



PRIMEWEST ENERGY TRUST ANNOUNCES THIRD QUARTER 2005 RESULTS

CALGARY, November 4, 2005 (TSX: PWI.UN; PWI.DB.A; PWI.DB.B; NYSE: PWI) – PrimeWest Energy Trust (PrimeWest or the Trust) today announces interim operating and financial results for the third quarter ended September 30, 2005. Unless otherwise noted, all figures contained in this report are in Canadian dollars.

THIRD QUARTER HIGHLIGHTS

- Distributions in the third quarter were \$0.90 per unit representing a payout ratio of approximately 66% of operating cash flow compared to second quarter 2005 distributions of \$0.90 per unit, representing a payout ratio of 70% of operating cash flow. The 2005 year-to-date payout ratio is 71% compared to 72% in 2004.
- Third quarter production averaged 40,121 barrels of oil equivalent (BOE) per day, compared to the second quarter 2005 rate of 40,405 BOE per day. The decrease is due to natural decline and operational issues, which have been partially offset by incremental volumes from capital development activity.
- Development capital expenditures in the third quarter were \$36.6 million with drilling and completion expenditures of \$22 million resulting in 41 gross wells (17.2 net) being drilled with a success rate of 98%. The 2005 capital development program has been increased to \$185 million from the previously announced \$170 million to maintain access to our current drilling equipment in order to execute our fourth quarter drilling program and to position PrimeWest for 2006 winter activity. PrimeWest has identified a portfolio of capital opportunities of approximately \$800 million to be developed over the next several years.
- Net debt to annualized third quarter 2005 cash flow was approximately 0.9 times compared to net debt to annualized second quarter 2005 cash flow of 1.1 times at June 30, 2005. PrimeWest has approximately \$335 million available on its existing credit facilities.
- During the third quarter, \$37 million of Series I and Series II Convertible Subordinated Unsecured Debentures (Debentures) were converted into Trust Units of PrimeWest (Trust Units).
- Third quarter cash flow from operations was \$106.4 million, (\$1.36 per Trust Unit) compared to \$95.5 million (\$1.29 per Trust Unit) in the second quarter.
- As a result of non-cash charges, PrimeWest incurred a loss in the third quarter of \$26.3 million due mainly to the \$50.1 million unrealized loss on derivatives and \$33.0 million of non-cash general and administrative (G&A) expense.
- The Government of Canada announced a public consultation process on flow-through entities, which include Income Funds on September 8, 2005. PrimeWest is assessing the implications of the proposals set forth by the Government.



SUBSEQUENT EVENTS

- During the month of October 2005, \$12.7 million of Debentures were converted to Trust Units reducing the principal amount of the Debentures outstanding to \$61.9 million.
- As previously announced, effective with the distribution payment paid on October 14, 2005, PrimeWest extended its conventional distribution reinvestment program (DRIP) to Unitholders resident in the U.S.
- On October 11, 2005, Standard & Poor's confirmed that income trusts will be included in the S&P/TSX provisional composite index. PrimeWest will be included in the index, scheduled to be implemented late 2005 and in early 2006.

**Management's Discussion and Analysis as of November 4, 2005**

The following is management's discussion and analysis (MD&A) of PrimeWest's operating and financial results for the quarter ended September 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 – Third Quarter

\$ Millions, except per BOE ⁽¹⁾ and per Trust Unit amounts	Three Months Ended			Nine Months Ended	
	Sep 30, 2005	Jun 30, 2005	Sep 30, 2004	Sep 30, 2005	Sep 30, 2004
Gross revenue (net of transportation expense)	193.3	169.7	125.4	516.4	344.5
per BOE	52.38	46.15	38.44	46.84	38.68
Cash flow from operations	106.4	95.5	67.8	281.6	184.5
per BOE	28.83	25.98	20.78	25.54	20.71
per Trust Unit – basic ⁽²⁾	1.36	1.29	1.11	3.78	3.32
per Trust Unit - diluted ⁽³⁾	1.31	1.21	1.08	3.55	3.26
Royalty expense	44.4	36.8	28.9	117.3	78.0
per BOE	12.04	10.01	8.86	10.64	8.72
Operating expense	31.6	28.1	21.4	84.1	60.6
per BOE	8.56	7.63	6.56	7.63	6.78
G&A expense - Cash	5.7	4.8	3.4	16.0	11.1
per BOE	1.54	1.32	1.03	1.46	1.24
G&A expense - Non-cash	33.0	11.0	14.1	59.0	7.2
per BOE	8.95	2.98	4.31	5.36	0.80
Interest expense ⁽⁴⁾	6.0	7.7	2.9	22.8	8.9
per BOE	1.61	2.11	0.90	2.07	1.00
Distributions to Unitholders	70.1	66.5	50.4	200.5	133.5
per Trust Unit ⁽⁵⁾	0.90	0.90	0.83	2.70	2.40
Net debt ⁽⁶⁾	381.8	431.9	464.8	381.8	464.8
per Trust Unit ⁽⁷⁾	4.75	5.54	5.84	4.75	5.84

- (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			Nine Months Ended	
	Sep 30, 2005	Jun 30, 2005	Sep 30, 2004	Sep 30, 2005	Sep 30, 2004
Daily Sales Volumes					
Natural gas (mmcf/day)	176.8	178.4	143.5	178.6	131.0
Crude oil (bbls/day)	7,037	6,707	8,447	6,898	8,005
Natural gas liquids (bbls/day)	3,616	3,959	3,096	3,713	2,788
Total (BOE/day)	40,121	40,405	35,460	40,379	32,626
Realized Commodity Prices (Cdn \$)					
Natural gas (\$/mcf) ⁽¹⁾	8.41	7.52	6.14	7.57	6.42
Without hedging	8.66	7.55	6.31	7.66	6.57
Crude oil (\$/bbl) ⁽¹⁾	56.19	45.61	39.95	48.11	36.98
Without hedging	67.48	55.38	48.58	58.05	43.86
Natural gas liquids (\$/bbl)	59.83	53.57	45.30	54.76	41.92
Total (\$ per BOE) ⁽¹⁾	52.30	46.03	38.31	46.76	38.42
Without hedging	55.38	47.78	41.06	48.85	40.73

(1) Includes realized 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 profitability 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 September 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 and Procedures for Financial Reporting

There were no significant changes to PrimeWest's internal controls 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 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 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 third 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 September 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 Canada 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 third 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 is intended to help stabilize cash flow, reduce volatility, and when applicable, protect near term acquisition economics.

The Board of Directors targets a long-term distribution payout ratio that is a percentage of cash flow from operations. However, the actual distribution payout ratio may periodically vary from the target due to fluctuations in commodity prices and their impact on cash flow forecasts. The current distribution payout ratio is targeted to be approximately 70% - 90% of annual cash flow from operations. The third quarter 2005 payout ratio was approximately 66% of operating cash flow. The payout ratio for the nine months ended September 30, 2005 was 71%. The retained cash flow was utilized to fund the Trust's capital spending program and repay debt. PrimeWest's net debt to cash flow level was 0.9 times at the end of the third quarter using annualized third 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 and U.S. unitholders, PrimeWest offers participation in the Conventional Distribution Reinvestment Plan (DRIP), which represents a convenient way to maximize an investment in PrimeWest. Canadian residents may also participate in the Optional Trust Unit Purchase Plan (OTUPP) and the Premium Distribution Plan (PREP). 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 a high standard 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 - 40,500 BOE per day. Full year operating costs are expected to be between \$7.75 and \$8.00 per BOE. PrimeWest expects to invest approximately \$185 million in its capital development program for the year.



Guidance for 2006 performance is anticipated to be released by mid December 2005.

Cash Flow Reconciliation

(\$ millions)

Second quarter 2005 cash flow from operations	\$ 95.5
Volumes ⁽¹⁾	0.8
Commodity prices	28.0
Net hedging change from prior quarter	(5.0)
Operating expenses	(3.5)
Royalties	(7.6)
G&A expenses	(0.9)
Other	(0.9)
Third quarter 2005 cash flow from operations	\$106.4

⁽¹⁾ Oil volumes increased during the third 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 third quarter ended September 30, 2005, and the preceding seven quarters through 2004 and 2003.

\$ millions, except per Trust Unit amounts	2005			2004			2003	
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Net Revenues	99.8	153.6	109.3	155.7	82.5	83.1	73.4	73.0
Net (Loss)/Income	(26.3)	48.8	15.3	40.6	18.7	22.4	20.1	0.7
Cash Flow	106.4	95.5	79.7	81.8	67.8	58.2	58.5	43.2
Cash Flow Per Unit - Basic	1.36	1.29	1.12	1.15	1.11	1.05	1.16	0.87
Cash Flow Per Unit - Diluted	1.31	1.21	1.04	1.07	1.08	1.05	1.15	0.86
Net (Loss)/Income Per Unit – Basic	(0.34)	0.66	0.21	0.57	0.31	0.41	0.40	0.01
Net (Loss)/Income Per Unit – Diluted	(0.34)	0.64	0.21	0.56	0.29	0.40	0.40	0.01

Net revenues are primarily impacted by commodity prices, production volumes, royalties, and unrealized gains or losses on derivatives.

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			Nine Months Ended	
	Sep 30, 2005	Jun 30, 2005	Sep 30, 2004	Sep 30, 2005	Sep 30, 2004
Land and lease acquisitions	\$ 2.7	\$ 6.4	\$ 2.0	\$ 15.7	\$ 6.5
Geological and geophysical	0.3	4.8	3.3	6.7	5.8
Drilling and completions	22.0	23.4	12.0	80.9	39.8
Investment in facilities					
Equipping and tie-in	6.4	8.1	1.0	20.3	7.8
Compression and processing	0.3	1.6	1.3	8.7	3.8
Gas gathering	2.0	0.3	1.8	2.8	2.5
Production facilities	2.2	2.5	3.6	7.3	10.8
Capitalized G&A	0.7	0.8	0.4	2.1	1.4
Development capital	36.6	47.9	25.4	144.5	78.4
Corporate/property acquisitions	2.6	(1.0)	767.0	2.1	806.0
Dispositions	(1.5)	1.0	(6.3)	(3.7)	(11.3)
Leasehold improvements, furniture and equipment	0.8	1.5	0.6	3.4	1.2
Net capital expenditures	\$ 38.5	\$ 49.4	\$ 786.7	\$ 146.3	\$ 874.3

During the third quarter of 2005, PrimeWest's development capital expenditures totalled \$36.6 million, compared to \$25.4 million invested in the third quarter of 2004 and \$47.9 million in the previous quarter of 2005. Of the \$36.6 million in development capital, \$28.4 million or 77% was invested on drilling, completions and tie-ins that contribute to new reserve additions and help offset natural production decline. PrimeWest also invested \$2.7 million on land acquisitions within its core areas in the third quarter of 2005.

Corporate/property acquisitions in the third quarter of 2004 of \$767.0 million consisted mainly of the Calpine asset acquisition.

PrimeWest drilled 41 gross wells (17.2 net wells) in the third quarter of 2005 with a success rate of 98%. Year-to-date, 89 gross wells (47.0 net wells) were drilled with a success rate of 94%.

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

During the first nine months of 2005, PrimeWest invested \$144.5 million on development opportunities. Development plays are grouped in the categories of Tight Gas, Southeast Alberta Shallow Gas, Conventional Development and Coalbed Methane (CBM). PrimeWest's development capital expenditures for 2005 are expected to be \$185 million, allocated \$80 to \$85 million to Tight Gas development, \$25 to \$30 million to Southeast Alberta Shallow Gas development, \$65 to \$70 million to Conventional Development and \$3 to \$6 million to Coalbed Methane.



PrimeWest has identified \$800 million of capital opportunities that can be executed over the next several years, depending upon commodity prices. This is allocated approximately \$400 million to Tight Gas, over \$200 million to Conventional Development, approximately \$100 million to Coalbed Methane and over \$50 million to Southeast Alberta Shallow Gas.

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 third quarter. Capital expenditures for the nine months ended September 30, 2005 included \$38.1 million for drilling and completions, \$15.5 million for land and seismic and \$17.0 million for equipping, tie-in and facilities. Twenty-one gross 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 expenditures at Caroline of \$35.2 million were comprised of \$16.5 million for drilling and completion, \$6.6 million for equipping, tie-in and facilities and \$12.0 million for land and seismic. Eleven gross wells have been drilled at Caroline. Drilling success continues on lands secured by farm-in arrangements negotiated as part of a 2003 acquisition.

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. Three wells were drilled in the second quarter on lands acquired. Two of the wells were tied in during the third quarter and the remaining well will be tied-in during the fourth quarter. Two additional wells were drilled on original acreage in the third quarter. One well was tied in during the quarter and the other well will be tied in early in 2006. PrimeWest is looking at alternatives to increase the processing capacity from the area.

During the third quarter, PrimeWest completed the pipeline crossing project under the Red Deer River to expand the capture area and open up areas for additional development.

Columbia Area

Year-to-date capital expenditures at Columbia of \$27.6 million were comprised of \$17.9 million for drilling and completions, \$6.6 million for equipping, tie-in and facilities and \$3.1 million for land and seismic. Eight gross wells have been drilled at Columbia.

Columbia is PrimeWest's newest tight gas development play, acquired in 2004 from Calpine. Upgrades at the Columbia compressor station were completed in the second quarter to provide additional capacity for volume increases. Two wells were tied in during the third quarter. A third quarter recompletion of an existing well bore will be placed on production in the fourth quarter. PrimeWest invested \$3.0 million year-to-date to acquire Crown land 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 Southeast 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 \$15.4 million, with \$9.3 million invested in drilling and completions, \$3.4 million in equipping, tie-ins and facilities, and \$2.7 million in land and seismic. Fourteen wells have been drilled in the play.

The following provides a description of the Brant Farrow area, which is a major property in the Southeast Alberta Shallow Gas play that has evolved to include development of the seismically identified Glauconitic channels.

Brant Farrow Area

Year-to-date capital expenditures at Brant Farrow were \$10.8 million, with \$6.5 million invested in drilling and completions, \$2.2 million in equipping, tie-ins and facilities and \$2.1 million in land and seismic. The drilling program is on schedule, with 9 gross 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 drill-ready locations.

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, Grand Forks and Valhalla. Year-to-date capital expenditures of \$56.9 million were comprised of \$32.5 million for drilling and completions, \$5.1 million for land and seismic and \$19.3 million for equipping, tie-in and facilities. A total of 54 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 development play.

Wilson Creek

In the Wilson Creek area PrimeWest has drilled 5 operated wells in the first nine months of 2005, and participated in 15 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 \$19.5 million, comprised of \$11.2 million for drilling and completions, \$1.9 million for land and seismic and \$6.4 million for equipping, tie-in and facilities. A waterflood study of the Wilson Creek Belly River oil pool was commissioned in the third quarter.

Lone Pine Creek/Crossfield Area

The 2004 Calpine acquisition increased PrimeWest's land base at Crossfield making it the Trust's second largest area. Year-to-date capital expenditures at Crossfield of \$9.4 million were comprised of \$5.8 million for drilling and completions, \$0.3 million for land and seismic and \$3.3 million for equipping, tie-in and facilities.

Three Pekisko wells have been drilled during 2005 in the Lone Pine Creek area. One well is currently waiting on completion. Three additional deeper drilling opportunities are targeted for completion in early 2006.

Coalbed Methane

Coalbed Methane (CBM) is an emerging resource play in Western Canada. PrimeWest has approximately 124,000 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.

A total of 10 re-completions have been conducted at Brant Farrow and Thorsby year-to-date. Eight of these wells will be placed on production in the fourth quarter to establish deliverability and reserves. Additionally, 3 to 4 re-completions are planned for the fourth quarter. PrimeWest will continue to evaluate this resource through 2006.

**Production Volumes**

	Three Months Ended			Nine Months Ended	
	Sep 30, 2005	Jun 30, 2005	Sep 30, 2004	Sep 30, 2005	Sep 30, 2004
Natural gas (mmcf/day)	176.8	178.4	143.5	178.6	131.0
Crude oil (bbls/day)	7,037	6,707	8,447	6,898	8,005
Natural gas liquids (bbls/day)	3,616	3,959	3,096	3,713	2,788
Total (BOE/day)	40,121	40,405	35,460	40,379	32,626
Gross Overriding Royalty volumes included above (BOE/day)	1,518	1,425	1,404	1,488	1,371

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

PrimeWest's production volumes averaged 40,121 BOE per day in the third quarter of 2005 compared to 40,405 BOE per day in the second quarter. The marginal decrease is due to operational issues at Valhalla and Caroline and to natural decline, largely offset by incremental volumes averaging approximately 3,200 BOE per day added through capital development activity in 2005.

Compared to the first nine months of 2004, production in the first nine months of 2005 was 20% higher, primarily as a result of the Calpine acquisition which occurred in the third quarter of 2004.

At the end of the third quarter 2005, approximately 1,500 BOE per day of production volumes remains behind pipe, awaiting tie-in. In addition, production at Cecil (500 BOE per day) was curtailed until late in the quarter due to regulatory restrictions. The restriction was temporarily removed by the government to address production shortfalls resulting from hurricane activity in the Gulf of Mexico. PrimeWest does not know when the curtailment of production may be reinstated.

Production Outlook

PrimeWest expects full year production volumes to average between 40,000 – 40,500 BOE per day.

Some of the capacity issues at the Quirk Creek gas plant were resolved late in the third quarter allowing some of the Whiskey Creek volumes to be intermittently placed on production. We anticipate that 100 – 200 BOE per day will remain shut in until the operational issues are fully resolved.

Commodity Prices

Benchmark Prices	Three Months Ended			Nine Months Ended	
	Sep 30, 2005	Jun 30, 2005	Sep 30, 2004	Sep 30, 2005	Sep 30, 2004
Natural gas					
NYMEX (US\$/mcf)	8.25	6.80	5.84	7.12	5.83
AECO (Cdn\$/mcf)	8.17	7.38	6.66	7.41	6.69
Crude oil WTI (US\$/bbl)	63.19	53.17	43.88	55.40	39.11

**Average Realized Sales Prices**

	Three Months Ended			Nine Months Ended	
	Sep 30, 2005	Jun 30, 2005	Sep 30, 2004	Sep 30, 2005	Sep 30, 2004
Natural gas (\$/Mcf) ⁽¹⁾⁽²⁾	8.41	7.52	6.14	7.57	6.42
Without hedging	8.66	7.55	6.31	7.66	6.57
Crude oil (\$/bbl) ⁽¹⁾	56.19	45.61	39.95	48.11	36.98
Without hedging	67.48	55.38	48.58	58.05	43.86
Natural gas liquids (\$/bbl)	59.83	53.57	45.30	54.76	41.92
Total Oil Equivalent ⁽¹⁾ (\$/BOE)	52.30	46.03	38.31	46.76	38.42
Without hedging	55.38	47.78	41.06	48.85	40.73
Realized hedging loss included in prices above (\$/BOE)	3.08	1.75	2.75	2.09	2.31

⁽¹⁾ Includes hedging losses.⁽²⁾ Excludes sulphur.

Canadian commodity prices were higher in the third quarter of 2005 when compared to the previous quarter and the third 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 third quarter 2005, PrimeWest incurred a realized hedging loss of \$11.4 million compared to a loss of \$9.0 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⁾			
	Q4 2004	Q1 2005	Q2 2005	Q3 2005	Q4 2005	Q1 2006	Q2 2006	Q3 2006
Natural gas								
NYMEX (US\$/mcf)	6.87	6.32	6.80	8.25	13.78	14.44	10.74	10.62
AECO (\$Cdn/mcf)	7.09	6.69	7.38	8.17	12.41	13.88	10.28	10.26
Crude oil WTI (US\$/bbl)	48.28	49.85	53.17	63.19	66.39	67.03	67.08	66.79

⁽¹⁾ As at Sep 30, 2005**Sales Revenue**

	Three Months Ended				Nine Months Ended			
	Sep 30 2005	% of total	Jun 30 2005	% of total	Sep 30 2004	% of total	Sep 30 2005	Sep 30 2004
Revenue (\$ millions) ⁽¹⁾⁽²⁾								
Natural gas	136.8	71%	122.1	72%	81.0	65%	369.3	230.4
Crude oil	36.4	19%	27.8	17%	31.1	25%	90.6	81.1
Natural gas liquids	19.9	10%	19.3	11%	12.9	10%	55.5	32.0



Total	193.1	100%	169.2	100%	125.0	100%	515.4	343.5
Hedging losses included above	11.4		6.4		9.0		23.1	20.6

⁽¹⁾ Excludes sulphur.

⁽²⁾ Net of transportation expenses.

Third quarter revenues are 14% higher than the previous quarter due to higher realized prices.

Third 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, September 2005 revenues exceeded September 2004 revenues by 50%, due to increases in production volumes and commodity prices.

PrimeWest derives approximately 71% 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 September 30, 2005, net of anticipated royalties, reflecting full production declines with no offsetting additions.

Production Volumes Hedged (%)	Q4/05	Q1/06	Q2/06	Q3/06	Q4/06	Q1/07
Crude Oil	61	60	40	25	26	0
Natural Gas	68	64	30	27	27	0

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 September 30, 2005 follows:

Crude Oil (US\$/bbl)

Period	Volume (bbls/d)	Type	WTI Price (US\$/bbl)
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
Oct – Dec 2005	500	Costless Collar	50.00/80.35
Jan – Mar 2006	1000	Costless Collar	35.00/49.90



Period	Volume (bbls/d)	Type	WTI Price (US\$/bbl)
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
Jan – Mar 2006	1000	Costless Collar	50.00/82.80
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
Apr – Jun 2006	1000	Costless Collar	50.00/82.75
Jul – Sep 2006	500	Costless Collar	50.00/75.30
Jul – Sep 2006	1000	Costless Collar	50.00/82.05
Oct – Dec 2006	500	Costless Collar	50.00/75.03
Oct – Dec 2006	1000	Costless Collar	50.00/81.50

Natural Gas (Cdn\$/Mcf)

Period	Volume (mmcf/d)	Type	AECO Price (Cdn\$/mcf)
Oct – Dec 2005	10.0	Costless Collar	6.33/8.97
Oct – Dec 2005	10.0	Costless Collar	6.33/8.71
Oct – Dec 2005	10.0	Costless Collar	6.33/8.60
Oct – Dec 2005	10.0	Costless Collar	6.33/8.96
Oct – Dec 2005	5.0	3 Way	5.28/6.33/9.92
Oct – Dec 2005	5.0	3 Way	5.28/6.33/9.76
Oct – Dec 2005	5.0	3 Way	5.28/6.33/10.04
Oct – Dec 2005	5.0	Costless Collar	6.33/10.90
Oct – Dec 2005	5.0	Costless Collar	6.33/8.97
Oct – Dec 2005	5.0	Costless Collar	6.33/9.57
Oct – Dec 2005	5.0	Costless Collar	6.33/10.29
Oct – Dec 2005	5.0	Costless Collar	6.86/12.34
Oct – Dec 2005	10.0	Costless Collar	6.86/12.66
Jan – Mar 2006	10.0	Costless Collar	6.33/10.55
Jan – Mar 2006	10.0	Costless Collar	6.33/10.22
Jan – Mar 2006	10.0	Costless Collar	6.33/9.96
Jan – Mar 2006	5.0	Costless Collar	6.33/10.42
Jan – Mar 2006	5.0	Costless Collar	6.33/13.13
Jan – Mar 2006	5.0	Costless Collar	6.33/11.61
Jan – Mar 2006	5.0	Costless Collar	6.33/12.66
Jan – Mar 2006	5.0	Costless Collar	6.33/14.03
Jan – Mar 2006	5.0	Costless Collar	7.39/14.51



Period	Volume (mmcf/d)	Type	AECO Price (Cdn\$/mcf)
Jan – Mar 2006	10.0	Costless Collar	7.39/14.56
Jan – Mar 2006	5.0	Costless Collar	10.34/16.88
Jan – Mar 2006	5.0	Costless Collar	10.55/26.11
Jan – Mar 2006	5.0	Costless Collar	11.61/22.42
Apr – Jun 2006	5.0	Costless Collar	6.33/8.91
Apr – Jun 2006	5.0	Costless Collar	6.86/10.63
Apr – Jun 2006	10.0	Costless Collar	6.86/10.55
Apr – Jun 2006	5.0	Costless Collar	7.39/13.72
Apr – Jun 2006	10.0	Costless Collar	8.44/16.62
Jul – Sep 2006	5.0	Costless Collar	6.86/10.68
Jul – Sep 2006	10.0	Costless Collar	6.86/10.55
Jul – Sep 2006	5.0	Costless Collar	7.39/13.56
Jul – Sep 2006	10.0	Costless Collar	8.44/16.30
Oct – Dec 2006	5.0	Costless Collar	6.86/11.92
Oct – Dec 2006	10.0	Costless Collar	6.86/12.66
Oct – Dec 2006	5.0	Costless Collar	7.39/15.83
Oct – Dec 2006	10.0	Costless Collar	8.44/19.25

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 third quarter 2005 income statement includes an unrealized loss of \$50.1 million on derivatives resulting from the change in the Mark-to-Market valuation of the derivative financial instruments during the period. The loss was comprised of a \$0.9 million gain for crude oil hedges, a \$51.2 million loss for natural gas hedges and a \$0.2 million gain for electrical power hedges. For the nine months ended September 30, 2005, the change in the Mark-to-Market value of the derivatives resulted in an unrealized loss of \$67.6 million comprised of a \$2.7 million loss for crude oil hedges; a \$65.4 million loss for natural gas hedges and a \$0.5 million gain for electrical power hedges. The unrealized loss is a point-in-time measure of PrimeWest's hedging position at the end of the Third Quarter, when both oil and natural gas prices were near the high levels of 2005. The magnitude of the loss will continue to fluctuate with changes in commodity prices. Using the forward price deck as of October 31, 2005 would reduce the Mark-to-Market loss to approximately \$39 million.

Of the \$67.7 million change in Mark-to-Market value of the oil and gas hedges during the nine months ended September 30, 2005, \$51.9 million is categorized as a change in intrinsic value, resulting from the forward prices being higher than the upper range of our costless collar or 3-way option hedging contracts. The other \$15.4 million



is categorized as a change in extrinsic value, reflecting the cost of replacing all of PrimeWest's costless collar or 3-way option hedging contracts with new contracts based on the forward prices as of September 30, 2005. The extrinsic loss will have no impact on PrimeWest's cash flow on a go forward basis, if the costless collar or 3-way option hedging contracts are all held till maturity and the forward prices materialize as actuals.

For the three month period ended September 30, 2005 the cash impact of contract settlements was a \$11.1 million loss comprised of a \$7.3 million loss in crude oil, a \$4.0 million loss in natural gas and a \$0.2 million gain on electrical power hedges.

For the nine month period ended September 30, 2005 the cash impact of contract settlements was a \$23.0 million loss comprised of a \$18.7 million loss in crude oil, a \$4.4 million loss in natural gas and a \$0.1 million gain on electrical power hedges.

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			Nine Months Ended	
	Sep 30, 2005	Jun 30, 2005	Sep 30, 2004	Sep 30, 2005	Sep 30, 2004
Royalty expense (net of ARTC)	\$ 44.4	\$ 36.8	\$ 28.9	\$ 117.3	\$ 78.0
Per BOE	\$ 12.04	\$ 10.01	\$ 8.86	\$ 10.64	\$ 8.72
Royalties as % of sales revenues					
With hedge loss	23.0%	21.8%	23.1%	22.8%	22.7%
Excluding hedge loss	21.7%	21.0%	21.6%	21.8%	21.4%

Royalty expenses as a percentage of sales have remained relatively constant when comparing current quarter and year-to-date rates with the prior year. The previous quarter of 2005 reflects a 13th month Crown adjustment for gas cost allowance which reduced royalty expense by 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			Nine Months Ended	
	Sep 30, 2005	Jun 30, 2005	Sep 30, 2004	Sep 30, 2005	Sep 30, 2004
Operating expense	\$ 31.6	\$ 28.1	\$ 21.4	\$ 84.1	\$ 60.6
Per BOE	\$ 8.56	\$ 7.63	\$ 6.56	\$ 7.63	\$ 6.78

Third quarter 2005 operating expenses are 12% higher than the previous quarter mainly due to operating issues at the Valhalla plant, compressor repairs at Caroline, Boundary Lake pipeline maintenance and clean up costs, well workovers and 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 nine months ended September 30, 2005 compared to the same periods in the prior year due to increased production volumes resulting from 2004 acquisitions.



September 30, 2005 year-to-date operating expenses include \$1.2 million related to accelerated turnaround costs which were scheduled to be completed in 2006 and \$1.0 million of preventative pipeline maintenance and clean up costs at Boundary Lake. These expenses increased operating costs per BOE for the nine months ended September 30, 2005 by \$0.20 per BOE.

Operating Expenses Outlook

Year-to-date operating expenses are \$7.63 per BOE and are expected to average between \$7.75 and \$8.00 per BOE for the full year, up from the previous estimate of \$7.10 per BOE. The increase reflects the impact of operational issues at Valhalla, compressor repairs at Caroline, the acceleration of turnaround costs from 2006, anticipated increases to power costs, and inflationary pressure on goods and services in the oil and gas industry experienced year-to-date and the expected increases in fourth quarter power costs that are related to natural gas prices.

Operating Margin

(\$/BOE)	Three Months Ended			Nine Months Ended	
	Sep 30, 2005	Jun 30, 2005	Sep 30, 2004	Sep 30, 2005	Sep 30, 2004
Sales price and other revenue ⁽¹⁾	\$ 52.38	\$ 46.14	\$ 38.65	\$ 46.84	\$ 38.68
Royalties	12.04	10.01	8.86	10.64	8.72
Operating expenses	8.56	7.63	6.56	7.63	6.78
Operating margin	\$ 31.78	\$ 28.50	\$ 23.23	\$ 28.57	\$ 23.18

⁽¹⁾ Includes hedging and sulphur

Operating margin per BOE increased in the third quarter of 2005 compared to the previous quarter and the same period in 2004 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.

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.

General & Administrative Expense

(\$ millions, except per BOE)	Three Months Ended			Nine Months Ended	
	Sep 30, 2005	Jun 30, 2005	Sep 30, 2004	Sep 30, 2005	Sep 30, 2004
Cash G&A expense	\$ 5.7	\$ 4.8	\$ 3.4	\$ 16.0	\$ 11.1
Per BOE	\$ 1.54	\$ 1.32	\$ 1.03	\$ 1.46	\$ 1.24
Non-cash G&A expense	\$ 33.0	\$ 11.0	\$ 14.1	\$ 59.0	\$ 7.2
Per BOE	\$ 8.95	\$ 2.98	\$ 4.31	\$ 5.36	\$ 0.80

Cash G&A expense in the third quarter of 2005 increased 19% on a gross and 17% on a per BOE basis from the previous quarter due to an increase in information technology maintenance expenses and stock exchange fees associated with the launch of the US DRIP, offset by decreases to labour related expenses and legal fees.

The increase in cash G&A expense for the three and nine months ended September 30, 2005 compared to the same periods in 2004 is mainly due to increases in labour costs, information technology expenses, office rent and property taxes associated with additional staffing and office space 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. If an employee or director were to exercise UARs in excess of the Trust Units available for issuance, the obligation would be settled in cash.

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 third quarter non-cash G&A expense is \$32.3 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 \$57.6 million charge to non-cash G&A expense. The change in the value of the UARs is directly related to the change in the Trust Unit price which increased to \$36.40 per Unit at September 30, 2005 from \$30.66 per Unit at June 30, 2005. The Trust Unit price was \$26.62 at December 31, 2004.

G&A Expense Outlook

2005 cash G&A expenses are estimated to be approximately \$1.40 per BOE for the year. The 2004 Calpine acquisition resulted in additional labour related expenses, office rent and information technology expenses. The impact of the increases in costs on the G&A per BOE is partially offset by the increase in volumes.

Interest Expense

(\$ millions, except per Trust Unit)	Three Months Ended			Nine Months Ended	
	Sep 30, 2005	Jun 30, 2005	Sep 30, 2004	Sep 30, 2005	Sep 30, 2004
Interest expense	\$ 6.0	\$ 7.7	\$ 2.9	\$ 22.8	\$ 8.9
Period end net debt level	\$ 381.8	\$ 431.9	\$ 464.8	\$ 381.8	\$ 464.8
Debt per Trust Unit	\$ 4.75	\$ 5.54	\$ 5.84	\$ 4.75	\$ 5.84
Average cost of debt	4.9%	5.4%	3.9%	4.7%	4.2%

Interest expense, representing interest on bank debt, the Secured Notes and the Debentures decreased in the third quarter of 2005 compared to the second quarter of 2005, due to a lower net debt balance. The decrease in the net debt level at September 30, 2005 compared to the prior quarter end is due to the conversion of \$35.4 million of Debentures during the quarter and a decrease in the value of the Secured Notes of \$7.9 million due to the strengthening of the Canadian dollar.

The increase in interest expense for the three and nine month periods ended September 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 average cost of debt is lower in the third quarter of 2005 compared to the previous quarter due to the conversion of the Series I and Series II Debentures which bear interest at 7.5% and 7.75% respectively.

The increase in the average cost of debt in the third quarter of 2005 compared to the same period in the previous year is due to the impact of the issuance of the Debentures in the third quarter of 2004 to fund the Calpine acquisition.

Foreign Exchange

The foreign exchange gain of \$7.7 million for the three months ended September 30, 2005 and \$4.7 million for the nine months ended September 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			Nine Months Ended	
	Sep 30, 2005	Jun 30, 2005	Sep 30, 2004	Sep 30, 2005	Sep 30, 2004
Depletion, depreciation & amortization	\$ 56.5	\$ 56.0	\$ 50.2	\$ 169.7	\$ 133.4
\$/BOE	\$ 15.30	\$ 15.24	\$ 15.41	\$ 15.40	\$ 14.92

The DD&A rate for the nine months ended September 30, 2005 is higher than the same period in 2004 due to the impact of the Calpine asset acquisition.

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 September 30, 2005, the site reclamation fund contained a balance of \$11.1 million.

The abandonment and reclamation costs incurred in the third quarter 2005 were \$1.3 million, compared to \$1.1 million for the same period in 2004, and \$2.7 million for the previous quarter.

Income and Capital Taxes

(\$ millions)	Three Months Ended			Nine Months Ended	
	Sep 30, 2005	Jun 30, 2005	Sep 30, 2004	Sep 30, 2005	Sep 30, 2004
Income and capital taxes	\$ 0.6	\$ 0.2	\$ 1.1	\$ 1.6	\$ 1.9
Future income taxes recovery	(0.2)	(5.8)	(22.3)	(25.6)	(44.0)
Total	\$ 0.4	\$ (5.6)	\$ (21.2)	\$ (24.0)	\$ (42.1)

The decrease in the future income tax recovery for the quarter and year-to-date compared to prior periods is due to the large increase in non-cash G&A related to the LTIP which is not deductible for income tax purposes.

Net (Loss)/Income

(\$ millions)	Three Months Ended			Nine Months Ended	
	Sep 30, 2005	Jun 30, 2005	Sep 30, 2004	Sep 30, 2005	Sep 30, 2004
Net (loss)/income	\$ (26.3)	\$ 48.8	\$ 18.7	\$ 37.8	\$ 61.3

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.

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

**Liquidity & Capital Resources****Long-Term Debt**

(\$ millions)	As at		
	Sep 30, 2005	Jun 30, 2005	Jun 30, 2004
Long-term debt	\$ 383.8	\$ 427.1	\$ 461.7
Deficit / (working capital) ⁽¹⁾	(2.0)	4.8	3.1
Net debt	\$ 381.8	\$ 431.9	\$ 464.8
Market value of Trust Units and Exchangeable Shares outstanding ⁽²⁾⁽³⁾	2,878.6	2,366.9	1,861.5
Total capitalization	\$ 3,260.4	\$ 2,798.8	\$ 2,326.3
Net debt as a % of total capitalization	12%	15%	20%

⁽¹⁾ Does not include the derivative liability of \$65.2 million included in current liabilities

⁽²⁾ Based on September 30, 2005 Trust Unit closing price of \$36.40 and September 15, 2005 exchange ratio of 0.54957.

⁽³⁾ Does not include the Debentures

Long-term debt is comprised of bank credit facilities, Secured Notes and Debentures of \$165.0 million, \$145.3 million and \$73.5 million respectively.

PrimeWest had a borrowing base of \$650 million at September 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 third quarter 2005 net debt of \$381.8 was lower than June 30, 2005 net debt of \$431.9 million mainly due to the conversion of \$35.4 million of the Debentures and decreases to the Secured Notes of \$7.9 million due to the strengthening Canadian dollar.

At September 30, 2005 PrimeWest's net debt to annualized third quarter cash flow was approximately 0.9 times compared to 1.1 times at June 30, 2005. Net debt as a percentage of total capitalization was 12% at September 30, 2005, compared to 15% at June 30, 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 third quarter of 2005, \$18.4 million of the Series I and \$17.2 million of the Series II Debentures long-term debt component were converted to Trust Units. Accretion of \$0.2 million was realized on each of the Series I and Series II Debentures.

Year-to-date 2005, \$103.9 million of Series I Debentures and \$65.5 million of Series II Debentures were converted to equity from long-term debt. Accretion of \$0.9 million was realized.

Unitholders' Equity

At October 31, 2005, the Trust had 79,032,925 Trust Units outstanding. In addition, PrimeWest had 1,219,335 Exchangeable Shares outstanding that are exchangeable into a total of 675,877 Trust Units using the October 15, 2005 exchange ratio of 0.55430:1.



The equity component of the Series I and Series II Debentures have been reduced by \$0.4 million and \$0.9 million respectively, due to conversions to Trust Units in the quarter.

For Canadian and U.S. resident Unitholders, PrimeWest offers the DRIP. Canadian residents can also participate in the Optional Trust Unit Purchase Plan (OTUPP) and the Premium Distribution Plan (PREP). The DRIP gives Canadian and U.S. Unitholders the opportunity to reinvest their monthly distributions at a 5% discount to the volume weighted average market price. 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.

During the third quarter 2005, PrimeWest issued 41,780 Trust Units for \$1.3 million under the DRIP, 212,295 Trust Units for \$6.7 million pursuant to the PREP and 93,531 Trust Units for proceeds of \$3.0 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. Exchangeable Shares were also issued as part of PrimeWest's internalization transaction (See Note 14 in the Consolidated Financial Statement of the 2004 Annual Report) whereby PrimeWest agreed to issue Exchangeable Shares to the Executive Officers pursuant to a Special Employee Retention Plan.

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 October 31, 2005, there were 1,219,335 Exchangeable Shares outstanding. The exchange ratio on these shares was 0.55430:1 Trust Units for each Exchangeable Share as at October 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. 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.

The Board of Directors targets a long-term distribution payout ratio that is a percentage of cash flow from operations. However, the actual distribution payout ratio may periodically vary from the target due to fluctuations in commodity prices and their impact on cash flow forecasts. The current distribution payout ratio is targeted to be approximately 70% - 90% of annual cash flow from operations. In the third quarter of 2005, cash distributions totalled \$70.1 million, or \$0.90 per Trust Unit representing a payout ratio of approximately 66%, compared to \$50.4 million, or \$0.83 per



Trust Unit (74% payout ratio) for the same period in 2004. 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%.

For the nine months ended September 30, 2005 cash distributions totalled \$200.5 million, or \$2.70 per Trust Unit representing a payout ratio of 71% compared to \$133.5 million or \$2.40 per Trust Unit (72% payout ratio) for the same period in 2004.

For Unitholders resident in Canada, PrimeWest anticipates that the taxability of 2005 distributions will exceed 65% due to strong commodity prices.

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 September 30, 2005 (\$ millions)	Payments due by period				
	Total	Less than 1 year	1-3 years	4-5 years	More than 5 years
Long-term debt obligations	\$ 310.3	\$ -	\$ 237.6	\$ 72.7	\$ -
Debentures	73.5	-	-	43.4	30.1
Lease rental obligations	12.1	3.6	6.8	1.7	-
Pipeline transportation obligations	10.0	5.1	4.4	0.5	-
Total contractual obligations	\$ 405.9	\$ 8.7	\$ 248.8	\$ 118.3	\$ 30.1

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. For the nine months ended September 30, 2005, \$1.5 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 third 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 third quarter 2005, PrimeWest realized a \$11.4 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 – includes well operations, processing and the physical delivery of commodities to market.	Performing regular and proactive protective well, facility and pipeline maintenance supported by telemetry, physical inspection and diagnostic tools.
Commodity Price Fluctuations in natural gas, crude oil and natural gas liquid prices	Hedging. See page 15 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	Continually scanning the marketplace for opportunities to acquire



Risk	We Mitigate By
properties at low cost to renew our inventory of assets.	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 reporting requirements, income tax laws, operating practices, environmental protection requirements and royalty rates.	Keeping informed of proposed changes in regulations and laws to properly respond to and plan for the 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

Federal Government Consultation Process

During the fall of 2004 extensive industry consultations took place with the Government of Canada regarding the March 2004 budgetary proposals to limit the non-resident ownership of trusts to 50% and to amend the withholding tax structure. On December 6th, 2004 the Government of Canada announced that it would proceed with the withholding tax amendments, however the restriction on non-resident ownership was suspended subject to consultation. During March of 2005, industry and Government officials met informally to further discuss income trust issues, with an indication being that the Government would be issuing a paper detailing their concerns.

On September 8th, 2005 the Government of Canada issued the long awaited consultation paper regarding the income trust sector. PrimeWest looks forward to participating in the consultation process and is encouraged by the fact that the context of the paper is not entirely linked to the loss of tax revenue, but also encompasses the economic efficiency and contribution of trusts to the Canadian economy.



PrimeWest continues to make significant contributions to our stakeholders, including investors, employees and the communities where we operate. In an environment of volatile commodity prices, PrimeWest's management team strives to create long-term value for unitholders through ongoing acquisition and development activities. Since inception, PrimeWest has completed acquisition of over \$2.3 billion, including Canadian assets of foreign-based companies. PrimeWest has invested capital of over \$600 million to develop these assets and has distributed over \$1.1 billion to unitholders through monthly distributions. During 2005 PrimeWest will invest a record \$185 million on its development program, and expects to invest approximately \$800 million of future capital to develop its current asset base.

The importance of ongoing access to capital of the income trust sector cannot be overstated, including capital invested by non-residents. Canadian capital markets represent only 2% of the world's invested capital, while the US market represents approximately 40% of global invested capital, and ongoing access to this large capital base is beneficial to Canadians as represented by added capital values and greater liquidity.

PrimeWest urges Governments in Canada to be cognizant of the large positive economic contribution of the income trust sector to the Canadian economy. Besides an examination of trust unit taxation, any proposed changes should include changes to corporate taxation that would see a reduction in the tax burden on dividends paid by corporations

PrimeWest will be making a formal submission to the consultation process, as well as continuing to support the Canadian Association of Income Funds (CAIF) in its ongoing engagement with Governments.

Unitholders are encouraged to participate in the consultation process and make their views known to the Government of Canada. Copies of the consultation paper can be found on the Department of Finance website at http://www.fin.gc.ca/toce/2005/toirplf_e.html Submissions can be made by e-mail to trust-fiducies@fin.gc.ca or to the Minister of Finance, the Honourable Ralph Goodale, Department of Finance, 140 O'Connor Street, Ottawa, Ontario K1A 0A6, via fax at (613) 996-9790, or via e-mail at goodale.r@parl.gc.ca. Unitholders are also encouraged to contact their local Member of Parliament to express their views. A directory of Members of Parliament can be found at www.canada.gc.ca/directories/direct_e.html.

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)	Sep 30, 2005 (Unaudited)	Dec 31, 2004
ASSETS		
Current assets		
Cash and cash equivalents	\$ -	\$ 54.4
Marketable securities (note 2)	-	68.6
Accounts receivable	119.7	96.9
Assets held for sale	-	5.4
Prepaid expenses	14.2	10.9
Inventory	4.6	5.8
	138.5	242.0
Cash reserved for site restoration and reclamation	11.1	10.3
Other assets and deferred charges	9.5	10.9
Derivative asset	-	0.6
Property, plant and equipment	1,885.4	1,908.6
Goodwill	68.5	68.5
	\$ 2,113.0	\$ 2,240.9
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities		
Bank overdraft	\$ 3.9	\$ -
Accounts payable	35.2	47.7
Accrued liabilities	77.1	72.3
Derivative liability	65.2	0.5
Accrued distributions to unitholders	20.3	17.7
	201.7	138.2
Derivative liability	2.1	-
Long-term debt (note 4)	383.8	656.3
Future income taxes	185.6	211.2
Asset retirement obligation (note 3)	37.8	40.3
Long-term incentive plan liability (note 6)	25.0	-
	836.0	1,046.0
UNITHOLDERS' EQUITY		
Net capital contributions (note 5)	2,280.0	2,049.9
Capital issued but not distributed	3.1	3.3
Convertible unsecured subordinated debentures	2.5	8.1
Long-term incentive plan equity (note 6)	40.6	20.1
Accumulated income	127.0	89.2
Accumulated cash distributions	(1,168.2)	(967.7)
Accumulated dividends	(8.0)	(8.0)
	1,277.0	1,194.9
	\$ 2,113.0	\$ 2,240.9

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

**Consolidated Statements of Unitholders' Equity**

Nine Months Ended

(\$ millions)	Sep 30, 2005 (Unaudited)	Sep 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 (loss) income for the period	37.8	61.3
Net capital contributions	230.1	463.9
Convertible unsecured subordinated debentures	(5.6)	-
Capital issued but not distributed	(0.2)	(1.5)
Long-term incentive plan equity	20.5	4.3
Cash distributions	(200.5)	(133.5)
Unitholders' equity, end of period	\$ 1,277.0	\$ 1,186.4



Consolidated Statements of Cash Flow

(\$ millions)	Three Months Ended		Nine Months Ended	
	Sep 30, 2005 (Unaudited)	Sep 30, 2004 (Unaudited)	Sep 30, 2005 (Unaudited)	Sep 30, 2004 (Unaudited)
OPERATING ACTIVITIES				
Net (loss) income for the period	\$ (26.3)	\$ 18.7	\$ 37.8	\$ 61.3
Add/(deduct) items not involving cash from operations				
Depletion, depreciation and amortization	56.5	50.2	169.7	133.4
Non-cash general & administrative	33.0	14.1	59.0	7.2
Non-cash foreign exchange gain	(7.9)	(9.1)	(4.9)	(4.4)
Cash distributions from marketable securities	-	1.0	1.2	1.0
Gain on sale of marketable securities	-	-	(27.2)	-
Unrealized loss on derivatives	50.1	14.7	67.6	28.8
Future income taxes recovery	(0.2)	(22.3)	(25.6)	(44.0)
Accretion on asset retirement obligation	0.6	0.5	2.0	1.2
Other non-cash items	0.6	-	2.0	-
Cash flow from operations	106.4	67.8	281.6	184.5
Expenditures on site restoration and reclamation	(1.3)	(1.1)	(4.8)	(2.4)
Change in non-cash working capital	(15.1)	(3.2)	(40.1)	(10.0)
	90.0	63.5	236.7	172.1
FINANCING ACTIVITIES				
Proceeds from issue of Trust Units, net of issue costs	2.9	290.4	16.5	433.3
Proceeds from issue of Debentures	-	250.0	-	250.0
Net cash distributions to unitholders	(61.6)	(41.9)	(174.3)	(107.0)
Increase/(decrease) in bank credit facilities	-	291.0	(99.0)	206.0
Increase in deferred charges	-	(10.0)	-	(10.0)
Change in non-cash working capital	1.0	8.3	1.1	9.8
	(57.7)	787.8	(255.7)	782.1
INVESTING ACTIVITIES				
Expenditures on property, plant & equipment	(38.0)	(26.0)	(148.4)	(79.6)
Acquisition of capital/corporate assets	(2.0)	(767.0)	(1.6)	(806.0)
Proceeds on disposal of property, plant & equipment	1.5	6.3	9.1	11.3
Investment in marketable securities	-	(72.7)	-	(72.7)
Proceeds on sale of marketable securities	-	-	94.5	-
Increase in cash reserved for future site restoration	(0.6)	(0.6)	(0.8)	(2.2)
Change in non-cash working capital	(2.5)	(5.3)	7.9	(9.0)
	(41.6)	(865.3)	(39.3)	(958.2)
Decrease in cash for the period	(9.3)	(14.0)	(58.3)	(4.0)
Cash beginning of the period	5.4	12.5	54.4	2.5
Bank overdraft at end of the period	\$ (3.9)	\$ (1.5)	\$ (3.9)	\$ (1.5)
Cash interest paid	\$ 3.3	\$ 1.2	\$ 17.8	\$ 6.6
Cash taxes paid	\$ 1.6	\$ 0.8	\$ 3.0	\$ 3.1
Non-cash transactions – conversion of Convertible Unsecured Subordinated Debentures into Trust Units	\$ 37.0	\$ -	\$ 175.2	\$ -

**Consolidated Statements of Income**

(\$ millions) (except per Trust Unit amounts)	Three Months Ended		Nine Months Ended	
	Sep 30, 2005 (Unaudited)	Sep 30, 2004 (Unaudited)	Sep 30, 2005 (Unaudited)	Sep 30, 2004 (Unaudited)
REVENUES				
Sales of crude oil, natural gas and natural gas liquids	\$ 195.0	\$ 127.4	\$ 521.7	\$ 350.2
Transportation expenses	(1.7)	(2.0)	(5.3)	(5.7)
Crown and other royalties, net of ARTC	(44.4)	(28.9)	(117.3)	(78.0)
Unrealized loss on derivatives	(50.1)	(14.7)	(67.6)	(28.8)
Gain on sale of marketable securities	-	-	27.2	-
Other income	1.0	0.7	4.0	1.3
	99.8	82.5	362.7	239.0
EXPENSES				
Operating	31.6	21.4	84.1	60.6
Cash general and administrative	5.7	3.4	16.0	11.1
Non-cash general and administrative	33.0	14.1	59.0	7.2
Depletion, depreciation and amortization	56.5	50.2	169.7	133.4
Interest	6.0	4.4	22.8	10.4
Accretion on asset retirement obligation	0.6	0.5	2.0	1.2
Foreign exchange gain	(7.7)	(9.0)	(4.7)	(4.1)
	\$ 125.7	\$ 85.0	\$ 348.9	\$ 219.8
(Loss)Income before taxes for the period	\$ (25.9)	\$ (2.5)	\$ 13.8	\$ 19.2
Income and capital taxes	0.6	1.1	1.6	1.9
Future income taxes recovery	(0.2)	(22.3)	(25.6)	(44.0)
	0.4	(21.2)	(24.0)	(42.1)
Net (loss) income for the period	\$ (26.3)	\$ 18.7	\$ 37.8	\$ 61.3
Net (loss) income per Trust Unit - basic	\$ (0.34)	\$ 0.31	\$ 0.51	\$ 1.10
Net (loss) income per Trust Unit - diluted	\$ (0.34)	\$ 0.29	\$ 0.51	\$ 1.07

Notes to Consolidated Financial Statements

For the three and nine months ended September 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)	Sep 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 \$27.2 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:

(\$ millions)	
Asset Retirement Obligation, December 31, 2004	\$ 40.3
Change in estimate of liability	2.4
Liabilities settled	(4.8)
Accretion expense	2.0
Sale of capital assets	(2.1)
Asset Retirement Obligation, September 30, 2005	\$ 37.8

As at September 30, 2005, the undiscounted amount of estimated cash flows required to settle the obligation is \$206.1 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)	Sep 30, 2005	Dec 31, 2004
Bank credit facilities	\$ 165.0	\$ 264.0
Senior Secured Notes	145.3	150.3
Convertible Unsecured Subordinated Debentures	73.5	242.0
	\$ 383.8	\$ 656.3

5. Unitholders' Equity

The weighted average number of Trust Units and Exchangeable Shares outstanding for the three months ended September 30, 2005 was 78,222,344 (2004 – 61,606,757). For purposes of calculating diluted net income per Trust Unit for the three months ended September 30, 2005, 1,975,913 (2004 – 0) and 1,475,518 (2004 – 0) Trust units issuable pursuant to the conversion of the Convertible Unsecured Subordinated Debentures Series I and II respectively and 1,277,819 Trust Units (2004 – 467,393) 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 nine months ended September 30, 2005 was 74,466,505 (2004 – 55,590,651). For purposes of calculating diluted net income per Trust Unit for the nine months ended September 30, 2005, 3,876,893 (2004 – 0) and 2,728,364 (2004 – 0) Trust Units issuable pursuant to the conversion of the Convertible Unsecured Subordinated Debentures Series I and Series II respectively and 1,277,819 Trust Units (2004 – 467,393) issuable pursuant to the Long-Term Incentive Plan were added to the weighted average number.

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	6,609,448	175.1
Issued on exchange of Exchangeable Shares	38,205	0.7
Issued pursuant to Distribution Reinvestment Plan	157,419	4.5
Issued pursuant to the Premium Distribution Plan	760,229	21.8
Issued pursuant to Long-Term Incentive Plan	373,972	12.1
Issued pursuant to Optional Trust Unit Purchase Plan	587,039	16.6
Balance, September 30, 2005	78,412,423	\$ 2,268.5

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 October 15, 2005 was 0.55430:1.

Exchangeable Shares	Number of shares	(\$ millions)
Balance, December 31, 2004	1,294,391	\$ 12.2
Exchanged for Trust Units	(73,444)	(0.7)
Balance, September 30, 2005	1,220,947	\$ 11.5

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 September 30, 2005

Year of Grant	UARs issued & outstanding	UARs vested	Current return per UARs	Total equity (\$ millions)	Trust Unit dilution
2000 grants	64,020	64,020	44.47	2.9	78,212
2001 grants	238,480	238,146	31.60	7.5	206,715
2002 grants	626,942	612,804	25.18	15.8	423,889
2003 grants	821,538	526,322	21.80	17.9	314,175
2004 grants	1,331,486	490,880	16.13	15.6	219,647
2005 grants	1,487,499	138,464	9.35	5.9	35,181
Total grants	4,569,965	2,070,636		65.6	1,277,819

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

As at September 30, 2005, 1,210,257 Trust Units have been issued from Treasury and 589,743 Trust Units remain available for issuance from Treasury. The settlement of LTIP obligation at September 30, 2005 would require the issuance of 1,277,819 Trust Units. The LTIP obligation in excess of the Trust Units available for issuance of \$25.0 million would be settled in cash and therefore is included in long term liabilities on the balance sheet.

7. Cash Distributions

(\$ millions, except per Trust Unit amounts)	Three Months Ended		Nine Months Ended	
	Sep 30, 2005	Sep 30, 2004	Sep 30, 2005	Sep 30, 2004
Cash flow from operations	\$ 106.4	\$ 67.8	\$ 281.6	\$ 184.5
Deduct amounts to reconcile to distribution:				
Cash retained from cash available for distribution ⁽¹⁾	(34.4)	(15.7)	(75.4)	(46.4)
Contribution to reclamation fund	(1.9)	(1.7)	(5.7)	(4.6)
	\$ 70.1	\$ 50.4	\$ 200.5	\$ 133.5
Cash Distributions to Unitholders	\$ 70.1	\$ 50.4	\$ 200.5	\$ 133.5
Cash Distributions per Trust Unit	\$ 0.90	\$ 0.83	\$ 2.70	\$ 2.40

⁽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	Sep 30 2005	Jun 30 2005	Mar 31 2005	Dec 31 2004	Sep 30 2004	Jun 30 2004
TSX Trust Unit prices (Cdn\$ per Trust Unit)						
High	36.42	31.68	32.00	28.33	26.70	26.80
Low	30.86	28.35	26.15	25.06	23.29	22.18
Close	36.40	30.66	28.99	26.62	26.70	23.25
Average daily traded volume	183,469	202,225	269,714	255,944	254,219	187,767
For the quarter ended	Sep 30 2005	Jun 30 2005	Mar 31 2005	Dec 31 2004	Sep 30 2004	Jun 30 2004
NYSE Trust Unit prices (US\$ per Trust Unit)						
High	31.37	25.59	26.60	22.98	21.16	20.44
Low	25.15	22.50	21.30	20.85	17.65	16.00
Close	31.33	25.05	23.96	22.18	21.16	17.43
Average daily traded volume	445,338	377,264	536,170	542,483	329,862	279,882
Number of Trust Units outstanding including Exchangeable Shares (millions of units)	79.1	77.2	72.9	70.5	69.7	56.8
Distribution paid per Trust Unit (\$Cdn)	0.90	0.90	0.90	0.90	0.83	0.75

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