

CALGARY, November 2, 2004 (TSX: PWL.UN; PWX; PWL.DB.A-T; PWL.DB.B-T; NYSE: PWI) -- PrimeWest Energy Trust (PrimeWest or the Trust) today announced interim operating and financial results for the third quarter ended September 30, 2004. Unless otherwise noted, all figures contained in this report are in Canadian dollars.

PRIMEWEST ENERGY TRUST ANNOUNCES THIRD QUARTER 2004 RESULTS

Third Quarter Highlights:

- On September 2, 2004, PrimeWest completed the acquisition of Calpine Canada assets at a cost of \$806 million acquiring approximately 14,500 BOE per day of production and a 25% interest in Calpine Natural Gas Trust. Transaction costs associated with the acquisition were \$8.7 million. PrimeWest entered into a series of transactions that hedged up to 90% of the volumes acquired from Calpine. This was achieved through the use of wide costless collar instruments that continue through to the first quarter of 2006.
- In the third quarter, PrimeWest increased the monthly cash distributions by approximately 20% or \$0.05 per month to \$0.30 per unit effective with the October 15, 2004 distribution.
- During the quarter, PrimeWest concluded a financing of \$550 million comprised of a \$300 million equity issuance and \$250 million of convertible unsecured subordinated debentures. These funds, together with additional bank borrowings, were used to acquire the Calpine assets.
- Debt to annualized third quarter 2004 cash flow is 1.7 times.
- Third quarter production averaged 35,460 barrels of oil equivalent (BOE) per day, compared to the second quarter 2004 rate of 31,185 BOE per day.
- Distributions of \$0.83 per unit represent a payout ratio of approximately 74%, compared to second quarter 2004 distributions of \$0.75 per unit, representing a payout ratio of 72%.
- Cash flow from operations of \$68.3 million (\$1.06 per unit) compared to \$58.2 million (\$1.05 per unit) in the second quarter of 2004, primarily due to a continued strong commodity price environment and increased production volumes for the month of September from the Calpine asset acquisition.
- Following the completion of the Calpine transaction where the assets were acquired with full tax pools, PrimeWest has re-evaluated its taxability of the 2004 distributions. For unitholders resident in Canada, PrimeWest anticipates that approximately 55% of 2004 distributions will be taxable and 45% will be deemed a return of capital.

Subsequent Events

- On October 4, 2004, PrimeWest commenced an asset divestiture program targeting to sell approximately \$100 million of non-core assets. Bids are due on November 4, 2004 and the targeted closure of successful asset sales is December 31, 2004.

Management's Discussion and Analysis

The following is management's discussion and analysis (MD&A) of PrimeWest's operating and financial results for the quarter ended September 30, 2004, 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, 2003 and 2002, together with accompanying notes, as contained in the Trust's 2003 Annual Report.

Financial and Operating Highlights – Third Quarter

Financial Highlights (millions of dollars, except per BOE and per Trust Unit amounts)	Three Months Ended			Nine Months Ended	
	Sep 30, 2004	June 30, 2004	Sep 30, 2003	Sep 30, 2004	Sep 30, 2003
Net revenue	97.2	84.9	77.2	267.8	256.9
per BOE ⁽¹⁾	29.79	29.91	25.70	29.96	27.91
Cash flow from operations	68.3	58.2	51.8	185.0	173.7
per BOE	20.93	20.52	17.25	20.69	18.88
per Trust Unit ⁽²⁾	1.06	1.05	1.11	3.24	3.85
Royalty expense	28.9	25.7	23.1	78.0	80.8
per BOE	8.86	9.06	7.70	8.72	8.77
Operating expenses	21.4	19.6	17.2	60.6	58.2
per BOE	6.56	6.89	5.73	6.78	6.32
G&A expenses - Cash	3.4	3.5	3.5	11.1	10.5
per BOE	1.03	1.23	1.15	1.24	1.14
G&A expenses - Non-cash	14.1	(7.3)	2.3	7.2	5.9
per BOE	4.31	(2.57)	0.76	0.80	0.64
Interest expense	2.9	2.8	4.0	8.9	11.0
per BOE	0.90	1.00	1.32	1.00	1.20
Distributions to unitholders	50.4	42.0	43.7	133.5	146.3
per Trust Unit ⁽³⁾	0.83	0.75	0.96	2.40	3.36
Net debt ⁽⁴⁾	464.8	169.2	233.4	464.8	233.4
per Trust Unit ⁽⁵⁾	5.84	2.97	4.68	5.84	4.68

⁽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⁾ Weighted Average Trust Units, Exchangeable Shares, Convertible Unsecured Debentures and Trust Units issueable pursuant to Long-Term Incentive Plan (diluted).

⁽³⁾ Based on Trust Units outstanding at date of distribution.

⁽⁴⁾ Net debt is long-term debt adjusted for working capital excluding financial derivative assets and liabilities.

⁽⁵⁾ Trust Units, Exchangeable Shares outstanding, Convertible Unsecured Debentures and Trust Units issueable pursuant to the Long-Term Incentive Plan (diluted) at end of period.

Operating Highlights	Three Months Ended			Nine Months Ended	
	Sep 30, 2004	June 30, 2004	Sep 30, 2003	Sep 30, 2004	Sep 30, 2003
Daily Sales Volumes					
Natural gas (<i>mmcf/day</i>)	143.5	125.5	131.4	131.0	136.5
Crude oil (<i>bbls/day</i>)	8,447	7,699	7,913	8,005	8,091
Natural gas liquids (<i>bbls/day</i>)	3,096	2,569	2,811	2,788	2,879
Total (<i>BOE/day</i>)	35,460	31,185	32,623	32,626	33,722
Realized Commodity Prices⁽¹⁾ (<i>Cdn \$</i>)					
Natural gas (<i>\$/mcf</i>)	6.14	6.59	5.59	6.42	6.21
Without hedging	6.31	6.82	5.93	6.57	6.83
Crude oil (<i>\$/bbl</i>)	39.95	35.83	32.65	36.98	34.85
Without hedging	48.58	43.20	34.40	43.86	37.61
Natural gas liquids (<i>\$/bbl</i>)	45.30	41.22	33.06	41.92	35.62
Total (<i>\$ per BOE</i>)	38.31	38.77	33.29	38.42	36.55
Without hedging	41.06	41.51	35.07	40.73	39.72

(1) Includes hedging gains (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”, “may”, “will”, “project”, “should”, “believe”, “outlook” and similar expressions are intended to identify forward-looking statements. 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.

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 the 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.

Evaluation of Disclosure Controls and Procedures

The Chief Executive Officer, Don Garner, and Chief Financial Officer, Dennis Feuchuk, evaluated the effectiveness of PrimeWest Energy's disclosure controls and procedures as of September 30, 2004 and concluded that PrimeWest Energy'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.

Vision, Core Business and Strategy

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

Maximizing total return to unitholders, in the form of cash distributions and change in unit price, is PrimeWest's overriding objective. Our strategies for asset management and growth, financial management and corporate governance are outlined in this MD&A, along with a discussion of our performance in the third quarter of 2004 and our goals for the remainder of 2004 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 field optimization 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. We will continue to be an opportunistic acquirer who uses the business cycles to make accretive acquisitions. 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.

The acquisition of the Calpine assets, with current production volumes of approximately 14,500 BOE per day added the equivalent of 4,700 BOE per day in the third quarter of 2004. In addition, the 2004 capital program has been increased by \$35 million to develop some of the opportunities on Calpine lands by year-end.

Assets acquired from Seventh Energy Ltd. (Seventh) contributed 1,412 BOE per day to production volumes in the third quarter of 2004. PrimeWest plans to invest approximately \$7 million during 2004 to develop the Seventh assets.

Financial Management

PrimeWest strives to maintain a conservative debt position, to allow us to take advantage of opportunities that arise in the acquisition market, as well as fund development activities. 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 U.S. dollars. PrimeWest's commodity hedging approach helps to stabilize cash flow, reduce volatility, and protect transaction economics.

PrimeWest continues to target a payout ratio between 70% and 90% of annual cash flow to increase the Trust's financial flexibility. The third quarter 2004 payout ratio was approximately 74%, and the retained cash flow was utilized to fund the

Trust's capital spending program. PrimeWest's debt to cash flow level of 1.7 times for the third quarter is less than our internal limit of 2.0 times.

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 in the future. Our status as a corporation for U.S. tax purposes simplifies tax reporting for our U.S. unitholders.

For eligible Canadian unitholders, PrimeWest offers participation in the Distribution Reinvestment Plan (DRIP), Premium Distribution Plan (PREP), and Optional Trust Unit Purchase Plan (OTUPP), which represent a convenient way to maximize an investment in PrimeWest. For alternate investment styles, PrimeWest also has Exchangeable Shares available, which permit participation in PrimeWest without the ongoing tax implications associated with receiving a distribution.

Corporate Governance

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

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

Outlook - 2004

PrimeWest expects full year 2004 production volumes to average approximately 35,500 BOE per day. Full year operating costs are expected to be approximately \$6.70 per BOE. PrimeWest expects to invest approximately \$125 million in its capital development program, with the focus primarily in the core areas of Caroline, Valhalla, Brant/Farrow and Princess/Hays.

The taxability of 2004 distributions for U.S. unitholders cannot be accurately estimated at this time, but will be confirmed after year-end. For residents of the U.S., Canadian withholding tax of 15% applies to the distribution. In addition, the Canadian Federal Government announced a proposal on March 23, 2004, that would expand Canadian withholding tax on non-Canadian residents (15% for U.S. unitholders) by applying it to both the "taxable income" portion, as well as the return of capital portion of the distributions effective January 1, 2005. A withholding tax of 15% has always been applied by PrimeWest to the total value of distributions paid to U.S. unitholders, however, the tax withheld on the return of capital portion has been refundable. As of September 30, 2004, non-resident ownership of PrimeWest was approximately 60%. For more details on withholding tax, please visit our website at www.primewestenergy.com.

On September 16, 2004, the Canadian Federal Government tabled specific legislation relevant to the budget announcement of March 23, 2004, which proposed changes to non-resident withholding taxes and the placement of non-resident ownership restrictions upon the income trust sector. These legislative proposals would require a Canadian income trust to maintain at least 50% Canadian ownership on the basis of fair market value. Under the terms of the proposed legislation because PrimeWest's non-resident ownership exceeded 50% as at March 22, 2004, PrimeWest has until January 1, 2007 to conform to the new proposed requirements. PrimeWest is actively supporting the efforts of the Canadian Association of Income

Funds to have the proposed legislation modified or withdrawn. We will endeavor to keep our unitholders informed of the status of this legislation.

Cash Flow Reconciliation

(\$ millions)	
Second quarter 2004 cash flow from operations	\$ 58.2
Volumes	17.6
Commodity prices	(1.4)
Net hedging change from prior quarter	(1.2)
Operating expenses	(1.8)
Royalties	(3.2)
Other	0.1
Third quarter 2004 cash flow from operations	\$ 68.3

The above table includes non-GAAP measurements which may not be comparable to other companies.

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, hedging gains or losses, royalties and currency exchange rates. Some of these factors are uncontrollable from PrimeWest's perspective such as commodity prices, the currency exchange rate and royalties. Other factors that are controllable by PrimeWest are production levels and operating expenses, as well as interest and general and administrative (G&A) expenses. It is expected that these factors will impact cash flows in the future.

Quarterly Performance

(\$ millions, except per Trust Unit amounts)	2004			2003			2002	
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Net Revenues	97.2	84.9	85.7	73.0	77.2	85.6	94.0	68.8
Net Income	20.2	22.4	20.1	(0.7)	7.0	61.4	22.4	(7.3)
Net Income Per Unit - Basic	0.31	0.41	0.40	(0.01)	0.15	1.34	0.53	(0.20)
Net Income Per Unit - Diluted	0.31	0.40	0.40	(0.01)	0.15	1.33	0.53	(0.20)

The above table highlights PrimeWest's performance for the third quarter ended 2004, and the preceding seven quarters through 2003 and 2002.

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

Net income and net income per unit are secondary measures for a royalty trust because they include both cash and non-cash items. The non-cash items such as depletion, depreciation and amortization (DD&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, except per BOE)	Three Months Ended			Nine Months Ended	
	Sep 30, 2004	June 30, 2004	Sep 30, 2003	Sep 30, 2004	Sep 30, 2003
Land & lease acquisitions	\$ 2.0	\$ 2.7	\$ 1.6	\$ 6.5	\$ 3.9
Geological and geophysical	3.3	0.8	0.4	5.8	1.4
Drilling and completions	12.0	9.0	18.9	39.8	41.5
Investment in facilities					
Equipping & tie-in	1.0	2.8	-	7.8	6.7
Compression & processing	1.3	0.5	2.0	3.8	4.7
Gas gathering	1.8	0.2	3.0	2.5	7.0
Production facilities	3.6	5.1	4.6	10.8	7.4
Capitalized G&A	0.4	0.6	0.3	1.4	0.8
Development capital	25.4	21.7	30.8	78.4	73.4
Corporate/property acquisitions	767.0	0.4	1.3	806.0	207.0
Dispositions	(6.3)	(1.6)	(0.6)	(11.3)	(0.8)
Head office equipment	0.6	0.5	-	1.2	0.1
Total	\$ 786.7	\$ 21.0	\$ 31.5	\$ 874.3	\$ 279.7

During the third quarter of 2004, PrimeWest's capital expenditures totaled \$786.7 million, compared to \$31.5 million invested in the same quarter the previous year. Development capital of \$25.4 million invested in the third quarter 2004 was lower than the third quarter 2003 investment of \$30.8 million. Of the \$25.4 million in development capital, \$13.0 million or 51% was spent on drilling, completions and tie-ins that contribute to new reserve additions and help offset natural production decline. In the third quarter, PrimeWest's capital spending was focused primarily in the areas of Caroline, Brant Farrow, and Valhalla. Gross wells drilled in the third quarter totaled 23 (15 net wells), with a success rate of approximately 91%. Year to date 70 gross wells (46 net wells) have been drilled with a success rate of approximately 90%.

Compared to the second quarter of 2004, development capital spending of \$25.4 million in the third quarter of 2004 was higher due to a higher level of drilling activity. Corporate acquisitions in 2003 included the purchase of two private Canadian companies. In 2004 PrimeWest completed the corporate acquisition of Seventh Energy and the asset acquisition of Calpine Canada.

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

Assets

Since inception, PrimeWest has focused on the conventional oil and natural gas plays of the Western Canadian Sedimentary Basin. Within this focused area, we have a diversified, multi-zone suite of assets stretching from northeast B.C., across much of Alberta and down through southwest Saskatchewan. We believe this diversity reduces risks to overall corporate production and cash flow, while the core area focus allows us to capitalize on our existing technical knowledge in each of the core areas.

Production Volumes

	Three Months Ended			Nine Months Ended	
	Sep 30, 2004	June 30, 2004	Sep 30, 2003	Sep 30, 2004	Sep 30, 2003
Natural gas (mmcf/day)	143.5	125.5	131.4	131.0	136.5
Crude oil (bbls/day)	8,447	7,699	7,913	8,005	8,091
Natural gas liquids (bbls/day)	3,096	2,569	2,811	2,788	2,879
Total (BOE/day)	35,460	31,185	32,628	32,626	33,722
Gross Overriding Royalty volumes included above (BOE/day)	1,404	1,355	1,270	1,371	1,607

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

PrimeWest's production volumes in the third quarter increased when compared with the second quarter of 2004 due to additional volumes contributed by the Calpine assets. PrimeWest's development activity also added volumes, which partially offset natural production decline. Compared to the first nine months of 2003, production was 3% lower, attributable to production decline, and offset by development and acquisition volume additions.

In the second quarter of 2004, the Alberta Energy and Utilities Board ruled on the natural gas over bitumen issue, which resulted in approximately 330 BOE per day of production at Ells being permanently shut-in effective July 1, 2004. The impact of this shut-in has been factored into PrimeWest's 2004 full year production guidance. Working with the operator, PrimeWest intends to seek compensation for the shut-in production from the Province of Alberta.

Production at PrimeWest's non-operated Whiskey Creek area is expected to remain restricted for the remainder of 2004 due to capacity constraints in third party facilities.

PrimeWest expects full year 2004 production to average approximately 35,500 BOE per day. This estimate incorporates PrimeWest's expected natural production decline and the production volume shut-ins described above, offset by production additions from the capital development program, acquired production from the Calpine and Seventh Energy acquisitions and other property acquisitions.

Commodity Prices

Benchmark Prices	Three Months Ended			Nine Months Ended	
	Sep 30, 2004	June 30, 2004	Sep 30, 2003	Sep 30, 2004	Sep 30, 2003
Natural gas (\$/Mcf AECO)	6.66	6.80	6.29	6.69	7.07
Crude oil (U.S.\$/bbl WTI)	43.88	38.32	30.20	39.11	30.99

Average realized prices in the market place are indicated by these benchmark prices

Average Realized Sales Prices

(Canadian Dollars)	Three Months Ended			Nine Months Ended	
	Sep 30, 2004	June 30, 2004	Sep 30, 2003	Sep 30, 2004	Sep 30, 2003
Natural gas (\$/Mcf) ⁽¹⁾⁽²⁾	6.14	6.59	5.59	6.42	6.21
Without hedging	6.31	6.82	5.93	6.57	6.83
Crude oil (\$/bbl) ⁽¹⁾	39.95	35.83	32.65	36.98	34.85
Without hedging	48.58	43.20	34.40	43.86	37.61
Natural gas liquids (\$/bbl)	45.30	41.22	33.06	41.92	35.62
Total Oil Equivalent ⁽²⁾ (\$/BOE)	38.31	38.77	33.29	38.42	36.55
Without hedging	41.06	41.51	35.07	40.73	39.72
Realized hedging loss included in prices above (\$/BOE)	(2.75)	(2.74)	(1.78)	(2.31)	(3.17)

⁽¹⁾ Includes hedging gains / losses.

⁽²⁾ Excludes sulphur.

Canadian commodity prices were higher in the third quarter 2004 than during the same period in 2003 resulting in higher average realized selling prices per BOE.

The realized selling price in Canadian dollars is impacted by currency exchange rates. Oil and gas prices are denominated in U.S. dollars, therefore, a strengthened Canadian dollar translates into lower realized prices and lower Canadian revenue for producers.

Compared to the second quarter 2004, average realized sales prices per BOE decreased marginally in the third quarter 2004 due to lower average price for natural gas, partially offset by higher crude oil and natural gas liquids prices.

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 of 2004, PrimeWest had a \$9.0 million hedging loss compared to a loss of \$5.4 million for the same period in 2003.

As of the end of the third quarter 2004 year-to-date, hedging losses total \$20.6 million compared to hedging losses of \$29.2 million for the same period of 2003.

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

Benchmark Commodity Prices	Past Four Quarters (Actual)				Next Four Quarters (Forward Markets) ⁽¹⁾			
	Q4 2003	Q1 2004	Q2 2004	Q3 2004	Q4 2004	Q1 2005	Q2 2005	Q3 2005
Natural gas								
NYMEX (\$U.S./mcf)	4.58	5.69	5.97	5.84	6.63	7.92	6.49	6.46
AECO (\$Cdn/mcf)	5.59	6.61	6.80	6.66	7.09	8.74	7.07	7.17
Crude oil WTI (\$U.S./bbl)	31.18	35.15	38.32	43.88	48.96	47.08	45.17	43.59

(1) As at September 30, 2004

Sales Revenue

Revenue (\$ millions)	Three Months Ended				Nine Months Ended			
	Sep 30, 2004	% of total	June 30, 2004	% of total	Sep 30, 2003	% of total	Sep 30, 2004	Sep 30, 2003
Natural gas ⁽¹⁾	\$ 81.0	65%	\$ 75.3	68%	\$ 67.6	68%	\$ 230.4	\$ 231.5
Crude oil	31.1	25%	25.1	23%	23.8	24%	81.1	77.0
Natural gas liquids	12.9	10%	9.6	9%	8.6	8%	32.0	28.0
Total	\$ 125.0	100%	\$ 110.0	100%	\$ 100.0	100%	\$ 343.5	\$ 336.5
Hedging (losses)/gains included above ⁽²⁾	\$ (9.0)		\$ (7.8)		\$ (5.4)		\$(20.6)	\$ (29.2)

(1) Excludes sulphur.

(2) Net of amortized premiums.

Third quarter 2004 revenues were 25% higher than the same period in 2003, due to higher commodity prices and increased production volumes. Revenues are higher in the third quarter 2004 compared to the second quarter 2004 due to the higher volumes from the Calpine acquisition partially offset by lower natural gas prices. Revenues are higher in the first nine months of 2004 compared to the same period in 2003 due to higher commodity prices, partially offset by reduced production volumes.

Since a greater portion of PrimeWest's revenues (65%) are derived from natural gas, 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. PrimeWest's hedging program delivered gains of \$17 million over the period from January 1, 2001 to September 30, 2004. 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.

Approximate percentage of future anticipated production volumes hedged at September 30, 2004, net of anticipated royalties, reflecting full production declines with no offsetting additions:

	Q4/04	Q1 /05	Q2/05	Q3/05	Q4/05	Q1/06
Crude Oil	60%	51%	47%	35%	30%	0%
Natural Gas	64%	58%	49%	50%	50%	35%

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 these contracts in place at September 30, 2004 follows:

Crude Oil (\$U.S./bbl)

Period	Volume (bbls/d)	Type	WTI Price (\$U.S./bbl)
Oct – Dec 2004	500	Swap	26.00
Oct – Dec 2004	500	Swap	27.03
Oct – Dec 2004	500	Swap	28.53
Oct – Dec 2004	500	Swap	30.10
Oct – Dec 2004	500	Costless Collar	24.00/30.00
Oct – Dec 2004	500	Costless Collar	25.00/28.30
Oct – Dec 2004	500	Costless Collar	26.00/32.72
Oct – Dec 2004	500	Costless Collar	40.00/44.75
Oct – Dec 2004	500	Costless Collar	40.00/45.90
Oct – Dec 2004	500	Costless Collar	40.00/56.25
Jan – Mar 2005	500	Swap	27.25
Jan – Mar 2005	500	Swap	28.60
Jan – Mar 2005	500	Swap	30.00
Jan – Mar 2005	500	Costless Collar	28.00/34.35
Jan – Mar 2005	500	3 Way	25.00/30.00/35.50
Jan – Mar 2005	500	Costless Collar	35.00/49.80
Jan – Mar 2005	500	Costless Collar	35.00/50.00
Jan – Mar 2005	500	Costless Collar	40.00/51.50
Apr – Jun 2005	500	Swap	27.07
Apr – Jun 2005	500	Swap	28.50
Apr – Jun 2005	500	Swap	30.00
Apr – June 2005	500	3 Way	25.00/30.00/36.75
Apr – June 2005	500	Costless Collar	35.00/47.00
Apr – June 2005	500	Costless Collar	35.00/46.90
Apr – June 2005	500	Costless Collar	37.50/50.90
Jul – Sep 2005	500	Swap	27.05
Jul – Sep 2005	500	Swap	28.50
Jul – Sep 2005	500	Costless Collar	35.00/44.90
Jul – Sep 2005	500	Costless Collar	35.00/44.35
Jul – Sep 2005	500	Costless Collar	35.00/51.30
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

Natural Gas (Cdn\$/Mcf)

Period	Volume (mmcf/d)	Type	AECO Price (Cdn\$/mcf)
Jan 2004 – Oct 2004	9.5	3 Way	3.17/4.22/6.09
Jan 2004 – Dec 2004	1.0	Swap	6.02
Apr 2004 – Oct 2004	4.7	Swap	5.45
Apr 2004 – Oct 2004	4.7	Swap	6.02
Apr 2004 – Oct 2004	4.7	Swap	6.06
Apr 2004 – Oct 2004	4.7	Costless Collar	5.01/6.06
Apr 2004 – Oct 2004	4.7	Costless Collar	5.28/7.39
Apr 2004 – Oct 2004	4.7	Swap	6.25
Apr 2004 – Oct 2004	4.7	Swap	6.20
Oct 2004 – Dec 2004	10.0	Costless Collar	6.33/8.20
Oct 2004 – Dec 2004	10.0	Costless Collar	6.33/7.91
Oct 2004 – Dec 2004	10.0	Costless Collar	6.33/7.68
Oct 2004 – Dec 2004	10.0	Costless Collar	6.33/8.19
Oct 2004 – Dec 2004	10.0	Costless Collar	6.33/8.65
Oct 2004 – Dec 2004	5.0	Costless Collar	5.80/6.99
Oct 2004 – Dec 2004	5.0	Costless Collar	5.80/7.29
Nov 2004 – Dec 2004	5.0	Costless Collar	6.33/9.76
Nov 2004 - Mar 2005	4.7	Costless Collar	5.80/7.91
Nov 2004 - Mar 2005	4.7	Swap	6.71
Nov 2004 – Mar 2005	4.7	Costless Collar	6.33/11.87
Nov 2004 – Mar 2005	4.7	Costless Collar	6.86/11.61
Jan 2005 – Mar 2005	10.0	Costless Collar	6.33/11.18
Jan 2005 – Mar 2005	10.0	Costless Collar	6.33/10.76
Jan 2005 – Mar 2005	10.0	Costless Collar	6.33/10.55
Jan 2005 – Mar 2005	10.0	Costless Collar	6.33/12.13
Jan 2005 – Mar 2005	5.0	3 Way	5.28/6.33/10.44
Jan 2005 – Mar 2005	5.0	3 Way	5.28/6.33/10.35
Jan 2005 – Mar 2005	5.0	3 Way	5.28/6.33/12.53
Apr 2005 – Jun 2005	10.0	Costless Collar	6.33/7.75
Apr 2005 – Jun 2005	10.0	Costless Collar	6.33/7.63
Apr 2005 – Jun 2005	10.0	Costless Collar	6.33/7.49
Apr 2005 – Jun 2005	10.0	Costless Collar	6.33/7.84
Apr 2005 – Jun 2005	5.0	Costless Collar	6.33/7.85
Apr 2005 – Jun 2005	5.0	Costless Collar	6.33/6.99
Apr 2005 – Jun 2005	5.0	Costless Collar	6.33/7.09
Apr 2005 – Jun 2005	5.0	Costless Collar	6.33/7.44
Jul 2005 – Sep 2005	10.0	Costless Collar	6.33/7.81
Jul 2005 – Sep 2005	10.0	Costless Collar	6.33/7.66
Jul 2005 – Sep 2005	10.0	Costless Collar	6.33/7.53
Jul 2005 – Sep 2005	10.0	Costless Collar	6.33/7.86
Jul 2005 – Sep 2005	2.4	Costless Collar	6.33/7.88
Jul 2005 – Sep 2005	5.0	Costless Collar	6.33/7.50
Jul 2005 – Sep 2005	5.0	Costless Collar	6.33/7.60
Jul 2005 – Sep 2005	5.0	Costless Collar	6.33/7.79

Period	Volume (mmcf/d)	Type	AECO Price (Cdn\$/mcf)
Oct 2005 – Dec 2005	10.0	Costless Collar	6.33/8.97
Oct 2005 – Dec 2005	10.0	Costless Collar	6.33/8.71
Oct 2005 – Dec 2005	10.0	Costless Collar	6.33/8.60
Oct 2005 – Dec 2005	10.0	Costless Collar	6.33/8.96
Oct 2005 – Dec 2005	5.0	3 Way	5.28/6.33/9.92
Oct 2005 – Dec 2005	5.0	3 Way	5.28/6.33/9.76
Oct 2005 – Dec 2005	5.0	3 Way	5.28/6.33/10.04
Jan 2006 – Mar 2006	10.0	Costless Collar	6.33/10.55
Jan 2006 – Mar 2006	10.0	Costless Collar	6.33/10.22
Jan 2006 – Mar 2006	10.0	Costless Collar	6.33/9.96
Jan 2006 – Mar 2006	5.0	Costless Collar	6.33/10.42

A 3-way option is like 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 \$6.09, purchased a put at \$4.22, and resold the put at \$3.17. Should the market price drop below \$4.22, PrimeWest will receive \$4.22 until the price is less than \$3.17, at which time PrimeWest would then receive market price plus \$1.05. However, should market prices rise above \$6.09, PrimeWest would receive a maximum of \$6.09. Should the market price remain between \$4.22 and \$6.09, PrimeWest would receive the market price.

Natural Gas Basis Differential

Period	Volume (mmcf/day)	Type	Basis Price (\$U.S./mcf)
Apr – Oct 2004	5	Basis Swap	\$0.71

The AECO basis is the difference between the NYMEX gas price in \$U.S. per Mcf and the AECO price in \$U.S. per Mcf. Using the basis swap above as an example, PrimeWest has fixed this price difference between the two markets at \$U.S. 0.71 per Mcf from April 2004 through October 2004. If the NYMEX price for the period turned out to be \$U.S. 5.00 per Mcf, PrimeWest would receive an AECO equivalent price of \$U.S. 4.29 per Mcf.

Electrical Power

Period	Power Amount (MW)	Type	Price (\$/MW-hr)
Q4 2004	10	Fixed Price Swap	44.83
Calendar 2005	5	Fixed Price Swap	51.65

CICA Accounting Guideline 13 (AcG-13), "Hedging Relationships," became effective for fiscal years beginning on or after July 1, 2003. AcG-13 addresses the identification, designation, documentation and effectiveness of hedging transactions for the purposes of applying hedge accounting. It also establishes conditions for applying or discontinuing hedge accounting. Under the new guideline, hedging transactions must be documented and it must be demonstrated that the hedges are sufficiently effective in order to continue accrual accounting for positions hedged with derivatives. PrimeWest is not applying hedge accounting to its hedging relationships. As a result, PrimeWest's derivatives are marked-to-market with the resulting gain or loss reflected in earnings for the reporting period.

As of September 30, 2004, PrimeWest had an outstanding derivative loss of \$0.5 million, relating to transitional provisions, comprised of a \$0.5 million loss for crude oil, a \$0.2 million loss for natural gas and a \$0.2 million gain for electrical power. The derivative loss is shown as a current asset on the balance sheet. The loss will continue to be amortized to earnings upon settlement of the corresponding hedges that are expected to expire by March 2005.

The unrealized loss on derivatives on the income statement results from the change in the mark-to-market valuation of the derivative financial instruments during the period. It represents the loss that would be incurred if the contracts were settled on the period end date. The unrealized loss on derivatives for the nine months ended September 30, 2004, was \$28.8 million. The loss was comprised of a \$20.3 million loss for crude oil, an \$8.6 million loss for natural gas and a \$0.1 million gain for electrical power.

The \$14.7 million unrealized derivative loss for the three months ended September 30, 2004, was comprised of a \$10.0 million loss on crude oil, a \$4.4 million loss on natural gas and a \$0.3 million loss on electrical power.

The mark-to-market valuation of the derivatives in place at September 30, 2004, was a \$29.3 million loss consisting of a \$20.8 million loss in crude oil, an \$8.9 million loss in natural gas and a \$0.4 million gain on electrical power. \$26.9 million of the derivative loss is shown as a current liability on the balance sheet as these derivatives will be settled in the next twelve months. The remaining liability of \$2.4 million is reported as a long-term derivative liability.

For the three months ended September 30, 2004, the cash impact of contracts settling was an \$8.8 million loss consisting of a \$6.7 million loss in crude oil, a \$2.3 million loss in natural gas and a \$0.2 million gain on electrical power. For the nine months ended September 30, 2004 the cash impact of contracts settling was a \$20.7 million loss comprised of a \$15.1 million loss in crude oil, a \$5.5 million loss in natural gas, a \$0.6 million gain on electrical power and a \$0.7 million loss in interest rate swaps.

Royalties (Net of ARTC)

Royalties are paid by PrimeWest 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, 2004	June 30, 2004	Sep 30, 2003	Sep 30, 2004	Sep 30, 2003
Royalty expense (net of ARTC)	\$ 28.9	\$ 25.7	\$ 23.1	\$ 78.0	\$ 80.8
Per BOE	\$ 8.86	\$ 9.06	\$ 7.70	\$ 8.72	\$ 8.77
Royalties as % of sales revenues					
With hedge loss	23.1%	23.4%	23.1%	22.7%	24.0%
Excluding hedge loss	21.6%	21.8%	21.9%	21.4%	22.1%

Royalty expense in the third quarter of 2004 were approximately 25% higher than the same period the previous year due to overall higher commodity prices and volumes. For the first nine months of 2004, royalties were \$78 million, lower than the same period in 2003 due to lower year-to-date production volumes and offset by higher commodity prices in 2004.

Royalty rates are based on commodity prices; therefore future changes to prices will be accompanied by changes in royalty expense.

Operating Expenses

(\$ millions, except per BOE)	Three Months Ended			Nine Months Ended	
	Sep 30, 2004	June 30, 2004	Sep 30, 2003	Sep 30, 2004	Sep 30, 2003
Operating expense (\$ millions)	\$ 21.4	\$ 19.6	\$ 17.2	\$ 60.6	\$ 58.2
Per BOE	\$ 6.56	\$ 6.89	\$ 5.73	\$ 6.78	\$ 6.32

Compared to the second quarter of 2004, PrimeWest's total operating expenses for the third quarter 2004 are higher as a result of the Calpine asset acquisition, which added \$2.8 million of expenses in the quarter. On a gross and per BOE basis, operating costs are higher in the third quarter in 2004 compared to the same quarter in the previous year due to the Calpine acquisition and well workovers of \$0.7 million in 2004. Operating expenses are higher for the nine months of 2004 compared to 2003 as a result of the Calpine acquisition adding approximately \$2.8 million and the Seventh Energy acquisition adding approximately \$2.2 million, offset by lower power costs in 2004.

Operating Expenses Outlook

Operating costs for the year are expected to be higher than in 2003, and PrimeWest expects 2004 operating expenses to be approximately \$6.70 per BOE.

Operating Margin

(\$/BOE)	Three Months Ended			Nine Months Ended	
	Sep 30, 2004	June 30, 2004	Sep 30, 2003	Sep 30, 2004	Sep 30, 2003
Sales price and other revenue ⁽¹⁾	\$ 38.65	\$ 38.96	\$ 33.40	\$ 38.68	\$ 36.68
Royalties	8.86	9.06	7.70	8.72	8.77
Operating expenses	6.56	6.89	5.73	6.78	6.32
Operating margin	\$ 23.23	\$ 23.01	\$ 19.97	\$ 23.18	\$ 21.59

⁽¹⁾ Includes hedging and sulphur

Operating margin per BOE increased 16% during the third quarter 2004 compared to the same quarter in 2003. This is primarily due to higher sales prices 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 barrel of oil equivalent that is produced, before head office expenses and financing charges.

Operating margin increased in the third quarter compared to the second quarter of 2004, primarily as a result of slightly lower operating expenses and royalties. Compared to the first nine months of 2003, operating margin for 2004 year to date is approximately 7% higher.

Based on PrimeWest's outlook on commodity prices, the Canadian/U.S. dollar exchange rate, operating expense expectations and hedge positions, margins are expected to be higher in 2004 than 2003. PrimeWest will continue to focus on achieving lower than average operating expenses to maximize margins, which can reduce the volatility of cash flows through commodity price cycles.

General & Administrative Expense

(\$ millions, except per BOE)	Three Months Ended			Nine Months Ended	
	Sep 30, 2004	June 30, 2004	Sep 30, 2003	Sep 30, 2004	Sep 30, 2003
Cash G&A expense (\$ millions)	\$ 3.4	\$ 3.5	\$ 3.5	\$ 11.1	\$ 10.5
Per BOE	\$ 1.03	\$ 1.23	\$ 1.15	\$ 1.24	\$ 1.14
Non-cash G&A expense (\$ millions)	\$ 14.1	\$ (7.3)	\$ 2.3	\$ 7.2	\$ 5.9
Per BOE	\$ 4.31	\$(2.57)	\$ 0.76	\$ 0.80	\$ 0.64

Cash G&A expense in the third quarter 2004 decreased approximately 16% on a per BOE basis from the previous quarter and 10% from the same period in 2003 due to higher production volumes as a result of the Calpine asset acquisition.

The increase in the year-to-date cash G&A compared to the same period in 2003 is mainly due to increases in salaries and information technology expenditures offset by higher overhead recoveries.

PrimeWest's non-cash G&A expenses (on a total and per BOE basis) increased in the third quarter of 2004 and on a year-to-date basis compared to the same period in 2003. The increase is due to a higher average Unit Appreciation Rights (UARs) value under PrimeWest's Long-Term Incentive Plan (LTIP).

Non-cash G&A expense consists mainly of the change in the value of the UARs. UARs in a trust are similar to stock options in a corporation. Consistent with the resolution approved by unitholders at the last annual meeting of unitholders, PrimeWest continues to pay for the exercise of UARs in Trust Units. The program rewards employees based on total unitholder return, which is comprised of cumulative distributions on a reinvested basis plus growth in unit price. No benefit accrues to employees who hold UARs until the unitholders have first achieved a 5% total annual return from the time of grant. 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 reported quarterly, as a charge to the income statement.

G&A Expense Outlook

Cash G&A expenses in 2004 are expected to be higher than in 2003 and are expected to be approximately \$1.25 per BOE for the year.

Interest Expense

(\$ millions, except per Trust Unit)	Three Months Ended			Nine Months Ended	
	Sep 30, 2004	June 30, 2004	Sep 30, 2003	Sep 30, 2004	Sep 30, 2003
Interest expense	\$ 2.9	\$ 2.8	\$ 4.0	\$ 8.9	\$ 11.0
Period end net debt level	\$ 464.8	\$ 169.2	\$ 233.4	\$ 464.8	\$ 233.4
Debt per Trust Unit	\$ 5.84	\$ 2.97	\$ 4.68	\$ 5.84	\$ 4.68
Average cost of debt	3.9%	4.4%	4.7%	4.2%	4.5%

Interest expense, representing interest on bank debt and private placement debt, decreased in the third quarter and year-to-date 2004 compared to the same periods in 2003, due to lower average interest rates and a lower debt balance. Interest expense excludes any interest owing on the Convertible Unsecured Subordinated Debentures.

The significant increase in the net debt level at September 30, 2004 compared to prior periods is due to the drawdown on the credit facility relating to the acquisition of the Calpine assets and 25% interest in Calpine Natural Gas Trust.

In May of 2003, PrimeWest closed a private placement debt financing of \$U.S. 125 million at a U.S. fixed coupon rate of 4.19%, successfully diversifying its debt. The actual Canadian interest expense on the \$U.S. debt will fluctuate with any changes in the Canadian/U.S. foreign exchange rates. Canadian interest rates are expected to be lower through 2004 compared to 2003.

Foreign Exchange Gain

The foreign exchange gain of \$9.0 million for the three months ended September 30, 2004 and \$4.1 million for the nine months ended September 30, 2004, results from the translation of the U.S. dollar denominated secured notes issued under the private placement and related interest payable in Canadian dollars.

Depletion, Depreciation and Amortization

(\$ millions, except per BOE)	Three Months Ended			Nine Months Ended	
	Sep 30, 2004	June 30, 2004	Sep 30, 2003	Sep 30, 2004	Sep 30, 2003
Depletion, depreciation and amortization	\$ 50.2	\$ 41.4	\$ 50.7	\$ 133.4	\$ 153.3
\$/BOE	\$ 15.41	\$ 14.59	\$ 16.91	\$ 14.92	\$ 16.66

The third quarter 2004 DD&A rate of \$15.41 per BOE is lower than the 2003 third quarter rate of \$16.91 per BOE due to the January 1, 2004 ceiling test write down of \$309 million. This write down also had the same effect on the full year rate per BOE. DD&A rate per BOE increased in the third quarter of 2004 versus the previous quarter as a result of a higher DD&A rate associated with the Calpine asset acquisition, which closed on September 2, 2004.

Ceiling Test

Effective January 1, 2004, PrimeWest has adopted CICA Accounting Guideline 16 (AcG-16), "Oil and Gas Accounting - Full Cost". This new standard replaces the CICA Accounting Guideline 5 (AcG-5), "Full Cost Accounting in the Oil and Gas Industry".

Under AcG-5, the cost recovery test is calculated based on undiscounted future net revenues for proved reserves, less general and administrative expenses, site restoration, future financing costs and applicable taxes. The aggregate result is limited to capitalized costs, less accumulated depletion and site restoration, the lower of cost and market value of unproved land and future income taxes. The cost recovery test is based on costs and commodity prices existing at the balance sheet date.

AcG-16 impacts the application of the cost centre impairment test (ceiling test). The guideline is effective for fiscal years beginning on or after January 1, 2004. The cost impairment test is now a two stage process which is to be performed at least annually. The first stage of the test determines if the cost pool is impaired. An impairment loss exists when the carrying amount of an asset is not recoverable and exceeds its fair value. The carrying amount is not recoverable if it exceeds the sum of the undiscounted cash flows from Proved reserves plus unproved properties using management's best estimate of future prices. The second stage determines the amount of the impairment loss to be recorded. The impairment is measured as the amount by which the carrying amount of capitalized assets exceeds the future discounted cash flows from Proved plus Probable reserves. The discount rate used is the risk free rate.

Performing this test at January 1, 2004, using consultant's average prices as at January 1, 2004 of AECO \$5.90 per Mcf for natural gas and \$U.S. 29.21 per barrel WTI for crude oil resulted in a before tax impairment of \$308.9 million, and an after tax impairment of \$233.2 million. The write down was booked to accumulated income in the first quarter of 2004.

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 2004 contribution rate for the fund is unchanged from 2003 at \$0.50 per BOE, which is expected to be sufficient to meet expenditure requirements for the future. As at September 30, 2004, \$10.4 million is residing in the site reclamation fund.

The reclamation and abandonment costs in the third quarter of 2004 were \$1.1 million, compared to \$0.4 million for the same period in 2003, and \$0.3 million for the previous quarter.

Asset Retirement Obligation

PrimeWest adopted the new CICA Handbook section 3110, "Asset Retirement Obligations" in the first quarter of 2004. This standard focuses on the recognition and measurement of liabilities related to legal obligations associated with the retirement of property, plant and equipment. Under this standard, these obligations are initially measured at fair value and subsequently adjusted for the accretion of discount and any changes in the underlying cash flows. The asset retirement cost is capitalized to the related asset and amortized into earnings over time.

Income and Capital Taxes

(\$ millions)	Three Months Ended			Nine Months Ended	
	Sep 30, 2004	June 30, 2004	Sep 30, 2003	Sep 30, 2004	Sep 30, 2003
Income and capital taxes	\$ 1.1	\$ 0.5	\$ 0.8	\$ 1.9	\$ 3.5
Future income taxes recovery	(22.3)	(3.4)	(8.7)	(44.0)	(71.1)
Total:	\$ (21.2)	\$ (2.9)	\$ (7.9)	\$ (42.1)	\$ (67.6)
Cash taxes paid	\$ 0.8	\$ 1.3	\$ 2.6	\$ 3.1	\$ 3.4

The Alberta Government enacted a tax rate reduction of 1% in the first quarter of 2004, reducing the rate from 12.5% to 11.5% effective April 1, 2004. This resulted in an additional tax recovery during the first quarter of approximately \$9 million. The increase in the future income tax recovery in the third quarter of 2004 versus the prior quarter and the same period in 2003 is due to the increase in the derivative liability and Long-Term Incentive Plan liability.

During 2003, the Canadian Government enacted Federal income tax changes for the oil and gas resource sector. The Federal income tax changes effectively reduced the statutory tax rates for current and future periods. Specifically, the 100% deductibility of the resource allowance will be completely phased out by the year 2007. During the same time frame, Crown charges will become 100% deductible and resource tax rates will decline from the current 27% to 21%. The reduction in statutory tax rates resulted in the large income tax recovery in the second quarter of 2003.

Cash taxes paid include tax installments for current and prior years and payments for taxes owing upon the filing of year end tax returns. Cash taxes paid in the nine months ending September 30, 2004, include \$1.3 million relating to prior years. Income and capital tax expense includes the estimate of the current year's taxes and any adjustments resulting from prior year tax assessments. The nine months ended September 30, 2004 include a recovery of \$0.4 million related to prior years.

Net Income

(\$ millions)	Three Months Ended			Nine Months Ended	
	Sep 30, 2004	June 30, 2004	Sep 30, 2003	Sep 30, 2004	Sep 30, 2003
Net income	\$ 20.2	\$ 22.4	\$ 7.0	\$ 62.8	\$ 90.1

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 loss on derivatives, future taxes and non-cash G&A.

Net income for the third quarter of 2004 was slightly lower than the second quarter of 2004 but higher than the third quarter of 2003. Third quarter 2004 net income was impacted by non-cash G&A expenses of \$14.1 million and an unrealized loss on derivatives of \$14.7 million offset by future income tax recoveries of \$22.3 million and foreign exchange gains of \$9.0 million.

Net income for the nine months ended September 30, 2004, is lower than the same period in 2003 due to higher operating expenses, an unrealized loss on derivatives, reduced future income tax recoveries, offset by higher net revenues and lower DD&A.

Liquidity & Capital Resources

Long Term Debt

(\$ millions)	As at		
	Sep 30, 2004	June 30, 2004	Sep 30, 2003
Long-term debt	\$ 461.7	\$ 179.7	\$ 247.7
Deficit / (working capital) ⁽²⁾	3.1	(10.5)	(14.3)
Net debt	\$ 464.8	\$ 169.2	\$ 233.4
Market value of Trust Units and Exchangeable Shares outstanding ⁽¹⁾⁽³⁾	1,861.5	1,321.6	1,247.3
Total capitalization	\$ 2,326.3	\$ 1,490.8	\$ 1,480.7
Net debt as a % of total capitalization	20.0%	11.3%	15.8%

(1) Based on September 30, 2004 Trust Unit closing price of \$26.70 and September 15, 2004 exchange ratio of 0.48773:1

(2) Does not include the derivative liabilities of \$26.9 million or the derivative loss of \$0.5 million included in current liabilities and current assets respectively

(3) Does not include the Convertible Unsecured Subordinated Debentures

Long-term debt is comprised of bank credit facilities and senior secured notes of \$304.0 million and \$157.7 million, respectively. PrimeWest had a borrowing base of \$625 million at September 30, 2004 as established by the lenders. The bank credit facilities consist of a revolving term loan of \$437.5 million, operating facility of \$25 million, and the balance of \$162.5 million of senior secured notes.

PrimeWest's third quarter 2004 net debt totaled \$464.8 million. The year-over-year and quarter-over-quarter increase is due to the debt incurred to acquire the Calpine assets and the 25% interest in the Calpine Natural Gas Trust.

Being in a cyclical business, it is important that PrimeWest maintain financial flexibility to ensure we can operate with the minimum of financial restrictions regardless of where commodities are in the price cycle. PrimeWest's objective is to maintain conservative debt levels. Our internal targets are to keep debt at 2 times or less than our annual cash flow and less than 25% of total capitalization. For the third quarter of 2004, PrimeWest's debt to annualized cash flow is approximately 1.7 times, and 20% of our total capitalization. In 2003, PrimeWest expanded its debt financing strategy by undertaking a U.S. private placement and thus reducing its total dependence on bank financing.

Unitholders' Equity

At the end of the third quarter 2004, the Trust had 69,077,455 Trust Units outstanding, compared to 47,821,358 Trust Units outstanding at the end of the third quarter 2003. In addition, PrimeWest had 1,315,173 (2003 – 3,968,010) Exchangeable Shares outstanding that are exchangeable into a total of 641,449 (2003 – 1,695,133) Trust Units using the September 15, 2004 exchange ratio of 0.48773:1 (2003 – 0.42720:1). On September 2, 2004, PrimeWest issued Series I and Series II Convertible Unsecured Subordinated Debentures which are convertible into 5,660,377 and 3,773,585 Trust Units respectively at a conversion price of \$26.50 per Trust Unit.

For Canadian resident unitholders, PrimeWest offers a Distribution Reinvestment Plan (DRIP). Components of it include the Optional Trust Unit Purchase Plan (OTUPP) and the Premium Distribution Plan (PREP). The DRIP gives Canadian unitholders the chance to reinvest their monthly distributions at a 5% discount to the volume weighted average market price, while the OTUPP gives Canadian unitholders an opportunity to purchase additional Trust Units directly from PrimeWest at the same 5% discount to the volume weighted average market price. The PREP allows eligible Canadian unitholders to elect to receive a premium cash distribution of up to 102% of the cash that the unitholder would otherwise have received on the

distribution date, subject to proration in certain events. The DRIP and PREP components are mutually exclusive. Participation in the OTUPP requires enrollment in either the DRIP or PREP. 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 efficient method to raise additional capital. Proceeds from these plans are used for debt reduction of PrimeWest's credit facility 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 of PrimeWest. A tax deferral is not permitted by Canadian tax law when shares are exchanged for Trust Units.

The Exchangeable Shares do not receive cash distributions. In lieu of receiving cash 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 each month.

At September 30, 2004, there were 1,315,173 Exchangeable Shares outstanding. The exchange ratio on these shares was 0.48773:1 Trust Units for each exchangeable share as at the end of the third quarter. For purposes of calculating basic per Trust Unit amounts, these Exchangeable Shares have been assumed to be exchanged into Trust Units at the current exchange ratio.

Convertible Debentures

PrimeWest issued 7.5% (Series I) and 7.75% (Series II) Convertible Unsecured Subordinated Debentures on September 2, 2004 for net proceeds of \$144.0 million and \$96.0 million respectively.

The Series I Debentures pay interest semi-annually on March 31 and September 30 and have a maturity date of September 30, 2009. The Series I Debentures are convertible at the option of the holder at a conversion price of \$26.50 per Trust Unit. PrimeWest has the option to redeem the Series I Debentures at a price of \$1,050 per Series I Debenture after September 30, 2007 and on or before September 30, 2008, and at a price of \$1,025 per Series I Debenture after September 30, 2008 and before maturity. On redemption or maturity the Trust may elect to satisfy its obligation to repay the principal by issuing PrimeWest Trust Units.

The Series II Debentures pay interest semi-annually on June 30 and December 30 and have a maturity date of December 31, 2011. The Series II Debentures are convertible at the option of the holder at conversion price of \$26.50 per Trust Unit. PrimeWest has the option to redeem the Series II Debentures at a price of \$1,050 per Series II Debenture after December 31, 2007 and on or before December 31, 2008, at a price of \$1,025 per Debenture after December 31, 2008 and on or before December 31, 2009 and after December 31, 2009 and before maturity at \$1,000 per Series II Debenture. On redemption or maturity the Trust may elect to satisfy its obligations to repay the principal by issuing PrimeWest Trust Units.

New accounting rules will be in effect for fiscal years ending on or after November 1, 2004, which will require the Debentures to be disclosed as financial liabilities rather than equity on the balance sheet.

Cash Distributions

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

In the third quarter of 2004, cash distributions totaled \$50.4 million, or \$0.83 per Trust Unit representing a payout ratio of 74%, compared to \$43.7 million, or \$0.96 per Trust Unit (84% payout ratio) for the same period in 2003. In the second quarter of 2004 cash distributions totaled \$42.0 million, or \$0.75 per Trust Unit representing a payout ratio of approximately 72% in that quarter. Cash distributions for the nine-month period of 2004 are \$2.40 per Trust Unit representing a payout ratio of approximately 72% versus the same 2003 period amounts of \$3.36 per Trust Unit representing a payout ratio of approximately 84% for the same period in 2003.

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

Contractual Obligations

PrimeWest enters into many contractual obligations as part of conducting day-to-day business. Material contractual obligations include lease rental commitments that run from 2004 through 2009 and a pipeline transportation commitment that runs to October 31, 2007. The details of the timing of these contractual obligations are included in the following table.

As at September 30, 2004	Payments due by period (\$ millions)				
	Total	Less than 1 year	1-3 years	4-5 years	More than 5 years
Long-term debt obligations	461.7	304.0	39.4	78.9	39.4
Series I and II debentures	250.0	-	-	150.0	100.0
Lease rental obligations	7.7	1.4	5.5	0.8	-
Pipeline transportation obligations	8.2	2.7	5.4	0.1	-
Derivative liabilities	29.3	26.9	2.4	-	-
Total contractual obligations	756.9	335.0	52.7	229.8	139.4

As part of PrimeWest's internalization transaction (see Note 11 in the Consolidated Financial Statements of the 2003 Annual Report), PrimeWest agreed to pay \$3.5 million in Exchangeable Shares pursuant to a Special Employee Retention Plan. One quarter of the Exchangeable Shares will be issuable to the senior managers of PrimeWest on each of the second, third, fourth and fifth anniversary of transaction closing, November 6, 2002. As at September 30, 2004, \$0.8 million has been accrued in non-cash general and administrative expenses related to the Special Employee Retention Plan.

Critical Accounting Estimates

PrimeWest's financial statements have been prepared in accordance with generally accepted accounting principles. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The following discussion reviews such accounting policies and is included in Management's Discussion and Analysis to aid the reader in assessing the critical accounting policies and practices of the Trust and the likelihood of materially different results being reported. PrimeWest's

management reviews its estimates regularly, but new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates.

The following assessment of significant accounting policies is not meant to be exhaustive. The Trust may realize different results from the application of new accounting standards proposed and/or implemented, from time to time, by various rule-making bodies.

Proved and Probable Oil and Gas Reserves

Proved oil and gas reserves, as defined by the Canadian Securities Administrators' National Instrument 51-101 (NI 51-101), are the estimated quantities of crude oil, natural gas liquids, including condensate, and natural gas that geological and engineering data demonstrate with reasonable certainty can be recovered in future years from known reservoirs under existing economic and operating conditions, (i.e., prices and costs as of the date the estimate is made).

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable (i.e. it is likely that the actual remaining quantities recovered will exceed the estimated proved reserves). In accordance with this definition, the level of certainty targeted by the reporting company should result in at least a 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves.

For probable reserves, which are by definition less certain to be recovered than proved reserves, NI 51-101 states that it must be equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. With respect to the consideration of certainty, in order to report reserves as proved plus probable, the level of certainty targeted by the reporting company should result in at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

The oil and gas reserve estimates are made using all available geological and reservoir data as well as historical production data. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in PrimeWest's plans. The effect of changes in proved oil and gas reserves on the financial results and position of PrimeWest is described under the heading "Full Cost Accounting for Oil and Gas Activities".

Full Cost Accounting For Oil and Gas Activities

PrimeWest adopted CICA Accounting Guideline 16 (AcG-16), "Oil and Gas Accounting – Full Costs" on January 1, 2004. The new guideline modifies how the ceiling test is performed and requires cost centers be tested for recoverability using undiscounted future cash flows from proved reserves which are determined by using forward indexed prices. When the carrying amount of a cost center is not recoverable, the cost center would be written down to its fair value. Fair value is estimated using accepted present value techniques which incorporate risks and other uncertainties when determining expected cash flows.

Depletion Expense

PrimeWest uses the full cost method of accounting for exploration and development activities. In accordance with this method of accounting, all costs associated with exploration and development are capitalized whether successful or not. The aggregate of net capitalized costs and estimated future development costs less estimated salvage values is amortized using the unit of production method based on estimated proved oil and gas reserves. An increase in estimated proved oil and gas reserves would result in a corresponding reduction in depletion expense. A decrease in estimated future development costs would result in a corresponding reduction in depletion expense.

Fair Value of Derivative Instruments

As part of its financial management strategy, PrimeWest utilizes financial derivatives to manage market risk. The purpose of the hedge is to provide an element of stability to PrimeWest's cash flow in a volatile commodity price environment. Effective January 1, 2004, PrimeWest adopted CICA Accounting Guideline 13, "Hedging Relationships" ("AcG-13").

The estimation of the fair value of certain hedging derivatives requires considerable judgment. The estimation of the fair value of commodity price hedges requires sophisticated financial models that incorporate forward price and volatility data and, which when compared with PrimeWest's outstanding hedging contracts, produce cash inflow or outflow variances over the contract period. The estimate of fair value for interest rate and foreign currency hedges is determined primarily through quotes from financial institutions.

Asset Retirement Obligations

Effective January 1, 2004, PrimeWest changed its accounting policy with respect to accounting for asset retirement obligations. CICA section 3110 requires the fair value of asset retirement obligations to be recorded when they are incurred rather than merely accumulated or accrued over the useful life of the respective asset.

PrimeWest, under the current policy, is required to provide for future removal and site restoration costs. PrimeWest must estimate these costs in accordance with existing laws, contracts or other policies. These estimated costs are charged to earnings and the appropriate liability account over the expected service life of the asset. When the future removal and site restoration costs cannot be reasonably determined, a contingent liability may exist. Contingent liabilities are charged to earnings when management is able to determine the amount and the likelihood of the future obligation.

Legal, Environmental Remediation and Other Contingent Matters

The Trust is required to both determine whether a loss is probable based on judgment and interpretation of laws and regulations and whether that loss can reasonably be estimated. When the loss is determined, it is charged to earnings. PrimeWest's management must continually monitor known and potential contingent matters and make appropriate provisions through charges to earnings when warranted by circumstance.

Income Tax Accounting

The determination of the Trust's income and other tax liabilities requires interpretation of complex laws and regulations. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

Business Combinations

Since inception, PrimeWest has grown considerably through combining with other businesses. PrimeWest acquired Seventh Energy Ltd. in the first quarter of 2004 and the assets of Calpine Canada in the third quarter of 2004. These transactions were accounted for using what is now the only accounting method available, the purchase method. Under the purchase method, the acquiring company includes the fair value of the assets of the acquired entity on its balance sheet. The determination of fair value necessarily involves many assumptions. The valuation of oil and gas properties primarily involves placing a value on the oil and gas reserves. The valuation of oil and gas reserves entails the process described above under the caption "Proved and Probable Oil and Gas Reserves" but also incorporates the use of economic forecasts that estimate future changes in prices and costs. This methodology is also used to value unproved oil and gas reserves. The valuation of these reserves, by their nature, is less certain than the valuation of proved reserves.

Goodwill

The process of accounting for the purchase of a company, described above, results in recognizing the fair value of the acquired company's assets on the balance sheet of the acquiring company. Any excess of the purchase price over fair value is recorded as goodwill. Since goodwill results from the culmination of a process that is inherently imprecise, the determination of goodwill is also imprecise. In accordance with the recent issuance of CICA section 3062, "Goodwill and Other Intangible Assets", goodwill is no longer amortized but assessed periodically for impairment. The process of assessing goodwill for impairment necessarily requires PrimeWest to determine the fair value of its assets and liabilities. Such a process involves considerable judgment.

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.

Commodity Price, Foreign Exchange And Interest Rate Risk

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 of 2004, PrimeWest lost \$8.8 million from commodity hedges, but has added \$17.2 million to revenue from its hedging program from January 1, 2001 to the end of the third quarter of 2004.

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. In 2003, approximately 25% of natural gas production was sold to aggregators and 75% into the Alberta short-term or export long-term markets and we do not anticipate any material change to this breakdown in 2004.

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

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:

Production

Risk associated with the production of oil and gas – includes well operations, processing and the physical delivery of commodities to market.

We mitigate by:

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

We mitigate by:

Hedging. See page 11 of this press release.

Transportation

Market risk related to the availability of transportation to market and potential disruption in delivery systems.

We mitigate by:

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.

We mitigate by:

Diversifying our capital spending program over a large number of projects so that significant capital is not risked on any one activity. We also have a highly skilled technical team of geologists, geophysicists and engineers working to apply the latest technology in planning and executing capital programs. Capital is spent only after strict economic criteria for production and reserve additions are assessed.

Acquisitions

Acquisition risk associated with acquiring producing properties at low cost to renew our inventory of assets.

We mitigate by:

Continually scanning the marketplace for opportunities to acquire assets. Our technical acquisition specialists evaluate potential corporate or property acquisitions and identify areas for value enhancement through operational efficiencies or capital investment. All prospects are subjected to rigorous economic review against established acquisition and economic

hurdle rates. In some cases we may also hedge commodity prices to protect the acquisition economics in the near term period.

Reserves

Reserve risk in respect of the quantity and quality of recoverable reserves.

We mitigate by:

Contracting our reserves evaluation to a reputable third party consultant, Gilbert Laustsen Jung (GLJ). The work and independence of GLJ is reviewed by the Operations and Reserves Committee of the Board of Directors of PrimeWest. 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.

We mitigate by:

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, which acts as PrimeWest's Environmental, Health and Safety Committee.

Regulation, Tax and Royalties

Changes in government regulations including reporting requirements, income tax laws, operating practices, environmental protection requirements and royalty rates.

We mitigate by:

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.

Additional Information

Additional information pertaining to PrimeWest, including the Trust's most recently filed Annual Report and Annual Information Form, is available on SEDAR at www.sedar.com and on the PrimeWest website at www.primewestenergy.com. PrimeWest welcomes questions from unitholders and potential investors; call Investor Relations at 403-234-6600 or toll-free in Canada and the U.S. at 1-877-968-7878; or visit us at our website, www.primewestenergy.com. 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 of dollars)	<i>(Unaudited)</i> Sep 30, 2004	<i>(Audited)</i> Dec 31, 2003 <i>(Restated – Note 2)</i>
ASSETS		
Current assets		
Cash and short term deposits	\$ -	\$ 2.5
Accounts receivable	75.2	65.4
Derivative loss (Note 5)	0.5	-
Prepaid expenses	8.9	6.5
Inventory	6.6	2.1
	91.2	76.5
Cash reserved for site restoration and reclamation	10.4	8.2
Other assets and deferred charges (Note 4)	73.3	1.5
Property, plant and equipment	2,019.4	1,548.2
Goodwill	68.5	56.1
	\$ 2,262.8	\$ 1,690.5
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities		
Bank overdraft	\$ 1.5	\$ -
Accounts payable	21.1	26.7
Accrued liabilities	54.3	45.3
Derivative liabilities (Note 5)	26.9	-
Accrued distributions to unitholders	16.9	10.3
	120.7	82.3
Derivative liabilities (Note 5)	2.4	-
Long-term debt (Note 7)	461.7	250.1
Future income taxes	204.8	313.2
Asset retirement obligation (Note 6)	46.7	19.7
	836.3	665.3
UNITHOLDERS' EQUITY		
Net capital contributions (Note 8)	2,029.8	1,565.9
Convertible unsecured subordinated debentures (Note 8)	240.0	-
Capital issued but not distributed	3.8	5.2
Long-term incentive plan equity	18.9	14.6
Accumulated income	48.6	219.1
Accumulated cash distributions	(905.1)	(771.6)
Accumulated debenture interest	(1.5)	-
Accumulated dividends	(8.0)	(8.0)
	1,426.5	1,025.2
	\$ 2,262.8	\$ 1,690.5

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

Consolidated Statements of Unitholders' Equity (Unaudited)

For the nine months ended (millions of dollars)	Sep 30, 2004	Sep 30, 2003 <i>(Restated – Note 2)</i>
Unitholders' equity, beginning of period	\$ 1,019.6	\$ 847.2
Adjustment to Unitholders' equity at beginning of period to adopt:		
New Asset Retirement Obligation (Note 2)	5.6	-
New Oil and Gas Accounting Standard (Note 2)	(233.3)	-
Net income for the period	62.8	90.1
Net capital contributions	463.9	253.1
Convertible unsecured subordinated debentures	240.0	-
Capital issued but not distributed	(1.4)	-
Long-term incentive plan equity	4.3	1.8
Cash distributions	(133.5)	(146.3)
Debenture interest expense	(1.5)	-
Unitholders' equity, end of period	\$ 1,426.5	\$ 1,045.9

Consolidated Statements of Cash Flow (Unaudited)

(millions of dollars)	Three Months Ended		Nine Months Ended	
	Sep 30, 2004	Sep 30, 2003	Sep 30, 2004	Sep 30, 2003
OPERATING ACTIVITIES		<i>(Restated – Note 2)</i>		<i>(Restated – Note 2)</i>
Net income for the period	\$ 20.2	\$ 7.0	\$ 62.8	\$ 90.1
Add/(deduct):				
Items not involving cash from operations				
Depletion, depreciation and amortization	50.2	50.7	133.4	153.3
Non-cash general & administrative	14.1	2.3	7.2	5.9
Non-cash foreign exchange loss (gain)	(9.1)	0.2	(4.4)	(5.4)
Accretion on asset retirement obligation	0.5	0.3	1.2	0.9
Future income taxes recovery	(22.3)	(8.7)	(44.0)	(71.1)
Unrealized loss on derivatives	14.7	-	28.8	-
Cash flow from operations	68.3	51.8	185.0	173.7
Expenditures on site restoration and reclamation	(1.1)	(0.4)	(2.4)	(0.8)
Change in non-cash working capital	(3.7)	5.4	(10.5)	0.1
	63.5	56.8	172.1	173.0
FINANCING ACTIVITIES				
Proceeds from issue of Trust Units, net of issue costs	290.4	80.1	433.3	240.3
Proceeds from issue of Debentures, net of issue costs	240.0	-	240.0	-
Net cash distributions to unitholders	(41.9)	(40.8)	(107.0)	(137.3)
Increase/(decrease) in bank credit facilities	291.0	(51.0)	206.0	(146.0)
Increase in senior secured notes	-	-	-	174.0
Increase in deferred charges	-	0.1	-	(1.3)
Change in non-cash working capital	8.3	(2.5)	9.8	0.5
	787.8	(14.1)	782.1	130.2
INVESTING ACTIVITIES				
Expenditures on property, plant & equipment	(26.0)	(31.4)	(79.6)	(75.6)
Corporate acquisitions (Note 3)	-	(0.5)	(34.8)	(200.9)
Acquisition of capital assets	(767.0)	(0.2)	(771.2)	(4.0)
Proceeds on disposal of property, plant & equipment	6.3	0.6	11.3	0.8
Equity investment	(72.7)	-	(72.7)	-
Increase in cash reserved for future site restoration and reclamation	(0.6)	(3.7)	(2.2)	(6.4)
Change in non-cash working capital	(5.3)	5.2	(9.0)	7.9
	(865.3)	(30.0)	(958.2)	(278.2)
(Decrease)/increase in cash for the period	(14.0)	12.7	(4.0)	25.0
Cash (bank overdraft) beginning of the period	12.5	9.2	2.5	(3.1)
(Bank overdraft)/cash end of the period	\$ (1.5)	\$ 21.9	\$ (1.5)	\$ 21.9
Cash interest paid	\$ 1.2	\$ 1.2	\$ 6.6	\$ 6.3
Cash taxes paid	\$ 0.8	\$ 2.6	\$ 3.1	\$ 3.4

Consolidated Statements of Income (Unaudited)

(millions of dollars, except per Trust Unit amounts)	Three Months Ended		Nine Months Ended	
	Sep 30, 2004	Sep 30, 2003	Sep 30, 2004	Sep 30, 2003
		<i>(Restated – Note 2)</i>		<i>(Restated – Note 2)</i>
REVENUES				
Sales of crude oil, natural gas and natural gas liquids	\$ 127.4	\$ 102.3	\$ 350.2	\$ 343.7
Transportation expenses	(2.0)	(2.1)	(5.7)	(6.3)
Crown and other royalties, net of ARTC	(28.9)	(23.1)	(78.0)	(80.8)
Other income	0.7	0.1	1.3	0.3
	97.2	77.2	267.8	256.9
EXPENSES				
Operating	21.4	17.2	60.6	58.2
Cash general and administrative	3.4	3.5	11.1	10.5
Non-cash general and administrative	14.1	2.3	7.2	5.9
Interest	2.9	4.0	8.9	11.0
Accretion on asset retirement obligation	0.5	0.3	1.2	0.9
Unrealized loss on derivatives	14.7	-	28.8	-
Foreign exchange loss (gain)	(9.0)	0.1	(4.1)	(5.4)
Depletion, depreciation and amortization	50.2	50.7	133.4	153.3
	\$ 98.2	\$ 78.1	\$ 247.1	\$ 234.4
Income before taxes for the period	\$ (1.0)	\$ (0.9)	\$ 20.7	\$ 22.5
Income and capital taxes	1.1	0.8	1.9	3.5
Future income taxes recovery	(22.3)	(8.7)	(44.0)	(71.1)
	(21.2)	(7.9)	(42.1)	(67.6)
Net income for the period	\$ 20.2	\$ 7.0	\$ 62.8	\$ 90.1
Net income per Trust Unit - basic	\$ 0.31	\$ 0.15	\$ 1.10	\$ 2.01
Net income per Trust Unit - diluted	\$ 0.31	\$ 0.15	\$ 1.10	\$ 2.00

Notes to Consolidated Financial Statements

For the nine months ended September 30, 2004 (millions of dollars except per Trust Unit/share amounts) all amounts are expressed in millions of Canadian dollars unless otherwise indicated.

1. Significant Accounting Policies

These interim consolidated financial statements of PrimeWest Energy Trust 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 69 through 91 of the Trust's 2003 annual report and should be read in conjunction with these interim financial statements.

2. Changes in Accounting Policies**Full Cost Accounting**

The adoption of AcG-16 modifies how the ceiling test is performed resulting in a two stage process. The first stage requires the carrying amount of the cost centers to be tested for recoverability using undiscounted future cash flows from proved reserves using management's best estimate of forward indexed prices. When the carrying amount of a cost center is not

recoverable, the second stage of the process will determine the impairment whereby the cost center would be written down to its fair value. The second stage requires the calculation of discounted future cash flows from proved plus probable reserves. The fair value is estimated using accepted present value techniques, which incorporate risks and other uncertainties when determining expected cash flows.

PrimeWest has performed the ceiling test under AcG-16 as of January 1, 2004. The impairment test was calculated using the consultant's average prices at January 1 for the years 2004 to 2008 as follows:

Consultant's Average Price Forecasts	Year				
	2004	2005	2006	2007	2008
WTI (\$U.S./bbl)	29.21	26.43	25.42	25.38	25.51
AECO (\$Cdn/Mcf)	5.90	5.33	4.98	4.95	4.92

The ceiling test resulted in a before tax impairment of \$308.9 million and an after tax impairment of \$233.2 million. This write down was recorded to accumulated income in the first quarter of 2004 with the adoption of AcG-16.

Asset Retirement Obligation

Effective January 1, 2004, the Trust retroactively adopted the CICA Handbook section 3110, "Asset Retirement Obligations". The new standard requires the recognition of the liability associated with the future site reclamation costs of tangible long-lived assets. This liability would be comprised of the Trust's net ownership interest in producing wells and processing plant facilities. The liability for future retirement obligations is to be recorded in the financial statements at the time the liability is incurred.

The asset retirement obligation is initially recorded at the estimated fair value as a long-term liability with a corresponding increase to property, plant and equipment. The depreciation of property, plant and equipment is allocated to expense on the unit-of-production basis. The liability is increased each reporting period for the fair value of any new future site reclamation costs and the corresponding accretion on the original provision. The accretion is charged to earnings in the period incurred. The provision will also be revised for any changes to timing related to cash flows or undiscounted reclamation costs. Actual expenditures incurred for the purpose of site reclamation are charged to the asset retirement obligation to the extent that the liability exists on the balance sheet. Differences between the actual costs incurred and the fair value of the liability recorded are recognized to earnings in the period incurred.

The Trust previously estimated the costs of dismantlement, removal, abandonment and site reclamation on a unit-of-production basis over the remaining life of the estimated proved reserves. This estimate was charged to earnings with a corresponding offset to the accumulated site provision liability on the balance sheet. The adoption of CICA Handbook section 3110 allows for the cumulative effect of the change in accounting policy to be recorded to accumulated income with retroactive restatement of prior period comparatives. At January 1, 2004, this resulted in an increase to the asset retirement obligation of \$19.7 million (2003 - \$15.3 million), an increase to PP&E of \$10.6 million (2003 - \$9.0 million), a \$5.6 million (2003 - \$0.04 million) increase to accumulated income, a decrease of site restoration provision of \$17.8 million (2003 - \$6.2 million) and an increase to the future tax liability of \$3.1 million (2003 - \$(0.03) million). See Note 6 for the reconciliation of the asset retirement obligation.

Implementation of this accounting standard did not affect the Trust's cash flow or liquidity.

Financial Derivatives

Effective January 1, 2004, the Trust has implemented CICA Accounting Guideline (AcG-13), "Hedging Relationships", which is effective for fiscal years beginning on or after July 1, 2003. AcG-13 addresses the identification, designation,

documentation and effectiveness of hedging transactions for the purposes of applying hedge accounting. It also established conditions for applying or discontinuing hedge accounting. Under the new guideline, hedging transactions must be documented and it must be demonstrated that the hedges are sufficiently effective in order to continue accrual accounting for position hedges with derivatives. The trust is not applying hedge accounting to its hedging relationships.

As of January 1, 2004, the Trust recorded \$6.0 million for the mark-to-market value of the outstanding hedges as a derivative liability and a \$6.0 million deferred derivative loss, to be realized upon settlement of the corresponding derivative instrument. The deferred loss at January 1, 2004 was comprised of a \$3.9 million loss for crude oil, \$2.1 million loss for natural gas, \$0.6 million loss for interest rate swaps and a gain of \$0.6 million for electrical power. See Note 5 for the reconciliation of the derivative liability and deferred derivative loss.

3. Asset and Corporate Acquisitions

a) On September 2, 2004, PrimeWest Gas Corp. acquired oil and gas assets from Calpine Canada. The acquisition was accounted for using the purchase method of accounting with the net assets acquired and consideration paid as follows:

Net Assets Acquired at Assigned Values	(\$ millions)	Consideration Paid	(\$ millions)
Petroleum and natural gas assets	\$ 762.3		
Inventory	4.2	Cash	\$ 747.0
Working capital	2.9	Net closing adjustments	(10.3)
Asset Retirement Obligation	(27.4)	Costs associated with acquisition	5.3
	\$ 742.0		\$ 742.0

b) On March 16, 2004, PrimeWest Gas Corp. completed the acquisition of Seventh Energy Ltd. Subsequent to the acquisition, Seventh Energy was amalgamated with PrimeWest Gas Corp. The acquisition was accounted for using the purchase method of accounting with net assets acquired and consideration paid as follows:

Net Assets Acquired at Assigned Values	(\$ millions)	Consideration Paid	(\$ millions)
Petroleum and natural gas assets	\$ 46.5		
Goodwill	12.4		
Working capital	(2.5)		
Long-term debt assumed	(9.9)		
Office lease obligation	(0.1)		
Asset retirement obligation	(0.5)	Cash	\$ 34.6
Future income taxes	(11.1)	Costs associated with acquisition	0.2
	\$ 34.8		\$ 34.8

4. Other Assets and Deferred Charges

(\$ millions)	Sep 30, 2004	Dec 31, 2003
Equity investments	\$ 72.1	\$ 0.2
Deferred charges	1.2	1.3
	\$ 73.3	\$ 1.5

On September 2, 2004, PrimeWest Energy Trust acquired 25% of Calpine Natural Gas Trust. The investment is being recorded using the equity method of accounting.

Consideration Paid	(\$ millions)
Cash	\$ 78.0
Net closing adjustments	(5.3)
	\$ 72.7

Investment in Calpine Natural Gas Trust	(\$ millions)
Consideration paid, September 2, 2004	\$ 72.7
Equity income	-
Cash distributions	(1.0)
Investment in Calpine Natural Gas Trust, September 30, 2004	\$ 71.7

5. Derivative Liabilities

Derivative Liability	(\$ millions)
Derivative Liability, January 1, 2004	\$ 6.0
Derivative instruments settled	(19.4)
Mark-to-market unrealized loss	42.7
Derivative Liability, September 30, 2004	\$ 29.3

Current Derivative Liability	\$ 26.9
Long term Derivative Liability	2.4
Derivative Liability, September 30, 2004	\$ 29.3

Derivative Loss	(\$ millions)
Derivative Loss, January 1, 2004	\$ 6.0
Derivative instruments settled that existed on January 1, 2004 or prior	(5.5)
Derivative Loss, September 30, 2004	\$ 0.5

6. Asset Retirement Obligations

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

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

Asset Retirement Obligation	(\$ millions)
Asset Retirement Obligation, December 31, 2003	\$ 19.7
Liabilities incurred	0.3
Liabilities settled	(2.4)
Accretion expense	1.2
Acquisition of capital assets	27.4
Acquisition of Seventh Energy	0.5
Asset Retirement Obligation, September 30, 2004	\$ 46.7

As at September 30, 2004, the undiscounted amount of estimated cash flows required to settle the obligation is \$124.6 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 costs are expected to 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.

7. Long-Term Debt

(\$ millions)	Sep 30, 2004	Dec 31, 2003
Bank credit facilities	\$ 304.0	\$ 88.0
Senior secured notes	157.7	162.1
	\$ 461.7	\$ 250.1

8. Unitholders' Equity

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

Trust Units	Number of Units	(\$ millions)
Balance, December 31, 2003	48,751,883	\$ 1,537.9
Issued pursuant to equity offering	17,700,000	419.5
Issued on exchange of Exchangeable Shares	775,603	15.9
Issued pursuant to Distribution Reinvestment Plan	203,282	4.8
Issued pursuant to the Premium Distribution Plan	961,921	23.2
Issued pursuant to Long-Term Incentive Plan	97,103	2.6
Issued pursuant to Optional Trust Unit Purchase Plan	587,663	13.8
Balance, September 30, 2004	69,077,455	\$ 2,017.7

The weighted average number of Trust Units and Exchangeable Shares outstanding for the three and nine months ended September 30, 2004 were 61,006,757 (2003 – 46,422,055) and 55,590,651 (2003 – 44,767,269) respectively. For purposes of calculating diluted net income per Trust Unit for the three months ended September 30, 2004, 2,973,749 Trust units issuable pursuant to the conversion of the Convertible Unsecured Subordinated Debentures Series I and II and 467,393 Trust Units (2003 – 386,804) issuable pursuant to the Long-Term Incentive Plan were added to the weighted average number.

For the purpose of calculating diluted net income per Trust unit for the nine months ended September 30, 2004, 998,485 Trust Units issuable pursuant to the conversion of the Convertible Unsecured Subordinated Debentures Series I and II and 467,393 Trust Units (2003 – 386,804) issuable pursuant to the Long-Term Incentive Plan were added to the weighted average number.

The per unit cash distribution amounts paid or declared reflects distributions paid or declared to Trust Units outstanding on the record dates.

PrimeWest Exchangeable Class A Shares

The Exchangeable Shares are exchangeable into PrimeWest 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 September 15, 2004 was 0.48773:1 and December 31, 2003 was 0.44302:1.

Exchangeable Shares	# of shares	(\$ millions)
Balance, December 31, 2003	3,041,124	\$ 28.0
Exchanged for Trust Units	(1,725,951)	(15.9)
Balance, September 30, 2004	1,315,173	\$ 12.1

7.5% Convertible Unsecured Subordinated Debentures (Series I)

On September 2, 2004, PrimeWest issued \$150 million of Series I Convertible Unsecured Subordinated Debentures for net proceeds of \$144 million. The Debentures bear interest at an annual rate of 7.5% payable semi-annually on March 31 and September 30 commencing March 31, 2005. The Debentures are convertible at any time at the option of the holder into PrimeWest Trust Units at a conversion price of \$26.50 per Trust Unit prior to maturity on September 30, 2009.

The Debentures may be redeemed in whole or in part at the option of the Trust at a price of \$1,050 per Debenture after September 30, 2007 and on or before September 30, 2008 and at a price of \$1,025 per Debenture after September 30, 2008 and before maturity. On redemption or maturity the Trust may opt to satisfy its obligation to repay the principal by issuing PrimeWest Trust Units.

7.5% Convertible Unsecured Subordinated Debentures (Series I)	(\$ millions)
Balance, December 31, 2003	\$ -
Issue of Series I Debentures (net of issue costs of \$6 million)	144.0
Balance, September 30, 2004	\$ 144.0

7.75% Convertible Unsecured Subordinated Debenture (Series II)

On September 2, 2004, PrimeWest issued \$100 million of Series II Convertible Unsecured Subordinated Debentures for net proceeds of \$96 million. The Debentures bear interest at 7.75% payable semi-annually at June 30 and December 31 commencing December 31, 2004. The Debentures are convertible at any time at the option of the debenture holder into PrimeWest Trust units at a conversion price of \$26.50 per Trust unit prior to maturity on December 31, 2011.

The Debentures may be redeemed in whole or in part at the option of the Trust at a price of \$1,050 per Debenture after December 31, 2007 and on or before December 31, 2008, at a price of \$1,025 per Debenture after December 31, 2008 and on or before December 31, 2009 and at a price of \$1,000 per Debenture after December 31, 2009 and before maturity. On redemption or maturity the Trust may opt to satisfy its obligation to repay the principal by issuing PrimeWest Trust Units.

7.75% Convertible Unsecured Subordinated Debentures (Series II)	(\$ millions)
Balance, December 31, 2003	\$ -
Issue of Series II Debentures (net of issue costs of \$4 million)	96.0
Balance, September 30, 2004	\$ 96.0

9. 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 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 the members of the Board, whose UARs 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 Sep 30, 2004

Year of Grant	UARs issued & outstanding	UARs vested	Current return per UARs	Total equity	Trust Unit dilution
1999 grants	38,111	38,111	\$ 37.64	\$ 1.4	53,731
2000 grants	110,985	110,985	18.12	2.0	75,300
2001 grants	335,332	296,083	9.22	3.1	97,190
2002 grants	839,876	585,151	7.98	6.7	143,058
2003 grants	975,828	388,187	5.80	4.2	82,826
2004 grants	1,371,235	163,912	\$ 2.40	1.5	15,288
Total grants	3,671,367	1,582,429		\$ 18.9	467,393

10. Cash Distributions

(millions of dollars, except per Trust Unit amounts)	Three Months Ended		Nine Months Ended	
	Sep 30, 2004	Sep 30, 2003	Sep 30, 2004	Sep 30, 2003
		(Restated – Note 2)		(Restated – Note 2)
Net income for the period				
Add back (deduct) amounts to reconcile to distribution:	\$ 20.2	\$ 7.0	\$ 62.8	\$ 90.1
Depletion, depreciation and amortization	50.2	50.7	133.4	153.3
Cash retained from cash available for distribution	(16.2)	(4.0)	(46.9)	(20.2)
Contribution to reclamation fund	(1.7)	(4.1)	(4.6)	(7.2)
Non-cash general and administrative	14.1	2.3	7.2	5.9
Unrealized loss on derivatives	14.7	-	28.8	-
Non-cash foreign exchange loss (gain)	(9.1)	0.2	(4.4)	(5.4)
Accretion on asset retirement obligation	0.5	0.3	1.2	0.9
Future income taxes recovery	(22.3)	(8.7)	(44.0)	(71.1)
	\$ 50.4	\$ 43.7	\$ 133.5	\$ 146.3
Cash Distributions to Trust Unitholders	\$ 50.4	\$ 43.7	\$ 133.5	\$ 146.3
Cash Distributions per Trust Unit	\$ 0.83	\$ 0.96	\$ 2.40	\$ 3.36

Trading Performance

For the quarter ended	Sep 30/04	Jun 30/04	Mar 31/04	Dec 31/03	Sep 30/03
TSX Trust Unit prices (\$ per Trust Unit)					
High	26.70	26.80	28.35	28.15	26.80
Low	23.29	22.18	22.70	23.40	25.19
Close	26.70	23.25	26.65	27.56	25.19
Average daily traded volume	259,219	187,767	256,922	202,661	149,148

For the quarter ended	Sep 30/04	Jun 30/04	Mar 31/04	Dec 31/03	Sep 30/03
NYSE Trust Unit prices (\$U.S. per Trust Unit)					
High	21.16	20.44	22.14	21.48	19.29
Low	17.65	16.00	17.31	18.67	18.08
Close	21.16	17.43	20.31	21.27	18.68
Average daily traded volume	329,862	279,882	469,694	243,921	151,813

Number of Trust Units outstanding including					
Exchangeable Shares (millions of units)	69.7	56.8	50.87	50.10	49.52
Distribution paid per Trust Unit	\$0.83	\$0.75	\$0.82	\$0.96	\$0.96

For Investor Relations inquiries, please contact:

George Kesteven
 Manager, Investor Relations
 403-699-7367

Diane Zuber
 Investor Relations Advisor
 403-699-7356

Toll-free: 1-877-968-7878
 E-mail: investor@primewestenergy.com