



PRIMEWEST ENERGY TRUST ANNOUNCES SECOND QUARTER 2005 RESULTS

CALGARY, August 2, 2005 (TSX: PWI.UN; PWX; PWI.DB.A; PWI.DB.B; NYSE: PWI) -- PrimeWest Energy Trust (PrimeWest or the Trust) today announces interim operating and financial results for the second quarter ended June 30, 2005. Unless otherwise noted, all figures contained in this report are in Canadian dollars.

SECOND QUARTER HIGHLIGHTS:

- Distributions in the second quarter 2005 were \$0.90 per unit representing a payout ratio of approximately 70% of operating cash flow compared to first quarter 2005 distributions of \$0.90 per unit, representing a payout ratio of 80% of operating cash flow.
- Second quarter production averaged 40,405 barrels of oil equivalent (BOE) per day, compared to the first quarter 2005 rate of 40,616 BOE per day. The decrease is mainly due to natural decline which has been partially offset by incremental volumes from capital development activity.
- Total capital expenditures were approximately \$49 million with drilling and completion expenditures of \$23.4 million resulting in 19 wells gross (13 net) being drilled in the second quarter with a success rate of 100%.
- Net debt to annualized second quarter 2005 cash flow was approximately 1.1 times compared to net debt to annualized cash flow of 1.6 times at March 31, 2005. PrimeWest has approximately \$324 million available on its existing borrowing base.
- \$97.9 million of Series I and Series II Convertible Subordinated Unsecured Debentures (Debentures) were converted into Trust Units of PrimeWest (Trust Units) during the second quarter.
- Second quarter cash flow from operations was \$95.5 million (\$1.29 per unit) compared to \$79.7 million (\$1.12 per unit) in the first quarter of 2005, representing the highest quarterly cash flow in PrimeWest's history.
- For Unitholders resident in Canada, PrimeWest anticipates that approximately 65% of 2005 distributions will be taxable and 35% will be deemed return of capital. The 65% taxability reflects the impact of high commodity prices on taxable income.

SUBSEQUENT EVENTS

- During the month of July 2005, \$17.0 million of Debentures were converted to Trust Units.



MANAGEMENT'S DISCUSSION AND ANALYSIS AS OF AUGUST 2, 2005

The following is management's discussion and analysis (MD&A) of PrimeWest's operating and financial results for the quarter ended June 30, 2005, compared with the preceding quarter and the corresponding period in the prior year as well as information and opinions concerning the Trust's future outlook based on currently available information. This discussion should be read in conjunction with the Trust's audited consolidated financial statements for the years ended December 31, 2004 and 2003, together with accompanying notes, as contained in the Trust's 2004 Annual Report.

Financial and Operating Highlights - Second Quarter

(\$ millions, except per BOE ⁽¹⁾ and per Trust Unit amounts)	Three Months Ended			Six Months Ended	
	Jun 30, 2005	Mar 31, 2005	Jun 30, 2004	Jun 30, 2005	Jun 30, 2004
Gross revenue (net of transportation expense)	169.7	153.3	110.4	323.0	219.1
per BOE	46.15	41.94	38.90	44.05	38.59
Cash flow from operations	95.5	79.7	58.2	175.2	116.7
per BOE	25.98	21.79	20.52	23.89	20.56
per Trust Unit - basic ⁽²⁾	1.29	1.12	1.05	2.41	2.21
per Trust Unit - diluted ⁽³⁾	1.21	1.04	1.05	2.26	2.20
Royalty expense	36.8	36.0	25.7	72.8	49.0
per BOE	10.01	9.85	9.06	9.93	8.64
Operating expenses	28.1	24.4	19.6	52.5	39.2
per BOE	7.63	6.68	6.89	7.16	6.91
G&A expenses - Cash	4.8	5.5	3.5	10.3	7.7
per BOE	1.32	1.51	1.23	1.41	1.36
G&A expenses - Non-cash	11.0	15.1	(7.3)	26.0	(6.8)
per BOE	2.98	4.12	(2.57)	3.55	(1.21)
Interest expense ⁽⁴⁾	7.7	9.1	2.8	16.8	6.0
per BOE	2.11	2.49	1.00	2.29	1.06
Distributions to Unitholders	66.5	63.8	42.0	130.4	83.1
per Trust Unit ⁽⁵⁾	0.90	0.90	0.75	1.80	1.57
Net debt ⁽⁶⁾	431.9	516.1	169.2	431.9	169.2
per Trust Unit ⁽⁷⁾	5.54	7.01	2.97	5.54	2.97



- (1) All calculations required to convert natural gas to a crude oil equivalent (BOE) have been made using a ratio of 6,000 cubic feet of natural gas to one barrel of crude oil. BOE's may be misleading, particularly if used in isolation. The BOE conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
- (2) The basic per Trust Unit calculation includes the weighted average Trust Units and Trust Units issuable upon exchange of the Exchangeable Shares of PrimeWest Energy Inc. (Exchangeable Shares).
- (3) The diluted per Trust Unit calculation includes the weighted average Trust Units, Trust Units issuable upon exchange of the Exchangeable Shares, the deemed conversion of the Debentures and Trust Units issuable pursuant to Long-Term Incentive Plan (LTIP). Interest expense incurred on the Debentures is added back to cash flow for the diluted per Trust Unit calculation.
- (4) Interest expense includes the interest on the Debentures.
- (5) Based on Trust Units outstanding at date of distribution.
- (6) Net debt is long-term debt including Debentures less working capital, excluding financial derivative assets and liabilities.
- (7) The net debt per Trust Unit calculation includes outstanding Trust Units, Trust Units issuable upon exchange of the outstanding Exchangeable Shares and Trust Units issuable pursuant to the LTIP at the end of the period.

Operating Highlights

	Three Months Ended			Six Months Ended	
	Jun 30, 2005	Mar 31, 2005	Jun 30, 2004	Jun 30, 2005	Jun 30, 2004
Daily Sales Volumes					
Natural gas (mmcf/day)	178.4	180.6	125.5	179.5	124.7
Crude oil (bbls/day)	6,707	6,948	7,699	6,827	7,782
Natural gas liquids (bbls/day)	3,959	3,563	2,569	3,762	2,632
Total (BOE/day)	40,405	40,616	31,185	40,510	31,193
Realized Commodity Prices (Cdn \$)					
Natural gas (\$/mcf) ⁽¹⁾	7.52	6.79	6.59	7.16	6.58
Without hedging	7.55	6.79	6.82	7.17	6.72
Crude oil (\$/bbl) ⁽¹⁾	45.61	42.18	35.83	43.88	35.38
Without hedging	55.38	50.90	43.20	53.12	41.30
Natural gas liquids (\$/bbl)	53.57	50.82	41.22	52.28	39.85
Total (\$ per BOE) ⁽¹⁾	46.03	41.88	38.77	43.96	38.49
Without hedging	47.78	43.35	41.51	45.57	40.54

⁽¹⁾ Includes hedging losses

Forward Looking Information

This MD&A contains forward-looking or outlook information with respect to PrimeWest.

The use of any of the words "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "project", "should", "believe", "plan", "outlook" and similar expressions are intended to identify forward-looking statements. In addition, statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in our forward-looking statements. We believe the expectations reflected in those forward-looking statements are reasonable. However, we cannot assure you that these expectations will prove to be correct. You should not unduly rely on forward-looking statements included in this report. These statements are made as of the date of this MD&A. Please refer to PrimeWest's public disclosure documents for more information on these risks and uncertainties as they apply to PrimeWest.

In particular, this MD&A contains forward-looking statements pertaining to the following:



- The quantity and recoverability of our reserves;
- The timing and amount of future production;
- Prices for oil, natural gas, and natural gas liquids produced;
- Operating and other costs;
- Business strategies and plans of management;
- Supply and demand for oil and natural gas;
- Expectations regarding our ability to raise capital and to add to our reserves through acquisitions and exploration and development;
- Our treatment under governmental regulatory regimes;
- The focus of capital expenditures on development activity rather than exploration;
- The sale, farming in, farming out or development of certain exploration properties using third party resources;
- The objective to achieve a predictable level of monthly cash distributions;
- The use of development activity and acquisitions to replace and add to reserves;
- The impact of changes in oil and natural gas prices on cash flow after hedging;
- Drilling plans;
- The existence, operation and strategy of the commodity price risk management program;
- The approximate and maximum amount of forward sales and hedging to be employed;
- The Trust's acquisition strategy, the criteria to be considered in connection therewith and the benefits to be derived therefrom;
- The impact of the Canadian federal and provincial governmental regulation on the Trust relative to other oil and gas issuers of similar size;
- The goal to sustain or grow production and reserves through prudent management and acquisitions;
- The emergence of accretive growth opportunities; and
- The Trust's ability to benefit from the combination of growth opportunities and the ability to grow through capital markets.

Our actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this MD&A:

- Volatility in market prices for oil, natural gas and natural gas liquids;
- Risks inherent in our oil and gas operations;
- Uncertainties associated with estimating reserves;
- Competition for, among other things: capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- Incorrect assessments of the value of acquisitions;
- Geological, technical, drilling and processing problems;
- General economic conditions in Canada, the United States and globally;
- Industry conditions, including fluctuations in the price of oil, natural gas and natural gas liquids;
- Royalties payable in respect of PrimeWest's oil and gas production;
- Governmental regulation of the oil and gas industry, including environmental regulation;
- Fluctuation in foreign exchange or interest rates;
- Unanticipated operating events that can reduce production or cause production to be shut-in or delayed;
- Failure to obtain industry partner and other third party consents and approvals, when required;
- Stock market volatility and market valuations;
- The need to obtain required approvals from regulatory authorities, and
- The other factors discussed under "Operational and Other Business Risks" in this MD&A.

These factors should not be construed as exhaustive. The forward-looking statements contained in this report are expressly qualified by this cautionary statement. We undertake no obligation to publicly update or revise any forward-looking statements.



Evaluation of Disclosure Controls and Procedures

The Chief Executive Officer, Don Garner, and Chief Financial Officer, Dennis Feuchuk, evaluated the effectiveness of PrimeWest's disclosure controls and procedures as of June 30, 2005 and concluded that PrimeWest's disclosure controls and procedures were effective to ensure that information PrimeWest is required to disclose in its filings with the Securities and Exchange Commission (SEC) under the Securities Exchange Act of 1934 (Exchange Act) is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms, and to ensure that information required to be disclosed by PrimeWest in the reports that it files under the Exchange Act is accumulated and communicated to PrimeWest's management, including its principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Changes to Internal Controls Over Financial Reporting

There were no significant changes to PrimeWest's internal controls over financial reporting or in other factors that could significantly affect these controls subsequent to the evaluation date.

Non-GAAP Measures

The quarterly report contains the following measurements that are not defined by Canadian Generally Accepted Accounting Principles ("GAAP"):

- Cash flow from operations on a total and per Unit basis;
- Distributions per Trust Unit; and
- Net debt per Trust Unit.

These measurements do not have any standardized meaning prescribed by GAAP and are, therefore, unlikely to be comparable to similar measures presented by other entities.

Cash flow from operations is calculated from the Trust's cash flow statement as cash flow from operating activities before changes in working capital. Cash flow from operations per Trust Unit on a basic basis is calculated by dividing cash flow by the weighted average number of Trust Units and Trust Units issuable upon the exchange of Exchangeable Shares. Cash flow from operations per Trust Unit on a diluted basis is calculated using cash flow and adding back the interest expense on the Debentures, divided by the diluted weighted average number of Trust Units in the period. The diluted weighted average number of Trust Units consists of the weighted average Trust Units outstanding and Trust Units issuable upon the exchange of outstanding Exchangeable Shares and includes the Trust Units issuable pursuant to the conversion of the Debentures, and Trust Units issuable pursuant to the Long-Term Incentive Plan (LTIP). Cash flow from operations is a key performance indicator of PrimeWest's ability to generate cash and finance operations and pay monthly distributions.

Distributions per Trust Unit disclose the cash distributions accrued in the second quarter of 2005 based on the number of Trust Units outstanding on the date the distributions were declared.

Net debt per Trust Unit is calculated as long-term debt, including Debentures, less working capital, excluding financial derivative assets and liabilities, divided by the number of Trust Units and Trust Units issuable upon the exchange of outstanding Exchangeable Shares and Trust Units issuable pursuant to the LTIP at June 30, 2005.



Critical Accounting Estimates

See pages 57 to 59 of the 2004 Annual Report for Discussion on Critical Accounting Estimates.

Vision, Core Business and Strategy

PrimeWest is a conventional oil and gas royalty trust actively managed to generate monthly cash distributions for Unitholders. The Trust's operations are focused in Canada, with its assets concentrated in the Western Canadian Sedimentary Basin. PrimeWest is one of North America's largest natural gas weighted energy trusts.

Maximizing total return to Unitholders, in the form of cash distributions and change in unit price, is PrimeWest's overriding objective. Our strategies for asset management and growth, financial management and corporate governance are outlined in this MD&A, along with a discussion of our performance in the second quarter of 2005 and our goals for the remainder of 2005 and beyond.

We believe that PrimeWest can maximize total return to Unitholders through the continued development of our core properties, making opportunistic acquisitions that emphasize value creation, exercising disciplined financial management which broadens access to capital while minimizing risk to Unitholders, and complying with strong corporate governance to protect the interests of all stakeholders.

Asset Management and Growth

PrimeWest has a strategy to focus our expansion efforts on existing Canadian core areas, and pursue depletion optimization strategies within those core areas to maximize asset value. We strive to control our operations whenever possible, and maintain high working interests. Maintaining control of 80% of operations allows us to use existing infrastructure and synergies within our core areas. We believe this high level of operatorship can translate into control over costs and timing of capital outlays and projects. The current size of the Trust gives us the ability and critical mass to make acquisitions of significant size, while still being able to add value by transacting smaller acquisitions.

Financial Management

PrimeWest strives to maintain a conservative debt position to allow us to fund smaller acquisitions without tapping into the capital markets, and to fund ongoing development activities. Our long-term debt is comprised of bank credit facilities through a bank syndicate, U.S. dollar denominated Senior Secured Notes (Secured Notes) and the Debentures. Our diversified debt instruments help to reduce our reliance on the bank syndicate, as well as afford additional foreign exchange protection because a portion of our debt, the Secured Notes, are denominated in US dollars. PrimeWest's commodity hedging approach helps to stabilize cash flow, reduce volatility, and protect acquisition economics.

PrimeWest continues to target a payout ratio between 70% and 90% of annual operating cash flow to increase the Trust's financial flexibility. The second quarter 2005 payout ratio was approximately 70% of operating cash flow. The retained cash flow was utilized to fund the Trust's capital spending program and repay debt. PrimeWest's net debt to cash flow from operations level was 1.1 times at the end of the second quarter using annualized second quarter cash flows.

PrimeWest's dual listing on both the Toronto Stock Exchange (TSX) and New York Stock Exchange (NYSE) provide increased liquidity and a broadened investor base. The NYSE listing enables U.S. Unitholders to conveniently trade in our Trust Units, and allows us to access the U.S. capital markets. Our status as a corporation for U.S. tax purposes simplifies tax reporting for our U.S. Unitholders.



For eligible Canadian unitholders, PrimeWest offers participation in the Distribution Reinvestment Plan (DRIP), which represents a convenient way to maximize an investment in PrimeWest. For alternate investment requirements, PrimeWest also has Exchangeable Shares and Debentures available, which permit participation in PrimeWest without the ongoing tax implications associated with receiving a distribution.

Corporate Governance

PrimeWest remains committed to the highest standards of corporate governance and upholds the rules of the governing regulatory bodies under which it operates. Full disclosure of our compliance with existing corporate governance rules and regulations is available on our website at www.primewestenergy.com. PrimeWest actively monitors the corporate governance and disclosure environment to ensure compliance with current and future requirements.

Our high standards of corporate governance are not limited to the boardroom. At the field level PrimeWest proactively manages environmental, health and safety issues. We place a great deal of importance on community involvement and maintaining good relationships with landowners.

Outlook - 2005

PrimeWest expects full year 2005 production volumes to average between 40,000 - 41,000 BOE per day. Full year operating costs are expected to be approximately \$7.10 per BOE. PrimeWest expects to invest \$170 million in its capital development program throughout the year.

Cash Flow Reconciliation

(\$ millions)

First quarter 2005 cash flow from operations	\$ 79.7
Volumes	1.1 ⁽¹⁾
Commodity prices	16.1
Net hedging change from prior quarter	(1.0)
Operating expenses	(3.7)
Royalties	(0.8)
G&A expenses	0.7
Other	3.4
Second quarter 2005 cash flow from operations	\$95.5

⁽¹⁾ NGL volumes rose significantly during the second quarter of 2005 compared to the previous quarter resulting in a quarter-over-quarter increase to cash flow in spite of an overall reduction in production volumes.

The above table includes non-GAAP measurements. (Refer to discussion on Non-GAAP Measures on Page 5)

A key performance driver for the Trust is cash flow from operations, which directly affects PrimeWest’s ability to pay monthly distributions. Cash flow is generated through the production and sale of crude oil, natural gas and natural gas liquids, and is dependent on production levels, commodity prices, operating expenses, interest expense, general and administrative expense (G&A), hedging gains or losses, royalties and currency exchange rates. Some of these factors such as commodity prices, the currency exchange rate and royalties are uncontrollable from PrimeWest’s perspective. Other factors that are, to a certain extent, controllable by PrimeWest are production levels and operating expenses, as well as interest and G&A expenses.

**Quarterly Performance - Selective Measures**

The table below highlights PrimeWest's performance for the second quarter ended June 30, 2005, and the preceding seven quarters through 2004 and 2003.

(\$ millions, except per Trust Unit amounts)	2005		2004				2003	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Net Revenues	153.6	109.3	155.7	82.5	83.1	73.4	73.0	77.3
Net Income	48.8	15.3	40.6	20.2	22.4	20.1	0.7	8.8
Cash Flow	95.5	79.7	81.8	68.3	58.2	58.5	43.2	51.8
Cash Flow Per Unit - Basic	1.29	1.12	1.15	1.12	1.05	1.16	0.87	1.12
Cash Flow Per Unit - Diluted	1.21	1.04	1.07	1.06	1.05	1.15	0.86	1.11
Net Income Per Unit - Basic	0.66	0.21	0.57	0.31	0.41	0.40	0.01	0.19
Net Income Per Unit - Diluted	0.64	0.21	0.56	0.31	0.40	0.40	0.01	0.19

Net revenues are primarily impacted by commodity prices, production volumes and royalties.

Net income and net income per unit are secondary measures for a royalty trust because they include both cash and non-cash items. The non-cash items, which include depletion, depreciation and amortization (DD&A), non-cash G&A, future income taxes, unrealized foreign exchange gains or losses, and unrealized gains or losses on derivatives will not affect PrimeWest's ability to pay a monthly distribution.

Capital Expenditures

(\$ millions)	Three Months Ended			Six Months Ended	
	Jun 30, 2005	Mar 31, 2005	Jun 30, 2004	Jun 30, 2005	Jun 30, 2004
Land and lease acquisitions	\$ 6.4	\$ 6.7	\$ 2.7	\$ 13.1	\$ 4.5
Geological and geophysical	4.8	1.6	0.8	6.4	2.5
Drilling and completions	23.4	35.4	9.0	58.8	27.8
Investment in facilities					
Equipping and tie-in	8.1	5.8	2.8	13.9	6.8
Compression and processing	1.6	6.8	0.5	8.4	2.5
Gas gathering	0.3	0.4	0.2	0.7	0.7
Production facilities	2.5	2.7	5.1	5.2	7.2
Capitalized G&A	0.8	0.6	0.6	1.4	1.0
Development capital	47.9	60.0	21.7	107.9	53.0
Corporate/property acquisitions	(1.0)	0.5	0.4	(0.4)	39.0
Dispositions	1.0	(3.3)	(1.6)	(2.3)	(5.1)
Leasehold improvements, furniture and equipment	1.5	1.1	0.5	2.5	0.6
Net capital expenditures	\$ 49.4	\$ 58.3	\$ 21.0	\$ 107.7	\$ 87.5

During the second quarter of 2005, PrimeWest's net capital expenditures totalled \$49.4 million, compared to \$21.0 million invested in the second quarter of 2004 and \$58.3 million in the previous quarter of 2005. Of the \$47.9 million in development capital, \$31.5 million or 66% was invested on drilling, completions and tie-ins that contribute to new reserve additions and help offset natural production decline. PrimeWest also invested \$6.4 million on land acquisitions within core areas in the second quarter of 2005.



Gross wells drilled in the second quarter of 2005 totalled 19 (13 net wells), with a success rate of 100%.

Through acquisitions as well as development drilling, workovers, and re-completion activities, PrimeWest strives to offset natural production declines and add to reserves in order to sustain cash flows. Capital resources are allocated to projects on the basis of anticipated rate of return. At PrimeWest, every capital project is measured against stringent economic evaluation criteria prior to approval. These criteria include expected return, risks and further development opportunities.

Development Capital Update

PrimeWest has a development portfolio of potential capital expenditures of approximately \$400 to \$500 million to pursue over the next five years. Development plays are grouped in the categories of Tight Gas, Southeast Alberta Shallow Gas, Other Conventional Development and Coalbed Methane (CBM). PrimeWest's capital budget for 2005 is \$170 million, allocated \$65 to \$70 million to Tight Gas development, \$20 to \$25 million to Shallow Gas development, \$65 to \$70 million to Conventional development and \$3 to \$6 million to Coalbed Methane. During the first six months of 2005, PrimeWest invested approximately \$108 million on development opportunities. PrimeWest drilled 48 gross wells (29.8 net wells) during the six months ended June 30, 2005 with a success rate of 91.5%.

Tight Gas Plays

PrimeWest's Tight Gas plays are located in west central Alberta, and target the deeper Viking, Mannville and Cardium sandstones. Tight gas wells are characterized by high initial production rates that settle into a low decline stabilized rate and produce high heat content, liquids-rich gas.

PrimeWest continued its development program in its Tight Gas plays in the second quarter. Capital expenditures for the six months ended June 30, 2005 included \$27.8 million for drilling and completions, \$13.3 million for land and seismic and \$11.6 million for equipping, tie-in and facilities. Fourteen wells have been drilled year-to-date. The expenditures on land and seismic have increased PrimeWest's inventory of drilling opportunities. The following provides an overview of activity in the Tight Gas region.

Caroline Area

Year-to-date development capital expenditures at Caroline of \$25.8 million were comprised of \$12.2 million for drilling and completion, \$3.2 million for equipping, tie-in and facilities and \$10.4 million for land and seismic. Seven wells have been drilled at Caroline. Drilling success continues on lands secured by farm-in arrangements negotiated as part of a 2003 acquisition. Additional completions in uphole zones in these farm-in wells began during the second quarter.

Extension of the core Caroline property has been aggressively pursued this year with the acquisition of over 10,000 net acres of Crown land and the shooting of an extensive program of 3D seismic. In addition, PrimeWest has been successful in securing the rights to drill on approximately 9,000 additional acres through a farm-in with an industry major. Three step-out wells have been successful and will be tied-in to the 100% owned Caroline gas plant during the third quarter. Modifications at the plant have been initiated to provide for the expansion of raw gas throughput capacity to approximately 38 MMcf per day.

During the second quarter, PrimeWest commenced a pipeline crossing project under the Red Deer River to expand the capture area and open up areas for further development.



Columbia Area

Year-to-date capital expenditures at Columbia of \$22.7 million were comprised of \$14.0 million for drilling and completions, \$6.5 million for equipping, tie-in and facilities and \$2.2 million for land and seismic. Seven gross wells have been drilled at Columbia. There are two wells scheduled for completion and tie-in during the third quarter.

Columbia is PrimeWest's newest tight gas development play, acquired in 2004 from Calpine. Upgrades at the Columbia compressor station were completed to provide additional capacity for volume increases. PrimeWest invested \$3.0 million to acquire over 7,000 net acres of Crown land year-to-date to expand the inventory of drilling locations. Technical work continues with a focus on initiatives to reduce drilling costs and to finalize the development plan for the property.

Southeast Alberta Shallow Gas

PrimeWest's Southern Alberta Shallow Gas Play consists of shallow gas pools in the Medicine Hat and Milk River formations plus deeper, more prolific pools in Glauconitic zones. Lying at typical depths of 600 to 1,000 metres, the shallow zones are amenable to a low-risk, low-cost "manufacturing" development approach. The main properties that comprise the Shallow Gas Play are Medicine Hat, Princess, Bindloss, Dinosaur and Brant Farrow. This area has evolved through a combination of development activities and acquisitions. Year-to-date, development expenditures were \$11.2 million, with \$7.3 million invested in drilling and completions, \$1.7 million in equipping, tie-ins and facilities, and \$2.2 million in land and seismic. Nine wells have been drilled.

The following provides a description of the Brant Farrow area, which is a major property in the Southeast Alberta Shallow Gas play.

Brant Farrow Area

Year-to-date capital expenditures at Brant Farrow were \$7.9 million, with \$5.2 million invested in drilling and completions, \$1.0 million in equipping, tie-ins and facilities and \$1.7 million in land and seismic. The drilling program is on schedule, with seven operated wells drilled to date in 2005. Additional seismic has been shot this year and the total inventory of drilling opportunities has grown to 23 locations.

Other Conventional Development

PrimeWest continues to invest in development opportunities at our other conventional plays, which include properties at Lone Pine Creek/Crossfield, Wilson Creek, Boundary, Laprise and Valhalla. Year-to-date capital expenditures of \$45.1 million were comprised of \$23.7 million for drilling and completions, \$4.5 million for land and seismic and \$16.9 million for equipping, tie-in and facilities. A total of seven wells have been drilled.

The following provides a description of the Wilson Creek and Lone Pine Creek/Crossfield areas, which are major properties in our conventional plays.

Wilson Creek

In the Wilson Creek area PrimeWest has drilled one operated well during in the first six months of 2005, and participated in three non-operated wells targeted at various formations including Edmonton, Belly River, Glauconitic, Mannville, and Rock Creek. Year-to-date capital expenditures at Wilson Creek were \$13.3 million, comprised of \$6.0 million for drilling and completions, \$1.7 million for land and seismic and \$5.6 million for equipping, tie-in and facilities. A waterflood study of the Wilson Creek Belly River oil pool was commissioned and will be concluded in the latter half of the year.



Lone Pine Creek/Crossfield Area

The 2004 Calpine acquisition increased PrimeWest’s land base at Crossfield making it the second largest area in PrimeWest. Year-to-date capital expenditures at Crossfield of \$7.1 million were comprised of \$5.1 million for drilling and completions, \$0.2 million for land and seismic and \$1.8 million for equipping, tie-in and facilities.

Two Pekisko formation wells have been drilled during 2005 in the Lone Pine Creek area. A third well is currently being drilled and is waiting on completion. Deeper Devonian wells targeting the Leduc and Nisku horizons are slated for completion during the third quarter of 2005. Four additional deeper drilling opportunities are targeted for completion in early 2006.

Horseshoe Canyon Coalbed Methane

CBM is an emerging resource play in Western Canada. PrimeWest has approximately 123,600 net acres of land on the developing Horseshoe Canyon CBM trend. PrimeWest is involved in preliminary assessments of the area. Acreage is concentrated within three large operated properties with gas plants and extensive field infrastructure.

Plans for 2005 are for re-completion of 10 to 15 wells to establish deliverability and extensive coal desorption studies for reserve forecasting. Based on this work, PrimeWest could be in a position to make initial commercial development decisions to pursue a three to four year development program commencing in the summer of 2006.

Production Volumes

	Three Months Ended			Six Months Ended	
	Jun 30, 2005	Mar 31, 2005	Jun 30, 2004	Jun 30, 2005	Jun 30, 2004
Natural gas (mmcf/day)	178.4	180.6	125.5	179.5	124.7
Crude oil (bbls/day)	6,707	6,948	7,699	6,827	7,782
Natural gas liquids (bbls/day)	3,959	3,563	2,569	3,762	2,632
Total (BOE/day)	40,405	40,616	31,185	40,510	31,193
Gross Overriding Royalty volumes included above (BOE/day)	1,425	1,521	1,355	1,473	1,355

All production information is reported before the deduction of crown and freehold royalties.

PrimeWest’s production volumes averaged 40,405 BOE per day in the second quarter of 2005 compared to 40,616 BOE per day in the first quarter. The marginal decrease is due to natural decline partially offset by incremental volumes averaging approximately 2,500 BOE per day added through capital development activity. Compared to the first six months of 2004, production in the first half of 2005 was 30% higher, primarily as a result of the Calpine acquisition which occurred in the third quarter of 2004.

At the end of the second quarter 2005, approximately 1,740 BOE per day of production volumes remains behind pipe, awaiting tie-in. In addition, 500 BOE per day of production has been curtailed in the Cecil area and 400 BOE per day are shut-in in the Whiskey Creek area.

Production Outlook

PrimeWest expects full year production volumes to average between 40,000 - 41,000 BOE per day.



Shut-in volumes in the Whiskey Creek area (400 BOE per day) are the result of limited capacity at the Quirk Creek gas plant. With no alternate facilities in the area, PrimeWest's production will remain behind pipe until processing capacity becomes available at the Quirk Creek facility, which is expected to occur late in the third quarter of 2005.

Production at Cecil (500 BOE per day) has been curtailed due to regulatory restrictions and will resume once the lands have been pooled and a waterflood has been initiated by the operator. PrimeWest is continuing to work with the operator to resolve the outstanding issues, with no volumes forecast for the remainder of 2005.

Commodity Prices

Benchmark Prices	Three Months Ended			Six Months Ended	
	Jun 30, 2005	Mar 31, 2005	Jun 30, 2004	Jun 30, 2005	Jun 30, 2004
Natural gas					
NYMEX (U.S.\$/mcf)	6.80	6.32	5.97	6.56	5.83
AECO (Cdn\$/mcf)	7.38	6.69	6.80	6.67	6.36
Crude oil WTI (U.S.\$/bbl)	53.17	49.85	38.32	51.51	36.74

Average Realized Sales Prices

	Three Months Ended			Six Months Ended	
	Jun 30, 2005	Mar 31, 2005	Jun 30, 2004	Jun 30, 2005	Jun 30, 2004
Natural gas (\$/Mcf) ⁽¹⁾⁽²⁾	7.52	6.79	6.59	7.16	6.58
Without hedging	7.55	6.79	6.82	7.17	6.72
Crude oil (\$/bbl) ⁽¹⁾	45.61	42.18	35.83	43.88	35.38
Without hedging	55.38	50.90	43.20	53.12	41.30
Natural gas liquids (\$/bbl)	53.57	50.82	41.22	52.28	39.85
Total Oil Equivalent ⁽¹⁾					
(\$/BOE)	46.03	41.88	38.77	43.96	38.49
Without hedging	47.78	43.35	41.51	45.57	40.54
Realized hedging loss included in prices above (\$/BOE)	1.75	1.47	2.74	1.61	2.05

⁽¹⁾ Includes hedging losses.

⁽²⁾ Excludes sulphur.

Canadian commodity prices were higher in the second quarter of 2005 when compared to the previous quarter and the second quarter of 2004 resulting in higher average realized selling prices per BOE.

PrimeWest's cash flow from operations is directly impacted by commodity prices, but the use of hedging can increase or decrease the prices realized by the Trust. In the second quarter 2005, PrimeWest incurred a realized hedging loss of \$6.4 million compared to a loss of \$7.8 million for the same period in 2004.

Benchmark Commodity Prices

The following table sets forth benchmark historical and estimated future commodity prices.



	Past Four Quarters (Actual)				Next Four Quarters (Forward Markets) ⁽¹⁾			
	Q3 2004	Q4 2004	Q1 2005	Q2 2005	Q3 2005	Q4 2005	Q1 2006	Q2 2006
Natural gas								
NYMEX (US\$/mcf)	5.84	6.87	6.32	6.80	7.06	7.71	8.65	7.61
AECO (\$Cdn/mcf)	6.66	7.09	6.69	7.38	7.17	8.25	9.36	7.94
Crude oil WTI (US\$/bbl)	43.88	48.28	49.85	53.17	57.76	59.12	59.24	58.98

⁽¹⁾ As at June 30, 2005

Sales Revenue

	Three Months Ended				Six Months Ended			
	Jun 30, 2005	% of total	Mar 31, 2005	% of total	Jun 30, 2004	% of total	Jun 30, 2005	Jun 30, 2004
Revenue (\$ millions) ^{(1) (2)}								
Natural gas	122.1	72%	110.4	72%	\$ 75.3	68%	232.5	\$149.3
Crude oil	27.8	17%	26.4	17%	25.1	23%	54.2	50.1
Natural gas liquids	19.3	11%	16.3	11%	9.6	9%	35.6	19.1
Total	169.2	100%	153.1	100%	\$110.0	100%	322.3	\$218.5
Hedging losses included above	6.4		5.4		7.8		11.8	11.6

⁽¹⁾ Excludes sulphur.

⁽²⁾ Net of transportation expenses.

Second quarter revenues are 11% higher than the previous quarter due to higher realized prices offset by a decrease in production volumes.

Second quarter 2005 revenues were 54% higher than the same period in 2004, due to higher commodity prices and increased production volumes resulting from the Calpine acquisition in the third quarter of 2004. On a year-to-date basis, June 2005 revenues exceeded June 2004 revenues by 48%, due to increases in production volumes and commodity prices.

PrimeWest derives approximately 72% of its revenues from natural gas; therefore, the Trust has greater sensitivity to changes in natural gas prices than crude oil prices.

Financial Derivatives

As part of our financial management strategy, PrimeWest uses a consistent commodity hedging approach. The purpose of the hedging program is to reduce volatility in cash flows, protect acquisition economics and to stabilize cash flow against the unpredictable commodity price environment. The hedging policy reflects a willingness to risk forfeiting a portion of the pricing upside in return for protection against a significant downturn in prices.

The following table sets forth the approximate percentage of future anticipated production volumes hedged at June 30, 2005, net of anticipated royalties, reflecting full production declines with no offsetting additions:

Production Volumes Hedged (%)	Q3 /05	Q4/05	Q1/06	Q2/06	Q3/06	Q4/06
Crude Oil	62	57	51	27	9	10
Natural Gas	59	60	48	4	0	5



PrimeWest generally sells its oil and gas under short-term market-based contracts. Derivative financial instruments, options and swaps may be used to hedge the impact of oil and gas price fluctuations.

A listing of hedging contracts in place at June 30, 2005 follows:

Crude Oil (US\$/bbl)

Period	Volume (bbls/d)	Type	WTI Price (US\$/bbl)
Jul - Sep 2005	500	Swap	27.05
Jul - Sep 2005	500	Swap	28.50
Jul - Sep 2005	500	Costless Collar	35.00/44.90
Jul - Sep 2005	500	Costless Collar	35.00/44.35
Jul - Sep 2005	500	Costless Collar	35.00/51.30
Jul - Sep 2005	500	Costless Collar	35.00/56.50
Jul - Sep 2005	500	Costless Collar	40.00/55.30
Jul - Sep 2005	500	Costless Collar	40.00/65.00
Oct - Dec 2005	500	Swap	27.18
Oct - Dec 2005	500	Costless Collar	35.00/42.80
Oct - Dec 2005	500	Costless Collar	35.00/42.40
Oct - Dec 2005	500	Costless Collar	35.00/48.05
Oct - Dec 2005	500	Costless Collar	35.00/53.25
Oct - Dec 2005	500	Costless Collar	40.00/55.50
Oct - Dec 2005	500	Costless Collar	50.00/75.45
Jan - Mar 2006	1000	Costless Collar	35.00/49.90
Jan - Mar 2006	500	Costless Collar	40.00/60.25
Jan - Mar 2006	500	Costless Collar	40.00/71.75
Jan - Mar 2006	500	Costless Collar	50.00/70.00
Jan - Mar 2006	500	Costless Collar	50.00/75.00
Apr - Jun 2006	500	Costless Collar	40.00/71.25
Apr - Jun 2006	500	Costless Collar	50.00/70.00
Apr - Jun 2006	500	Costless Collar	50.00/75.70
Jul - Sep 2006	500	Costless Collar	50.00/75.30
Oct - Dec 2006	500	Costless Collar	50.00/75.03

Natural Gas (Cdn\$/Mcf)

Period	Volume (mmcf/d)	Type	AECO Price (Cdn\$/mcf)
Jul 2005 - Sep 2005	10.0	Costless Collar	6.33/7.81
Jul 2005 - Sep 2005	10.0	Costless Collar	6.33/7.66
Jul 2005 - Sep 2005	10.0	Costless Collar	6.33/7.53
Jul 2005 - Sep 2005	10.0	Costless Collar	6.33/7.86
Jul 2005 - Sep 2005	2.4	Costless Collar	6.33/7.88
Jul 2005 - Sep 2005	5.0	Costless Collar	6.33/7.50
Jul 2005 - Sep 2005	5.0	Costless Collar	6.33/7.60
Jul 2005 - Sep 2005	5.0	Costless Collar	6.33/7.79



Period	Volume (mmcf/d)	Type	AECO Price (Cdn\$/mcf)
Jul 2005 - Sep 2005	5.0	Costless Collar	6.33/9.28
Jul 2005 - Sep 2005	5.0	Costless Collar	6.33/8.02
Jul 2005 - Sep 2005	5.0	Costless Collar	6.33/8.49
Jul 2005 - Sep 2005	5.0	Costless Collar	6.33/8.55
Jul 2005 - Sep 2005	5.0	Costless Collar	6.33/7.75
Oct 2005 - Dec 2005	10.0	Costless Collar	6.33/8.97
Oct 2005 - Dec 2005	10.0	Costless Collar	6.33/8.71
Oct 2005 - Dec 2005	10.0	Costless Collar	6.33/8.60
Oct 2005 - Dec 2005	10.0	Costless Collar	6.33/8.96
Oct 2005 - Dec 2005	5.0	3 Way	5.28/6.33/9.92
Oct 2005 - Dec 2005	5.0	3 Way	5.28/6.33/9.76
Oct 2005 - Dec 2005	5.0	3 Way	5.28/6.33/10.04
Oct 2005 - Dec 2005	5.0	Costless Collar	6.33/10.90
Oct 2005 - Dec 2005	5.0	Costless Collar	6.33/8.97
Oct 2005 - Dec 2005	5.0	Costless Collar	6.33/9.57
Oct 2005 - Dec 2005	5.0	Costless Collar	6.33/10.29
Oct 2005 - Dec 2005	5.0	Costless Collar	6.86/12.34
Jan 2006 - Mar 2006	10.0	Costless Collar	6.33/10.55
Jan 2006 - Mar 2006	10.0	Costless Collar	6.33/10.22
Jan 2006 - Mar 2006	10.0	Costless Collar	6.33/9.96
Jan 2006 - Mar 2006	5.0	Costless Collar	6.33/10.42
Jan 2006 - Mar 2006	5.0	Costless Collar	6.33/13.13
Jan 2006 - Mar 2006	5.0	Costless Collar	6.33/11.61
Jan 2006 - Mar 2006	5.0	Costless Collar	6.33/12.66
Jan 2006 - Mar 2006	5.0	Costless Collar	6.33/14.03
Jan 2006 - Mar 2006	5.0	Costless Collar	7.39/14.51
Apr 2006 - Jun 2006	5.0	Costless Collar	6.33/8.91
Oct 2006 - Dec 2006	5.0	Costless Collar	6.86/11.92

A 3-way option is similar to a traditional collar, except that PrimeWest has resold the put at a lower price. Utilizing the first 3-way natural gas contract above as an example, PrimeWest has sold a call at \$9.92, purchased a put at \$6.33, and resold the put at \$5.28. Should the market price drop below \$6.33, PrimeWest will receive \$6.33 until the price is less than \$5.28, at which time PrimeWest will then receive market price plus \$1.05. However, should market prices rise above \$9.92, PrimeWest will receive a maximum of \$9.92. Should the market price remain between \$6.33 and \$9.92, PrimeWest will receive the market price.

Electrical Power

Period	Power Amount (MW)	Type	Price (\$/MW-hr)
Calendar 2005	5.0	Swap	51.65

PrimeWest's derivatives are Marked-to-Market at the end of each reporting period with the resulting gain or loss reflected in earnings for that period.



The second quarter 2005 income statement includes an unrealized gain of \$17.8 million on derivatives resulting from the change in the Mark-to-Market valuation of the derivative financial instruments during the period. The gain was comprised of a \$6.0 million gain for crude oil hedges and an \$11.8 million gain for natural gas hedges. For the six months ended June 30, 2005, the change in the Mark-to-Market value of the derivatives resulted in an unrealized loss of \$17.4 million comprised of a \$3.6 million loss for crude oil hedges; a \$14.1 million loss for natural gas hedges and a \$0.3 million gain for electrical power hedges.

For the three month period ended June 30, 2005 the cash impact of contract settlements was a \$6.4 million loss comprised of a \$6.0 million loss in crude oil and a \$0.4 million loss in natural gas.

For the six month period ended June 30, 2005 the cash impact of contract settlements was a \$11.8 million loss comprised of a \$11.4 million loss in crude oil and a \$0.4 million loss in natural gas.

Royalties (Net of ARTC)

PrimeWest pays royalties to the owners of mineral rights with whom PrimeWest holds leases. PrimeWest has mineral leases with the Crown (Provincial and Federal Governments), freeholders (individuals or other companies) and other operators. ARTC is the Alberta Royalty Tax Credit, a tax rebate provided by the Alberta government to producers that paid eligible Crown royalties in the year.

(\$ millions, except per BOE)	Three Months Ended			Six Months Ended	
	Jun 30, 2005	Mar 31, 2005	Jun 30, 2004	Jun 30, 2005	Jun 30, 2004
Royalty expense (net of ARTC)	\$ 36.8	\$ 36.0	\$ 25.7	\$ 72.8	\$ 49.0
Per BOE	\$ 10.01	\$ 9.85	\$ 9.06	\$ 9.93	\$ 8.64
Royalties as % of sales revenues					
With hedge loss	21.8%	23.5%	23.4%	22.6%	22.4%
Excluding hedge loss	21.0%	22.7%	21.8%	21.8%	21.3%

Royalty expense as a percentage of sales revenue decreased in the second quarter of 2005 compared to the same period in 2004 and the previous quarter despite increases to commodity prices due a 13th month Crown adjustment for gas cost allowance of approximately \$3.0 million.

The Crown royalty system is based on a sliding scale structure that increases the royalty rates as commodity prices rise. Because of the sliding scale, future changes to commodity prices will result in changes in royalty rates and expenses.

Operating Expenses

(\$ millions, except per BOE)	Three Months Ended			Six Months Ended	
	Jun 30, 2005	Mar 31, 2005	Jun 30, 2004	Jun 30, 2005	Jun 30, 2004
Operating expense	\$ 28.1	\$ 24.4	\$ 19.6	\$ 52.5	\$ 39.2
Per BOE	\$ 7.63	\$ 6.68	\$ 6.89	\$ 7.16	\$ 6.91

Second quarter 2005 operating expenses are 15% higher than the previous quarter mainly due to increases in processing fees resulting from incremental volumes, compressor repairs, turnarounds, and well workovers. The increase in operating costs also reflects inflationary pressures on the price of goods and services due to the current commodity price environment. The increase in operating costs per BOE from the previous quarter is due to the overall increase in operating costs and lower production volumes.

Gross operating expenses are higher for the three months and six months ended June 30, 2005 compared to the same periods in the prior year due to increased production volumes resulting from 2004 acquisitions.



Operating expenses include \$0.3 million for the three months and \$1.2 million for the six months ended June 30, 2005 related to accelerated turnaround costs which were scheduled to be completed in 2006. The turnaround expenses increased operating costs per BOE for the quarter and six months ended June 30, 2005 by \$0.07 per BOE and \$0.16 per BOE respectively.

Operating Expenses Outlook

PrimeWest expects 2005 operating expenses to average approximately \$7.10 per BOE, up from the previous estimate of \$6.60 per BOE. The increase reflects the impact of operational issues at Valhalla, the acceleration of turnaround costs from 2006, and inflationary pressure on goods and services in the oil and gas industry.

Operating Margin

(\$/BOE)	Three Months Ended			Six Months Ended	
	Jun 30, 2005	Mar 31, 2005	Jun 30, 2004	Jun 30, 2005	Jun 30, 2004
Sales price and other revenue ⁽¹⁾	\$ 46.14	\$ 41.94	\$ 38.96	\$ 44.05	\$ 38.69
Royalties	10.01	9.85	9.06	9.93	8.64
Operating expenses	7.63	6.68	6.89	7.16	6.91
Operating margin	\$ 28.50	\$ 25.41	\$ 23.01	\$ 26.96	\$ 23.14

⁽¹⁾ Includes hedging and sulphur

Operating margin per BOE increased 24% in the second quarter of 2005 compared to the same quarter in 2004. This is primarily due to higher sales prices and production volumes offset by higher operating expenses and higher royalties. Operating margin is an important measure of our business because it gives an indication of the amount of cash flow PrimeWest realizes per BOE that is produced, before head office expenses and financing charges.

Operating margin was higher in the second quarter 2005 compared to the first quarter 2005, primarily as a result of higher sales prices.

On a year-to-date basis the 2005 operating margin was higher than 2004 due to higher sales prices offset by increases in operating costs and royalties.

The actual operating margin for 2005 will be heavily dependent on commodity prices. PrimeWest will continue to pursue a strategy to maintain lower than average operating expenses to maximize margins, which can help to reduce the volatility of cash flows through commodity price cycles.

General & Administrative Expense

(\$ millions, except per BOE)	Three Months Ended			Six Months Ended	
	Jun 30, 2005	Mar 31, 2005	Jun 30, 2004	Jun 30, 2005	Jun 30, 2004
Cash G&A expense	\$ 4.8	\$ 5.5	\$ 3.5	\$ 10.3	\$ 7.7
Per BOE	\$ 1.32	\$ 1.51	\$ 1.23	\$ 1.41	\$ 1.36
Non-cash G&A expense	\$ 11.0	\$ 15.1	\$ (7.3)	\$ 26.0	\$ (6.8)
Per BOE	\$ 2.98	\$ 4.12	\$ (2.57)	\$ 3.55	\$ (1.21)



Cash G&A expense in the second quarter of 2005 decreased 13% on a gross and per BOE basis from the previous quarter due to reductions in labour related expenses, annual report costs, regulatory fees and information technology expenses offset by increases to office rent and property taxes and reduced overhead recoveries.

The increase in cash G&A expense for the three and six months ended June 30, 2005 compared to the same periods in 2004 is mainly due to increases in labour costs, office rent and property taxes associated with additional staffing requirements resulting from the Calpine acquisition. These increases are partially offset by higher overhead recoveries resulting from increases to capital expenditures and operating costs.

The PrimeWest Long-Term Incentive Plan (LTIP) program is based on total Unitholder return, which is comprised of cumulative distributions on a reinvested basis plus growth in Trust Unit price. Unit Appreciation Rights (UARs) issued under the LTIP are similar to stock options in a corporation. No benefit accrues to the UARs until the Unitholders have first achieved a 5% total annual return from the time of the UAR grant. PrimeWest continues to pay for the exercise of UARs in Trust Units.

Expenses related to the LTIP are recorded on a Mark-to-Market basis, whereby increases or decreases in the valuation of the UAR liability are reflected in the income statement. Included in the second quarter non-cash G&A expense is \$10.5 million relating to the change in the value of the UARs issued under the LTIP. On a year-to-date basis the change in value resulted in a \$25.2 million charge to non-cash G&A expense. The change in the value of the UAR is directly related to the change in the Trust Unit price which increased to \$30.66 per Unit at June 30, 2005 from \$28.99 per Unit at March 31, 2005. The Trust Unit price was \$26.62 at December 31, 2004.

G&A Expense Outlook

Cash G&A expenses per BOE are expected to be lower in 2005 than in 2004 and are estimated to be approximately \$1.25 per BOE for the year as a result of additional production volumes acquired in the 2004 Calpine acquisition.

Interest Expense

(\$ millions, except per Trust Unit)	Three Months Ended			Six Months Ended	
	Jun 30, 2005	Mar 31, 2005	Jun 30, 2004	Jun 30, 2005	Jun 30, 2004
Interest expense	\$ 7.7	\$ 9.1	\$ 2.8	\$ 16.8	\$ 6.0
Period end net debt level	\$ 431.9	\$ 516.1	\$ 169.2	\$ 431.9	\$ 169.2
Debt per Trust Unit	\$ 5.54	\$ 7.01	\$ 2.97	\$ 5.56	\$ 2.97
Average cost of debt	5.4%	5.3%	4.4%	5.4%	4.4%

Interest expense, representing interest on bank debt, the Secured Notes and the Debentures decreased in the second quarter of 2005 compared to the first quarter of 2005, due to a lower net debt balance. The decrease in the net debt level at June 30, 2005 compared to the prior quarter end is due to the conversion of \$94.7 million of Debentures during the quarter offset by an increase in the bank debt of \$15.0 million and an increase in the Secured Notes of \$2.0 million due to a weakening of the Canadian dollar.

The increase in interest expense for the three and six month periods ended June 30, 2005 compared to the same periods in 2004 is mainly due to the issuance of the Debentures to finance the acquisition of Calpine oil and gas assets in the third quarter of 2004.

The increase in the average cost of debt in the second quarter of 2005 compared to the same period in the previous year is due to the impact of the issuance of Series I and Series II Debentures which bear interest at 7.5% and 7.75% respectively.

**Foreign Exchange**

The foreign exchange loss of \$2.1 million for the three months ended June 30, 2005 and \$3.0 million for the six months ended June 30, 2005 results from the translation of the U.S. dollar denominated Secured Notes and related interest payable into Canadian dollars.

Depletion, Depreciation and Amortization

(\$ millions, except per BOE)	Three Months Ended			Six Months Ended	
	Jun 30, 2005	Mar 31, 2005	Jun 30, 2004	Jun 30, 2005	Jun 30, 2004
Depletion, depreciation & amortization	\$ 56.0	\$ 57.3	\$ 41.4	\$ 113.3	\$ 83.0
\$/BOE	\$ 15.24	\$ 15.67	\$ 14.59	\$ 15.46	\$ 14.63

The second quarter 2005 DD&A rate of \$15.24 per BOE is higher than the second quarter 2004 rate of \$14.59 due to the impact of the Calpine asset acquisition. The second quarter 2005 DD&A rate has decreased from the previous quarter due to reserve additions resulting from capital spending in the first and second quarters.

Site Reclamation and Restoration Reserve

Since the inception of the Trust, PrimeWest has maintained a site reclamation fund to pay for future costs related to well abandonment and site clean up. The fund is used to pay for such costs as they are incurred. The 2005 contribution rate for the fund is unchanged from 2004 at \$0.50 per BOE. As at June 30, 2005, the site reclamation fund contained a balance of \$10.5 million.

The abandonment and reclamation costs incurred in the second quarter 2005 were \$2.7 million, compared to \$0.3 million for the same period in 2004, and \$0.9 million for the previous quarter.

Income and Capital Taxes

(\$ millions)	Three Months Ended			Six Months Ended	
	Jun 30, 2005	Mar 31, 2005	Jun 30, 2004	Jun 30, 2005	Jun 30, 2004
Income and capital taxes	\$ 0.2	\$ 0.7	\$ 0.5	\$ 1.0	\$ 0.8
Future income taxes recovery	(5.8)	(19.6)	(3.4)	(25.4)	(21.6)
Total	\$ (5.6)	\$ (18.9)	\$ (2.9)	\$ (24.4)	\$ (20.8)

The decrease in the future income tax recovery in the second quarter of 2005 compared to the previous quarter is mainly due to an increase in net income.

Net Income

(\$ millions)	Three Months Ended			Six Months Ended	
	Jun 30, 2005	Mar 31, 2005	Jun 30, 2004	Jun 30, 2005	Jun 30, 2004
Net income	\$ 48.8	\$ 15.3	\$ 22.4	\$ 64.1	\$ 42.6

Cash flow from operations, as opposed to net income, is the primary measure of performance for an energy trust. The generation of cash flow is critical for an energy trust to continue paying its distributions to unitholders.



Conversely, net income is an accounting measure impacted by both cash and non-cash items. The largest non-cash items impacting PrimeWest's net income are DD&A, the unrealized gain or loss on derivatives, future taxes and non-cash G&A.

Second quarter 2005 net income was higher than the previous quarter due to higher net oil and gas revenues, lower cash and non-cash G&A expenses, and unrealized gains on derivatives offset by increases to operating expenses and lower future income tax recoveries.

Liquidity & Capital Resources

Long-Term Debt

(\$ millions)	As at		
	Jun 30, 2005	Mar 31, 2005	Jun 30, 2004
Long-term debt	\$ 427.1	\$ 504.5	\$ 179.7
Deficit / (working capital) ⁽¹⁾	4.8	11.6	(10.5)
Net debt	\$ 431.9	\$ 516.1	\$ 169.2
Market value of Trust Units and Exchangeable Shares outstanding ⁽²⁾⁽³⁾	2,366.9	2,112.6	1,321.6
Total capitalization	\$ 2,798.8	\$ 2,628.7	\$ 1,490.8
Net debt as a % of total capitalization	15%	20%	11%

⁽¹⁾ Does not include the derivative liability of \$17.2 million included in current liabilities

⁽²⁾ Based on June 30, 2005 Trust Unit closing price of \$30.66 and June 15, 2005 exchange ratio of 0.53538

⁽³⁾ Does not include the Debentures

Long-term debt is comprised of bank credit facilities, Secured Notes and Debentures of \$165.0 million, \$153.2 million and \$108.9 million respectively.

PrimeWest had a borrowing base of \$650 million at June 30, 2005. The bank credit facilities consist of an available revolving term loan of \$458.7 million and an operating facility of \$35 million with the balance being attributed to the Secured Notes valued at \$156.3 million based on the U.S. dollar exchange rate at the time of the last renewal. In addition to amounts outstanding under the bank credit facility, PrimeWest has outstanding letters of credit in the amount of \$4.8 million (2004 - \$4.8 million). The bank credit facility revolves until June 30, 2006, by which time the lenders will have conducted their annual borrowing base review.

PrimeWest's second quarter 2005 net debt of \$431.9 was lower than March 31, 2005 net debt of \$516.1 million mainly due to the conversion of \$94.7 million of the Debentures offset by increases to the bank credit facility of \$15.0 million.

At June 30, 2005 PrimeWest's net debt to annualized second quarter cash flow was approximately 1.1 times compared to 1.6 times at March 31, 2005. Net debt as a percentage of total capitalization was 15% at June 30, 2005, compared to 20% at March 31, 2005.

In accordance with CICA Handbook Section 3860 - "Financial Instruments", Series I and Series II Debentures were initially recorded in long-term debt at their fair values of \$147.0 million and \$94.9 million respectively. The difference between the fair value and proceeds was recorded in Unitholders' equity.

The Series I and Series II Debentures are being accreted such that the liability at maturity will equal the initial proceeds of \$150 and \$100 million less conversions, respectively.



During the second quarter of 2005, \$59.0 million of the Series I and \$35.7 million of the Series II Debentures long-term debt component were converted to Trust Units. Accretion of \$0.3 million was realized on each of the Series I and Series II Debentures.

Year-to-date 2005, \$85.5 million of Series I Debentures and \$48.3 million of Series II Debentures were converted to equity from long-term debt. Accretion of \$0.7 million was realized.

Unitholders' Equity

At July 31, 2005, the Trust had 77,289,205 Trust Units outstanding. In addition, PrimeWest had 1,220,947 Exchangeable Shares outstanding that are exchangeable into a total of 659,653 Trust Units using the July 15, 2005 exchange ratio of 0.54028:1.

The Series I and Series II Debentures equity components have been reduced by \$1.2 million and \$1.9 million respectively, due to conversions to Trust Units in the quarter.

For Canadian resident Unitholders, PrimeWest offers the DRIP. Components of the DRIP include the Optional Trust Unit Purchase Plan (OTUPP) and the Premium Distribution Plan (PREP). The DRIP gives Canadian Unitholders the opportunity to reinvest their monthly distributions at a 5% discount to the volume weighted average market price, while the OTUPP gives Canadian Unitholders an opportunity to purchase additional Trust Units directly from PrimeWest at the same 5% discount to the volume weighted average market price. The PREP allows eligible Canadian Unitholders to elect to receive a premium cash distribution of up to 102% of the cash that the Unitholder would otherwise have received on the distribution date, subject to proration in certain events. The DRIP and PREP components are mutually exclusive. Participation in the OTUPP requires enrolment in either the DRIP or the PREP.

Subject to regulatory approval, PrimeWest plans to offer the DRIP to U.S. residents holding PrimeWest Units in the fourth quarter of 2005.

During the second quarter, PrimeWest issued 50,587 Trust Units for \$1.4 million under the DRIP, 256,239 Trust Units for \$7.2 million pursuant to the PREP and 217,137 Trust Units for proceeds of \$6.1 million under the OTUPP.

For further details on these plans or to obtain the enrolment forms, please contact PrimeWest's Plan Agent, Computershare Trust Company of Canada at 1-800-564-6253, or visit PrimeWest's website at www.primewestenergy.com.

These plan components benefit Unitholders by offering alternatives to maximize their investment in PrimeWest while providing the Trust with an inexpensive method to raise additional capital. Proceeds from these plans are used for debt reduction and to help fund ongoing capital development programs.

Exchangeable Shares

Exchangeable Shares were issued in connection with both the Venator Petroleum Company Ltd. acquisition in April 2000 and the Cypress Energy Inc. acquisition in March 2001. These shares were issued to provide a tax-deferred rollover of the adjusted cost base from the shares being exchanged to the Exchangeable Shares. Canadian tax law does not permit a tax deferral when shares are exchanged for Trust Units.

The Exchangeable Shares do not receive cash distributions. In lieu of receiving distributions, the number of Trust Units that the exchangeable shareholder will receive upon exchange increases each month based on the distribution amount divided by the market price of the Trust Units on the 15th day of that month.



At July 31, 2005, there were 1,220,947 Exchangeable Shares outstanding. The exchange ratio on these shares was 0.54028:1 Trust Units for each Exchangeable Share as at July 15, 2005. For purposes of calculating basic per Trust Unit amounts, the assumption is that these Exchangeable Shares are exchanged into Trust Units at the current exchange ratio.

Cash Distributions

Cash distributions to Unitholders are at the discretion of the Board of Directors and can fluctuate depending on the cash flow generated from operations. As discussed previously, the cash flow available for distribution is dependent upon many factors including commodity prices, production levels, debt levels, capital spending requirements, and factors in the overall industry environment. In order to maintain PrimeWest's financial flexibility, the Board of Directors maintains a longer-term target distribution payout ratio of approximately 70% to 90% of cash flow from operations.

In the second quarter of 2005, cash distributions totalled \$66.5 million, or \$0.90 per Trust Unit representing a payout ratio of approximately 70%, compared to \$42.0 million, or \$0.75 per Trust Unit (72% payout ratio) for the same period in 2004. In the first quarter of 2005 cash distributions totalled \$63.8 million, or \$0.90 per Trust Unit representing a payout ratio of approximately 80%.

For Unitholders resident in Canada, PrimeWest anticipates that approximately 65% of 2005 distributions will be taxable and 35% will be deemed return of capital.

Distribution payments to U.S. Unitholders are subject to a 15% Canadian withholding tax, which is deducted from the entire distribution amount prior to deposit into Unitholder accounts.

Contractual Obligations

PrimeWest enters into many contractual obligations as part of conducting day-to-day business. Material contractual obligations include debt obligations, lease rental commitments that run from 2005 through 2009 and various pipeline transportation commitments that run through 2010. The details of the timing of these contractual obligations are included in the following table.

As at June 30, 2005	Payments due by period (\$ millions)				
	Total	Less than 1 year	1-3 years	4-5 years	More than 5 years
Long-term debt obligations	\$ 318.2	\$ -	\$ 241.6	\$ 76.6	\$ -
Debtentures	108.9	-	-	61.7	47.2
Lease rental obligations	13.1	3.7	6.9	2.5	-
Pipeline transportation obligations	12.0	6.1	5.8	0.1	-
Total contractual obligations	\$ 452.2	\$ 9.8	\$ 254.3	\$ 140.9	\$ 47.2

As part of PrimeWest's internalization transaction (see Note 14 in the Consolidated Financial Statements of the 2004 Annual Report), PrimeWest agreed to issue 377,360 Exchangeable Shares to the Executive Officers pursuant to a Special Employee Retention Plan. One quarter (94,340 shares) of the Exchangeable Shares were issued to the Officers on November 6, 2004. On each of November 6, 2005, 2006, and 2007, an additional 94,340 Exchangeable Shares will be issued to the Executive Officers. As at June 30, 2005, \$0.8 million has been accrued in non-cash G&A expenses related to the Special Employee Retention Plan.



Business Risks

PrimeWest’s operations are affected by a number of underlying risks, both internal and external to the Trust. These risks are similar to those affecting others in both the conventional oil and gas royalty trust sector and the conventional oil and gas producers sector. The Trust’s financial position, results of operations, and cash available for distribution to Unitholders are directly impacted by these factors. These factors are discussed under two broad categories - “Commodity Price, Foreign Exchange and Interest Rate Risk”, and “Operational and Other Business Risks.” For additional information on Business Risks, including Risks Related to the Trust Structure and the Ownership of Trust Units, see PrimeWest’s most recently filed Annual Information Form.

Commodity Price, Foreign Exchange And Interest Rate Risk

The two most important factors affecting the level of cash distributions available to Unitholders are the level of production achieved by PrimeWest, and the price received for its products. These prices are influenced in varying degrees by factors outside the Trust’s control. Some of these factors include:

- World market forces, specifically the actions of OPEC and other large crude oil producing countries including Russia, and their implications on the supply of crude oil;
- World and North American economic conditions which influence the demand for both crude oil and natural gas and the level of interest rates set by the governments of Canada and the U.S.;
- Weather conditions that influence the demand for natural gas and heating oil;
- The Canadian/U.S. dollar exchange rate that affects the price received for crude oil as the price of crude oil is referenced in U.S. dollars;
- Transportation availability and costs; and
- Price differentials among World and North American markets based on transportation costs to major markets and quality of production.

To mitigate these risks, PrimeWest has an active hedging program in place based on an established set of criteria that has been approved by the Board of Directors. The results of the hedging program are reviewed against these criteria and the results actively monitored by the Board.

Beyond our hedging strategy, PrimeWest also mitigates risk by having a well-diversified marketing portfolio and by transacting with a number of counterparties and limiting exposure to each counterparty. For the second quarter of 2005 approximately 25% of natural gas production was sold to aggregators and 75% of production was sold into the Alberta short-term or export long-term markets.

The contracts that PrimeWest has with aggregators vary in length. They represent a blend of domestic and US markets and fixed and floating prices designed to provide price diversification to our revenue stream.

The primary objective of our commodity risk management program is to reduce the volatility of our cash distributions, to lock in the economics on major acquisitions and to protect our capital structure when commodity prices cycle downwards. In the second quarter 2005, PrimeWest incurred a \$6.4 million loss from commodity hedges.

Operational And Other Business Risks

PrimeWest is also exposed to a number of risks related to its activities within the oil and gas industry that have an impact on the amount of cash available to Unitholders. These risks, and the manner in which PrimeWest seeks to mitigate these risks include, but are not limited to:

Risk	We Mitigate By
Production Risk associated with the production of oil and gas -	Performing regular and proactive protective well, facility and pipeline maintenance supported by



Risk	We Mitigate By
includes well operations, processing and the physical delivery of commodities to market.	telemetry, physical inspection and diagnostic tools.
Commodity Price Fluctuations in natural gas, crude oil and natural gas liquid prices	Hedging. See page 13 of this quarterly report.
Transportation Market risk related to the availability of transportation to market and potential disruption in delivery systems.	Diversifying the transportation systems on which we rely to get our product to market.
Natural Decline Development risk associated with capital enhancement activities undertaken - the risk that capital spending on activities such as drilling, well completions, well workovers and other capital activities will not result in reserve additions or in quantities sufficient to replace annual production declines.	Diversifying our capital spending program over a large number of projects so that large amounts of capital are not risked on any one activity. We also have a highly skilled technical team of geologists, geophysicists and engineers working to apply the latest technology in planning and executing capital programs. Capital is spent only after strict economic criteria for production and reserve additions are assessed.
Acquisitions Acquisition risk associated with acquiring producing properties at low cost to renew our inventory of assets.	Continually scanning the marketplace for opportunities to acquire assets. Our technical acquisition specialists evaluate potential corporate or property acquisitions and identify areas for value enhancement through operational efficiencies or capital investment. All prospects are subjected to rigorous economic review against established acquisition and economic hurdle rates. In some cases we may also hedge commodity prices to protect the acquisition economics in the near term period.
Reserves Reserve risk in respect of the quantity and quality of recoverable reserves.	Contracting our reserves evaluation to a reputable third party consultant, Gilbert Laustsen Jung Associates Ltd. (GLJ). The Operations and Reserves Committee of the Board of Directors and PrimeWest review the work and independence of GLJ. Our strategy is to invest in mature, longer life properties having a higher proved producing component where the reserve risk is generally lower and cash flows are more stable and predictable.
Environmental Health and Safety (EH&S) Environmental, health and safety risks associated with oil and gas properties and facilities.	Establishing and adhering to strict guidelines for EH&S including training, proper reporting of incidents, supervision and awareness. PrimeWest has active community involvement in field locations including regular meetings with stakeholders in the area. PrimeWest carries adequate insurance to cover property losses, liability and business interruption. These risks are reviewed regularly by the Corporate Governance and EH&S Committee of the Board.
Regulation, Tax and Royalties Changes in government regulations including	Keeping informed of proposed changes in regulations and laws to properly respond to and plan for the



Risk	We Mitigate By
reporting requirements, income tax laws, operating practices, environmental protection requirements and royalty rates.	effects that these changes may have on our operations.
Historical Liability to Unitholders is Uncertain Because of uncertainties in the law prior to July 1, 2004, relating to investments in trusts, there is a risk that a Unitholder could be held personally liable for obligations of the Trust.	On July 1, 2004, a new statute entitled the Income Trusts Liability Act (Alberta) was proclaimed in force, creating a statutory limitation on the liability of Unitholders of Alberta income trusts such as PrimeWest. The legislation provides that a Unitholder is not, as beneficiary, liable for any act, default, obligation or liability of the Trust that arises after July 1, 2004. Similar legislation was proclaimed in force in Ontario in December of 2004.

Additional Information

Additional information pertaining to PrimeWest, including the Trust's most recently filed Annual Report and Annual Information Form, is available on SEDAR at www.sedar.com and on the PrimeWest website at www.primewestenergy.com. PrimeWest welcomes questions from Unitholders and potential investors; call Investor Relations at 403-234-6600 or toll-free in Canada and the U.S. at 1-877-968-7878. We make every effort to respond to queries as quickly as possible, but during periods of heavy call volume, our response time may take up to 2 business days.



CONSOLIDATED BALANCE SHEET

(\$ millions)	Jun 30, 2005 (Unaudited)	Dec 31, 2004
ASSETS		
Current assets		
Cash and cash equivalents	\$ 5.4	\$ 54.4
Marketable securities (note 2)	-	68.6
Accounts receivable	97.1	96.9
Assets held for sale	-	5.4
Prepaid expenses	15.6	10.9
Inventory	2.8	5.8
	120.9	242.0
Cash reserved for site restoration and reclamation	10.5	10.3
Other assets and deferred charges	9.9	10.9
Derivative asset	-	0.6
Property, plant and equipment	1,905.0	1,908.6
Goodwill	68.5	68.5
	\$ 2,114.8	\$ 2,240.9
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities		
Accounts payable	\$ 32.2	\$ 47.7
Accrued liabilities	73.2	72.3
Derivative liability	17.2	0.5
Accrued distributions to unitholders	20.3	17.7
	142.9	138.2
Long-term debt (note 4)	427.1	656.3
Future income taxes	185.8	211.2
Asset retirement obligation (note 3)	40.1	40.3
	795.9	1,046.0
UNITHOLDERS' EQUITY		
Net capital contributions (note 5)	2,226.8	2,049.9
Capital issued but not distributed	2.7	3.3
Convertible unsecured subordinated debentures	3.8	8.1
Long-term incentive plan equity (note 6)	38.4	20.1
Accumulated income	153.3	89.2
Accumulated cash distributions	(1,098.1)	(967.7)
Accumulated dividends	(8.0)	(8.0)
	1,318.9	1,194.9
	\$ 2,114.8	\$ 2,240.9

The accompanying notes form an integral part of these financial statements.

**CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY**

For the six months ended (\$ millions)	Jun 30, 2005 (Unaudited)	Jun 30, 2004 (Unaudited)
Unitholders' equity, beginning of period	\$ 1,194.9	\$ 1,019.6
Adjustment to Unitholders' equity at beginning of period to adopt:		
New Asset Retirement Obligation	-	5.6
New Oil and Gas Accounting Standard	-	(233.3)
Net income for the period	64.1	42.6
Net capital contributions	176.9	166.1
Convertible unsecured subordinated debentures	(4.3)	-
Capital issued but not distributed	(0.6)	(2.9)
Long-term incentive plan equity	18.3	(9.3)
Cash distributions	(130.4)	(83.1)
Unitholders' equity, end of period	\$ 1,318.9	\$ 905.3



CONSOLIDATED STATEMENTS OF CASH FLOW

(\$ millions)	Three Months Ended		Six Months Ended	
	Jun 30, 2005 (Unaudited)	Jun 30, 2004 (Unaudited)	Jun 30, 2005 (Unaudited)	Jun 30, 2004 (Unaudited)
OPERATING ACTIVITIES				
Net income for the period	\$ 48.8	\$ 22.4	\$ 64.1	\$ 42.6
Add/(deduct) items not involving cash from operations				
Depletion, depreciation and amortization	56.0	41.4	113.3	83.0
Non-cash general & administrative	11.0	(7.3)	26.0	(6.8)
Non-cash foreign exchange loss	2.1	2.9	3.0	4.7
Cash distributions from marketable securities	0.2	-	1.2	-
Gain on sale of marketable securities	(0.3)	-	(27.2)	-
Unrealized loss/(gain) on derivatives	(17.8)	1.8	17.4	14.1
Future income taxes recovery	(5.8)	(3.4)	(25.4)	(21.6)
Accretion on asset retirement obligation	0.7	0.4	1.3	0.7
Other non-cash items	0.6	-	1.5	-
Cash flow from operations	95.5	58.2	175.2	116.7
Expenditures on site restoration and reclamation	(2.7)	(0.3)	(3.6)	(1.3)
Change in non-cash working capital	(3.1)	(8.0)	(24.9)	(6.8)
	89.7	49.9	146.7	108.6
FINANCING ACTIVITIES				
Proceeds from issue of Trust Units, net of issue costs	6.1	140.0	13.6	142.8
Net cash distributions to unitholders	(58.3)	(35.1)	(112.7)	(65.0)
Increase/(decrease) in bank credit facilities	15.0	(123.1)	(99.0)	(84.9)
Change in non-cash working capital	(0.4)	1.6	0.1	1.4
	(37.6)	(16.6)	(198.0)	(5.7)
INVESTING ACTIVITIES				
Expenditures on property, plant & equipment	(49.4)	(22.2)	(109.6)	(53.6)
Acquisition of capital/corporate assets	1.0	(0.4)	(0.4)	(39.0)
Proceeds on disposal of property, plant & equipment	(1.0)	1.6	7.7	5.1
Proceeds on sale of marketable securities	-	-	94.5	-
Decrease/(Increase) in cash reserved for future site restoration and reclamation	0.7	(1.1)	(0.2)	(1.7)
Change in non-cash working capital	(6.7)	(5.1)	10.3	(3.7)
	(55.4)	(27.2)	2.3	(92.9)
(Decrease)/Increase in cash for the period	(3.3)	6.1	(49.0)	10.0
Cash beginning of the period	8.7	6.4	54.4	2.5
Cash end of the period	\$ 5.4	\$ 12.5	\$ 5.4	\$ 12.5
Cash interest paid	\$ 7.0	\$ 4.2	\$ 14.5	\$ 5.4
Cash taxes paid	\$ 0.8	\$ 1.3	\$ 1.4	\$ 2.3
Non-cash transactions - conversion of Convertible Unsecured Subordinated Debentures into Trust Units	\$ 97.9	\$ -	\$ 138.2	\$ -



CONSOLIDATED STATEMENTS OF INCOME

(\$ millions) (except per Trust Unit amounts)	Three Months Ended		Six Months Ended	
	Jun 30, 2005 (Unaudited)	Jun 30, 2004 (Unaudited)	Jun 30, 2005 (Unaudited)	Jun 30, 2004 (Unaudited)
REVENUES				
Sales of crude oil, natural gas and natural gas liquids	\$ 171.4	\$ 112.2	\$326.6	\$ 222.8
Transportation expenses	(1.7)	(1.8)	(3.6)	(3.7)
Crown and other royalties, net of ARTC	(36.8)	(25.7)	(72.8)	(49.0)
Unrealized (loss)/gain on derivatives	17.8	(1.8)	(17.4)	(14.1)
Gain on sale of marketable securities	0.3	-	27.2	-
Other income	2.6	0.2	2.9	0.5
	153.6	83.1	262.9	156.5
EXPENSES				
Operating	28.1	19.6	52.5	39.2
Cash general and administrative	4.8	3.5	10.3	7.7
Non-cash general and administrative	11.0	(7.3)	26.0	(6.8)
Depletion, depreciation and amortization	56.0	41.4	113.3	83.0
Interest	7.7	2.8	16.8	6.0
Accretion on asset retirement obligation	0.7	0.4	1.3	0.7
Foreign exchange loss	2.1	3.2	3.0	4.9
	\$ 110.4	\$ 63.6	\$ 223.2	\$ 134.7
Income before taxes for the period	\$ 43.2	\$ 19.5	\$ 39.7	\$ 21.8
Income and capital taxes	0.2	0.5	1.0	0.8
Future income taxes recovery	(5.8)	(3.4)	(25.4)	(21.6)
	(5.6)	(2.9)	(24.4)	(20.8)
Net income for the period	\$ 48.8	\$ 22.4	\$ 64.1	\$ 42.6
Net income per Trust Unit - basic	\$ 0.66	\$ 0.41	\$ 0.88	\$ 0.80
Net income per Trust Unit - diluted	\$ 0.64	\$ 0.40	\$ 0.88	\$ 0.80

Notes to Consolidated Financial Statements

For the three and six months ended June 30, 2005, (except per Trust unit amounts) all amounts are expressed in millions of Canadian dollars unless otherwise indicated.

1. Significant Accounting Policies

These interim consolidated financial statements of PrimeWest have been prepared in accordance with Canadian generally accepted accounting principles. The specific accounting principles used are described in the annual consolidated financial statements of the Trust appearing on pages 70 through 72 of the Trust's 2004 Annual Report and should be read in conjunction with these interim financial statements.



2. Marketable Securities

(\$ millions)	Jun 30, 2005	Dec 31, 2004
Investment in Viking Trust (formerly Calpine Natural Gas Trust)	\$ -	\$ 68.6

In the first quarter of 2005 PrimeWest sold its 8% interest in Viking Energy Royalty Trust for net proceeds of \$94.5 million. The investment was accounted for using the cost method. The sale resulted in a gain of \$27.1 million.

3. Asset Retirement Obligations

Management has estimated the total future asset retirement obligation based on the Trust's net ownership interest in all wells and facilities. This includes all estimated costs to dismantle, remove, reclaim and abandon the wells and facilities and the estimated time period during which these costs will be incurred in the future.

The following table reconciles the asset retirement obligation associated with the retirement of oil and gas properties:

Asset Retirement Obligation	(\$ millions)
Asset Retirement Obligation, December 31, 2004	\$ 40.3
Change in estimate of liability	3.7
Liabilities settled	(3.6)
Accretion expense	1.3
Sale of capital assets	(1.6)
Asset Retirement Obligation, June 30, 2005	\$ 40.1

As at June 30, 2005, the undiscounted amount of estimated cash flows required to settle the obligation is \$219.3 million. The estimated cash flow has been discounted using a credit-adjusted risk free rate of 7.0 percent and an inflation rate of 1.5 percent. Although the expected period until settlement ranges from a minimum of 1 year to a maximum of 50 years, the expectation is that costs will be paid over an average of 34 years. These future asset retirement costs will be funded from the cash reserved for site restoration and reclamation. This cash reserve is currently funded at \$0.50 per BOE from PrimeWest's operating resources.

4. Long-Term Debt

(\$ millions)	Jun 30, 2005	Dec 31, 2004
Bank credit facilities	\$ 165.0	\$ 264.0
Senior Secured Notes	153.2	150.3
Convertible Unsecured Subordinated Debentures	108.9	242.0
	\$ 427.1	\$ 656.3



5. Unitholders' Equity

The authorized capital of the Trust consists of an unlimited number of Trust Units.

Trust Units	Number of Units	(\$ millions)
Balance, December 31, 2004	69,886,111	\$ 2,037.7
Conversion of Convertible Unsecured Subordinated Debentures	5,213,746	138.2
Issued on exchange of Exchangeable Shares	37,938	0.6
Issued pursuant to Distribution Reinvestment Plan	115,639	3.1
Issued pursuant to the Premium Distribution Plan	547,934	15.1
Issued pursuant to Long-Term Incentive Plan	224,924	6.9
Issued pursuant to Optional Trust Unit Purchase Plan	493,442	13.6
Balance, June 30, 2005	76,519,734	\$2,215.2

The weighted average number of Trust Units and Exchangeable Shares outstanding for the three months ended June 30, 2005 was 73,861,968 (2004 - 55,296,924). For purposes of calculating diluted net income per Trust Unit for the three months ended June 30, 2005, 4,260,034 (2004 - 0) and 3,056,495 (2004 - 0) Trust units issuable pursuant to the conversion of the Convertible Unsecured Subordinated Debentures Series I and II respectively and 797,975 Trust Units (2004 - 165,830) issuable pursuant to the Long-Term Incentive Plan were added to the weighted average number.

The weighted average number of Trust Units and Exchangeable Shares outstanding for the six months ended June 30, 2005 was 72,557,643 (2004 - 52,886,415). For purposes of calculating diluted net income per Trust Unit for the six months ended June 30, 2005, 4,843,151 (2004 - 0) and 3,365,198 (2004 - 0) Trust Units issuable pursuant to the conversion of the Convertible Unsecured Subordinated Debentures Series I and Series II respectively and 797,975 Trust Units (2004 - 165,830) issuable pursuant to the Long-Term Incentive Plan were added to the weighted average number.

Exchangeable Shares

The Exchangeable Shares are exchangeable into Trust Units at any time up to March 29, 2010 based on an exchange ratio that adjusts each time the Trust makes a distribution to its Unitholders. The exchange ratio, which was 1:1 on the date that the Exchangeable Shares were first issued, is based on the total monthly distribution, divided by the closing unit price on the distribution payment date. The exchange ratio effective June 15, 2005 was 0.53538:1.

Exchangeable Shares	# of shares	(\$ millions)
Balance, March 31, 2005	1,226,049	\$ 12.2
Exchanged for Trust Units	(4,602)	(0.6)
Balance, June 30, 2005	1,221,447	\$ 11.6



6. Long-Term Incentive Plan

Under the terms of the Long-Term Incentive Plan, a maximum of 1,800,000 Trust Units are reserved for issuance pursuant to the exercise of Unit Appreciation Rights (UARs) granted to Directors and employees of PrimeWest. Payouts under the plan are based on total unitholder return, calculated using both the change in the Trust Unit price as well as cumulative distributions paid. The plan requires that a hurdle return of 5% per annum be achieved before payouts accrue. UARs have a term of up to six years and vest equally over a three-year period, except for those issued to the members of the Board, which vest immediately. The Board of Directors has the option of settling payouts under the plan in PrimeWest Trust Units or in cash. To date, all payouts under the plan have been in the form of Trust Units.

As at June 30, 2005

Year of Grant	UARs issued & outstanding	UARs vested	Current return per UARs	Total equity (\$ millions)	Trust Unit dilution
1999 grants	24,909	24,909	\$54.12	\$ 1.3	43,966
2000 grants	70,573	70,573	\$29.24	2.1	67,309
2001 grants	261,113	260,779 ⁽¹⁾	\$19.60	5.1	166,755
2002 grants	680,719	467,888	\$15.13	10.3	235,027
2003 grants	863,284	429,159	\$13.29	10.7	189,972
2004 grants	1,386,200	308,993	\$8.60	7.1	81,992
2005 grants	797,050	74,536	\$5.26	1.8	12,954
Total grants	4,083,848	1,636,837		\$ 38.4	797,975

⁽¹⁾ The UARs vested differs from the UARs issued and outstanding due to a delay in the vesting period for employees on leave.

7. Cash Distributions

(\$ millions, except per Trust Unit amounts)	Three Months Ended		Six Months Ended	
	Jun 30, 2005	Jun 30, 2004	Jun 30, 2005	Jun 30, 2004
Cash flow from operations	\$ 95.5	\$ 58.2	\$ 175.2	\$ 116.7
Deduct amounts to reconcile to distribution:				
Cash retained from cash available for distribution ⁽¹⁾	(27.1)	(14.7)	(41.0)	(30.6)
Contribution to reclamation fund	(1.9)	(1.5)	(3.8)	(3.0)
	\$ 66.5	\$42.0	\$ 130.4	\$ 83.1
Cash Distributions to Unitholders	\$ 66.5	\$42.0	\$ 130.4	\$ 83.1
Cash Distributions per Trust Unit	\$ 0.90	\$0.75	\$ 1.80	\$ 1.57

⁽¹⁾ The Board of Directors determines the cash distribution level, which results in a discretionary amount of cash being retained.

**Trading Performance**

For the quarter ended	Jun 30/05	Mar 31/05	Dec 31/04	Sep 30/04	Jun 30/04
TSX Trust Unit prices (Cdn\$ per Trust Unit)					
High	31.68	32.00	28.33	26.70	26.80
Low	28.35	26.15	25.06	23.29	22.18
Close	30.66	28.99	26.62	26.70	23.25
Average daily traded volume	202,225	269,714	255,944	254,219	187,767
For the quarter ended	Jun 30/05	Mar 31/05	Dec 31/04	Sep 30/04	Jun 30/04
NYSE Trust Unit prices (US\$ per Trust Unit)					
High	25.59	26.60	22.98	21.16	20.44
Low	22.50	21.30	20.85	17.65	16.00
Close	25.05	23.96	22.18	21.16	17.43
Average daily traded volume	377,264	536,170	542,483	329,862	279,882
Number of Trust Units outstanding including Exchangeable Shares (millions of units)	77.2	72.9	70.5	69.7	56.8
Distribution paid per Trust Unit (\$Cdn)	0.90	0.90	0.90	0.83	0.75

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Corporate Information

Board of Directors

Harold Milavsky, ^{1,3} *Chair*

Barry E. Emes, ³

Harold N. Kvisle, ^{2,4}

Kent J. MacIntyre, ⁴

Michael W. O'Brien, ^{1,3}

James W. Patek, ^{2,4}

W. Glen Russell, ^{2,4}

Peter Valentine, ¹

¹ Member of the Audit and Finance Committee

² Member of the Compensation Committee

³ Member of the Corporate Governance & EH&S Committee

⁴ Member of the Operations & Reserves Committee

Officers

Donald A. Garner
President and Chief Executive Officer

Ronald J. Ambrozy
Vice-President, Business Development

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

Timothy S. Granger
Chief Operating Officer

Trust Units and Exchangeable Shares

The Toronto Stock Exchange (PWI.UN; PWX)
The New York Stock Exchange (PWI)

Convertible Debentures

The Toronto Stock Exchange
Series I Debentures (PWI.DB.A)
Series II Debentures (PWI.DB.B)

Registrar and Transfer Agent

Computershare Trust Company of Canada
Toll-free in Canada: 1-800-564-6253

Auditor

PricewaterhouseCoopers LLP
Calgary, Alberta

Engineering Consultants

Gilbert Laustsen Jung Associates Ltd.
Calgary, Alberta

Legal Counsel

Stikeman Elliott LLP
Calgary, Alberta



PRIMWEST

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