that are the subject of any proposal that Amoco does not match. In addition, any time after September 1, 1997, PrimeWest may decontract up to 10 percent of the quantity of crude oil and natural gas liquids that were purchased by Amoco under the marketing arrangements, covering the period from September 1, 1996 to August 31, 1997. In late 1997, PrimeWest solicited proposals from other parties to market 10 percent of the Amoco contract, and decontracted the full amount, in order to better influence the price it receives and diversify its markets.

Approximately 58 percent of the natural gas produced from the properties is sold through natural gas sales contracts with aggregators, including TransCanada Gas Services Limited ("TCGS") and CanWest Gas Supply Inc. ("CanWest"). The balance of the natural gas produced (42 percent) is sold into the short and longer-term Alberta markets.

The TCGS and CanWest contracts are multi-year, reserve-based netback contracts. The quantities of natural gas deliverable under those contracts are determined by the actual production performance of the properties dedicated to those contracts. The natural gas delivered by PrimeWest under these contracts is sold by TCGS and CanWest, together with the natural gas delivered by other producers in the TCGS and CanWest supply pools, to various markets throughout North America. The price received by PrimeWest for the natural gas sold under these aggregator contracts is determined by the prices obtained by TCGS and CanWest and approved by producers in those supply pools, less the costs associated with those sales.

Natural gas production from the Laprise Creek property was subject to a natural gas price swap agreement for the period from September 1, 1996 to December 31, 1997. Under this agreement, that natural gas production effectively realized a minimum price of at least \$1.35 per mcf.

In March 1998, PrimeWest entered into a two-year ongoing price adjustment through a "price collar" based on the price of crude oil. If the actual average field selling price of the crude oil produced from the Grand Forks property during a month is less than \$18.51 per bbl in 1998 (\$21.14 per bbl in 1999), (the "fixed forward price") but not less than \$15.51 per bbl in 1998 (\$18.41 per bbl in 1999), then the vendor of the property must pay PrimeWest an amount equal to the product of that difference in prices and 2,776 bbls/d (2,304 bbls/d in 1999), net of a deemed royalty adjustment. If the actual average field selling price of the crude oil produced from the Grand Forks property is less than \$15.51 per bbl in 1998 (\$18.14 per bbl in 1999), then the vendor of the property must pay PrimeWest \$3.00 per bbl. PrimeWest has a reciprocal obligation where the average field selling price during a month is greater than the fixed forward price. Neither party is liable to the other for adjustments which aggregate more than \$3,000,000 over the two-year term of the adjustment period. Up to December 31, 1998, PrimeWest realized \$2.2 million under this collar arrangement

Effective January 1, 1998, PrimeWest entered into a foreign exchange swap agreement with a Canadian chartered bank to hedge approximately two-thirds of its budgeted oil production by fixing the exchange rate at \$1.42 (\$Cdn./\$U.S.), based on a notional principal amount of U.S. \$1 million per month. On June 19, 1998, PrimeWest revised this swap agreement by fixing the exchange rate at \$1.4487 (\$Cdn./\$U.S.) with a maturity date of December 31, 1999.

During late 1998, PrimeWest entered into a series of natural gas price hedging transactions covering the November 1998 gas year (through to October 1999) which provide greater certainty of PrimeWest's natural gas revenue stream over the next year. Through these transactions, PrimeWest has fixed the average natural gas price that it will receive at \$2.50 per mcf on 12.5 mmcf/d, which is approximately 55 percent of PrimeWest's direct-market natural gas sales, or approximately 23 percent of PrimeWest total natural gas sales.

In late 1998, PrimeWest entered into a price hedge that fixes the price differential between West Texas Intermediate crude and Hardisty, Alberta medium crude benchmark, at U.S. \$3.85 per barrel on approximately 1,650 bbls/d from Grand Forks oil production. This price hedge is effective for the 1999 calendar year.

### **Reserve Continuity**

Gilbert Laustsen Jung Associates Ltd., independent petroleum consultants, ("Gilbert"), has prepared a reserves report ("Gilbert Report") evaluating the crude oil, natural gas, natural gas liquids and sulphur reserves attributable to PrimeWest's properties as at January 1, 1999. The following table sets forth the reconciliation of the Established Reserves of PrimeWest for the year ended December 31, 1998.

<b><u>Reconciliation of Reserves</u></b>	<b>Oil &amp; Liquids (mmbls)</b>	<b>Natural Gas (bcf)</b>	<b>Total<sup>(1)</sup> (mmboe)</b>
As at January 1, 1998.....	21.9	227.3	44.6
Capital Enhancement Program and Revisions.....	3.6	20.6	5.7
Acquisitions, net of dispositions.....	5.5	14.1	6.9
Production.....	(2.7)	(18.5)	(4.5)
As at January 1, 1999.....	<u>28.3</u>	<u>243.5</u>	<u>52.5</u>
Net Increase in Reserves.....	6.4	16.2	7.9
Percent Increase.....	<u>29%</u>	<u>7%</u>	<u>18%</u>

(1) may not add due to rounding

## Drilling Activity

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

	Year Ended December 31, 1997		Year Ended December 31, 1998	
	Gross	Net	Gross	Net
Natural Gas.....	3	0.7	3	2.0
Crude Oil .....	24	1.1	37	10.4
Service wells...	8	0.5	-	-
Dry .....	1	0.4	3	1.7
Total .....	<u>36</u>	<u>2.7</u>	<u>43</u>	<u>14.1</u>

## Finding and On-Stream Costs

The following table sets forth PrimeWest's finding and on-stream costs for the Trust's last two financial years:

(millions of dollars except per boe)	<u>Year Ended December 31, 1997</u>	<u>Year Ended December 31, 1998</u>
Total development expenditures – drilling and completion.....	\$ 15.8	\$ 17.4
Established reserve additions, including revisions and excluding net acquisitions (mmboe) .....	6.0	5.7
Average cost per boe.....	\$ 3.28	\$ 3.09
Total property acquisition expenditures, net of dispositions .....	\$ 33.9	\$ 47.8
Established reserve additions net of dispositions (mmboe) .....	5.8	6.9
Average cost per boe.....	\$ 5.42	\$ 4.92 <sup>(1)</sup>
Total capital expenditures, net of dispositions .....	\$ 49.7	\$ 51.5
Established reserve additions, including revisions (mmboe) .....	11.8	12.6
Average cost per boe .....	\$ 4.61	\$ 4.09

<sup>(1)</sup> The average cost of property acquisition expenditures, net of dispositions have been adjusted for processing and undeveloped land purchases and proceeds from disposition of a minor property, received in January 1999 have been included.

## Recent Developments

Mr. D. Hugh Gillard joined PrimeWest as President and Chief Operating Officer on January 16, 1999. Mr. Gillard has over 26 years of oil and gas industry experience primarily in accounting, business development, marketing, land, property rationalization and senior management. Effective March 19, 1999, Mr. Gillard was appointed to the Board of Directors of PrimeWest.

Mr. Jacob Roorda resigned as a Director of PrimeWest effective March 19, 1999.

On January 18, 1999, PrimeWest closed an asset sale of non-operated interests in the Tweedie property, for proceeds of \$4 million, or \$0.13 per Trust Unit. This disposition represents approximately 600,000 boe of Established Reserves or production of 172 boe/d. A deposit of \$0.6 million was received in late 1998, and the balance, \$3.4 million, was received and applied against long-term debt in January 1999.

On March 10, 1999, PrimeWest completed an asset exchange transaction whereby all of its interests in the non-operated Niton properties (valued at \$14.8 million) plus

cash of \$1.95 million were exchanged for an average working interest of 53.3 percent in the Ricinus Cardium Unit #2. PrimeWest will operate the Ricinus Cardium Unit #2.

On March 31, 1999 the Board of Directors adopted a Unitholders Rights Plan, subject to Unitholder approval at the Special and Annual General Meeting to be held on May 18, 1999. Details of the Unitholders Rights Plan are incorporated by reference on pages 4 through 9 of the Circular.

### **Attributes of PrimeWest's Properties**

PrimeWest's properties 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, 1998, make the properties particularly suitable for a conventional 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 10.3 years, and a Proved plus Probable Reserve Life Index of 12.1 years;
- (b) **Operated Properties:** Approximately 80 percent 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) **Balanced Portfolio:** Production from the properties is approximately 58 percent crude oil and natural gas liquids and 42 percent natural gas, on a barrel-of-oil-equivalent basis. Established Reserves for the properties is approximately 54 percent crude oil and natural gas liquids and 46 percent natural gas on a barrel-of-oil-equivalent basis. Oil reserves are predominantly light-gravity oil, averaging 32 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 Gilbert and the Manager. These opportunities have not been included in the valuations provided in the Gilbert Report.

The Gilbert Report assigns 52,498 mboe of net remaining Established Reserves to the properties. The following table sets forth certain property interest, reserve, production, economic life and reserve value information relating to the properties for the year ended and as at December 31, 1998:

Area/Property <sup>(1)</sup>	<b>1998 Company Interest Production <sup>(2)</sup></b> <b>(boe/d)</b>	<b>Company Interest Reserves <sup>(2)</sup></b> <b>(mboe)</b>	<b>Economic Life <sup>(3)(4)(5)</sup></b> <b>(years)</b>	<b>1998 Cash Flow<sup>(6)</sup></b> <b>(\$000's)</b>
Sundre Area				
Garrington <sup>(7)</sup> .....	1,117	3,561	42	3,218
Westward Ho <sup>(7)</sup> .....	895	4,453	39	2,833
Caroline <sup>(7)</sup> .....	767	5,866	50	2,112
Laprise Creek Area				
Laprise <sup>(7)</sup> .....	1,232	6,714	25	3,897
Kobes Creek.....	111	2,388	49	387
Southeastern Alberta Area				
Grand Forks <sup>(7)</sup> .....	2,114	6,384	31	5,871
Medicine Hat.....	603	2,560	50	1,668
Crossfield/ Lone Pine Creek Area <sup>(7)</sup>	1,685	6,969	37	3,219
.....				
Boundary Lake Area <sup>(7)</sup> .....	782	4,528	50 <sup>(8)</sup>	2,344
Kaybob South Area <sup>(7)</sup> .....	1,074	2,563	22	3,388
Others.....	1,754	6,512	50	4,116
ARTC.....	-	-	-	344
Total.....	12,134	52,498		33,397

Notes:

- (1) See individual property descriptions.
- (2) The average percentage interest share of reserves and production owned by PrimeWest before the deduction of royalties.
- (3) Based on Established Reserves as derived from the Gilbert Report.
- (4) Utilizing escalating cost and price assumptions.
- (5) "Economic Life" means the time remaining before production of petroleum and natural gas from the property is forecast to be uneconomic.
- (6) Working interest revenue less royalties and operating expenses.
- (7) Primarily operated by PrimeWest.
- (8) Greater than 50 years.

## Oil and Natural Gas Reserves

Gilbert has prepared the Gilbert Report evaluating the properties as at January 1, 1999. **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 (\$000's)*			
	Crude Oil and Natural Gas Liquids (mbbls)		Natural Gas (mmcf)		Sulphur (mlt)		Undiscounted	Discounted at		
	Gross	Net	Gross	Net	Gross	Net		10%	15%	20%
Proved										
Producing .....	18,967	15,994	161,404	125,467	693	577	384,979	220,228	183,943	159,004
Non-Producing..	2,506	1,988	34,168	26,986	18	16	65,100	33,292	24,195	17,903
Total Proved .....	21,473	17,982	195,572	152,453	711	593	450,079	253,520	208,138	176,907
Risked Probable.....	6,813	5,580	47,939	36,874	121	100	155,994	59,324	41,738	30,834
Established .....	28,286	23,562	243,511	189,327	832	693	606,073	312,844	249,876	207,741

\*Does not include the value of the unproved lands

**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 (\$000's)*			
	Crude Oil and Natural Gas Liquids (mbbls)		Natural Gas (mmcf)		Sulphur (mlt)		Undiscounted	Discounted at		
	Gross	Net	Gross	Net	Gross	Net		10%	15%	20%
Proved										
Producing .....	17,956	15,162	160,597	125,814	691	575	280,921	177,289	152,171	134,283
Non-Producing..	2,290	1,793	34,190	27,122	19	16	51,983	25,502	18,374	13,429
Total Proved .....	20,246	16,955	194,787	152,936	710	591	332,904	202,791	170,545	147,712
Risked Probable.....	6,643	5,471	47,749	37,042	121	101	104,625	43,112	30,908	23,112
Established .....	26,889	22,426	242,536	189,978	831	692	437,529	245,903	201,453	170,824

\*Does not include the value of the unproved lands

Notes:

- (1) Columns may not add due to rounding.
- (2) The following definitions have been used in the Gilbert Report:
  - (a) "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) and interests owned by others.
- (3) In 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.
  
  - (4) All natural gas reserve values are reserves remaining after deducting surface losses due to processing shrinkage and raw gas used as lease fuel.
  
  - (5) The \$US/\$CDN exchange rate is assumed in the Gilbert Report to be \$0.6633 in 1999, \$0.6867 in 2000, \$0.71 in 2001 and \$0.73 thereafter.
  
  - (6) 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 \$53.9 million (\$38.9 million if discounted by 15 percent per annum) with \$13.1 million, \$16.5 million and \$12.4 million of those capital expenditures estimated for the calendar years 1999, 2000 and 2001, 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 \$51.4 million (\$37.8 million if discounted by 15 percent per annum) with \$13.1 million, \$16.2 million and \$11.9 million of these capital expenditures estimated for the calendar years 1999, 2000 and 2001, respectively.

- (7) The Gilbert Report estimates total capital expenditures (net to PrimeWest) to achieve the estimated future pre-tax net cash flows from the Proved Reserves based on escalating cost and price assumptions to be \$32.5 million (\$23.1 million if discounted by 15 percent per annum) with \$10.4 million, \$7.8 million and \$6.0 million of those capital expenditures estimated for the calendar years 1998, 1999 and 2000, respectively. The corresponding capital expenditures to achieve the estimated future pre-tax net cash flows from the Proved Reserves based on constant cost and price assumptions are \$30.8 million (\$22.5 million if discounted by 15 percent per annum) with \$10.4 million, \$7.7 million and \$5.8 million of these capital expenditures estimated for the calendar years 1999, 2000 and 2001, respectively.
- (8) The extent and character of PrimeWest's interests 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.
- (9) The constant cost and price evaluation was based on wellhead product prices as set forth below:

(Cdn.\$)

Crude Oil.....	\$17.77 per bbl
Propane.....	\$11.00 per bbl
Butane .....	\$11.15 per bbl
Pentanes Plus.....	\$6.75 per bbl
Natural Gas.....	\$2.25 per mcf
Sulphur .....	\$6.68 per lt

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

- (10) 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, 1999 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.

	<u>Light Crude Oil</u>		<u>Natural Gas Liquids of Edmonton</u>			<u>Natural Gas</u>			
	<u>WTI Cushing Oklahoma*</u>	<u>Edmonton Par price 40? API</u>	<u>Propane</u>	<u>Butane</u>	<u>Pentanes Plus</u>	<u>Henry Hub \$US/ MMBTU</u>	<u>Alberta Gov't Market Price \$Cdn./ MMBTU</u>	<u>BC Direct \$Cdn./ MMBTU</u>	<u>Sulphur \$/lt</u>
1999.....	14.67	21.06	12.65	13.14	21.09	2.16	2.25	1.80	6.50
2000.....	16.61	23.07	13.64	14.26	23.02	2.23	2.28	1.81	13.17
2001.....	18.57	24.98	14.83	15.59	24.86	2.33	2.31	1.87	18.33
2002.....	20.05	26.37	15.54	16.38	26.20	2.41	2.37	1.93	23.18
2003.....	20.69	27.18	16.04	16.82	26.98	2.50	2.45	1.99	25.31
2004.....	21.13	27.70	16.41	17.20	27.50	2.56	2.53	2.06	26.56
2005.....	21.57	28.25	16.79	17.62	28.05	2.63	2.61	2.14	28.01
2006.....	22.01	28.86	17.28	18.08	28.66	2.68	2.66	2.19	29.51
2007.....	22.45	29.47	17.75	18.55	29.27	2.73	2.72	2.25	31.05

2008.....	22.85	30.07	18.16	18.97	29.87	2.79	2.78	2.29	32.67
2009.....	23.34	30.67	18.58	19.43	30.47	2.84	2.84	2.34	34.16
2010.....	23.82	31.25	18.97	19.87	31.05	2.90	2.89	2.39	35.57
2011.....	24.32	31.86	19.42	20.29	31.62	2.96	2.96	2.46	37.02
2012.....	24.81	32.47	19.85	20.72	32.23	3.02	3.01	2.51	38.34
2013.....	25.31	33.13	20.27	21.15	32.90	3.07	3.07	2.54	39.69
2014.....	25.81	33.84	20.66	21.58	33.60	3.13	3.12	2.59	41.11
2015.....	26.31	34.54	21.09	22.08	34.31	3.19	3.18	2.64	42.77
Thereafter	1.3%	1.3%	1.3%	1.3%	1.3%	1.3%	1.3%	1.3%	1.3%

\*40 degrees API, 0.4 percent sulphur

- (11) (Operating and capital costs have been escalated at 2.0 percent annually for 16 years and 1.3 percent thereafter.

**Estimated Pre-Tax Net Cash Flows  
Established Reserves of the Properties  
Escalating Cost and Price Case  
(\$000's except for production)**

	Annual Production n	Company Interest Revenue <sup>(1)</sup>	Royalty Burdens <sup>(2)</sup>	Net Revenue After Royalty Burdens	Alberta Royalty Tax Credit	Operating Expenses	Net Production Revenue <sup>(4)</sup>	Abandonment Costs	Net Capital Investment	Net Cash Flow Before Income Taxes <sup>(5)(6)</sup>
	(mboe)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)
1999.....	5,076	98.5	18.6	79.9	1.3	25.2	56.0	1.3	13.1	41.7
2000.....	4,944	101.9	19.0	82.9	1.1	25.6	58.4	1.2	16.5	40.8
2001.....	4,718	103.1	18.9	84.2	1.0	26.0	59.2	1.5	12.4	45.4
2002.....	4,309	98.9	18.2	80.7	1.0	25.7	56.0	1.5	2.3	52.3
2003.....	3,827	90.7	16.2	74.5	0.8	25.0	50.3	1.5	2.7	46.2
2004.....	3,430	83.4	14.7	68.7	0.7	23.7	45.7	0.7	0.7	44.2
2005.....	3,043	76.0	13.2	62.8	0.7	23.0	40.5	0.8	0.2	39.4
2006.....	2,697	68.9	11.6	57.3	0.6	22.7	35.2	0.6	0.4	34.1
2007.....	2,410	63.0	10.4	52.6	0.5	21.7	31.4	0.7	2.1	28.8
2008.....	2,139	57.2	9.2	48.0	0.5	19.5	29.0	0.9	0.8	27.3
2009.....	1,898	51.9	8.3	43.6	0.4	17.8	26.2	1.4	0.4	24.4
2010.....	1,663	46.5	7.4	39.1	0.3	16.1	23.3	0.6	0.4	22.5
Remainder...	12,344	400.7	58.3	342.4	2.0	166.6	177.8	16.9	1.9	158.9
TOTAL.....	52,498	1,340.7	224.0	1,116.7	10.9	438.6	689.0	29.6	53.9	606.0

Total net cash flow before income taxes discounted at:

10 percent: \$312.8 million ~~≈~~

15 percent: \$249.9 million

20 percent: \$207.7 million

Notes:

- (1) Includes working-interest revenue and royalty-interest revenue.
- (2) Includes royalties net of processing allowances and mineral taxes.
- (3) Includes other expenses, net-profits interest payments, and capital taxes less third party processing and other income.
- (4) Company-interest revenue less Company interest royalty burdens and operating expenses.

- (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  
(\$000's except for production)**

	<b>Annual Production</b>	<b>Company Interest Revenue (<sup>1</sup>)</b>	<b>Royalty Burdens (<sup>2</sup>)</b>	<b>Net Revenue after Royalty Burdens</b>	<b>Alberta Royalty Tax Credit</b>	<b>Operating Expenses (<sup>3</sup>)</b>	<b>Net Production Revenue(<sup>4</sup>)</b>	<b>Abandonment Costs</b>	<b>Net Capital Investment</b>	<b>Net Cash Flow Before Income Taxes(<sup>5</sup>/<sup>6</sup>)</b>
	<b>(mboe)</b>	<b>(\$)</b>	<b>(\$)</b>	<b>(\$)</b>	<b>(\$)</b>	<b>(\$)</b>	<b>(\$)</b>	<b>(\$)</b>	<b>(\$)</b>	<b>(\$)</b>
1999.....	5,076	98.5	18.5	80.0	1.3	25.2	56.1	1.4	13.1	41.6
2000.....	4,931	95.1	17.6	77.5	1.2	24.8	53.9	1.3	16.2	36.4
2001.....	4,695	90.5	16.2	74.3	1.1	24.5	50.9	1.5	11.9	37.5
2002.....	4,285	82.9	14.9	68.0	1.2	23.6	45.6	1.5	2.2	41.9
2003.....	3,793	73.5	12.8	60.7	1.1	22.4	39.4	1.4	2.5	35.5
2004.....	3,392	65.8	11.3	54.5	1.0	20.7	34.8	0.7	0.6	33.5
2005.....	2,993	58.1	9.8	48.3	1.0	19.5	29.8	0.6	0.2	29.0
2006.....	2,646	51.5	8.4	43.1	0.9	18.8	25.2	1.2	0.4	23.6

2007.....	2,303	45.1	7.2	37.9	0.8	16.7	22.0	0.8	1.8	19.4
2008.....	2,032	39.8	6.2	33.6	0.7	14.2	20.1	0.9	0.6	18.6
2009.....	1,809	35.5	5.5	30.0	0.6	12.9	17.7	0.5	0.4	16.8
2010.....	1,625	31.9	4.9	27.0	0.5	12.1	15.4	1.9	0.3	13.2
Remainder.	11,423	226.6	32.2	194.4	3.1	96.4	101.1	9.4	1.4	90.3
TOTAL...	<u>51,003</u>	<u>994.8</u>	<u>165.5</u>	<u>829.3</u>	<u>14.5</u>	<u>331.8</u>	<u>512.0</u>	<u>23.1</u>	<u>51.6</u>	<u>437.3</u>

Total net cash flow before income taxes discounted at:

10 percent: \$245.9 million  
15 percent: \$201.5 million  
20 percent: \$170.8 million

Notes:

- (1) Includes working-interest revenue and royalty-interest revenue.
- (2) Includes royalties net of processing allowances and mineral taxes.
- (3) Includes other expenses, net-profits interest payments and capital taxes, less third party processing and other income.
- (4) Company-interest revenue less Company interest royalty burdens and operating expenses.
- (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 significant properties owned by PrimeWest as of December 31, 1998. 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 PrimeWest's working interest in the properties.

### **Sundre Area**

The Sundre Area is comprised of properties located in Westward Ho, Garrington and Caroline.

### **Westward Ho**

The Westward Ho properties are located approximately 50 miles northwest of Calgary, Alberta. PrimeWest has a working interest in 33 (20.5 net) Non-Unit wells in Westward Ho, a 98.7291 percent working interest in the Westward Ho Unit No. 1 and a 2.70083 percent working interest in the Harmattan East Viking Unit No. 1. The Gilbert Report assigns remaining Established Reserves of 1,583 mbbbl of oil, 18,866 mmcf of natural gas and 984 mbbbl of natural gas liquids (for a total of 4,453 mboe), before deduction of royalties, to the Westward Ho Area properties. The average net production from the properties for the year ended December 31, 1998 was approximately 527 bbls/d of oil and natural gas liquids, and 3,679 mcf/d of natural gas (for a total of 895 boe/d), before royalties.

#### *Westward Ho Non-Unit*

The Westward Ho Non-Unit Property consists of an interest in 21 (10.4 net) producing oil wells and eight (4.1 net) producing natural gas wells, the majority of which are operated by PrimeWest. Light-gravity crude oil and solution gas production is obtained mainly from the Rundle Formation, with additional non-associated natural gas production from eight (6.9 net) Basal Mannville Formation wells. Minor oil production is obtained from three Viking Formation wells. All Rundle and Viking oil is produced under a primary drive mechanism. Solution gas is conserved except at three oil wells in the Eagle Hill portion of the property. PrimeWest has interests in the associated facilities, including the 12-05-34-04 W5M battery and compressor, and capacity in the Amoco operated South Caroline Gas Plant.

The Gilbert Report assigns remaining Established Reserves of 951 mbbbls of crude oil, 17,566 mmcf of natural gas and 934 mbbbls of natural gas liquids (for a total of 3,641 mboe), before deduction of royalties, to the Westward Ho Non-Unit Property. Included in the Gilbert Report are capital expenditures for the drilling of five wells (two of which are infill wells) and various other projects primarily relating to

compression.

### *Westward Ho Unit No. 1*

PrimeWest has a 98.7291 percent working interest in the Westward Ho Unit No. 1 operated by PrimeWest. The Unit has produced 31 degree API crude oil from the Elkton Formation since 1955, and water injection was initiated in 1963. As at December 31, 1998, oil production occurred from 17 oil wells with water injected into five water injection wells. Solution gas is conserved and processed at the Amoco-operated South Caroline Gas Plant.

Production has been improved through production optimization and well workovers and removing water disposal restrictions which currently limit oil well productivity. The Gilbert Report assigns net remaining Established Reserves of 688 mboe, before deduction of royalties, to the Unit. Future development projects included in the Gilbert Report are capital expenditures for facilities maintenance.

### *Harmattan East Viking Unit No. 1*

PrimeWest has a 2.70083 percent working interest in the Harmattan East Viking Unit No. 1, which produces a 39 degree API light gravity crude oil from the East Harmattan Viking "E" Pool discovered in 1979 and is operated by Mobil Oil Canada. Waterflooding of the Pool commenced in 1986. All solution gas is conserved and processed to remove natural gas liquids at the Mobil Harmattan Area Gas Plant. The Gilbert Report assigns net remaining Established Reserves of 124 mboe, before deduction of royalties, to the Harmattan East Viking Unit No. 1.

## **Garrington**

The Garrington properties are located approximately 25 miles southwest of Red Deer, Alberta. Oil and natural gas production is obtained from the Elkton, Rock Creek, Mannville, Viking, Second White Specks and Cardium Formations. Production is obtained from depths of 6,850 to 9,200 feet and, in general, consists of gassy, sweet 39-degree API light-gravity crude oil. The Gilbert Report assigns net remaining Established Reserves of 2,086 mbbbl of oil, 9,782 mmcf of natural gas and 497 mbbbl of natural gas liquids (for a total of 3,561 mboe), before deduction of royalties, to the Garrington Area properties. The average net production from the Garrington Area properties for the year ended December 31, 1998 was approximately 755 bbls/d of crude oil and natural gas liquids and 3,617 mmcf/d of natural gas (for a total of 1,117 boe/d), before royalties.

### *Garrington Non-Unit*

PrimeWest has a working interest in 19 (13.3 net) producing oil wells and three (2.5 net) shut-in oil wells in the Garrington Non-Unit area. PrimeWest operates the majority of these wells and related facilities. Oil and natural gas production is gathered to a central battery facility. The majority of the solution gas is conserved and

is transported to the North Carolina Gas Plant for processing. The natural gas is liquids-rich, (approximately 38 bbls of natural gas liquids per mmcf of raw natural gas). In the report prepared for PrimeWest by Gilbert in connection with PrimeWest's initial public offering, upside potential in the Elkton "M" Pool, in which PrimeWest has a 100 percent working interest, was identified. PrimeWest performed the optimisation work, which increased daily production rates from 250 boe/d to nearly 600 boe/d in late December 1997.

The Gilbert Report assigns net remaining Established Reserves of 2,037 mboe, before deduction of royalties, to the Garrington Non-Unit Property. Included in the Gilbert Report are forecast capital expenditures to drill two wells and to recompleting three wells.

#### *Garrington Cardium Unit No. 1*

PrimeWest has a 41.27231 percent working interest in the Garrington Cardium Unit No. 1 operated by Altana Exploration Company. The Unit produces 39 degree API light gravity crude oil and solution gas from both the Cardium "A" and Cardium "B" pools. The Unit was established in September, 1963 to accommodate the implementation of a waterflood project which commenced in February, 1964. All of the wells were drilled during the 1960s with the exception of one infill well drilled in 1987. The Garrington Cardium Unit No. 1 currently consists of seven (2.9 net) producing oil wells, three (1.2 net) water-injection wells; the remainder of the wells are either suspended or abandoned.

The Gilbert Report assigns net remaining Established Reserves of 84 mboe, before deduction of royalties, to the Garrington Cardium Unit No. 1.

#### *Garrington Cardium Unit No. 2*

PrimeWest has a 72.63705 percent working interest in the Garrington Cardium Unit No. 2 operated by PrimeWest. The Unit produces 38-degree API light-gravity crude oil and solution gas from both the Cardium "A" and Cardium "B" pools. The Unit was established in September, 1964 and was placed under secondary recovery by waterflood in May, 1965. The Unit currently consists of ten (7.3 net) producing oil wells, 13 (9.4 net) water injection wells and the remainder of the wells are either suspended or abandoned.

The Gilbert Report assigns net remaining Established Reserves of 409 mboe, before deduction of royalties, to the Garrington Cardium Unit No. 2. Included in the Gilbert Report are future capital expenditures for the drilling of one infill well, the fracture stimulation of several wells and facilities consolidation.

### *North Caroline Gas - North Leg*

PrimeWest has an average working interest of 65.185 percent in 27 (17.6 net) wells in the North Caroline Gas - North Leg Property. Six (5.2 net) of the wells are presently producing natural gas and natural gas liquids from the Mannville and Elkton Formations. The vast majority of the natural gas is processed at the Amoco operated North Caroline Gas Plant referred to in the North Caroline Gas - South Leg description above. PrimeWest has a majority interest in four field compressors, a minority interest in the central dehydration facility and capacity in the high-pressure gas gathering line from the central dehydration facility to the North Caroline Gas Plant. A compressor expansion project in 1997 lowered gathering system pressure and two natural gas wells were tied-in during 1998.

The Gilbert Report assigns net remaining Established Reserves of 1,031 mboe, before deduction of royalties, to the North Caroline Gas - North Leg Property. Future development projects in the Gilbert Report include capital expenditures for facility optimization, well bore optimisation and the drilling of one well in 2000.

### **Caroline**

The Caroline properties are located approximately 60 miles northwest of Calgary, Alberta. PrimeWest has a working interest in four separate contiguous properties in the Caroline Area, as described below. The Gilbert Report assigns remaining Established Reserves of 290 mbbbl of oil, 37,186 mmcf of natural gas and 1,858 mbbbl of natural gas liquids (for a total of 5,866 mboe), before deduction of royalties, to the four Caroline Area properties. The average net production from the Caroline Area properties for the year ended December 31, 1998 was approximately 372 bbls/d of oil and natural gas liquids and 3,957 mcf/d of natural gas (for a total of 767 boe/d), before royalties.

### *North Caroline Gas - South Leg*

PrimeWest has a working interest in 29 (25.4 net) wells operated by PrimeWest in the North Caroline Gas - South Leg Property. Natural gas and natural gas liquids are presently produced from 13 (12.3 net) natural gas wells primarily in the Basal Quartz Formation. Gas production is processed at the Amoco-operated North Caroline Gas Plant in which PrimeWest has a 4.7175 percent working interest. In addition, PrimeWest has a 12.58 percent working interest in the refrigeration system.

The Gilbert Report assigns net remaining Established Reserves of 2,942 mboe, before deduction of royalties, to the North Caroline Gas -- South Leg Property. Future development projects in the Gilbert Report include capital expenditures for the drilling of infill wells and various workover, stimulation, tie-in and compressor optimization projects.

### *East Caroline*

PrimeWest has a working interest and/or royalty interest in 13 (5.6 net) producing oil wells, two (0.4 net) producing natural gas wells, three (0.6 net) shut-in oil wells and 28 (14.9 net) suspended wells in the East Caroline property. The property produces 40-degree API light-gravity crude oil with solution gas from the Cardium, Viking and Mannville Formations, and non-associated gas from the Viking and Mannville Formations. Solution gas is conserved from all of the oil wells and is rich in natural gas liquids (60 bbls/mmcf). The Gilbert Report assigns net remaining Established Reserves of 82 mboe, before deduction of royalties, to the East Caroline Property. The Gilbert Report includes capital expenditures for certain well recompletions and facility consolidations.

### *Southwest Caroline/Northridge*

PrimeWest has an average working interest of 73.8 percent in nine producing natural gas wells operated by PrimeWest, and royalty interests in one producing oil well and two producing natural gas wells in the Southwest Caroline property. Natural gas and natural gas liquids reserves have been developed in the Glauconitic and Basal Quartz Formations. The oil well produces from the Cardium Formation. Most of the wells have been producing since 1983. Average net natural gas production for the year ended December 31, 1998 was approximately 976 mcf/d (137 boe/d including natural gas liquids), before royalties. The natural gas production is custom-processed at the Canadian Abraxas Caroline Gas Plant.

The Gilbert Report assigns net remaining Established Reserves of 1,867 mboe, before deduction of royalties, to the Southwest Caroline property. The Gilbert Report includes future capital expenditures for the drilling of five infill wells between 1999 and 2001 and the completion or refracturing of several other wells.

### *West Caroline*

PrimeWest operates and has a 100 percent interest in a majority of 58 wells in the West Caroline Property. Oil and solution gas production occurs from the Cardium, Viking, Glauconitic and Basal Quartz Formations, with the majority of the production from the Caroline Viking "A" Pool. Net production for the year ended December 31, 1998 occurred from 27 (26 net) oil wells. The majority of the oil is treated at the 04-28-35-06 W5M battery, which includes solution gas compression facilities in which PrimeWest has a 50 percent working interest. The solution-gas is transported via a low-pressure gas gathering system to the Amoco-operated North Caroline Gas Plant referred to in the North Caroline Gas - South Leg description above.

The Gilbert Report assigns net remaining Established Reserves of 978 mboe, before deduction of royalties, to the West Caroline Property. The Gilbert Report

includes future capital costs for facility consolidations and the completion and re-completion of three wells.

## **Laprise Creek Area**

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. The Gilbert Report assigns net remaining Established Reserves of 76,051 mmcf of natural gas and 1,497 mbbbl of natural gas liquids (for a total of 9,102 mboe), before deduction of royalties, to the Laprise Creek Area properties. The average net production from the Laprise Creek Area properties for the year ended December 31, 1998 was approximately 11,521 mcf/d of natural gas and 192 bbls/d of crude oil and natural gas liquids (for a total of 1,344 boe/d), before deduction of royalties.

### *Laprise Creek Baldonnel Unit No. 1*

PrimeWest has a 75.625 percent working interest in the Laprise Creek Baldonnel Unit No. 1, which is operated by PrimeWest. The Laprise Creek Baldonnel Unit No. 1 occupies the western portion of the Laprise Creek Baldonnel A Pool, which has been on production since 1960 and is in competitive drainage with the Petro-Canada project to the east. The Gilbert Report assigns net remaining Established Reserves of 6,190 mboe, before deduction of royalties, to the Laprise Creek Baldonnel Unit No. 1. The Unit consists of 19 (14.4 net) producing natural gas wells and one (0.76 net) suspended well.

The Laprise Creek Baldonnel Unit No. 1 includes a 75.625 percent working interest in the associated field gathering system and two field compressors. The natural gas is transported through the Westcoast Gas Transmission System and is processed at Aitken Creek.

The current recovery factor of the Baldonnel pool is 73 percent. PrimeWest intends to restage the Laprise compressor in two phases. Phase One re-staging was done in 1998, and will decrease compressor suction and increase recovery to 89 percent. Phase Two, scheduled for 2003, is expected to further decrease suction and increase recovery factors to 92 percent.

### *Laprise Creek Non-Unit*

Interests in the Laprise Creek Non-Unit area include a 100 percent interest in one producing natural gas well completed in the Bubbles Baldonnel A Pool, which was tied-in during 1997. Compression was installed and the well was put back on production in October 1997 at a constant rate of 2.3 mmcf/d. In addition, PrimeWest

has one (0.025 net) natural gas well in the Laprise Creek West Field, which produced from 1979 to 1993, when it was shut-in due to low natural gas prices and pipeline leaks.

The Gilbert Report assigns net remaining Established Reserves of 524 mboe, before deduction of royalties, to the Laprise Creek Non-Unit property.

### *Kobes Creek*

The Kobes Creek property is located approximately 90 miles northwest of Fort St. John, British Columbia. Natural gas reserves occur in the Baldonnel Formation at an average depth of 5,200 feet. PrimeWest has a 15 percent royalty interest in two natural gas wells which will convert to 40 percent working interest after payout, a 40 percent working interest after penalty payout in a third natural gas well and a 40 percent working interest in a fourth well that was drilled in late 1997. The average net production for the year ended December 31, 1998 was approximately 1,117 mcf/d of natural gas, before deduction of royalties. Gas is processed at the Amoco-operated Cypress processing facility or at Westcoast's McMahon plant.

The Gilbert Report assigns net remaining Established Reserves of 22,826 mmcf of natural gas and 106 mbbls of natural gas liquids (for a total of 2,388 net mboe), before deduction of royalties, to the Kobes Creek property. Capital expenditures for the installation of gas gathering and compression facilities are included in the Gilbert Report for the years 2002 and 2007.

## **Southeastern Alberta Area**

### *Grand Forks*

The Grand Forks property is located 45 miles west of Medicine Hat, Alberta. Crude oil reserves are found in the Sawtooth formation at an average depth of 3,100 feet. PrimeWest has a 63 percent working interest in 340 (214 net) oil wells and a 41 percent working interest in 8 (3.28 net) natural gas wells.

During 1998, PrimeWest completed a ten-well development drilling program which resulted in nine oil wells and one dry hole. PrimeWest's working interest in the new wells range from 80 percent to 100 percent, averaging 87.25 percent. The combined initial oil production rate from this program is 580 bbls/d (500 bbls/d net). The 1998 drilling activity represents the first phase of a multi-year program that has identified 55 potential development drilling locations. It is expected that the incremental production developed through this multi-year program will offset previously predicted production declines and significantly extend the area's reserve life. Capital costs associated with drilling 31 of the identified wells have been included in the Gilbert Report.

The Gilbert Report assigns net remaining Established Reserves of 6,352 mbbl of oil and natural gas liquids and 313 mmcf of natural gas (for a total of 6,384 net mboe),

before deduction of royalties to the Grand Forks property. The average net production from the Grand Forks property was approximately 2,104 bbls/d of crude oil and natural gas liquids and 105 mcf/d of natural gas (for a total of 2,114 boe/d), before deduction of royalties.

#### *Medicine Hat*

The Medicine Hat property covers a 25 mile radius around Medicine Hat, Alberta. The Gilbert Report assigns net remaining Established Reserves of 855 mbbbl of oil and 17,068 mmcf of natural gas (for a total of 2,562 net mboe), before deduction of royalties to the Medicine Hat properties. The average net production from the Medicine Hat properties was approximately 233 bbls/d of crude oil and natural gas liquids and 3,691 mcf/d of natural gas (for a total of 603 boe/d), before deduction of royalties.

#### *Medicine Hat Glauconitic C Pool*

PrimeWest operates and has a 96.6989 percent average working interest in 17 oil wells (16 net) in the Medicine Hat Glauconitic C Pool. Crude oil reserves are found in the Glauconitic formation at an average depth of 2,700 feet. Average net production was approximately 233 bbls/d of crude oil and 153 mcf/d of natural gas for a total of 248 boe/d before deduction of royalties. There were no development activities on this property during 1998. The Gilbert Report assigns net remaining Established Reserves of 916 net mboe before deduction of royalties to the Medicine Hat Glauconitic C Pool.

#### *Medicine Hat Consolidated Unit #2*

PrimeWest has a 20.0025 percent working interest in the Medicine Hat Consolidated Unit #2 which is located 25 miles northeast of Medicine Hat and operated by Gascan Resources. Gas is produced from the Medicine Hat "A", "C", "D", Lower Colorado and Milk River zones. The Unit consists of 176 (87.9 net) wells which produced approximately 5.25 mmcf/d (1.05 mmcf/d net) of natural gas during 1998. The Gilbert report assigns 768 mboe of net remaining Established Reserves, before deducting royalties to the Unit.

#### *Bowmanton*

The Bowmanton property is located 15 miles northeast of Medicine Hat. Natural gas is produced from the Medicine Hat "C", "D", Milk River and Lower Colorado zones. PrimeWest has a 30 percent working interest in 93 (27.9 net) wells which produced approximately 4.65 mmcf/d (1.4 mmcf/d net) of natural gas during 1998. The Bowmanton compressor station, which consists of five compressors totalling 400 hp, compresses and dehydrates natural gas delivered from the Medicine Hat Consolidated Unit #2, Dauntless, Vale South and Sunlite properties. PrimeWest has a 30 percent working interest in the compressor station. Gascan Resources is the

operator. The Gilbert Report assigns net remaining Established Reserves of 604 net mboe, before deduction of royalties, to the Bowmanton property.

#### *Other Properties*

PrimeWest has a 40 percent working interest in the Dauntless, Vale South and Sunlite properties. Vale South and Sunlite are located northeast and Dauntless is located immediately southwest of Medicine Hat. These properties produce natural gas primarily from the Medicine Hat "C", "D" and Second White Specks zones. In total, there are 74 (29.6 net) wells, which produced an average net 673 mcf/d of natural gas in 1998. Gascan Resources operates Vale South and Sunlite and the City of Medicine Hat operates the Dauntless property. The Gilbert report assigns net remaining Established Reserves of 272 net mboe, before royalties to these other properties.

#### **Crossfield/Lone Pine Creek Area**

The Crossfield/Lone Pine Creek Area is located approximately 20 miles north of Calgary, Alberta, and was discovered in 1960 by Amoco. Production of natural gas and natural gas liquids occurs from the Elkton, Wabamun (Crossfield), Leduc and Nisku Formations. Oil production occurs from the Cardium, Basal Quartz, Elkton and Nisku Formations. The Gilbert Report assigns net remaining Established Reserves of 304 mbbbl of oil, 59,039 mmcf of natural gas and 761 mbbbl of natural gas liquids (for a total of 6,969 mboe), before deduction of royalties, and 772 mlt of sulphur to the East Crossfield/Lone Pine Creek Area properties. The aggregate average net daily sales volumes from this area for the year ended December 31, 1998 was approximately 14,416 mcf/d of natural gas and 246 bbls/d of oil and natural gas liquids (for a total of 1,685 boe/d), in each case before royalties.

PrimeWest operates and has a net working interest in the following: 54.58034 percent in the East Crossfield Unit - Crossfield Formation, 68.42 percent in the Lone Pine Creek Gas Unit No. 1, 75 percent in the Lone Pine Creek Gas Unit No. 3, 76.5625 percent in the Lone Pine Creek Gas Unit No. 5, 54.6479 percent in the Lone Pine Creek D-3 Gas Unit No. 1, 100 percent in the East Crossfield Elkton "F" Pool, six (4.6 net) non-unit gas wells and a 100 percent working interest in one non-unit oil well. These properties were contract-operated for PrimeWest by Amoco until March 1, 1998. In addition, PrimeWest has varying working interests averaging 25 percent in two non-operated oil wells, and a 100 percent working interest in two PrimeWest-operated, producing natural gas wells.

All operated natural gas production is processed at the East Crossfield Sour Gas Processing Facility operated by Amoco. PrimeWest has a 20 percent interest in the facility. All PrimeWest's natural gas produced from this area is processed on a plant operating-cost basis. During 1998, plant utilization was approximately 50 percent, as a result, operating costs billed to PrimeWest on a throughput basis were approximately

54.58 percent. Pursuant to the agreement under which PrimeWest acquired its interest in the East Crossfield Sour Gas Processing Facility, Amoco remains liable and has indemnified PrimeWest for all environmental obligations and liabilities associated with the Amoco East Crossfield Sour Gas Processing Facility existing as at September 1, 1996. Other major facilities acquired by PrimeWest from Amoco in respect of this Property include the Lone Pine Creek Central Gathering and Compression Facility (38.59 percent interest), the Lone Pine Creek Waukashaw Compressor (50.09167 percent interest), the Lone Pine Creek D-1 Unit Booster Compressor (68.42024 percent interest) and the Lone Pine Creek to East Crossfield Amalgamation Pipeline (64.579549 percent interest).

The Gilbert Report notes that economically recoverable reserves could be enhanced by lowering the property's operating cost structure. PrimeWest has made arrangements in 1998 with a number of companies to bring third party natural gas to the East Crossfield plant, beginning in late 1998, for approximately 25 mmcf/d. This natural gas would be processed on a share-of-operating-cost basis, reducing the costs charged to PrimeWest. During 1998, horizontal re-entries were performed on two non-unit Wabamun wells increasing gross production from 3 mmcf/d to nearly 6 mmcf/d of natural gas. Based on these results, a 3D seismic survey was shot over a majority of Lone Pine Creek Unit No. 1, and 12 horizontal drilling locations have been identified and included in the Gilbert Report.

### **Boundary Lake Area**

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 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. The Gilbert Report assigns remaining Established Reserves of 4,479 mbbl of oil, 378 mmcf of natural gas and 11 mbbl of natural gas liquids (for a total of 4,528 mboe), before deduction of royalties, to the Boundary Lake Area properties. The average net production from the Boundary Lake Area properties for the year ended December 31, 1998 was approximately 758 bbls/d of oil and natural gas liquids and 240 mcf/d of natural gas, in each case before royalties.

#### *Boundary Lake Non-Unit*

PrimeWest operates and 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 4.19 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.

The Project No. 1 waterflood was implemented in 1965 and consists of 23 producing oil wells, seven water-injection wells and seven shut-in or suspended oil wells. Oil production is gathered to two main batteries and a satellite battery. Solution gas is processed at the Boundary Lake Gas Conservation Plant, operated by Imperial Oil Limited.

The Project No. 2 waterflood was also implemented in 1965 and consists of four producing oil wells, one water injector well and three shut-in oil wells. Oil production is tied to a main battery.

The Gilbert Report assigns net remaining Established Reserves of 4,030 mboe, before deduction of royalties, to the Boundary Lake Non-Unit Property. The Gilbert Report includes future capital expenditures associated with the drilling of three wells in Project No. 1, as well as various capital expenditures relating to maintenance, workovers, fracture stimulations and facilities consolidation.

#### *Boundary Lake Unit No. 1*

PrimeWest has a 2.05737 percent working interest in the Boundary Lake Unit No. 1. The Unit is located in the British Columbia and was formed in 1964 for the purpose of implementing a waterflood. Solution gas is processed at the Boundary Lake Gas Conservation Plant, in which PrimeWest has a 1.1839 percent working interest. The Unit and plant are operated by Imperial Oil Limited.

The Gilbert Report assigns 498 net mboe, before deduction of royalties, of remaining Established Reserves to the Boundary Lake Unit No. 1.

The Gilbert Report includes future expenditures associated with workovers/stimulations on wells in Project No. 1, over a three-year period commencing in 1999. Potential additional reserves may result from infill drilling to improve waterflood performance, and recompleting wells to shut off water production. A pilot hydrocarbon miscible flood to improve oil recovery commenced operations in March 1995, which if successful, may be expanded elsewhere in the pool on a commercial basis.

#### **Kaybob South Area**

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 42.4632 percent working interest in the Kaybob South Triassic Unit No. 1 and a 20.06 percent working interest in the Kaybob South Triassic Unit No. 2, both of which are operated by PrimeWest. The Gilbert Report assigns net remaining Established Reserves of 2,269 mbbbl of oil, 1,637 mmcf of natural gas and 132 mbbbl of natural gas liquids (for a total of 2,563 mboe), before deduction of royalties, to the Kaybob South Area properties. The

average net production from the Kaybob South Area properties for the year ended December 31, 1998 was 1,037 bbls/d of oil and natural gas liquids and 393 mcf/d (for a total of 1,074 boe/d), before deduction of royalties.

Production of 41.5-degree API light-gravity crude oil commenced from the Triassic "A" Pool in 1963. Unit No. 1 was established in 1967 in order to facilitate the implementation of a waterflood project. Development drilling commenced two years later, extending the pool eastward. Unit No. 2 was formed in 1976, also for the purpose of implementing a waterflood project. During 1984, a miscible flood process was implemented in the southern portion of Unit No. 1, which was followed by chase-gas injection in 1990 and subsequently water injection in 1996.

Oil production from Unit No. 1 and Unit No. 2 is primarily treated at the Unit No. 2 battery. Solution gas is conserved and custom-processed at the Kaybob South Gas Plant. Facilities included with the properties include inlet separation, treating and solution-gas compression facilities, water injection equipment, tankage and associated gathering and injection pipelines.

A number of development drilling operations have occurred on the Kaybob South Area properties since 1993, including the drilling of one edge well in Unit No. 1, and the drilling of seven infill wells and two horizontal wells in Unit No. 2. The Gilbert Report assigns net remaining Established Reserves of 1,263 mboe, before deduction of royalties, to the Kaybob South Triassic Unit No. 1. As at December, 1998 there were 18 (7.6 net) producing oil wells and 10 (4.2 net) water-injection wells. The average net production from Unit No. 1 for the year ended December 31, 1998 was approximately 471 boe/d, before royalties. Capital expenditures for future development projects included in the Gilbert Report for Unit No. 1 include ongoing maintenance and future facility consolidation to reduce fixed facility-operating expenses.

The Gilbert Report assigns net remaining Established Reserves of 1,300 mboe, before deduction of royalties, to the Kaybob South Triassic Unit No. 2. As at December, 1998, there were 21 (4.2 net) producing oil wells and 14 (2.8 net) water-injection wells. The average net production from Unit No. 2 for the year ended December 31, 1998 was 626 boe/d, before royalties. Capital expenditures for future development projects included in the Gilbert Report for Unit No. 2 include the installation of natural gas lift systems on three wells, the potential drilling of three vertical and three horizontal sidetrack wells, ongoing maintenance, and future facility consolidation to reduce fixed facility operating expenses.

### **Other Properties**

The following is a description of the balance of PrimeWest's properties. These properties represent approximately 12 percent of the total reserve value of all of the properties and primarily consist of small working interests in unitized properties.

### *Jumping Pound West*

PrimeWest has a 14.627 percent interest in the Jumping Pound West Unit No. 2 operated by Shell Canada Resources and located 30 miles west of Calgary. The unitized zone is 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 liquid rich, yielding 40 bbls of liquids per mmcf of natural gas.

The Gilbert Report assigns net remaining Established Reserves of 13,317 mmcf of natural gas and 416 mbbls of natural gas liquids (for a total of 1,748 net mboe), before deduction of royalties, to the Jumping Pound West property. Average net production for the year ended December 31, 1998 was 3,531 mcf/d of natural gas and 95 bbls/d of natural gas liquids (for a total of 448 boe/d).

### *Eagle Lake Viking Voluntary Unit*

PrimeWest has a 9.3807 percent working interest in the Eagle Lake Viking Voluntary Unit. The Unit was formed in 1966, and is located approximately 90 miles southwest of Saskatoon, Saskatchewan. The unitized zone consists of the Viking Formation, and 38 degree API light-gravity crude oil is recovered by waterflood, which was implemented in 1967. Infill drilling and refracturing has been in progress continuously since 1984, and conservation of solution gas commenced in 1985. Of the 455 unit wells, 301 were producing at December 31, 1998. Viking Holdings Trust is the Unit operator.

Net oil production for the unit for the year ended December 31, 1998 averaged 155 bbls/d of oil, before royalties. The Gilbert Report assigns net remaining Established Reserves of 869 mboe, before deduction of royalties, to the Eagle Lake Viking Voluntary Unit.

### *Midale Unit*

PrimeWest has a 3.91969 percent interest in the Shell-operated Midale Unit located in southeast Saskatchewan. The Unit was formed in 1962 when a waterflood project was implemented. Since that time, the operator has undertaken an infill drilling program, first vertical and then horizontal, commencing in 1989, resulting in over 120 wells being drilled. Recent activity in the Unit consists of multiple-leg horizontal drilling projects. In addition, enhanced recovery from CO<sub>2</sub> miscible flood was started in 1992. The Gilbert Report assigns net remaining Established Reserves of 1,288 mbbls of oil and 129 mmcf of natural gas for a total of 1,301 mboe to the Midale Unit property, before deduction of royalties. Average net production from the property for the year ended December 31, 1998 was 200 bbls/d of oil.

## *Willesden Green*

The Willesden Green properties are located approximately 10 miles northeast of Rocky Mountain House, Alberta. PrimeWest has a 13.448 percent working interest and a 0.2936937 percent royalty interest in the Willesden Green Cardium Unit No. 6. Petro-Canada is the operator of the Unit. The Unit produces a 40-degree API light-gravity crude oil from the Willesden Green Cardium "A" Pool at a depth of approximately 6,230 feet. The Pool was discovered in 1959 and Unit No. 6 was formed in 1966 when a field wide waterflood scheme was implemented. For the year ended December 31, 1998, from Unit No. 6 net oil production averaged 179 bbls/d of oil and natural gas liquids and 83 mcf/d of natural gas, before royalties.

A waterflood optimization program was initiated in 1995 based on an extensive reservoir study conducted to improve oil productivity and voidage replacement. The Gilbert Report indicates that additional recoverable reserves may be developed through infill drilling, injector conversions and refracturing.

In addition, PrimeWest has a 0.5026 percent royalty interest in the Willesden Green Cardium Unit No.1, a 0.6889 percent royalty interest in the Willesden Green Cardium Unit No. 2, a 1.884 percent royalty interest in the Willesden Green Cardium Unit No. 4, a 0.3306 percent royalty interest in the Willesden Green Cardium Unit No. 7 and a 0.9138416 percent royalty interest in the Willesden Green Cardium Unit No. 8. PrimeWest also has royalty interests on six non-unit producing wells of a fixed amount (37.39 percent) ranging from 12.5 percent to 20 percent and a seventh non-unit producing well earns 50 percent of a sliding scale royalty interest of 5 percent to 15 percent.

The Gilbert Report assigns net remaining Established Reserves of 826 mboe, before deduction of royalties, to the Willesden Green properties. Future development projects included in the Gilbert Report relate to capital expenditures for a number of well workovers and modifications to waterflood facilities.

## *Others*

PrimeWest has varying, small, non-operated working interests in a number of properties. These interests include Pembina Cardium Unit No. 4, Sibbald North, Wainwright, Clandonald, Morse River Unit No. 1, Chinook, Farrel – Chain Lakes and Sierra. The Gilbert Report assigns net remaining Established Reserves of 519 mboe to these properties.

## **Unproved Lands**

PrimeWest has an interest in approximately 278,410 (176,312 net) acres of unproved lands at December 31, 1998. Based on an evaluation by an independent consulting firm retained by PrimeWest, a value of \$10,093,300 has been assigned to

172,803 net acres and 3,509 net acres were acquired during 1998 at a cost of \$488,994 for a total value of \$10,582,294 (approximately \$60.02 per net acre). PrimeWest is currently reviewing available seismic and other data, and will develop an exploitation plan for these properties. Capital expenditures, farmouts and/or dispositions may result in future revenues from these undeveloped lands. The geographical area and value of the unproved lands is as follows:

## Unproved Lands

Area	Acres		Value
	Gross	Net	(\$)
Sundre			
Caroline	84,117	65,632	3,745,800
Garrington	25,718	13,635	282,550
Westward Ho	11,082	9,640	268,400
Laprise Creek			
Kobes Creek	7,160	2,864	253,100
Southeastern Alberta	54,368	21,351	417,300
Crossfield/Lone Pine Creek	52,345	39,237	4,291,744
Boundary Lake	5,886	5,129	94,300
Others	37,734	18,824	1,229,100
TOTAL	<u>278,410</u>	<u>176,312</u>	<u>10,582,294</u>

## 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 the Manager is unable to predict what additional legislation or amendments may be enacted.

### Pricing and Marketing - Oil

In Canada, producers of oil negotiate sales contracts directly with oil purchasers. 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 National Energy Board ("NEB"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issue of such a licence requires the approval of the Governor in Council.

### Pricing and Marketing - Natural Gas

In Canada, the price of natural gas sold 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 must continue to meet certain criteria prescribed by the NEB and the government of Canada. Natural gas exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 cubic metres per day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issue of such a licence requires the approval of the Governor in Council.

The 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.

### **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.

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

The Alberta Government has also introduced the Third Tier Royalty with a base rate of 10 percent and a rate cap of 25 percent for oil pools discovered after September 30, 1992. The new oil royalty reserved to the Crown has a base rate of 10 percent and a rate cap of 30 percent. The old oil royalty reserved to the Crown has a base rate of 10 percent and a rate cap of 35 percent.

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

In Alberta, a producer of oil or natural gas is entitled to a credit against the royalties payable to the Crown by virtue of the Alberta Royalty Tax Credit ("ARTC") program. The ARTC program is based on a price-sensitive formula, and the ARTC rate varies between 75 percent, at prices for oil below \$100 per cubic metre, and 25 percent, at prices above \$210 per cubic metre. The ARTC rate is applied to a maximum of \$2 million of Alberta Crown royalties payable for each producer or associated group of

producers. Crown royalties on production from producing properties acquired from corporations claiming maximum entitlement to ARTC will generally not be eligible for ARTC. The rate is established quarterly, based on the average "par price", as determined by the Alberta Department of Energy, for the previous quarterly period. On December 22, 1997, the Government of Alberta gave notice that they intended to review the ARTC program with expected changes to take effect prior to 2001.

The Government of Saskatchewan's fiscal regime for the oil and gas industry provides an incentive to encourage the drilling of new vertical oil wells through a revised royalty/tax structure for new vertical oil wells and incremental production from new or expanded waterflood projects. This "third tier" Crown royalty rate is price sensitive and varies between heavy and non-heavy oil (from a minimum of 10 percent for heavy oil at a base price to a maximum of 35 percent for non-heavy oil at a price above the base price). Previous time-based royalty/tax holidays applicable to vertically drilled oil wells have been replaced with volume-based royalty/tax-reduction incentives in which a maximum royalty of five percent will apply to various volumes depending on the depth and nature of the well (up to 25,000 cubic metres of oil in the case of deep exploratory wells). The maximum royalty applicable to the first 12,000 cubic metres of oil has been increased from five percent to 10 percent for production from certain horizontal wells. In addition, royalty/tax holidays for deep horizontal oil wells have been replaced with a 25,000 cubic meter volume incentive (five percent maximum royalty). Oil production from qualifying reactivated oil wells is subject to a maximum new royalty rate of five percent for the first five years following re-activation in the case of wells reactivated after 1993 and shut-in or suspended prior to January 1, 1993. With respect to qualifying exploratory natural gas wells, the first 25 million cubic metres of natural gas produced will be subject to an incentive maximum royalty rate of five percent. On February 9, 1998, the Government of Saskatchewan announced further royalty incentive programs to encourage oil and gas exploration. This includes a third tier royalty for natural gas.

In British Columbia, the amount payable as a royalty in respect of oil depends on the vintage of the oil (whether it was produced from a pool discovered before or after October 31, 1975), the quantity of oil produced in a month and the value of the oil. Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production. The royalty payable on natural gas is determined by a sliding scale based on a reference price which is the greater of the amount obtained by the producer and a prescribed minimum price. Gas produced in association with oil has a minimum royalty of 8 percent while the royalty in respect of other natural gas may not be less than 15 percent.

### **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. The Manager believes that PrimeWest is in material compliance with applicable environmental laws and regulations properties.

## **Risk Factors**

### **Volatility of Oil and Natural Gas Prices**

PrimeWest's results of operations and financial condition, and therefore the amounts paid to the Trust pursuant to the Royalty, will be dependent on the prices received for PrimeWest's oil and natural gas production. Crude oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil producing regions, which are beyond the control of PrimeWest or the Trust. Any decline in crude oil or natural gas prices could have a material adverse effect on PrimeWest's operations, financial condition, proved reserves and the level of expenditures for the development of its oil and natural gas reserves. The Manager may manage the risk associated with changes in commodity prices and foreign exchange rates by causing PrimeWest to, from time to time, enter into crude oil or natural gas price hedges and forward foreign-exchange contracts.

### **Reserves Replacement (Sustainability)**

The Trust has certain unique attributes which differentiate it from other oil and natural gas industry participants. Distributions of Distributable Income in respect of properties, absent commodity price increases or cost-effective acquisition and development activities, will decline over time in a manner consistent with declining production from typical oil, natural gas and natural gas liquids reserves. PrimeWest will not be reinvesting cash flow in the same manner as other oil and natural gas exploration and production company industry participants. PrimeWest's future oil and natural gas reserves and production, and therefore its cash flows, will be highly dependent on PrimeWest's success in exploiting its reserve base and acquiring additional reserves. Without reserve additions through acquisition and/or

development activities, PrimeWest's reserves and production will decline over time as reserves are produced.

Trust Units will have no value when reserves from the properties or additional properties can no longer be economically marketed and, as a result, subscribers for Trust Units will have to obtain the return of capital invested out of cash flow derived from their investment in Trust Units during the period when reserves can be economically recovered.

To the extent that external sources of capital, including the issuance of additional Trust Units, become limited or unavailable, 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 Distributable Income will be reduced.

There is strong competition relating to all aspects of the oil and natural gas industry. PrimeWest actively competes for reserve acquisitions and skilled industry personnel with a substantial number of other oil and natural gas companies, many of which have significantly greater financial resources than PrimeWest. There can be no assurance that PrimeWest will be successful in developing additional reserves or acquiring additional reserves on terms that meet the acquisition guidelines.

### **Changes in Legislation**

There can be no assurance that income tax laws or government incentive programs relating to the oil and natural gas industry, such as the status of mutual fund trusts and the resource allowance, will not be changed in a manner which adversely affects Unitholders.

### **Investment Eligibility**

If the Trust ceases to qualify as a mutual fund trust, the Trust Units will cease to be qualified investments for RRSPs, RRIFs and DPSPs and RESPs that acquired the Trust Units after October 27, 1998 ("Exempt Plans"). Where at the end of any month an Exempt Plan holds Trust Units that are not qualified investments, the Exempt Plan must, in respect of that month, pay a tax under Part XI.1 of the Tax Act equal to 1 percent of the fair market value of the Trust Units at the time those Trust Units were acquired by the Exempt Plan. In addition, where a trust governed by an RRSP holds Trust Units that are not qualified investments, the trust will become taxable on its income attributable to the Trust Units while they are not qualified investments.

### **Operational Matters**

The operation of oil and natural gas wells involves a number of operating and natural hazards which may result in blowouts, environmental damage and other unexpected or dangerous conditions, resulting in damage to PrimeWest and possible liability to third parties. PrimeWest maintains liability insurance, where available, in amounts consistent with industry standards. Business interruption insurance may also be purchased for selected facilities, to the extent that kind of insurance is available. PrimeWest may become liable for damages arising from those events against which it cannot insure or against which it may elect not to insure because of high premium costs or other reasons. In particular, insurance against environmental risks is not generally available to PrimeWest or to other companies in the oil and natural gas industry. Costs incurred to repair that damage or pay those liabilities will reduce Royalty Income.

Continuing production from a property, and to some extent the marketing of production therefrom, are largely dependent upon the capability of the operator of the property. To the extent the operator fails to perform these functions properly, revenue may be reduced. Payments from production generally flow through the operator, and there is a risk of delay and additional expense in receiving those revenues if the operator becomes insolvent.

Although satisfactory title reviews of the properties will be conducted in accordance with industry standards, those title reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat the claim of PrimeWest to a property. A reduction of Royalty Income could result in those circumstances.

### **Environmental Concerns**

The oil and natural gas industry is subject to environmental regulation pursuant to municipal, provincial and federal legislation. A breach of that legislation may result in the imposition of fines or the issuance of clean up orders. That legislation may be changed to impose higher standards and potentially more costly obligations on PrimeWest. See "Industry Conditions - Environmental Regulation". Although PrimeWest has established a reclamation fund for the purpose of funding its currently estimated future environmental and reclamation obligations based on its current knowledge, there can be no assurance that PrimeWest will be able to satisfy its actual future environmental and reclamation obligations. Ongoing environmental obligations will be funded out of PrimeWest's cash flow and will therefore reduce Distributable Income payable 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.

### **Debt Service**

Amounts paid in respect of interest and principal, and other costs, expenses and disbursements ("Debt Service Charges") relating to debt incurred in respect of the

properties will reduce Royalty Income. Variations in interest rates and other credit charges and scheduled principal repayments could result in significant changes in the amount required to be applied to Debt Service Charges before payment of the Royalty and Distributable Income. Certain covenants of the agreements with the bank providing the Credit Facility may also limit distributions to the Trust. Although the Manager and PrimeWest believe the Credit Facility will be sufficient for PrimeWest's immediate requirements, there can be no assurance that the amount will be adequate for the future financial obligations of PrimeWest or that additional funds will be able to be obtained.

The bank providing the Credit Facility will be provided with security over substantially all of the assets of PrimeWest. If PrimeWest becomes unable to pay its Debt Service Charges in respect of the Credit Facility, or otherwise commits an event of default such as bankruptcy, that bank may foreclose on or sell the properties free from or together with, the Royalty.

### **Delay in Cash Distributions**

In addition to the usual delays in payment by purchasers of Petroleum Substances produced from the properties to the operator of the properties, from the operator to PrimeWest (where PrimeWest is not the operator), from PrimeWest to the Trust and from the Trust to Unitholders, payments between any of those parties may also be affected or 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 properties, or the establishment by the operator of reserves for those expenses.

### **Reliance on the Manager**

Unitholders will be dependent on the management of the Manager in respect of the administration and management of all matters relating to the properties, the Royalty, the Trust and Trust Units. Investors who are not willing to rely on the management of the Manager should not invest in the Trust Units.

### **Potential Conflicts of Interest**

There may be circumstances in which the interests of the Manager will conflict with those of Unitholders.

The Manager will use all reasonable efforts to resolve such conflicts of interest in a manner that will treat the Trust or PrimeWest, as the case may be, and the other interested party fairly, taking into account all of the circumstances of the Trust or PrimeWest, as the case may be, and such interested party, and to act honestly and in good faith in resolving those matters.

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

### **Nature of Trust Units**

The Trust Units do not represent a traditional investment in the oil and natural gas sector and should not be viewed by investors as shares in PrimeWest. The Trust Units represent a fractional interest in the Trust. As holders of Trust Units, Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring oppression or derivative actions. The Trust's sole assets will be permitted short-term investments, direct and indirect interests in petroleum and natural gas properties and related contractual rights. The market price of the Trust Units will be a function of anticipated Distributable Income, the value of the properties owned by PrimeWest and the Trust, and the Manager's ability to effect long-term growth in the value of the Trust. The market price of the Trust Units will be sensitive to a variety of market conditions including, but not limited to, interest rates and the ability of the Trust to acquire suitable oil and natural gas properties. Changes in market conditions may adversely affect the trading price of the Trust Units.

### **Unitholder Limited Liability**

The Declaration of Trust provides that no Unitholder will be subject to any liability in connection with the Trust or its obligations and affairs and, in the event that a court determines Unitholders are subject to any of those liabilities, those liabilities will be enforceable only against, and will be satisfied only out of the Trust's assets. Pursuant to the Declaration of Trust, the Trust will indemnify and hold harmless each Unitholder from any costs, damages, liabilities, expenses, charges and losses suffered by a Unitholder resulting from or arising out of that Unitholder not having that limited liability.

The Declaration of Trust provides that all written instruments signed by or on behalf of the Trust must contain a provision to the effect that the obligations in those instruments will not be binding on Unitholders personally. The principal investment of the Trust is currently the Royalty Agreement, which contains that provision. Personal liability may also arise in respect of claims against the Trust that do not arise under contracts, including claims in tort, claims for taxes, and possibly certain other statutory liabilities. The possibility of any personal liability of this nature arising is considered unlikely.

The operations of the Trust will be conducted, on the advice of counsel, in such a way and in such jurisdictions as to avoid as far as possible any material risk of liability on the Unitholders for claims against the Trust.

## ITEM 4: SELECTED CONSOLIDATED FINANCIAL INFORMATION

Reference is made to the consolidated comparable financial statements of the Trust on pages 25 through 32 of the Annual Report, which financial statements are hereby incorporated into this Annual Information Form by reference.

### Selected Annual Information

(\$000's except per Unit)	For the Year Ended December 31		For the Period from August 2, 1996 to December 31, 1996 )
	1998	1997	
<b>Earnings Information</b>			
Total Revenue, net of royalties.....	66,057	59,593	18,043
Expenses .....	79,604	56,423	16,030
Net Income (Loss) .....	(13,547)	3,170	2,013
Net Income (Loss) per Unit (\$)			
Basic .....	(0.43)	0.13	0.24
Fully Diluted.....	(0.43)	0.13	0.24
<b>Distributable Income Information</b>			
Cash Available for Distribution.....	26,030	33,746	11,067
Cash Available for Distribution to Unitholders .....	25,769	33,409	10,956
Cash Available for Distribution per Unit (\$)			
Basic .....	0.82	1.34	0.44
Fully Diluted.....	0.82	1.34	0.44
<b>Balance Sheet Information</b>			
Total Assets .....	316,140	285,765	254,480
Long Term Debt, including current portion .....	73,112	66,829	14,228
Average Units Outstanding.....	31,426	24,931	8,323

### Selected Quarterly Information

(\$000's except per Unit)	For the Quarters Ended - 1998			
	March 31	June 30	September 30	December 31
Total Revenue, net of royalties .....	14,055	16,495	16,094	19,413
Expenses .....	16,983	21,202	20,308	21,111
Net Income (Loss) .....	(2,928)	(4,707)	(4,214)	(1,698)
Net Income (Loss) per Unit (\$)				
Basic.....	(0.11)	(0.14)	(0.13)	(0.05)
Fully diluted .....	(0.11)	(0.14)	(0.13)	(0.05)
	For the Quarters Ended - 1997			
	March 31	June 30	September 30	December 31
Total Revenue, net of royalties .....	14,853	13,750	14,191	16,799
Expenses .....	12,728	14,256	14,382	15,057

Net Income (Loss) .....	2,126	(506)	(191)	1,741
Net Income (Loss) per Unit (\$)				
Basic.....	0.09	(0.02)	(0.01)	0.07
Fully diluted .....	0.09	(0.02)	(0.01)	0.07

## **ITEM 5: MANAGEMENT'S DISCUSSION AND ANALYSIS**

Reference is made to the information under the heading "Management's Discussion and Analysis" on pages 16 through 22 of 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 PrimeWest Energy Trust are listed for trading on The Toronto Stock Exchange under the symbol PWI.UN.

## **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 and the Manager.

### **Directors**

The Trust has the right to nominate and cause the Manager to elect a majority of the board of directors of PrimeWest. Reference is made to the information under the heading "Election of Directors" on pages 2 and 3 of the Circular for the names of those persons who are directors of PrimeWest on the date of this Annual Information Form, their current occupation and principal occupations for the five years ended December 31, 1998, municipality of residence and ownership of Trust Units, which information is hereby incorporated in this Annual Information Form by reference.

PrimeWest does not have an executive committee, but is required to, and does have, an audit committee. The audit committee consists of those directors of PrimeWest who are nominees of the Trust. Barry E. Emes, Harold N. Kvisle and Harold P. Milavsky, who are Independent Directors, are members of the audit committee. The Independent Directors also act as the compensation committee of PrimeWest. Montreal Trust Company of Canada is currently the Trustee of the Trust.

### **Officers**

Each person who is an officer of the Manager also holds the same office with PrimeWest. The name, municipality of residence, position held and principal occupation of each officer of PrimeWest and the Manager on the date hereof are set out below:

<b><u>Name and Municipality</u></b>	<b><u>Position with the Manager</u></b>	<b><u>Principal Occupation</u></b>
Kent J. MacIntyre Calgary, Alberta	Director, Vice-Chairman and Chief Executive Officer	Vice-Chairman and Chief Executive Officer of the Manager and PrimeWest
D. Hugh Gillard Calgary, Alberta	Director, President and Chief Operating Officer	President and Chief Operating Officer of the Manager and PrimeWest
Allan F. Kiernan Calgary, Alberta	Vice-President, Production	Vice-President, Production of the Manager and PrimeWest
Susan M. Duncan Calgary, Alberta	Vice-President, Finance	Vice-President, Finance of the Manager and PrimeWest
Ronald Ambrozy Calgary, Alberta	Vice-President, Business Development	Vice-President, Business Development of the Manager and PrimeWest
Ann C. Laniel Calgary, Alberta	Land Manager	Land Manager of the Manager and PrimeWest
James T. Bruvall Calgary, Alberta	Secretary	Partner, Stikeman, Elliott

None of the above officers have been employed in their current positions for more than five years. Prior to October, 1996 Mr. MacIntyre was Chief Executive Officer of Triad Energy Inc. (March, 1994 - October, 1996). Prior to January 1999, Mr. Gillard was President and Chief Executive Officer of CanWest Gas Supply Inc. (1994–December, 1998). Prior to June, 1996, Mr. Kiernan was Senior Vice President, Production, at AEC Oil and Gas, a division of Alberta Energy Company Ltd. Prior to October, 1996 Ms. Duncan was Treasurer of Triad Energy Inc. (June, 1995 - October, 1996) and prior to June, 1995 a Principal with Coopers & Lybrand, Chartered Accountants. Prior to September, 1997, Mr. Ambrozy held several positions of progressive responsibility at Gulf Canada Resources Limited over the previous 22 years. Prior to October, 1996 Ms. Laniel was Landman of Triad Energy Inc. (March, 1994 - October, 1996). Mr. Bruvall is currently a partner at Stikeman, Elliott, barristers and solicitors (February, 1996 - present). Prior to that time Mr. Bruvall was an associate at Stikeman, Elliott, barristers and solicitors.

## **Management of the Manager**

### ***Kent J. MacIntyre, Director, Vice-Chairman and Chief Executive Officer***

Mr. MacIntyre has overall responsibility for leading and overseeing the business direction of the Manager. He has over 19 years of experience in the oil and natural gas industry, the last ten years as principal in the start-up and management of several energy ventures including Olympia and Triad. Through these ventures, Mr. MacIntyre has been directly involved in and responsible for the acquisition of various petroleum and natural gas properties and the enhancement of the value of those properties through selective operating, marketing, development and exploration strategies. In each of those acquisitions Mr. MacIntyre's companies became the operator of the acquired properties and developed a record of acquiring properties at costs substantially below industry averages.

Prior to 1994, Mr. MacIntyre held executive or engineering operating positions with Olympia Energy Ventures Ltd., Sabre Energy Ltd., Vikor Resources Ltd., and Hudson's Bay Oil and Gas Company Ltd. Mr. MacIntyre has a B.Sc. (Eng.) from the University of Manitoba and an MBA from the University of Calgary.

### ***D. Hugh Gillard, President and Chief Operating Officer***

Mr. Gillard joined the Manager on January 16, 1999 and has overall responsibility for the day-to-day business and operational activity of PrimeWest. He has more than 26 years of oil and natural gas industry experience, in finance, business development, marketing, land, property rationalization, and senior management. He was President and Chief Executive Officer of CanWest Gas Supply Inc., a major natural gas marketing company from 1994 to December 1998, prior to that, Mr. Gillard was Vice-President, Gas Supply at CanWest Gas Supply Inc. Prior to 1990, Mr. Gillard held various senior positions with Ashland Oil and Gas Inc., Amoco Canada petroleum Company Ltd. and Dome Petroleum Ltd. Mr. Gillard has a B. Comm. from the University of Calgary.

### ***Allan F. Kiernan, Vice President, Production***

Mr. Kiernan is a professional engineer with over 35 years of experience in petroleum engineering and production operations. Prior to joining PrimeWest in 1996, Mr. Kiernan was Senior Vice President, Production at AEC Oil and Gas, a division of Alberta Energy Company Ltd. responsible for drilling, production and natural gas storage operations, as well as development activities. Prior to joining AEC, Mr. Kiernan was Senior Vice President, Production for Chieftain Development Co. Ltd. Before joining Chieftain, he worked for 15 years at Hudson's Bay Oil & Gas Company Limited and Dome Petroleum Limited. Prior to leaving Dome Petroleum Limited in 1985, Mr. Kiernan was General Manager, Production for Dome Petroleum Ltd., where he held operational responsibility for 120,000 boe/d of production, including

responsibility for most of the properties initially acquired from Amoco by PrimeWest. Mr. Kiernan began his career with Shell Canada Limited.

***Susan M. Duncan, Vice-President, Finance***

Ms. Duncan is responsible for the general financial operations of the Manager and for providing advice to the Manager on tax and accounting matters. Ms. Duncan has over 14 years of experience in the finance, accounting, audit and income tax in the oil and natural gas industry and in public accounting. She was Treasurer of Triad from June, 1995 to October, 1996. Prior to 1995, Ms. Duncan was a Principal at Coopers & Lybrand in Calgary. Ms. Duncan has a B.Comm. from the University of Lethbridge and received her C.A. designation in 1988.

***Ronald Ambrozy, Vice-President, Business Development***

Mr. Ambrozy has over 22 years of experience in the petroleum and natural gas industry, all spent with Gulf Canada Resources Limited, where he held progressively more senior positions. Prior to joining the Manager, Mr. Ambrozy held the position of manager of Gulf's asset management group. Mr. Ambrozy has a Bachelor of Science in Engineering from the University of Manitoba.

***Ann C. Laniel, Land Manager***

Ms. Laniel is responsible for all of the Manager's land functions. Ms. Laniel has over 12 years of experience in the oil and natural gas industry, the last seven years of which were directly related to land negotiation, land contracts and mineral and surface administration with Triad and Olympia.

**Employees**

As of December 31, 1998, the Trust had no employees. The activities of PrimeWest and the Trust are carried out by the Manager pursuant to the terms of the Management Agreement. The Manager had 79 employees as of December 31, 1998, all of which devoted the majority of their working time to the business of the Trust and 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, 1998, 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, 1998 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, 1998 and a copy of the Circular dated April 2, 1999.

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:

<b>mbbls</b>	Barrels	<b>mcf/d</b>	1,000 cubic feet per day
<b>mmbbls</b>	1,000 barrels	<b>bcf</b>	1,000,000,000 cubic feet
<b>bbls/d</b>	1,000,000 barrels	<b>m</b>	1000 cubic metres
<b>mcf</b>	Barrels per day	<b>boe</b>	barrels of oil equivalent
<b>mmcf</b>	1,000 cubic feet	<b>mboe</b>	1,000 barrels of oil equivalent
<b>mlt</b>	1,000,000 cubic feet	<b>boe/d</b>	barrels of oil equivalent per day
	1,000 long tons		

For purposes of this document, 10 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:

**Amoco** means, collectively, Amoco Canada Petroleum Company Ltd. and its affiliates.

**Annual Report** means the 1998 Annual Report of PrimeWest Energy Trust, dated April 2, 1999.

**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, dated April 2, 1999.

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

**Distributable Income** means 99 percent of the Royalty Income together with any income earned by the Trust from permitted short term investments plus any ARTC, less Crown royalties and other Crown charges that are not deductible by PrimeWest for income tax purposes and that are reimbursed by the Trust to PrimeWest less general and administrative expenses 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 under the Management Agreement in respect of PrimeWest, the Trust or the Royalty or in the management and administration of PrimeWest, the Trust or the Royalty, other than Management Fees.

**Management Agreement** means the agreement dated October 16, 1996 among the Manager, PrimeWest and the Trustee for and on behalf of the Trust, pursuant to which the Manager provides management services to PrimeWest and the Trust.

**Management Fees** means the fees payable to the Manager pursuant to the Management Agreement.

**Manager** means PrimeWest Management Inc.

**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.

**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.

**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.

**PrimeWest** means PrimeWest Energy Inc.

**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, 1998.

**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 agreement dated October 16, 1996 between PrimeWest and the Trustee as trustee for and on behalf of the Trust 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, Management Fees, 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 Montreal Trust Company of Canada, or its successor as trustee of the Trust.

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