



PRIMEWEST

## PRIMEWEST ENERGY TRUST 2005 REPORT TO UNITHOLDERS

For the fourth quarter and twelve months ended December 31, 2005

### PRIMEWEST ENERGY TRUST ANNOUNCES FOURTH QUARTER AND FULL YEAR 2005 RESULTS

CALGARY, FEBRUARY 23, 2006 (TSX: PWI.UN; PWI.DB.A; PWI.DB.B; PWX; NYSE: PWI) – PRIMEWEST ENERGY TRUST (PRIMEWEST OR THE TRUST) TODAY ANNOUNCES INTERIM OPERATING AND FINANCIAL RESULTS FOR THE FOURTH QUARTER AND YEAR ENDED DECEMBER 31, 2005. UNLESS OTHERWISE NOTED, ALL FIGURES CONTAINED IN THIS REPORT ARE IN CANADIAN DOLLARS.

#### Fourth Quarter 2005 Highlights:

- Distributions in the fourth quarter were \$0.96 per Trust Unit representing a payout ratio of approximately 57% of operating cash flow compared to third quarter 2005 distributions of \$0.90 per Trust Unit, representing a payout ratio of 66% of operating cash flow. The full year payout ratio in 2005 was 67% compared to 74% in 2004. The 2005 lower payout ratio reflects the increase in cash flow due to increased commodity prices and retention of cash to fund development capital opportunities as well as reducing outstanding bank debt.
- Fourth quarter cash flow from operations was \$132.5 million (\$1.66 per Trust Unit) compared to \$106.4 million (\$1.36 per Trust Unit) in the third quarter 2005.
- Fourth quarter 2005 production averaged 40,269 barrels of oil equivalent per day (BOE/day), compared to the third quarter 2005 rate of 40,121 BOE/day. The increase is due to incremental volumes from capital development activity offset by decreases due to operational issues and natural decline.
- Development capital expenditures in the fourth quarter were \$41.2 million with drilling and completion expenditures of \$25.6 million resulting in 43 gross wells (15.8 net) being drilled with a success rate of 100%. PrimeWest has identified a portfolio of capital opportunities of approximately \$800 million to be developed over the next several years.
- In the fourth quarter of 2005, PrimeWest changed the method of accounting for its unit-based compensation. PrimeWest has applied the fair value method retroactively to Unit Appreciation Rights (UARs) issued on or after January 1, 2002. Prior periods have been restated. (Refer to note 3 in the Notes to Consolidated Financial Statements).
- Net debt to annual 2005 cash flow was approximately 0.8 times compared to net debt to annualized third quarter 2005 cash flow of 0.9 times at September 30, 2005. PrimeWest has approximately \$334 million available on its existing credit facilities at December 31, 2005.

#### Subsequent Event:

- On February 10, 2006, PrimeWest announced the appointment of Mr. Brian Lynam, P.Eng. to the position of Vice President, Operations. In this newly created position, Mr. Lynam will have responsibility for field operations, drilling and facilities. The addition of Mr. Lynam to PrimeWest's executive team reflects the increased portfolio of development opportunities being executed by the Trust, the increased focus on field operations and the preparation of the organization for future growth.

## Forward-Looking Information

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

Certain statements contained in this MD&A, and any documents incorporated by reference into this MD&A, constitute forward-looking statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "project", "should", "believe", "outlook" and similar expressions are intended to identify forward-looking statements. In addition, statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in our forward-looking statements.

We believe the expectations reflected in those forward-looking statements are reasonable. However, we cannot assure you that these expectations will prove to be correct. You should not unduly rely on forward-looking statements included in, or incorporated by reference into this MD&A. These statements speak only as of the date of this MD&A or as of the date specified in any documents incorporated by reference into this MD&A, as the case may be.

In particular, this MD&A, and any documents incorporated by reference, contain 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, operations and strategy of the commodity price risk management program;
- the approximate and maximum amount of forward sales and hedging to be employed;
- our 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 us relative to other oil and natural 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
- our ability to benefit from the combination of growth opportunities and the ability to grow through the capital markets.

With respect to forward-looking statements contained in this MD&A, including any documents incorporated herein by reference, we have made assumptions regarding, among other things:

- future oil and natural gas prices and differentials between light, medium and heavy oil prices;
- the cost of expanding our property holdings;
- our ability to obtain equipment in a timely manner to carry out development activities;
- our ability to market our oil and natural gas successfully to current and new customers;
- the impact of increasing competition;
- our ability to obtain financing on acceptable terms; and
- our ability to add production and reserves through our development and exploitation activities.

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 incorporated by reference into this MD&A:

- volatility in market prices for oil and natural gas;
- the impact of weather conditions on seasonal demand;
- risks inherent in our oil and natural 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 and natural gas;
- royalties payable in respect of our oil and natural gas production;
- government regulation of the oil and natural 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;
- OPEC's ability to control production and balance global supply and demand of crude oil at desired price levels;
- political uncertainty, including the risks of hostilities, in the petroleum producing regions of the world;
- the need to obtain required approvals from regulatory authorities; and
- the other factors discussed under "Risk Factors" contained this MD&A.

These factors should not be construed as exhaustive. The forward-looking statements contained in this MD&A and any documents incorporated by reference herein are expressly qualified by this cautionary statement. We undertake no obligation to publicly update or revise any forward-looking statements.

PrimeWest does not endorse any of the analyst or consultant sourced material contained herein.

All figures reported in Canadian dollars unless otherwise stated.

Production figures stated are Company Interest before the deduction of royalties.

## Evaluation of Disclosure Controls and Procedures

The Chief Executive Officer, Don Garner, and the Chief Financial Officer, Dennis Feuchuk, evaluated the effectiveness of PrimeWest's disclosure controls and procedures as of December 31, 2005, and concluded that PrimeWest's disclosure controls and procedures were effective to ensure that information PrimeWest is required to disclose:

- in its annual filings, interim filings or other reports (each as defined in National Instrument 52-109 of the Canadian Securities Administrators) filed or submitted by it under provincial securities legislation is recorded, processed, summarized and reported within the time periods specified in the provincial securities legislation and to ensure that information required to be disclosed by PrimeWest in its annual filings, interim filings or other reports filed or submitted under provincial securities legislation is accumulated and communicated to PrimeWest's management, including its chief executive officer and chief financial officer, as appropriate to allow timely decisions regarding required disclosure; and
- in its annual filings, interim filings or other reports with the United States Securities and Exchange Commission (SEC) in the United States (US) under the Securities Exchange Act of 1934 (Exchange Act) is recorded, processed, summarized and reported, within the time periods specified in the Commission'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.

The evaluation took into consideration PrimeWest's Communications and Disclosure Policy and the functioning of its executive officers, board of directors and board committees. In addition, the evaluation covered PrimeWest's processes, systems and capabilities relating to regulatory filings, public disclosures and the identification and communication of material information.

## Changes to Internal Controls Over Financial Reporting

There were no changes to PrimeWest's internal control over financial reporting since September 30, 2005 that have materially affected, or are reasonably likely to materially affect PrimeWest's internal control over financial reporting.

## Non-GAAP Measures

This MD&A contains the following measurements that are not defined by Canadian Generally Accepted Accounting Principles (GAAP):

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

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

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

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

Net debt per Trust Unit is calculated as long-term debt, including Debentures, less working capital, excluding financial derivative assets and liabilities and current future income tax assets divided by the number of Trust Units outstanding and Trust Units issuable upon the exchange of outstanding Exchangeable Shares and Trust Units issuable pursuant to the LTIP at December 31, 2005.

## Business Strategy

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

Maximizing total return to Unitholders, in the form of cash distributions and appreciation 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 2005 and our goals for 2006 and beyond.

We believe that PrimeWest can maximize total return to Unitholders by continuing to develop 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 principles to protect the interests of all stakeholders.

## Asset Management and Growth

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

## Financial Management

PrimeWest strives to maintain a prudent debt position, to allow us to fund smaller acquisitions and to fund ongoing development activities without tapping the capital markets. Our long-term debt is comprised of bank credit facilities through a bank syndicate, US-dollar-denominated Senior Secured Notes (Secured Notes) and the Debentures. Our diversified debt instruments help to reduce our reliance on the bank syndicate. PrimeWest's commodity hedging approach is intended to help to stabilize cash flow, reduce volatility, and when applicable protect near-term acquisition economics.

Since August 2003, PrimeWest has followed a strategy of maintaining a distribution payout ratio within 70-90% of cash flow, calculated on an annual basis. The strength in commodity prices has increased the Trust's cash flow from operations available for distribution to Unitholders. The Board of Directors of PrimeWest will continue to consider a variety of factors in establishing the monthly distribution level. These factors include, but are not limited to: commodity price outlook, cash flow forecast, capital development plans, debt levels, tax considerations and competitive industry distribution practices.

The 2005 payout ratio was approximately 67% of annual operating cash flow. The retained cash flow was utilized to fund the Trust's capital spending program and repay debt. PrimeWest's net debt to cash flow ratio was 0.8 times at December 31, 2005 using 2005 annual cash flows.

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

For eligible Canadian and US Unitholders, PrimeWest offers participation in the conventional Distribution Reinvestment Plan (DRIP), which represents a convenient way to maximize an investment in PrimeWest. Canadian residents may also participate in the Optional Trust Unit Purchase Plan (OTUPP) and the Premium Distribution Plan (PREP). For alternate investment requirements, PrimeWest also has Exchangeable Shares and Debentures available, which permit participation in PrimeWest without the ongoing tax implications associated with receiving a distribution.

## Corporate Governance

PrimeWest remains committed to high 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](http://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.

## MANAGEMENT'S DISCUSSION AND ANALYSIS AS OF FEBRUARY 23, 2006

The following is management's discussion and analysis (MD&A) of PrimeWest's operating and financial results for the fourth quarter and twelve months ended December 31, 2005, compared with the preceding quarter and the corresponding period in the prior year as well as information and opinions concerning the Trust's future outlook based on currently available information.

### FOURTH QUARTER 2005 RESULTS:

\$ millions, except per BOE <sup>(1)</sup> and per Trust Unit amounts	Three Months Ended		
	Dec 31, 2005	Sep 30, 2005	Dec 31, 2004
Gross revenue (net of transportation expense)	230.6	193.3	169.3
per BOE	62.97	52.38	41.46
Cash flow from operations	132.5	106.4	83.3
per BOE	35.76	28.83	20.41
per Trust Unit – basic <sup>(2)</sup>	1.66	1.36	1.17
Royalty expense	55.9	44.4	41.8
per BOE	15.08	12.04	10.24
Operating expense	32.9	31.6	28.3
per BOE	8.88	8.56	6.94
Cash general and administrative expense	6.9	5.7	7.9
per BOE	1.88	1.54	1.93
Non-cash general and administrative expense <sup>(3)</sup>	1.2	1.5	1.4
per BOE	0.33	0.41	0.34
Interest expense <sup>(4)</sup>	5.5	6.0	11.7
per BOE	1.48	1.61	2.86
Distributions to Unitholders	76.2	70.1	62.6
per Trust Unit <sup>(5)</sup>	0.96	0.90	0.90
Net debt <sup>(6)</sup>	323.7	381.8	552.0
per Trust Unit <sup>(7)</sup>	3.97	4.75	7.77

<sup>(1)</sup> 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.

<sup>(2)</sup> The basic per Trust Unit calculation includes the weighted average Trust Units and Trust Units issuable upon exchange of the Exchangeable Shares of PrimeWest Energy Inc. (Exchangeable Shares).

<sup>(3)</sup> Non-cash general and administrative expenses have been restated to reflect the change in method of accounting for the unit-based compensation. (see note 3 in the Notes to Consolidated Financial Statements).

<sup>(4)</sup> Interest expense includes the interest on the Debentures.

<sup>(5)</sup> Based on Trust Units outstanding at date of distribution.

<sup>(6)</sup> Net debt is long-term debt including Debentures less working capital, excluding financial derivative assets and liabilities and future income tax assets.

<sup>(7)</sup> The net debt per Trust Unit calculation includes outstanding Trust Units, Trust Units issuable upon exchange of the outstanding Exchangeable Shares and Trust Units issuable pursuant to the LTIP at the end of the period.

## Operating Highlights

	Three Months Ended		
	Dec 31, 2005	Sep 30, 2005	Dec 31, 2004
Daily production volumes			
Natural gas (mmcf/day)	176.8	176.8	187.2
Crude oil (bbls/day)	6,752	7,037	9,108
Natural gas liquids (bbls/day)	4,046	3,616	4,059
Total (BOE/day)	40,269	40,121	44,368

## Cash Flow Reconciliation

(\$ millions)	
Third quarter 2005 cash flow from operations	\$ 106.4
Volumes	0.6
Commodity prices	49.1
Net hedging change from prior quarter	(9.8)
Operating expenses	(1.3)
Royalties	(11.5)
General and administrative expenses	(1.2)
Other	0.2
Fourth quarter 2005 cash flow from operations	\$ 132.5

The above table includes non-GAAP measurements. (Refer to discussion on Non-GAAP Measures on Page 4)

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

## Capital Expenditures

(\$ millions)	Three Months Ended		
	Dec 31, 2005	Sep 30, 2005	Dec 31, 2004
Land and lease acquisitions	\$ 1.9	\$ 2.7	\$ 1.8
Geological and geophysical	0.9	0.3	2.4
Drilling and completions	25.6	22.0	30.1
Investment in facilities			
Equipping and tie-in	6.2	6.4	4.3
Compression and processing	0.4	0.3	0.9
Gas gathering	1.2	2.0	1.9
Production facilities	4.2	2.2	5.0
Capitalized G&A	0.8	0.7	0.4
Development capital	41.2	36.6	46.8
Corporate/property acquisitions	0.5	2.6	1.4
Dispositions	(16.9)	(1.5)	(88.1)
Leasehold improvements, furniture and equipment	0.8	0.8	3.2
Net capital expenditures	\$ 25.6	\$ 38.5	(36.7)

During the fourth quarter of 2005, PrimeWest's development capital expenditures totaled \$41.2 million, compared to \$46.8 million invested in the fourth quarter of 2004 and \$36.6 million in the previous quarter of 2005. Of the \$41.2 million total, \$31.8 million or 77% was invested in drilling, completions and tie-ins, which contribute to new reserve additions and help offset natural production decline.

Dispositions in the fourth quarter of 2005 of \$16.9 million consisted mainly of proprietary seismic data.

PrimeWest drilled 43 gross wells (15.8 net wells) in the fourth quarter of 2005 with a success rate of 100%.

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

### Daily Production Volumes

	Three Months Ended		
	Dec 31, 2005	Sep 30, 2005	Dec 31, 2004
Natural gas (mmcf/day)	176.8	176.8	187.2
Crude oil (bbls/day)	6,752	7,037	9,108
Natural gas liquids (bbls/day)	4,046	3,616	4,059
Total (BOE/day)	40,269	40,121	44,368

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

PrimeWest's production volumes averaged 40,269 BOE/day in the fourth quarter of 2005 compared to 40,121 BOE/day in the third quarter. The marginal increase is due to incremental volumes added through capital development activity in 2005 and to the lifting of the Maximum Rate Limitation (MRL) by the Alberta Energy and Utilities Board in September. Operational issues at Crossfield and Valhalla, and natural decline partially offset the incremental volumes.

At the end of the fourth quarter of 2005, approximately 2,200 BOE/day of production volumes remained behind pipe, awaiting tie-in.

### Operating Costs

Operating costs for the fourth quarter of 2005 were \$8.88/BOE, above the full year 2005 average of \$7.94/BOE. The run-up in power and fuel costs through the quarter along with prior period adjustments attributed to operations at the Valhalla plant were the significant items contributing to the higher operating costs.

Going forward into 2006, PrimeWest has budgeted power costs of \$85/mWhr. As part of our ongoing program to manage costs, a number of cost reduction initiatives are planned for 2006, including the shutdown of the Valhalla plant and consolidation of facilities at Thorsby and Grand Forks.

### Average Realized Sales Prices

	Three Months Ended		
	Dec 31, 2005	Sep 30, 2005	Dec 31, 2004
Natural gas (\$/Mcf) <sup>(1)(2)</sup>	10.98	8.41	7.00
Without hedging	11.99	8.66	6.98
Crude oil (\$/bbl) <sup>(1)</sup>	51.89	56.19	36.45
Without hedging	59.78	67.48	46.03
Natural gas liquids (\$/bbl)	59.07	59.83	47.32
Total <sup>(1)</sup> (\$/BOE)	62.87	52.30	41.37
Without hedging	68.59	55.38	43.24
Realized hedging loss included in prices above (\$/BOE)	5.72	3.08	1.87

<sup>(1)</sup> Includes realized hedging losses.

<sup>(2)</sup> Excludes sulphur.

Commodity prices were higher in the fourth quarter of 2005 when compared to the previous quarter and the fourth quarter of 2004, resulting in higher average realized selling prices per BOE.

PrimeWest's cash flow from operations is directly impacted by commodity prices, but the use of hedging can increase or decrease the prices realized by the Trust. In the fourth quarter 2005, PrimeWest incurred a realized hedging loss of \$21.2 million compared to a loss of \$11.4 million in the third quarter.

### Benchmark Commodity Prices

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

	Past Four Quarters (Actual)				Next Four Quarters (Forward Markets) <sup>(1)</sup>			
	Q1 2005	Q2 2005	Q3 2005	Q4 2005	Q1 2006	Q2 2006	Q3 2006	Q4 2006
Natural gas								
AECO (Cdn\$/mcf)	6.69	7.38	8.17	11.69	8.88	7.42	7.66	8.69
Crude oil WTI (US\$/bbl)	49.85	53.17	63.19	60.02	63.02	63.32	64.70	65.49

(1) As at February 17, 2006

## FINANCIAL AND OPERATING RESULTS - TWELVE MONTHS ENDED DECEMBER 31, 2005

### Full Year 2005 Highlights:

- Production in 2005 averaged 40,351 BOE/day, up 13% from the 2004 level of 35,578 BOE/day as a result of the Calpine acquisition in the third quarter of 2004 and development capital volume additions, partially offset by minor asset divestments transacted in December 2004 and natural production declines.
- Operating margin of \$31.54/BOE for 2005, up 25% from 2004 primarily due to higher commodity prices throughout the year, offset by the impact of the commodity hedging program as well as higher operating costs and royalties in 2005.
- Distributions of \$3.66 per Trust Unit in 2005 compared to \$3.30 per Trust Unit in 2004. The distribution level was increased in December 2005 by 20% from \$0.30 per Trust Unit per month to \$0.36 per Trust Unit per month, based on commodity price levels in effect at the time, coupled with PrimeWest's prudent risk management strategy. PrimeWest's payout ratio for 2005 was approximately 67% compared to the 2004 payout ratio of 74%.
- Capital development program of \$185.6 million added 14.7 mmBOE of Proved plus Probable reserves (including technical revisions) on a Company Interest basis at \$12.63/BOE, which excludes \$4.06/BOE for future development capital. The capital development program replaced 100% of the 2005 production on a Proved plus Probable basis by reinvesting approximately 45% of cash flow from operations.
- PrimeWest's Reserve Life Index (RLI) at year end 2005 is 11.0 years on a Company Interest Proved plus Probable basis. (Refer to the "Disclosure of Oil and Natural Gas Reserves" section later in this MD&A for reserve definitions).
- Operating expenses were 32% higher in 2005 than in 2004, reflecting higher production volumes and higher industry wide cost structure. On a unit of production basis, operating expenses were 16% higher than in 2004 at \$7.94/BOE versus \$6.83/BOE.
- Cash G&A increased \$3.9 million over 2004 reflecting increases in labour costs, information technology expenses, office rent and property taxes associated with additional staffing and office space requirements resulting from the 2004 Calpine asset acquisition.
- Interest expense during 2005 was 37% higher than in 2004 due to a higher average net debt balance and higher interest rates during the year resulting from the issuance of the Debentures in the third quarter of 2004 to acquire the Calpine assets.
- The Distribution Reinvestment, Premium Distribution and Optional Trust Unit Purchase Plans contributed \$55.7 million of equity capital to be reinvested in the capital development program and to repay debt.

### Outlook – 2006

PrimeWest expects 2006 production volumes to average approximately 38,000–39,000 BOE/day. Full-year operating costs are expected to be approximately \$8.00/BOE. PrimeWest expects to invest approximately \$275 million in its 2006 capital development program, with the focus primarily in the core areas of Caroline, Columbia, Wilson Creek, Crossfield and Brant Farrow.

## FULL YEAR 2005 RESULTS:

Financial				
(\$ millions, except Per BOE <sup>(1)</sup> and Per Trust Unit)	2005	2004	Change (%)	
Gross revenue (net of transportation expense)	\$ 749.7	\$ 513.7	46	
Per BOE	50.90	39.45	29	
Cash flow from operations	414.1	266.8	55	
Per BOE	28.11	20.49	37	
Per Trust Unit - basic <sup>(2)</sup>	5.46	4.49	22	
Per Trust Unit - diluted <sup>(3)</sup>	5.16	4.33	19	
Royalty expense	172.8	119.8	44	
Per BOE	11.73	9.20	28	
Operating expense	117.0	88.9	32	
Per BOE	7.94	6.83	16	
Cash general and administrative expense	22.9	19.0	21	
Per BOE	1.56	1.46	7	
Non-cash general and administrative expense <sup>(4)</sup>	5.4	4.1	32	
Per BOE	0.37	0.32	16	
Interest expense <sup>(5)</sup>	28.3	20.6	37	
Per BOE	1.92	1.58	22	
Net income	207.5	105.4	97	
Per Trust Unit - basic <sup>(2)</sup>	2.73	1.77	54	
Per Trust Unit - diluted <sup>(3)</sup>	2.66	1.77	50	
Distributions to Unitholders	276.6	196.1	41	
Per Trust Unit <sup>(6)</sup>	3.66	3.30	11	
Net debt <sup>(7)</sup>	323.7	552.0	(41)	
Per Trust Unit <sup>(8)</sup>	3.97	7.77	(48)	

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

**Daily Production Volumes**

	2005	2004	Change (%)
Natural gas (mmcf/day)	178.2	145.1	23
Crude oil (bbls/day)	6,861	8,282	(17)
Natural gas liquids (bbls/day)	3,797	3,107	22
Total (BOE/day)	40,351	35,578	13

**Realized Commodity Prices**

	2005	2004	Change (%)
Natural gas (\$/mcf) <sup>(1)(2)</sup>	8.43	6.61	28
Without hedging	8.75	6.70	31
Crude oil (\$/bbl) <sup>(1)</sup>	49.05	36.83	33
Without hedging	58.48	44.46	32
Natural gas liquids (\$/bbl)	55.92	43.69	28
Total (\$/BOE) <sup>(1)</sup>	50.81	39.35	29
Without hedging	53.82	41.51	30

(1) Includes realized hedging losses.

(2) Excludes sulphur

**Cash Flow Reconciliation**

(\$ millions)	
2004 cash flow from operations	\$ 266.8
Production volumes	67.3
Commodity prices	184.8
Net hedging change from prior year	(16.1)
Operating expense	(28.1)
Royalties	(53.0)
Interest expense	(7.7)
Other	0.1
2005 cash flow from operations	\$ 414.1

The above table includes non-GAAP measurements (refer to discussion on Non-GAAP measures on Page 4)

The 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 expense, interest expense, G&A expense, hedging gains or losses, royalties and currency exchange rates. Some of these factors such as commodity prices, the currency exchange rate and royalties are uncontrollable by PrimeWest. Factors that are, to a certain extent, controllable by PrimeWest are production levels and operating expense, as well as interest and G&A expense.

**Capital Spending**

(\$ millions)	2005	2004
Land and lease acquisitions	\$ 17.6	\$ 8.3
Geological and geophysical	7.6	8.2
Drilling and completions	106.5	69.8
Equipping and tie-in	26.5	12.1
Compression and processing	9.1	4.7
Gas gathering	3.9	4.4
Production facilities	11.5	15.8
Capitalized G&A expense	2.9	1.8
Development capital	\$ 185.6	\$ 125.1
Corporate/property acquisitions	2.7	807.4
Dispositions	(20.6)	(99.5)
Head office equipment	4.2	4.6
<b>Total</b>	<b>\$ 171.9</b>	<b>\$ 837.6</b>

Capital expenditures, including development, acquisitions and divestments totaled approximately \$171.9 million in 2005, versus \$837.6 million in 2004. PrimeWest's property acquisitions in 2004 included the Calpine oil and natural gas assets.

PrimeWest's 2005 capital development program totaled \$185.6 million (2004 - \$125.1 million). PrimeWest drilled 132 gross (62.8 net) wells with a success rate of 98.5%. The capital program focused on the core areas of Caroline, Columbia, Wilson Creek, Valhalla and Brant Farrow. The development program added 10.7 mmBOE of Company Interest Proved reserves and 14.7 mmBOE of Company Interest Proved plus Probable reserves, including technical revisions.

	2005	2004
<b>Development Program</b>		
Proved reserve additions (mmBOE) <sup>(1)</sup>	10.7	7.7
Average cost (\$/BOE) <sup>(2)(3)</sup>	\$ 22.25	\$ 16.59
Proved plus Probable reserve additions (mmBOE) <sup>(1)</sup>	14.7	9.1
Average cost (\$/BOE) <sup>(2)(3)</sup>	\$ 16.85	\$ 16.91
<b>Acquisition Program:</b> <sup>(4)</sup>		
Proved reserve additions (mmBOE)	(0.5)	42.4
Average cost (\$/BOE) <sup>(1)(4)</sup>	\$ (35.8)	\$ 16.57
Proved plus Probable reserve additions (mmBOE)	(0.6)	53.2
Average cost (\$/BOE) <sup>(1)(4)</sup>	\$ (29.83)	\$ 13.20

(1) Proved and Proved plus Probable reserve additions in 2004 exclude the impact of economic factors.

(2) Under National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities the implied methodology to be used to calculate finding development and acquisition (FD&A) costs includes the change during the current year in estimated future development costs (FDC). The average cost per BOE from Company Interest Proved reserves additions includes the change in the current year FDC of \$4.91/BOE (\$0.35/BOE for 2004) and the average cost per BOE from Company Interest Proved plus Probable reserve additions including the change in the current year FDC of \$4.22/BOE (\$3.17/BOE for 2004).

(3) The aggregate of the costs incurred under the capital development program in 2005 and the estimated FDC generally will not reflect total finding and development costs related to reserve additions for that year.

(4) Net of dispositions.

Investment in drilling, completions and tie-in represented 72% of development capital that contributed to new reserve additions in 2005. Investment in facilities totaled \$24.5 million, representing 13% of development capital, on projects related to debottlenecking, increasing capacity or other activities that contribute to future production volumes.

In 2006, PrimeWest plans to invest approximately \$275 million in its capital development programs.



Given that production volumes will decline naturally over time as oil or natural gas reservoirs are depleted, PrimeWest is continually striving to offset this natural decline, and add to reserves in an effort to sustain cash flows. Investment in activities such as development drilling, workovers and recompletions can add incremental production volumes and reserves.

Capital is allocated on the basis of anticipated rate of return on projects undertaken. At PrimeWest, every capital project is measured against economic evaluation criteria prior to approval. These criteria 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 Canada Sedimentary Basin. Within this focused area, we have a diversified suite of assets producing from multiple geological zones and stretching from northeast B.C. across much of Alberta. 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 major properties.

## Reserves and Production

### Company Interest Reserves – Forecast Prices and Costs

The following table sets forth a reconciliation of light, medium and heavy crude oil, natural gas, natural gas liquids and total BOE of the Company Interest reserves of PrimeWest for the year ended December 31, 2005. The table is derived from the January 23, 2006 report of the independent reserve evaluators, GLJ Petroleum Consultants Ltd. (GLJ), using forecast price and cost estimates, and reconciled to December 31, 2004 (the GLJ Report). PrimeWest's Company Interest reserves include working interest and royalty reserves receivable. This definition is consistent with the basis on which reserves were reported in prior years. See further discussion of reserves definitions and National Instrument 51-101 (NI 51-101) under "Disclosure of Oil and Gas Reserves – Standards of Disclosure for Oil and Gas Activities" below.

Forecast prices are based on the consultants' average price projections from GLJ Petroleum Consultants Ltd., Sproule Associates Limited and McDaniel & Associates Consultants Ltd., all of which are effective January 1, 2006.

	Light, Medium and Heavy Crude Oil (mbbls)				Natural Gas (Bcf)			
	Proved Producing	Total Proved	Probable	Proved Plus Probable	Proved Producing	Total Proved	Probable	Proved Plus Probable
Dec. 31, 2004	19,052	19,765	4,138	23,903	450.2	529.2	148.7	677.9
Capital Additions <sup>(1)</sup>	303	399	620	1,019	17.9	23.9	19.8	43.7
Improved Recovery <sup>(2)</sup>	474	501	189	690	10.6	23.7	2.0	25.7
Technical Revisions	806	760	(149)	611	10.1	1.3	(3.5)	(2.2)
Acquisitions	0	0	0	0	0.2	0.2	0	0.2
Dispositions	(57)	(57)	(15)	(72)	(2.6)	(2.6)	(0.4)	(3.0)
Economic Factors	0	0	0	0	0	0	0	0
Production	(2,504)	(2,504)	0	(2,504)	(65.0)	(65.0)	0	(65.0)
Dec. 31, 2005	18,073	18,864	4,783	23,646	421.4	510.7	166.6	677.3

Columns may not add due to rounding

	Natural Gas Liquids (mbbls)				Barrel of Oil Equivalent (mmBOE)			
	Proved Producing	Total Proved	Probable	Proved Plus Probable	Proved Producing	Total Proved	Probable	Proved Plus Probable
Dec. 31, 2004	11,739	13,988	4,282	18,270	105.8	121.9	33.3	155.2
Capital additions <sup>(1)</sup>	462	675	564	1,239	3.7	5.1	4.4	9.5
Improved Recovery <sup>(2)</sup>	327	741	59	801	2.6	5.2	0.6	5.8
Technical Revisions	(243)	(549)	(267)	(816)	2.2	0.4	(1.0)	(0.6)
Acquisitions	0	0	0	0	0	0	0	0
Dispositions	(36)	(36)	(4)	(40)	(0.5)	(0.5)	(0.1)	(0.6)
Economic Factors	0	0	0	0	0	0	0	0
Production	(1,386)	(1,386)	0	(1,386)	(14.7)	(14.7)	0	(14.7)
Dec. 31, 2005	10,864	13,434	4,634	18,068	99.2	117.4	37.2	154.6

Columns may not add due to rounding

(1) Capital additions include exploration discoveries and drilling extensions.

(2) Improved recovery includes infill drilling and improved recovery.

### Net Reserves – Forecast Prices and Costs

The following table sets forth a reconciliation of PrimeWest's Net Reserves for the year ended December 31, 2005 derived from the GLJ Report using forecast price and cost estimates. These year end reserves are reconciled to December 31, 2004 reserves. PrimeWest's Net Reserves include working interest reserves plus royalties receivable less royalties payable, as stipulated by NI 51-101. All data in the following tables was provided by GLJ.

	Light and Medium Crude Oil (mbbls)				Heavy Oil (mbbls)			
	Proved Producing	Total Proved	Probable	Proved Plus Probable	Proved Producing	Total Proved	Probable	Proved Plus Probable
Dec. 31, 2004	14,767	15,296	3,098	18,394	2,541	2,623	503	3,126
Capital Additions <sup>(1)</sup>	178	251	321	572	85	85	178	263
Improved Recovery <sup>(2)</sup>	369	389	146	535	41	49	18	68
Technical Revisions	268	261	(26)	235	104	92	(103)	(11)
Discoveries	0	0	0	0	0	0	0	0
Acquisitions	0	0	0	0	0	0	0	0
Dispositions	(48)	(48)	(12)	(60)	0	0	0	0
Economic Factors	137	133	17	150	149	151	34	185
Production	(1,573)	(1,573)	0	(1,573)	(564)	(564)	0	(564)
Dec. 31, 2005	14,098	14,709	3,544	18,253	2,355	2,436	630	3,066

Columns may not add due to rounding



	Associated and Non-Associated Gas (Bcf)				Natural Gas Liquids (mbbls)			
	Proved Producing	Total Proved	Probable	Proved Plus Probable	Proved Producing	Proved	Probable	Proved Plus Probable
Dec. 31, 2004	358.2	420.4	117.6	538.0	8,308	9,911	3,008	12,919
Capital Additions <sup>(1)</sup>	14.0	17.9	14.6	32.6	306	416	374	790
Improved Recovery <sup>(2)</sup>	8.2	18.5	1.4	19.9	219	528	36	563
Technical Revisions	5.8	(0.2)	(2.4)	(2.7)	(152)	(381)	(196)	(577)
Discoveries	0.1	0.9	0.3	1.2	0	45	18	63
Acquisitions	0.1	0.1	0.0	0.2	0	0	0	0
Dispositions	(1.9)	(1.9)	(0.3)	(2.2)	(24)	(24)	(3)	(27)
Economic Factors	1.3	1.1	0.4	1.5	(12)	(22)	(3)	(25)
Production	(49.5)	(49.5)	0	(49.5)	(977)	(977)	0	(977)
Dec. 31, 2005	336.4	407.2	131.7	539.0	7,668	9,495	3,234	12,729

Columns may not add due to rounding

	Natural Gas from Coal (mmcf)				Total (mmBOE)			
	Proved Producing	Total Proved	Probable	Proved Plus Probable	Proved Producing	Proved	Probable	Proved Plus Probable
Dec. 31, 2004	0	0	0	0	85.3	97.9	26.2	124.1
Capital Additions <sup>(1)</sup>	0	226	395	621	2.9	3.8	3.4	7.2
Improved Recovery <sup>(2)</sup>	177	386	113	499	2.0	4.1	0.5	4.6
Technical Revisions	37	38	11	48	1.2	(0.1)	(0.7)	(0.8)
Discoveries	0	0	0	0	0.0	0.2	0.1	0.3
Acquisitions	0	0	0	0	0.0	0.0	0.0	0.0
Dispositions	0	0	0	0	(0.4)	(0.4)	(0.1)	(0.5)
Economic Factors	0	0	0	0	0.5	0.4	0.1	0.6
Production	(44)	(44)	0	(44)	(11.4)	(11.4)	0.0	(11.4)
Dec. 31, 2005	171	606	518	1,124	80.2	94.6	29.5	124.1

Columns may not add due to rounding

Notes:

<sup>(1)</sup> Capital additions include exploration discoveries and drilling extensions.

<sup>(2)</sup> Improved recovery includes infill drilling and improved recovery.

**Reserves and Future Net Revenues**

The following tables provide reserves data and a breakdown of reserves on a Company Interest, Gross and Net basis and the net present value of future net revenues using consultant's average pricing.

Reserves Category	Reserves					
	Light And Medium Crude Oil (mdbl)			Heavy Oil (mdbl)		
	Company Interest	Gross	Net	Company Interest	Gross	Net
Proved						
Developed Producing	15,512	13,959	14,098	2,561	2,550	2,355
Developed Non-Producing	351	351	304	90	90	81
Undeveloped	350	331	307	0	0	0
Total Proved	16,212	14,641	14,709	2,652	2,640	2,436
Probable	4,085	3,777	3,545	697	696	630
Total Proved Plus Probable	20,297	18,417	18,253	3,349	3,335	3,066

Columns may not add due to rounding

Reserves Category	Reserves					
	Natural Gas (Bcf)			Natural Gas Liquids (mbls)		
	Company Interest	Gross	Net	Company Interest	Gross	Net
Proved						
Developed Producing	421.4	411.8	336.6	10,864	10,635	7,668
Developed Non-Producing	36.9	36.8	29.4	1,128	1,125	820
Undeveloped	52.5	52.5	41.9	1,442	1,442	1,008
Total Proved	510.7	501.1	407.8	13,434	13,203	9,495
Probable	166.6	164.5	132.3	4,634	4,583	3,233
Total Proved Plus Probable	677.3	665.6	540.1	18,068	17,786	12,729

Columns may not add due to rounding

Reserves Category	Total (mBOE)		
	Company Interest	Gross	Net
Proved			
Developed Producing	99,162	95,778	80,214
Developed Non-Producing	7,724	7,697	6,106
Undeveloped	10,535	10,517	8,292
Total Proved	117,422	113,993	94,612
Probable	37,181	36,474	29,450
Total Proved Plus Probable	154,603	150,466	124,062

Columns may not add due to rounding

Reserves Category	Net Present Values of Future Net Revenue (\$ millions)									
	Before Future Income Tax Expenses Discounted at (%)					After Future Income Tax Expenses Discounted at (%)				
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
Proved										
Developed Producing	3,241.2	2,387.1	1,935.7	1,656.2	1,464.1	3,241.2	2,387.1	1,935.7	1,656.2	1,464.1
Developed Non-Producing	265.0	178.6	140.3	118.2	103.5	265.0	178.6	140.3	118.2	103.5
Undeveloped	277.7	179.8	128.9	97.9	76.9	277.7	179.8	128.9	97.9	76.9
Total Proved	3,783.8	2,745.5	2,204.9	1,872.3	1,644.6	3,783.8	2,745.5	2,204.9	1,872.3	1,644.7
Probable	1,259.7	701.0	479.0	365.0	295.7	1,259.7	701.0	479.0	365.0	295.7
Total Proved Plus Probable	5,043.6	3,446.6	2,684.0	2,237.2	1,940.4	5,043.6	3,446.6	2,684.0	2,237.2	1,940.4

Columns may not add due to rounding

### Daily Production Volumes

	2005	2004	Change (%)
Natural gas (mmcf/day)	178.2	145.1	23
Crude oil (bbls/day)	6,861	8,282	(17)
Natural gas liquids (bbls/day)	3,797	3,107	22
Total (BOE/day)	40,351	35,578	13
Gross overriding royalty volumes included above (BOE/day)	1,338	1,440	(7)

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

The 13% increase in daily average production year-over-year is due in part to the acquisition of the Calpine assets in the third quarter of 2004, combined with production additions from 2005 development activity, offset partially by the natural decline of production. Based on 2005 production statistics, natural production decline is estimated at approximately 17%. During 2005, approximately 2,900 BOE/day of annualized incremental production was brought on-stream from development activities to help offset natural decline. Approximately 2,200 BOE/day of new production remained "behind pipe" or awaiting tie-in to production facilities, at the end of 2005.

PrimeWest expects production for full year 2006 to be 38,000 – 39,000 BOE/day. This estimate incorporates PrimeWest's expected natural decline rate, production volume shut-ins due to scheduled plant turnarounds at Crossfield, Caroline and Edson (estimated to affect approximately 600 BOE/day on a full-year average basis), the reinstatement effective January 1, 2006 of the Maximum Rate Limitation (MRL) on the Cecil wells and others, all offset by production additions from the 2006 capital development program.

### Commodity Prices

Average Benchmark Prices	2005	2004	Change (%)
Natural Gas			
NYMEX (US\$/mcf)	\$ 8.55	\$ 6.09	40
AECO (Cdn\$/mcf)	\$ 8.48	\$ 6.79	25
Crude oil - W.T.I. (US\$/bbl)	\$ 56.56	\$ 41.40	37

Average Realized Sales Prices <sup>(1)</sup> (Cdn\$)	2005	2004	Change (%)
Natural gas (\$/mcf) <sup>(2)</sup>	\$ 8.43	\$ 6.61	28
Crude oil (\$/bbl)	\$ 49.05	\$ 36.83	33
Natural gas liquids (\$/bbl)	\$ 55.92	\$ 43.69	28
Total (\$/BOE) <sup>(2)</sup>	\$ 50.81	\$ 39.35	29
Realized hedging loss include in prices above (\$/BOE)	\$ (3.01)	\$ (2.16)	(39)

(1) Includes hedging losses.

(2) Excludes sulphur.

The selling price that PrimeWest realized from its 2005 production, net of hedging impact, was 29% higher than in 2004. The commodity hedging program resulted in a reduction of PrimeWest's 2005 average realized price by \$3.01/BOE, compared to a reduction of \$2.16/BOE in 2004. This hedging impact reflects the amount of additional revenue foregone by PrimeWest as a result of its hedging program, through which the price of a portion of its production was capped at certain price levels in exchange for downward price protection. PrimeWest utilizes financial hedges as part of its financial strategy to reduce the impact of commodity price volatility and to improve the predictability of cash flow from operations.

The Canadian and US currency exchange rate is another factor that has an impact on the price PrimeWest realizes from its production. Since Canadian prices of oil and natural gas are influenced by benchmark prices that are set in US dollars, a stronger Canadian dollar will translate into lower realized prices and revenues when expressed in Canadian dollars. During 2005, the Canadian dollar exchange rate increased by approximately 3% versus the US dollar, from US\$0.831 at December 31, 2004 to US\$0.858 at December 31, 2005. The stronger Canadian dollar during 2005 negatively impacted PrimeWest's Canadian realized prices and revenue receipts.

### Crude Oil Prices

Continued growth in global oil demand combined with supply concerns resulted in strong crude oil prices in 2005. On the demand side, robust economic growth in Asia, notably in China and India, together with a strong consumer economy in the US have increased worldwide oil consumption. Supply disruptions occurred in various parts of the world, due to political uncertainty and natural disasters, such as hurricanes Katrina and Rita, which shut down a large volume of production in the Gulf of Mexico. Within OPEC, the excess production capacity that once existed among most members was reduced by the increased demand. In 2005 Saudi Arabia, Kuwait and the United Arab Emirates were the only OPEC member countries with meaningful spare capacity that could be used to offset supply disruptions. As a result, oil prices fluctuated throughout 2005 in response to world events and weather conditions. During 2005, oil went from US\$43.45/bbl at the beginning of the year to a historical high of US\$69.81/bbl on August 30, 2005, before dropping to US\$61.04/bbl by year end.

The forward price of crude oil as at December 31, 2005 indicated a rising trend over the next 12 months to approximately US\$64.00/bbl by 2006 year end. Key factors that are expected to influence prices in 2006 include: potential slow down in worldwide demand growth, particularly in China and India, as a response to higher prices; attempts by OPEC to influence prices by adjusting production quotas; the ability of Iraq to restore more of its oil export capability and the rate and magnitude of production growth from OPEC and non-OPEC producers.

The netbacks for Canadian companies and energy trusts that produce a heavier grade of crude oil were negatively affected by a wide price differential versus lighter, sweet crude in 2005. As the majority of crude production coming into the markets worldwide was of heavier and more sour quality, the discount versus lighter oil remained at a high level throughout 2005, as heavy-oil refining capacity was reaching full utilization. In addition, the realized price for heavy oil producers was negatively affected by an increase in the price of condensate, a natural gas by-product that is widely used as a diluent to blend heavier crude oil for pipeline transport.

Approximately 32% of PrimeWest's crude oil production is made up of medium to slightly heavy grades. These products do not require any diluent blending and attract a better pricing differential than heavier crude oil production.



## Natural Gas Prices

PrimeWest's realized natural gas prices in 2005 increased 28% to \$8.43/mcf from a 2004 average of \$6.61/mcf. At the beginning of 2005, the outlook for natural gas prices was markedly bearish due to mild winter weather and a decline in heating demand. The natural gas storage level at the end of the 2005 winter season was higher than at the end of the 2004 winter season, which had also experienced a warmer than normal winter. Over the ensuing summer, this year-on-year storage overhang was gradually worked off by the increased natural gas demands in response to hotter temperatures. The impact of Hurricanes Katrina and Rita turned a surplus storage position into deficit, causing a run-up of natural gas prices to approximately US\$15.00/mmbtu by early December. Prices began to soften in the latter part of December due to unseasonably warm weather. At 2005 year end, North American natural gas storage levels were approaching the five-year average. Forward natural gas prices as of December 31, 2005 reflected a bullish trend, but have softened with the warm weather in early 2006.

Key factors expected to influence prices in 2006 include: the speed of the restoration of shut-in Gulf of Mexico production; North American weather patterns during the upcoming summer and winter seasons; the ability of producers in Canada and the US to replace and add to production levels through increased drilling; the continued growth of natural gas demand in the electricity sector; and the impact of government regulations and conservation efforts in response to higher natural gas prices.

## Sales Revenue

Revenue (\$ millions) <sup>(1)</sup>	2005	% of Total	2004	% of Total	Change (%)
Natural gas <sup>(2)</sup>	\$ 548.0	73	\$ 351.0	69	56
Crude oil	122.8	16	111.7	22	10
Natural gas liquids	77.5	11	49.7	9	56
Total	748.3		512.4		
Hedging loss included above	\$ (44.3)		\$ (28.2)		

(1) Net of transportation expense

(2) Excludes sulphur

PrimeWest's revenues from the sale of commodities for 2005 were \$748.3 million compared to \$512.4 million in the previous year, including the effect of hedging. Higher commodity prices along with increases in natural gas sales volumes were the major contributors to the increased revenue in 2005.

If the pricing environment softens in 2006, and the Canadian dollar remains strong, oil and natural gas revenues will be negatively impacted. Since approximately 73% of PrimeWest's revenues are derived from natural gas, the Trust has greater sensitivity to changes in natural gas prices than crude oil prices.

## 2005 Hedging Results

As part of our financial management strategy, PrimeWest uses a consistent commodity hedging approach. The purposes of the hedging program are to reduce volatility in cash flows, to protect acquisition economics against the unpredictable commodity price environment and to protect our capital structure when commodity prices cycle downwards, while at the same time retaining exposure to pricing upside. PrimeWest's hedging policy reflects a willingness to forfeit a portion of the pricing upside in return for protection against a significant downturn in prices.

	Crude Oil (\$/bbl)		Natural Gas (\$/mcf) <sup>(1)</sup>		BOE (\$/BOE) <sup>(1)</sup>	
	2005	2004	2005	2004	2005	2004
Unhedged Price	\$ 58.48	\$ 44.46	\$ 8.75	\$ 6.70	\$ 53.82	\$ 41.51
Hedging Loss	(9.43)	(7.63)	(0.32)	(0.09)	(3.01)	(2.16)
Realized Price	\$ 49.05	\$ 36.83	\$ 8.43	\$ 6.61	\$ 50.81	\$ 39.35

(1) Excludes sulphur

	2005 Hedging Loss		2004 Hedging Loss	
	% Hedged	\$ millions	% Hedged	\$ millions
Crude oil	60	\$ 23.6	58	\$ 23.1
Natural gas	55	20.7	54	5.1
Total		\$ 44.3		\$ 28.2

(1) Excludes sulphur

The table below shows the production volumes hedged at December 31, 2005.

	Q1	Q2	Q3	Q4	Full Year
2006					
Crude oil (bbls/day)	4,000	3,000	2,000	2,000	2,750
Natural gas (mmcf/day)	79	42	42	42	51
2007					
Crude oil (bbls/day)	500	500	0	0	250
Natural gas (mmcf/day)	14	0	0	0	4

A summary of hedging contracts in place as at December 31, 2005 is available under Note 17 in the Notes to Consolidated Financial Statements.

PrimeWest's derivatives are marked-to-market with the resulting gain or loss reflected in earnings for the reporting period.

The 2005 income statement includes an unrealized loss of \$11.6 million on derivatives resulting from the change in the mark-to-market valuation of the derivative financial instruments during the period. The loss was comprised of a \$6.6 million gain for crude oil hedges, an \$18.3 million loss for natural gas hedges and a \$0.1 million gain for electrical power hedges.

For the year ended December 31, 2005 the cash impact of contract settlements was a \$43.5 million loss, comprised of a \$23.6 million loss in crude oil, a \$20.7 million loss in natural gas, and a \$0.8 million gain on electrical power.

## Royalties

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) and freeholders (individuals or other companies).

(\$ millions, except per BOE)	2005	2004	Change (%)
Royalty expense	\$ 172.8	\$ 119.8	44
Per BOE	\$ 11.73	\$ 9.20	28
Royalties as a percentage of sales revenues			
With hedge revenue	23%	23%	
Excluding hedge revenue	22%	22%	

Royalty expenses as a percentage of sales have remained constant when compared to the previous year.

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

## Operating Expenses

(\$ millions, except per BOE)	2005	2004	Change (%)
Operating expense	\$ 117.0	\$ 88.9	32
Per BOE	\$ 7.94	\$ 6.83	16



Operating expenses for 2005 increased \$28.1 million or 32% over 2004 mainly due to the increase in volumes resulting from the Calpine asset acquisition, which occurred in the third quarter of 2004.

The increase in operating costs per BOE is due mainly to the effects of inflationary pressures on the price of industry-related goods and services, due to the current commodity price environment. Operating issues at the Valhalla plant and Boundary Lake pipeline repairs and clean-up costs also contributed to the increase in operating costs per BOE.

### Operating Margin

(\$/BOE)	2005	2004	Change (%)
Sales price and other revenue <sup>(1)</sup>	\$ 51.70	\$ 40.13	29
Transportation expense	(0.49)	(0.63)	(22)
Royalties	(11.73)	(9.20)	28
Operating expense	(7.94)	(6.83)	16
Operating margin	\$ 31.54	\$ 23.47	34

(1) Includes hedging and sulphur.

Operating margins increased 34% from 2004 on a per BOE basis. The increase in 2005 from 2004 is primarily due to higher sales prices, offset by higher per unit operating expenses and higher royalties. Operating margin measures the level of cash flow per BOE at the field level and before head office expenses.

### G&A Expense

(\$ millions, except per BOE)	2005	2004 restated	Change (%)
Cash G&A expense	\$ 22.9	\$ 19.0	21
Per BOE	\$ 1.56	\$ 1.46	7
Non-cash G&A expense	\$ 5.4	\$ 4.1	32
Per BOE	\$ 0.37	\$ 0.32	16

Cash G&A expense increased 21% in 2005 from 2004, primarily due to higher staff levels resulting in increased employee costs, office rent, property taxes and information technology expenditures. These increases are primarily attributable to the Calpine asset acquisition which occurred in the third quarter of 2004. The increases were partially offset by overhead recoveries resulting from increases to capital expenditures and operating expenses.

Included in non-cash G&A expense is \$3.6 million relating to the UARs, granted under the LTIP. UARs in the Trust are similar to stock options in a corporation. 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 the UARs until the Unitholders have first achieved a 5% total annual return from the time of grant. PrimeWest continues to pay for the exercise of UARs in Trust Units. Also included in non-cash G&A expense is \$1.8 million related to the Special Employee Retention Plan (SERP). See Note 18 in the Notes to Consolidated Financial Statements.

### Interest Expense

(\$ millions, except per Trust Unit)	2005	2004	Change (%)
Interest expense	\$ 28.3	\$ 20.6	37
Period end net debt level	\$ 323.7	\$ 552.0	(41)
Debt per Trust Unit	\$ 3.97	\$ 7.77	(48)
Average cost of debt	5.2%	4.8%	

Interest expense, representing interest on bank debt, the Secured Notes and the Debentures increased to \$28.3 million in 2005 from \$20.6 million in 2004 due to higher average debt balances in 2005 compared to 2004 mainly resulting from the issuance of the Debentures to finance the Calpine acquisition. The Debentures also increased the average cost of debt with interest rates of 7.50% and 7.75% for the Series I and Series II Debentures respectively.

Net debt at December 31, 2005 is 41% lower than December 31, 2004 due to the repayment of \$111.0 million of the bank credit facility and to the conversion of \$186.2 million (net of accretion expense of \$1.0 million) of Debentures into Trust Units.

### Foreign Exchange Gain

The foreign exchange gain of \$4.6 million resulted mainly from the translation of the US dollar denominated Secured Notes and related interest payable into Canadian dollars.

### Depletion, Depreciation and Amortization (DD&A)

(\$ millions, except per BOE amounts)	2005	2004	Change (%)
Depletion, depreciation and amortization	\$ 230.2	\$ 197.3	17
Per BOE	\$ 15.63	\$ 15.15	

The 2005 DD&A rate of \$15.63/BOE is higher than the 2004 rate of \$15.15/BOE mainly due to the impact of the Calpine asset acquisition.

### Gain on Sale of Marketable Securities

PrimeWest sold its 8% ownership in the Viking Energy Royalty Trust (formerly Calpine Natural Gas Trust Units) in 2005 for net proceeds of \$94.5 million, resulting in a gain of \$27.1 million.

### 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 reclamation and abandonment costs incurred in 2005 were \$8.7 million, compared to \$4.6 million in 2004.

The 2005 contribution rate for the fund was unchanged from 2004 at \$0.50/BOE, which is expected to be sufficient to meet expenditure requirements for the future. As at December 31, 2005, the site reclamation fund had a balance of \$9.2 million.

### Net Asset Value

Net asset value (NAV) measures the net worth of PrimeWest by subtracting the value of debt from the estimated economic value of its underlying assets – primarily crude oil, natural gas and natural gas liquids reserves. The value placed on these reserves is the pre-tax present value of future net cash flows, discounted at 10%, as independently assessed by GLJ as at January 1, 2006. The present value of reserves reflects provisions for royalties, operating costs, future capital costs and site reclamation and abandonment costs, but is prior to deductions for income taxes, interest expense and G&A expense.

This calculation is a “snapshot” in time and is heavily dependent upon future commodity price expectations when the “snapshot” is taken. Accordingly, the NAV as at January 1, 2006 may not reflect fairly the equity market trading value of PrimeWest. It is also significant to note that NAV declines as reserves are produced and net operating cash flow is distributed to Unitholders. Value is delivered to Unitholders through such monthly distributions.

**Net Asset Value**

As at December 31 (\$ millions, except per Trust Unit amounts)	2005 Consultant's Average	2004 Consultant's Average
<b>Assets</b>		
Present value of future net cash flow discounted at 10% <sup>(1)(3)</sup>	\$ 2,684.0	\$ 1,714.4
Market value of Viking Energy Royalty Trust Units	-	91.0
Mark-to-market value of hedging contracts	(11.5)	0.1
Unproved lands	151.3	103.9
Reclamation fund	9.2	10.3
	\$ 2,833.0	\$ 1,919.7
<b>Liabilities</b>		
Debt and working capital surplus <sup>(2)</sup>	(267.9)	(378.5)
<b>Net asset value</b>	<b>\$ 2,565.1</b>	<b>\$ 1,541.2</b>
Outstanding Trust Units – millions, diluted	83.7	80.5
<b>Net asset value per Trust Unit</b>	<b>\$ 30.64</b>	<b>\$ 19.15</b>

(1) Company Interest Proved plus Probable reserves

(2) Debt excludes Debentures

(3) Refer to Summary of Oil and Natural Gas Reserves and Net Present Values of Future Net Revenues table under the section "Disclosure of Oil and Natural Gas Reserves" on page 28.

Price Assumptions	2005 Consultant's Average	2004 Consultant's Average
<b>Edmonton Par Oil – Cdn\$/bbl</b>		
2005	\$ -	\$ 50.37
2006	\$ 67.64	\$ 47.46
2007	\$ 66.40	\$ 43.88
2008	\$ 60.89	\$ 40.89
2009	\$ 56.83	\$ 39.20
2010	\$ 54.25	\$ -
<b>Spot Gas at AECO-C – Cdn\$/mcf</b>		
2005	\$ -	\$ 6.79
2006	\$ 10.93	\$ 6.52
2007	\$ 9.88	\$ 6.25
2008	\$ 8.48	\$ 5.95
2009	\$ 7.59	\$ 5.79
2010	\$ 7.23	\$ -

The NAV calculation is based on the above reference prices as of December 31, 2005 and 2004 and is highly sensitive to changes in price forecasts over time as well as in the exchange rate. In addition, the year-over-year change is impacted by the cash distributions made throughout the year, which totaled \$276.6 million or \$3.66 per Trust Unit in 2005. Also, the NAV calculation assumes a "blow down" scenario whereby existing reserves are produced without being replaced by acquisitions and development. A major cornerstone of PrimeWest's strategy is to replace reserves through accretive acquisitions and capital development.

### Income and Capital Taxes

(\$ millions)	2005	2004 restated	Change (%)
Income and capital taxes	\$ 2.8	\$ 3.3	(15)
Future income tax recovery	(14.8)	(34.3)	57
Total income and capital taxes and future income tax recovery	\$ (12.0)	\$ (31.0)	

The decrease in the future income tax recovery is due to the increase in net income resulting primarily from higher oil and natural gas revenues.

### Net Income

(\$ millions)	2005	2004 restated	Change (%)
Net income	\$ 207.5	\$ 105.4	97

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 to the ability of an energy trust to continue to sustain the monthly distribution of cash 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 the unrealized gains or losses on derivatives, foreign exchange gains or losses, DD&A and future income taxes.

Net income of \$207.5 million in 2005 was higher than 2004 net income of \$105.4 million primarily due to the increase in net oil and natural gas revenues resulting from increases to commodity prices and production volumes. Increases to operating expenses, DD&A, the unrealized loss on derivatives and lower future income tax recovery had a negative impact on net income.

### Liquidity and Capital Resources

Long-Term Debt (\$ millions)	2005	2004	Change (%)
Long-term debt	\$ 354.2	\$ 656.3	(46)
Working capital surplus <sup>(1)</sup>	(30.5)	(104.3)	(71)
Net debt	323.7	552.0	(41)
Market value of Trust Units and Exchangeable Shares outstanding <sup>(2)</sup>	2,884.7	1,877.7	54
Total capitalization	\$ 3,208.4	\$ 2,429.7	32
Net debt as a % of total capitalization	10%	23%	

(1) Working capital surplus excludes financial derivative assets and liabilities and current future income tax assets.

(2) Based on December 31, 2005 Trust Unit closing price of \$35.90 and exchangeable share ratio of 0.56399:1.

Long-term debt is comprised of bank credit facilities, Secured Notes and Debentures of \$153.0 million, \$145.4 million and \$55.8 million, respectively.

PrimeWest had a borrowing base of \$650 million at December 31, 2005. The bank credit facilities consist of an available revolving term loan of \$458.7 million and an operating facility of \$35 million, with the balance being attributed to the Secured Notes valued at \$156.3 million based on the agreed US dollar exchange rate at the time of last renewal. In addition to the amounts outstanding under the bank credit facility, PrimeWest has outstanding letters of credit in the amount of \$6.6 million (2004 - \$4.9 million). The credit facility revolves until June 30, 2006, by which time the lenders will have conducted their annual borrowing base review.

The Secured Notes in the amount of US\$125 million have a final maturity date of May 7, 2010, and bear interest at 4.19% per annum, with interest paid semi-annually on November 7 and May 7 of each year. The Note Purchase Agreement requires PrimeWest to make four annual principal repayments of US\$31,250,000 commencing May 7, 2007.

PrimeWest issued the 7.5% (Series I) and 7.75% (Series II) Debentures in the third quarter of 2004 for proceeds of \$150.0 million and \$100.0 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 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 a price of \$1,000 per Series II Debenture. On redemption or maturity the Trust may elect to satisfy its obligations to repay the principal by issuing Trust Units.

PrimeWest's net debt at December 31, 2005 was lower than at December 31, 2004 due to the conversion of \$114.3 million of Series I and \$72.9 million of Series II Debentures, offset by accretion of \$1.0 million. In addition, cash flow from operations in excess of distributions allowed for the repayment of \$111.0 million of the bank credit facility.

### Unitholders' Equity

The Trust had 79,666,352 Trust Units outstanding at December 31, 2005 compared to 69,886,111 Trust Units at the end of 2004. In addition, there were 1,219,335 Exchangeable Shares (see below) outstanding at year end, exchangeable into a total of 687,693 Trust Units. The weighted average number of Trust Units, including those issuable by the exchange of Exchangeable Shares, was 75,808,919 Trust Units for the twelve month period ended December 31, 2005 compared to 59,482,034 in 2004.

During the year, 487,421 Trust Units were issued to employees pursuant to the LTIP.

During 2005, PrimeWest issued 262,347 Trust Units under the DRIP for \$7.9 million (2004 - 268,677 Trust Units, \$6.5 million), 932,142 Trust Units for \$27.4 million pursuant to the PREP (2004 - 1,311,462 Trust Units, \$32.0 million) and 704,806 Trust Units for \$20.4 million pursuant to the OTUPP in 2005 (2004 - 894,167 Trust Units, \$21.5 million).

The DRIP gives Canadian and US Unitholders the opportunity to reinvest their monthly distributions at a 5% discount to the volume-weighted average market price of the Trust Units. As an alternative to the DRIP component of the Plan, 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 OTUPP gives Canadian Unitholders an opportunity to purchase additional Trust Units directly from PrimeWest at the same 5% discount. The DRIP and PREP components are mutually exclusive. Participation in the OTUPP requires enrolment in either the DRIP or PREP.

These plan components benefit Unitholders by offering alternatives to maximize their investment in PrimeWest, while providing the Trust with an inexpensive method of raising additional capital. The Trust expects interest in these plans in 2006 to be similar to 2005. Proceeds from these plans are used for debt reduction of PrimeWest's credit facility and to help fund ongoing capital development programs.

For additional information or to join these plans, contact the plan agent for the DRIP, OTUPP and PREP, Computershare Trust Company of Canada at 1-800-564-6253 or visit PrimeWest's website at [www.primewestenergy.com](http://www.primewestenergy.com).

### 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.

In 2005, 94,340 Exchangeable Shares were issued pursuant to the SERP (2004 - 94,340). See Note 18 in Notes to Consolidated Financial Statements.

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 December 31, 2005, there were 1,219,335 Exchangeable Shares outstanding. The exchange ratio was 0.56399:1 Trust Units for each Exchangeable Share at year end.

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.

### Cash Distributions

Since August 2003, PrimeWest has followed a strategy of targeting a distribution payout ratio within 70-90% of cash flow, calculated on an annual basis. The recent strength in commodity prices has increased the Trust's cash flow from operations available for distribution to Unitholders. The Board of Directors of PrimeWest will continue to consider a variety of factors in establishing the monthly distribution level. These factors include, but are not limited to: commodity price outlook, cash flow forecast, capital development plans, debt levels, taxability considerations and competitive industry distribution practices.

Cash distributions for 2005 were \$276.6 million or \$3.66 per Trust Unit, representing a payout ratio of approximately 67% versus 2004 amounts of \$196.1 million or \$3.30 per Trust Unit, representing a payout ratio of approximately 74%.

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

### Cash Flow Sensitivities

	Increase to Annual Cash Flow \$/Trust Unit <sup>(1)</sup>
Crude oil price (US\$1.00/bbl W.T.I. increase)	\$ 0.03
Natural gas price (\$0.10/mcf increase)	\$ 0.06
Exchange rate (US\$0.01 decrease)	\$ 0.09
Short term interest rate (1% decrease)	\$ 0.02
Production (1,000 BOE/day increase)	\$ 0.20

(1) Without the effect of hedging and assuming no change in operating costs and royalty costs.

The figures in the above table are provided for directional information only and are based on the number of Trust Units outstanding as at December 31, 2005. Should changes to the commodity price, interest rate, exchange rate or production levels noted above take place, it should not be assumed that a corresponding change would be made to the distribution level.

### Contractual Obligations

PrimeWest enters into many contractual obligations as part of conducting day-to-day business. Material contractual obligations include debt obligations, office lease rental commitments that run from 2006 through 2009 and various pipeline transportation commitments that run through 2011. The details of the timing of these contractual obligations are included in the following table.

As at December 31, 2005 (\$ millions)	Payments due by period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
Long-term debt obligations	\$ 298.4	\$ -	\$ 225.7	\$ 72.7	\$ -
Debentures	57.6	-	-	33.6	24.0
Office lease rental obligations	11.4	3.7	6.9	0.8	-
Pipeline transportation obligations	11.5	7.2	3.7	0.5	0.1
Derivative liability	11.5	11.3	0.2	-	-
Total contractual obligations	\$ 390.4	\$ 22.2	\$ 236.5	\$ 107.6	\$ 24.1

As part of PrimeWest's 2002 internalization transaction, which closed on November 6, 2002, PrimeWest agreed to issue 377,360 Exchangeable Shares to certain executive officers pursuant to the SERP. On November 6, 2004 and 2005, 94,340 Exchangeable Shares were issued to those officers. An additional 94,340 shares will be issued on November 6, 2006 and 2007. For the 12 months ended December 31, 2005, \$1.8 million was recorded in non-cash G&A expense related to the SERP.

**Quarterly Performance – Selected Measures**

(\$ millions, except per Trust Unit amounts)	2005 (Restated) <sup>(1)</sup>				2004 (Restated) <sup>(1)</sup>			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Net revenues <sup>(2)</sup>	\$ 236.4	\$ 101.5	\$ 155.3	\$ 111.2	\$ 158.2	\$ 84.5	\$ 84.9	\$ 75.2
Net income	101.5	27.3	54.7	24.0	42.2	27.1	16.5	19.6
Cash flow	132.5	106.4	95.5	79.7	83.3	66.8	58.2	58.5
Net income per Trust Unit-Basic	1.27	0.35	0.74	0.34	0.59	0.44	0.30	0.39
Net income per Trust Unit- Diluted	1.23	0.35	0.72	0.34	0.58	0.44	0.30	0.39
Cash flow per Trust Unit-Basic	1.66	1.36	1.29	1.12	1.17	1.09	1.05	1.16
Cash flow per Trust Unit–Diluted	\$ 1.60	\$ 1.31	\$ 1.21	\$ 1.04	\$ 1.07	\$ 1.08	\$ 1.05	\$ 1.15

(1) See note 3 in the Notes to Consolidated Financial Statements.

(2) Net revenues equals revenues from the sale of crude oil, natural gas and natural gas liquids less crown and other royalties plus unrealized gain or loss on derivatives, gain on sale of marketable securities and other income.

The above table highlights PrimeWest's performance by selected measures for the quarter ended December 31, 2005, and the preceding seven quarters.

Net revenues are primarily impacted by commodity prices, production volumes and royalties. Net revenues are also impacted by non-cash items including the unrealized gain or loss on derivatives and the gain on sale of marketable securities.

Net income and net income per Trust Unit are secondary measures for a royalty trust because they include both cash and non-cash items. The non-cash items such as 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.

**Annual Performance – Selected Measures**

(\$ millions, except per Trust Unit amounts)	2005	2004 Restated <sup>(1)</sup>	2003 Restated <sup>(1)</sup>
Gross revenue ( net of transportation expense)	\$ 749.7	\$ 513.7	\$ 434.6
Net income	\$ 207.5	\$ 105.4	\$ 102.7
Net income per Trust Unit – basic	\$ 2.73	\$ 1.77	\$ 2.23
Net income per Trust Unit – diluted	\$ 2.66	\$ 1.77	\$ 2.23
Total Assets	\$ 2,131.9	\$ 2,240.9	\$ 1,690.5
Long-term financial liabilities <sup>(2)</sup>	\$ 394.8	\$ 696.6	\$ 269.8

(1) See note 3 in the Notes to Consolidated Financial Statements.

(2) Includes long-term debt, derivative liabilities and the asset retirement obligation.

The above table highlights selected performance measures for the years ended December 31, 2005, 2004 and 2003.

The increase in gross revenues net of transportation from \$434.6 million in 2003 to \$749.7 million in 2005 was due to increases in production volumes and realized commodity prices over the period. The increase in production volumes is mainly due to the Calpine asset acquisition in the third quarter of 2004.

Net income has increased from 2003 to 2005 due to increases in gross revenues described above, offset by increases to royalties, operating expense, cash G&A expense and interest expense. Increases to non-cash expenses including DD&A and unrealized losses on derivatives, and reductions to future income tax recoveries have negatively impacted net income during the period. The increases to the operating and cash G&A expense are due mainly to additional production volumes and staffing requirements resulting from corporate and asset acquisitions.

Total assets at December 31, 2004 exceed the balance at December 31, 2003 mainly due to the Calpine asset acquisition.

Long-term financial liabilities increased from \$269.8 million at December 31, 2003 to \$696.6 million at December 31, 2004 due primarily to the issuance of the Series I and Series II Debentures and the drawdown on the credit facility to finance the Calpine

asset acquisition. The decrease in the liabilities from December 31, 2004 to December 31, 2005 is due to the conversion of \$186.2 million of Debentures into Trust Units and to the repayment of \$111.0 million of the bank credit facility.

### **Critical Accounting Estimates**

PrimeWest's financial statements have been prepared in accordance with GAAP. 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 this MD&A 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.

### **Disclosure of Oil and Natural Gas Reserves**

Disclosure in respect of the reserves of PrimeWest is for the year ended December 31, 2005 and is derived from the GLJ Report. Capitalized terms not otherwise defined in respect of PrimeWest's reserves and production have the meanings provided for them in NI 51-101.

Proved oil and natural gas reserves 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 entity should result in at least a 90% probability that the quantities 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 entity should result in at least a 50% probability that the quantities recovered will equal or exceed the sum of the estimated Proved plus Probable reserves.

The oil and natural 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 natural gas reserves on the financial results and position of PrimeWest are described under the heading "Full Cost Accounting for Oil and Natural Gas Activities".

In addition to the categorization of its reserves into "Gross" and "Net", as required by NI 51-101, PrimeWest also uses the term "Company Interest" to describe its reserves. Company Interest reserves include working interest and royalties receivable by PrimeWest, with no deduction of royalties payable. PrimeWest reported its reserves on a Company Interest basis prior to the implementation of NI 51-101 and PrimeWest continues to provide this disclosure for comparability purposes.

PrimeWest's disclosure of reserves data and other oil and natural gas information is made in conformity with NI 51-101. There are differences between the requirements under NI 51-101 and those imposed by the SEC, including with respect to the disclosure of Proved Reserves, Probable Reserves and estimated future net cash flows from Reserves.

### **Full Cost Accounting for Oil and Natural Gas Activities**

PrimeWest adopted Canadian Institute of Chartered Accountants (CICA) Accounting Guideline 16 (AcG-16), "Oil and Gas Accounting – Full Costs" on January 1, 2004. The guideline requires cost centres 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 centre is not recoverable, the cost centre is written down to its fair value. Fair value is estimated using accepted present value techniques that 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 activities, whether successful or not, are capitalized. 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 natural gas reserves. An increase in estimated Proved oil and natural 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, including commodity prices hedges, to manage market risk. The purpose of hedging 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 and that, 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 and policies. These estimated costs are charged to earnings and the appropriate liability account over the expected service life of the asset. 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 uses the purchase method to account for its acquisitions. 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 natural gas properties primarily involves placing a value on the oil and natural gas reserves. The valuation of oil and natural gas reserves entails the process described above under Proved, Probable and Proved Plus Probable Oil and Natural 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 natural 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 CICA section 3062, Goodwill and Other Intangible Assets, goodwill is not 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.

## Recent Accounting Pronouncements Issued But Not Implemented

The following new or amended standards and guidelines were issued but not implemented by PrimeWest.

### EXCHANGEABLE SHARE ACCOUNTING

In January 2005 the CICA issued Emerging Issues Committee (EIC) 151, "Exchangeable Securities Issued by Subsidiaries of Income Trusts". The EIC 151 deals with the presentation of exchangeable securities on the balance sheet. The EIC states that exchangeable securities should be included as part of Unitholders' equity only if the holders of the exchangeable securities are entitled to receive distributions of earnings economically equivalent to distributions received by units of the income trust and if the exchangeable securities ultimately are required to be exchanged for units of the income trust as a result of the passage of a fixed period of time. The Trust has reviewed the impact of the pronouncement and determined that it does not materially impact its Consolidated Financial Statements.

### FINANCIAL INSTRUMENTS

In May 2005, the CICA issued the Handbook Section "Financial Instruments – Recognition and Measurement". This Section establishes standards for recognizing and measuring financial assets, financial liabilities and non-financial derivatives. The new section will apply to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006. The Trust is reviewing the section and has yet to determine the impact on the Consolidated Financial Statements.

## 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 natural gas royalty trust sector and the conventional oil and natural gas exploration and production 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 below.

### COMMODITY PRICE, FOREIGN EXCHANGE AND INTEREST RATE RISK

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

- World market forces, specifically the actions of OPEC and other large crude oil producing countries including Russia, and their implications for the supply of crude oil;
- World and North American economic conditions which influence the demand for crude oil and natural gas and the level of interest rates set by the governments of Canada and the US;
- Weather conditions that influence the demand for natural gas and heating oil;
- The Canadian/US currency exchange rate, which affects the price received for crude oil, as the price of crude oil is referenced in US dollars;
- Transportation availability and costs; and
- Price differentials between 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 are actively monitored by the Board.

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

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

The primary objectives of our hedging program are to stabilize cash flow, reducing its volatility, to lock in the economics of major acquisitions and to protect our capital structure when commodity prices cycle downwards while retaining some exposure to pricing upside. In 2005, PrimeWest recorded a loss of \$44.3 million from commodity hedges (\$0.54 per Trust Unit), while in 2004, PrimeWest recorded a loss of \$28.2 million (\$0.45 per Trust Unit) to our cash flow through various physical and financial hedging transactions.

#### OPERATIONAL AND OTHER BUSINESS RISKS

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

Risk	We Mitigate By
<p><b>Production</b></p> <p>Risk associated with the production of oil and natural gas – includes well operations, processing and the physical delivery of commodities to market.</p>	<p>Performing regular and proactive protective well, facility and pipeline maintenance supported by telemetry, physical inspection and diagnostic tools.</p>
<p><b>Commodity Price</b></p> <p>Fluctuations in natural gas, crude oil and natural gas liquid prices.</p>	<p>Hedging. See note 17 to the Notes to Consolidated Financial Statements.</p>
<p><b>Transportation</b></p> <p>Market risk related to the availability of transportation to market and potential disruption in delivery systems.</p>	<p>Diversifying the transportation systems on which we rely to get our product to market.</p>
<p><b>Natural production decline</b></p> <p>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 added production in quantities sufficient to replace annual production declines.</p>	<p>Diversifying our capital spending program over a large number of projects so that excessive 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 estimated production and reserve additions are met.</p>
<p><b>Acquisitions</b></p> <p>Acquisition risk associated with acquiring producing properties at sufficiently low cost to renew our inventory of assets.</p>	<p>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.</p>



<p><b>Reserves</b></p> <p>Reserve risk in respect of the quantity and quality of recoverable reserves estimated versus ultimately recovered.</p>	<p>Contracting our reserves evaluation to a reputable third-party consultant, 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 in which the reserve risk is generally lower and cash flows are more stable and predictable.</p>
<p><b>Environmental Health and Safety (EH&amp;S)</b></p> <p>Environmental, health and safety risks associated with oil and natural gas properties and facilities.</p>	<p>Establishing and adhering to strict guidelines for EH&amp;S including training, proper reporting of incidents, supervision and awareness. PrimeWest has active community involvement in field locations including regular meetings with stakeholders in our operational areas. PrimeWest carries adequate insurance to cover property losses, liability and business interruption.</p> <p>These risks are reviewed regularly by the Corporate Governance and EH&amp;S Committee of the Board of Directors, which acts as PrimeWest's Environmental, Health and Safety Committee.</p>
<p><b>Regulation, Tax and Royalties</b></p> <p>Changes in government regulations, including reporting requirements, income tax laws, operating practices, environmental protection requirements and royalty rates.</p>	<p>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.</p>
<p><b>Liability of Unitholders is Uncertain</b></p> <p>There is no statutory protection for Unitholders from liabilities of the Trust arising prior to July 1, 2004.</p>	<p>Limiting the business of the Trust to the right to receive the net cash flow of PrimeWest Energy Inc. All of the oil and natural gas business operations of PrimeWest are conducted by PrimeWest Energy Inc. PrimeWest Energy Inc. has a vigorous EH&amp;S program as well as significant insurance protection.</p>

### Income Taxes – Unitholders – 2005

For the 2005 taxation year, Canadian Unitholders of PrimeWest were paid \$3.66 per Trust Unit in distributions. Of this distribution amount, 25% or \$0.92 per Trust Unit is deemed a tax-deferred return of capital, and 75% or \$2.74 per Trust Unit is taxable to Unitholders as other income (taxed at the same rate as interest income).

For Unitholders resident in the US, the taxability of distributions is calculated using US tax rules which allow for the deduction of Crown royalties and accounting-based depletion. Distributions are taxable as dividends with 81.25% of the 2005 distributions taxable as a "qualified dividend" and the remaining 18.75% treated as a tax-deferred return of capital. A 15% withholding tax applies to distributions paid to US Unitholders. Further details regarding the withholding tax is available on PrimeWest's website at [www.primewestenergy.com](http://www.primewestenergy.com).

For both Canadian and US Unitholders, the tax-deferred return of capital portion reduces the Unitholder's adjusted cost base for purposes of calculating a capital gain or loss upon ultimate disposition of their Trust Units. Unitholders contemplating a disposition may wish to consult the "Unitholder Info" section on PrimeWest's website and use the adjusted cost base calculator.

PrimeWest recommends that all Unitholders contact their tax advisors to discuss tax-related issues.

**CONSOLIDATED BALANCE SHEETS**

As at December 31 (\$ millions)	2005	2004 (restated- See note 3)
<b>ASSETS</b>		
Current assets		
Cash and cash equivalents	\$ 36.8	\$ 54.4
Marketable securities (note 4)	-	68.6
Accounts receivable	125.0	96.9
Assets held for sale (note 6)	-	5.4
Future income taxes (note 16)	3.9	-
Prepaid expenses	16.3	10.9
Inventory	3.5	5.8
	<b>185.5</b>	242.0
Cash reserved for site restoration and reclamation (note 10)	9.2	10.3
Other assets and deferred charges (note 7)	8.8	10.9
Derivative asset	-	0.6
Property, plant and equipment (note 6)	1,859.9	1,908.6
Goodwill	68.5	68.5
	<b>\$ 2,131.9</b>	\$ 2,240.9
<b>LIABILITIES AND UNITHOLDERS' EQUITY</b>		
Current liabilities		
Accounts payable	\$ 50.2	\$ 47.7
Accrued liabilities	75.9	72.3
Derivative liability (note 17)	11.3	0.5
Accrued distributions to Unitholders	25.0	17.7
	<b>162.4</b>	138.2
Long-term debt (note 8)	354.2	656.3
Derivative liability (note 17)	0.2	-
Future income taxes (note 16)	214.8	225.7
Asset retirement obligation (note 9)	40.4	40.3
	<b>772.0</b>	1,060.5
<b>UNITHOLDERS' EQUITY</b>		
Net capital contributions (note 11)	2,294.3	2,042.0
Capital issued but not distributed	3.6	3.3
Convertible Unsecured Subordinated Debentures (note 8)	1.8	8.1
Contributed surplus (note 12)	8.7	6.4
Accumulated income	303.8	96.3
Accumulated cash distributions	(1,244.3)	(967.7)
Accumulated dividends	(8.0)	(8.0)
	<b>1,359.9</b>	1,180.4
	<b>\$ 2,131.9</b>	\$ 2,240.9

Commitments and contingencies (note 18).

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

**CONSOLIDATED STATEMENT OF CHANGES IN UNITHOLDERS' EQUITY**

<b>For the years ended December 31 (\$ millions)</b>	<b>2005</b>	2004 (restated – see note 3)	2003 (restated – see note 3)
Unitholders' equity, beginning of year	\$ 1,180.4	\$ 1,014.0	\$ 847.1
Adjustment to Unitholders' equity at beginning of period to adopt:			
New oil and gas accounting standard (note 3)	-	(233.3)	-
Fair value method for unit based compensation (note 3)	-	-	(6.7)
Net income for the year	207.5	105.4	102.7
Net capital contributions (note 11)	252.3	481.4	256.7
Capital issued but not distributed	0.3	(1.9)	4.3
Convertible Unsecured Subordinated Debentures	(6.3)	8.1	-
Contributed surplus	2.3	2.8	2.5
Cash distributions (note 14)	(276.6)	(196.1)	(192.6)
Unitholders' equity, end of year	\$ 1,359.9	\$ 1,180.4	\$ 1,014.0

**CONSOLIDATED STATEMENTS OF CASH FLOW**

For the years ended December 31 (\$ millions)	2005	2004 (restated – see note 3)	2003 (restated – see note 3)
<b>Operating Activities</b>			
Net income for the year	\$ 207.5	\$ 105.4	\$ 102.7
Add/(deduct):			
Items not involving cash from operations			
Depletion, depreciation and amortization	230.2	197.3	197.4
Non-cash general and administrative	5.4	4.1	3.1
Non-cash foreign exchange gain	(4.9)	(11.9)	(12.1)
Cash distributions from marketable securities	1.2	4.1	-
Gain on sale of marketable securities (note 4)	(27.2)	-	-
Unrealized loss/(gain) on derivatives	11.6	(0.1)	-
Future income tax recovery	(14.8)	(34.3)	(75.4)
Accretion on asset retirement obligation	2.5	2.0	1.2
Other non-cash items	2.6	0.2	(0.3)
Cash flow from operations	414.1	266.8	216.6
Expenditures on site restoration and reclamation	(8.7)	(4.6)	(2.2)
Change in non-cash working capital	(28.0)	11.9	5.3
	377.4	274.1	219.7
<b>Financing Activities</b>			
Proceeds from issue of Trust Units (net of costs)	20.4	441.0	240.3
Proceeds from issue of Debentures	-	250.0	-
Net cash distributions to Unitholders (note 14)	(241.5)	(159.6)	(172.5)
Increase (decrease) in bank credit facilities	(111.0)	166.0	(137.0)
Increase in Senior Secured Notes	-	-	174.0
Increase in deferred charges	-	(10.0)	(1.5)
Change in non-cash working capital	4.2	10.9	(3.6)
	(327.9)	698.3	99.7
<b>Investing Activities</b>			
Expenditures on property, plant and equipment	(192.5)	(129.7)	(105.8)
Acquisition of capital/corporate assets	-	(807.4)	(210.1)
Proceeds on disposal of property, plant and equipment	26.0	96.5	2.3
Investment in marketable securities (note 4)	-	(72.7)	-
(Increase) decrease in cash reserved for future site restoration and reclamation	1.1	(2.1)	(6.6)
Proceeds on disposal of marketable securities	94.5	-	-
Change in non-cash working capital	3.8	(5.1)	6.4
	(67.1)	(920.5)	\$ (313.8)
(Decrease)/Increase in cash and cash equivalents for the year	\$ (17.6)	\$ 51.9	\$ 5.6
Cash and cash equivalents (bank overdraft) beginning of the year	54.4	2.5	(3.1)
Cash and cash equivalents end of the year	\$ 36.8	\$ 54.4	\$ 2.5
Cash interest paid	\$ 23.8	\$ 15.0	\$ 13.1
Cash taxes paid	\$ 5.4	\$ 3.8	\$ 3.9

**CONSOLIDATED STATEMENT OF INCOME**

For the years ended December 31 (\$ millions, except per Trust Unit amounts)	2005	2004 (restated – see note 3)	2003 (restated – see note 3)
<b>Revenues</b>			
Sales of crude oil, natural gas and natural gas liquids	\$ 756.9	\$ 521.9	\$ 442.9
Crown and other royalties	(172.8)	(119.8)	(101.9)
Unrealized (loss)/gain on derivatives	(11.6)	0.1	-
Gain on sale of marketable securities	27.2	-	-
Other income	4.7	0.6	(2.8)
	<b>604.4</b>	<b>402.8</b>	<b>338.2</b>
<b>Expenses</b>			
Operating	117.0	88.9	79.4
Transportation	7.2	8.2	8.3
Cash general and administrative	22.9	19.0	14.5
Non-cash general and administrative (note 13)	5.4	4.1	3.1
Interest	28.3	20.6	15.1
Depletion, depreciation and amortization	230.2	197.3	197.4
Accretion on asset retirement obligations	2.5	2.0	1.2
Foreign exchange gain	(4.6)	(11.7)	(11.9)
	<b>408.9</b>	<b>328.4</b>	<b>307.1</b>
Income before taxes for the year	<b>195.5</b>	74.4	31.1
Income and capital taxes	2.8	3.3	3.8
Future income tax recovery (note 16)	(14.8)	(34.3)	(75.4)
	<b>(12.0)</b>	<b>(31.0)</b>	<b>(71.6)</b>
Net income for the year	<b>\$ 207.5</b>	\$ 105.4	\$ 102.7
Net income per Trust Unit	<b>\$ 2.73</b>	\$ 1.77	\$ 2.23
Diluted net income per Trust Unit	<b>\$ 2.66</b>	\$ 1.77	\$ 2.22

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(ALL AMOUNTS ARE EXPRESSED IN MILLIONS OF CANADIAN DOLLARS UNLESS OTHERWISE INDICATED)

### 1. Structure of The Trust

PrimeWest Energy Trust (the Trust) is an open-ended investment trust formed under the laws of Alberta in accordance with a declaration of trust dated August 2, 1996, as Amended. The beneficiaries of the Trust are the holders of Trust Units (the Unitholders).

The principal undertaking of the Trust's operating companies, PrimeWest Energy Inc. and PrimeWest Gas Corp. (collectively referred to as PrimeWest) is to acquire and hold, directly and indirectly, interests in oil and natural gas properties. One of the Trust's primary assets is a royalty entitling it to receive 99% of the net cash flow generated by the oil and natural gas interests owned by PrimeWest. The royalty acquired by the Trust effectively transfers substantially all of the economic interest in the properties to the Trust.

The common shares of PrimeWest Energy Inc. are 100% owned by the Trust. PrimeWest Gas Corp., a wholly owned subsidiary of PrimeWest Energy Inc., was amalgamated with PrimeWest Energy Inc. effective January 1, 2006.

### 2. Accounting Policies

#### CONSOLIDATION

These consolidated financial statements include the accounts of the Trust and its wholly-owned subsidiaries, PrimeWest Energy Inc. and PrimeWest Gas Corp. The Trust, through the royalty, obtains substantially all of the economic benefits of the operations of PrimeWest.

#### CASH AND CASH EQUIVALENTS

Short-term investments, with maturities less than three months at the date of acquisition, are considered to be cash equivalents and are recorded at cost, which approximates market value.

#### MARKETABLE SECURITIES

Marketable securities are carried at the lower of cost or market.

#### INVENTORY

Inventory is measured at lower of cost and net realizable value.

#### GOODWILL

Goodwill represents the excess of purchase price over fair value of net assets acquired and liabilities assumed. Goodwill is assessed for impairment at least annually. To assess impairment, the fair value of each reporting unit is determined and compared to the book value of the reporting unit. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount.

#### PROPERTY, PLANT AND EQUIPMENT

PrimeWest follows the full cost method of accounting. All costs of acquiring oil and natural gas properties and related development costs are capitalized and accumulated in one cost centre. Maintenance and repairs are charged against earnings. Renewals and enhancements that extend the economic life of the capital asset are capitalized.

Gains and losses are not recognized on disposition of oil and natural gas properties unless that disposition would alter the rate of depletion by 20% or more.

#### i) Ceiling test

PrimeWest places a limit on the aggregate cost of capital assets that may be carried forward for depletion against net revenues of future periods (the ceiling test). The ceiling test is an impairment test whereby the carrying amount of capitalized assets is compared to the undiscounted cash flows from Proved reserves plus Unproved properties using management's best estimate of

future prices. If the asset value exceeds the undiscounted cash flows the impairment is measured as the amount by which the carrying amount of the capitalized asset exceeds the future discounted cash flows from Proved plus Probable reserves. The discount rate used is the risk-free rate.

ii) Asset retirement obligation

PrimeWest recognizes the future retirement obligations associated with the retirement of property, plant and equipment. The obligations are initially measured at fair value and subsequently adjusted for accretion of discount and changes in the underlying liability. The asset retirement cost is capitalized to the related asset and amortized to earnings over time.

iii) Depletion, depreciation and amortization (DD&A)

Provision for depletion and depreciation is calculated on the unit-of-production method, based on Proved reserves before royalties. Reserves are estimated by independent petroleum engineers. Reserves are converted to equivalent units on the basis of approximate relative energy content. Depreciation and amortization of head office furniture and equipment is provided for at rates ranging from 10-30%.

JOINT VENTURE ACCOUNTING

PrimeWest conducts substantially all of its oil and natural gas production activities through joint ventures, and the accounts reflect only PrimeWest's proportionate interest in such activities.

UNIT-BASED COMPENSATION

PrimeWest accounts for its Unit Appreciation Rights (UARs) issued to employees and the Board of Directors using the fair value method. The fair value of each UAR is estimated on the date of the grant using the Black-Scholes options pricing model and charged to earnings over the vesting period with a corresponding increase to contributed surplus.

INCOME TAXES

The Trust is considered an inter-vivos trust for income tax purposes. As such, the Trust is subject to tax on any taxable income that is not allocated to the Unitholders. Periodically, current taxes may be payable by PrimeWest, depending upon the timing of income tax deductions. Should these taxes prove to be unrecoverable, they will be deducted from royalty income in accordance with the royalty agreement.

Future income taxes are recorded for PrimeWest using the liability method of accounting. Future income taxes are recorded to the extent that the carrying value of PrimeWest's capital assets exceeds the available tax pools.

FINANCIAL INSTRUMENTS

PrimeWest uses financial instruments to manage its exposure to fluctuations in commodity prices and interest rates. PrimeWest does not use financial instruments for speculative trading purposes. The financial instruments are marked-to-market with the resulting gain or loss reflected in earnings for the reporting period.

MEASUREMENT UNCERTAINTY

Certain items recognized in the Financial Statements are subject to measurement uncertainty. The recognized amounts of such items are based on PrimeWest's best information and judgment. Such amounts are not expected to change materially in the near term. They include the amounts recorded for depletion, depreciation and future site restoration costs which depend on estimates of oil and natural gas reserves or the economic lives and future cash flows from related assets.

### 3. Changes in Accounting Policies

CHANGE IN METHOD OF ACCOUNTING FOR UNIT-BASED COMPENSATION

Beginning January 1, 2005, PrimeWest determined that if a series of assumptions were used, it was possible to use a traditional options pricing model to calculate a reasonable estimate of the fair value of PrimeWest's UARs granted under its Long-Term Incentive Plan (LTIP). Under the fair value method, PrimeWest recognizes compensation expense related to the UARs over the vesting period of the UARs granted with the related credit being charged to contributed surplus. In prior years, PrimeWest had been applying the intrinsic method to value its unit-based compensation whereby the value of the UARs was adjusted at the end of each accounting period to reflect the impact of the reinvestment of cumulative distributions and the changes in the trading price of the Trust Units. The changes in value of the UAR liability were reflected in non-cash G&A on the income statement.

PrimeWest has applied the fair value method retroactively to UARs issued on or after January 1, 2002 and prior periods have been restated. At January 1, 2005 the change in accounting policy resulted in an increase to the future income tax liability of \$14.5 million (2004 - \$11.2 million), a decrease to net capital contributions of \$7.9 million (2004 - \$5.3 million), a decrease to the LTIP equity of \$20.1 million (2004 - \$14.6 million), an increase in contributed surplus of \$6.4 million (2004 - \$3.6 million) and an increase to accumulated income of \$7.1 million (2004 - \$5.1 million).

The change in accounting method resulted in an increase to 2005 net income of \$54.9 million.

#### FULL COST ACCOUNTING

The adoption of CICA Accounting Guideline 16 (AcG-16) modifies how the ceiling test is performed resulting in a two stage process. The guideline is effective for fiscal years beginning on or after January 1, 2004. The cost impairment test is a two-stage process which is 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.

PrimeWest 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:

Consultants' Average Price Forecasts	2004	2005	2006	2007	2008
W.T.I. (US\$/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 \$233.3 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 standard requires the recognition of the liability associated with the future site reclamation costs of tangible long-lived assets. This liability is comprised of the Trust's net ownership interest in producing wells and processing plant facilities. The liability for future retirement obligations is 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 cumulative effect of the change in accounting policy was reflected in 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 9 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 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 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. Derivatives are marked-to-market with the resulting gain or loss reflected in earnings for the reporting period.

#### 4. Marketable Securities

(\$millions)	2005	2004
Investment in Viking Energy Royalty Trust	\$ -	\$ 68.6

PrimeWest sold its 8% ownership in the Viking Energy Royalty Trust in 2005 (formerly Calpine Natural Gas Trust) for net proceeds of \$94.5 million resulting in a gain of \$27.1 million.

#### 5. Acquisitions

a) On September 2, 2004, PrimeWest Gas Corp. acquired oil and natural 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	\$ 745.3		
Inventory	4.2	Cash	\$ 747.0
Working capital	2.7	Net closing adjustments	(11.1)
Asset retirement obligation	(12.0)	Costs associated with acquisition	4.3
	\$ 740.2		\$ 740.2

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

#### 6. Property, Plant and Equipment

(\$ millions)	Cost	2005 Accumulated Depletion Depreciation and Amortization	Net Book Value
Property acquisition oil and natural gas rights	\$ 2,677.1	\$ (1,260.7)	\$ 1,416.4
Drilling and completion	417.9	(110.7)	307.2
Production facilities and equipment	176.6	(48.4)	128.2
Head office furniture and equipment	16.8	(8.7)	8.1
	\$ 3,288.4	\$ (1,428.5)	\$ 1,859.9

(\$ millions)	2004		
	Cost	Accumulated Depletion and Amortization	Net Book Value
Property acquisition oil and natural gas rights	\$ 2,671.2	\$ (1,081.0)	\$ 1,590.2
Drilling and completion	298.0	(77.1)	220.9
Production facilities and equipment	125.1	(34.0)	91.1
Head office furniture and equipment	12.6	(6.2)	6.4
	\$ 3,106.9	\$ (1,198.3)	\$ 1,908.6

Unproved land costs of \$88.0 million (2004 – \$103.9 million) and \$4.1 million of capital not in use (2004 – \$0 million) are excluded from costs subject to depletion and depreciation.

PrimeWest capitalized \$3.7 million of G&A costs in 2005 (2004 - \$2.9 million).

In February 2005, PrimeWest closed the disposition of a property, receiving the balance of the proceeds of \$5.4 million. At December 31, 2004, the amount was recorded as assets held for sale in current assets on the balance sheet.

PrimeWest has performed a ceiling test as at December 31, 2005. The impairment test was calculated using the Consultant's Average Prices at January 1, 2006 for the years 2006 to 2010 as follows:

Consultants' Average Price Forecasts	2006	2007	2008	2009	2010
WTI (US\$/bbl)	58.44	57.34	52.70	49.23	47.05
AECO (Cdn\$/mcf)	10.93	9.88	8.48	7.59	7.23

Subsequent to 2010, prices increased by approximately 2% per year.

The December 31, 2005 ceiling test resulted in a surplus.

## 7. Other Assets and Deferred Charges

(\$ millions)	2005		2004
Deferred charges	\$ 8.7	\$	10.6
Other assets	0.1		0.3
	\$ 8.8	\$	10.9

## 8. Long-Term Debt

(\$ millions)	2005		2004
Bank credit facility	\$ 153.0	\$	264.0
Senior Secured Notes	145.4		150.3
Convertible Unsecured Subordinated Debentures	55.8		242.0
	\$ 354.2	\$	656.3

Long-term debt is comprised of bank credit facilities, Senior Secured Notes (Secured Notes) and Convertible Unsecured Subordinated Debentures (Debentures) of \$153.0 million, \$145.4 million and \$55.8 million respectively.

PrimeWest had a borrowing base of \$650 million at December 31, 2005 (2004- \$625 million). The bank credit facilities consist of an available revolving term loan of \$458.7 million and an operating facility of \$35 million with the balance being attributable to the Secured Notes valued at \$156.3 million based on the US dollar exchange rate at the time of the last renewal. In addition to

amounts outstanding under the bank credit facility, PrimeWest has outstanding letters of credit in the amount of \$6.6 million (2004 - \$4.9 million).

Advances under the bank credit facility are made in the form of Banker's Acceptances (BA), prime rate loans or letters of credit. In the case of BAs, interest is a function of the BA rate plus a stamping fee based on the Trust's current ratio of debt to cash flow. In the case of prime rate loans, interest is charged at the bank's prime rate. For 2005, the effective interest rate on the facilities was 4.0% (2004 - 4.0%).

The bank credit facility revolves until June 30, 2006, by which time the lenders will have conducted their annual borrowing base review. The lenders also have the right to re-determine the borrowing base at one other time during the year. During the revolving phase, the bank credit facility has no specific terms of repayment. At the end of the revolving period, the lenders have the right to extend the revolving period for a further 364-day period or to convert the facility to a term facility. If the lenders convert to a non-revolving facility, 60% of the aggregate principal amount of the loan shall be repayable on the date that is 366 days after such conversion date and the remaining 40% of the aggregate principal amount outstanding shall be repayable on the date that is 365 days after the initial term repayment date.

The Secured Notes in the amount of US\$125 million have a final maturity of May 7, 2010, and bear interest at 4.19% per annum, with interest paid semi-annually on November 7 and May 7 of each year. The Note Purchase Agreement requires PrimeWest to make four annual principal repayments of US\$31,250,000 commencing May 7, 2007.

Collateral for the Secured Notes and credit facility is a floating charge debenture covering all existing and after acquired property in the principal amount of US\$1 billion. The secured parties for the revolving credit facility and Secured Notes have agreed to share the security interests on a pari passu basis.

The costs incurred in connection with the Secured Notes, in the amount of \$1.5 million, were classified as deferred charges on the balance sheet and are being amortized over the term of the Notes.

The Secured Notes are the legal obligation of PrimeWest Energy Inc. and are guaranteed by PrimeWest Energy Trust.

The 7.5% (Series I) and 7.75% (Series II) Debentures were issued on September 2, 2004 for proceeds of \$150 million and \$100 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 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 Trust Units.

Debenture issue costs of \$10.0 million were included in deferred charges on the balance sheet and are being amortized over the terms of the Debentures.

In accordance with CICA Handbook section 3860 – "Financial Instruments," the Convertible Unsecured Subordinated Debentures were initially recorded at their fair value of \$147.0 million (Series I) and \$94.8 million (Series II). The difference between the fair value and proceeds of \$8.1 million was recorded in equity (\$3.0 million (Series I) and \$5.1 million (Series II)).

The Series I and Series II Debentures are being accreted such that the liability at maturity will equal the proceeds of \$150 million and \$100 million less conversions respectively. During 2005, \$114.3 million (2004 - \$0.3 million) of Series I and \$72.9 million (2004 - \$0 million) of Series II Debentures included in long-term debt were converted to equity. Accretion expense was \$1.0 million (2004 - \$0.4 million).



## 9. 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 natural gas properties:

Asset Retirement Obligations (\$ millions)	2005	2004
Asset retirement obligation, January 1	\$ 40.3	\$ 19.7
Liabilities incurred	8.3	13.1
Liabilities settled	(8.7)	(4.6)
Accretion expense	2.5	2.0
Acquisition of capital assets	-	12.0
Disposal of capital assets	(2.0)	(2.4)
Acquisition of Seventh Energy	-	0.5
Asset retirement obligation December 31	\$ 40.4	\$ 40.3

As at December 31, 2005, the undiscounted amount of estimated cash flows required to settle the obligation is \$222.3 million. The estimated cash flow has been discounted using a credit-adjusted risk free rate of 7.0% and an inflation rate of 1.5%. 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 33.9 years. These future asset retirement costs will be funded from the cash reserved for site restoration and reclamation.

## 10. Cash Reserve For Site Restoration And Reclamation

Commencing in 1998, funding for the reserve was provided for by reducing distributions otherwise payable based on an amount per BOE produced (\$0.50/BOE produced for 2005 and 2004). The cash amount contributed, including interest earned, was \$7.6 million in 2005 (2004 - \$6.7 million). Actual costs of site restoration and abandonment totaling \$8.7 million were paid out of this cash reserve for the year ended December 31, 2005 (2004 - \$4.6 million). As at December 31, 2005, the site reclamation fund had a balance of \$9.2 million (2004 - \$10.3 million).

## 11. Unitholders' Equity

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

Trust Units	Number of Units	Amounts (\$ millions)
<b>Balance, December 31, 2003</b>	48,751,883	\$ 1,532.5 <sup>(1)</sup>
Issued for cash	17,700,000	442.1
Issue expenses	-	(22.6)
Issued on exchange of Exchangeable Shares	833,162	17.0
Issued pursuant to Distribution Reinvestment Plan	268,677	6.5
Issued pursuant to Premium Distribution Plan	1,311,462	32.0
Issued pursuant to Long-Term Incentive Plan	116,233	0.5
Issued pursuant to conversion of Debentures	10,527	0.3
Issued pursuant to Optional Trust Unit Purchase Plan	894,167	21.5
<b>Balance December 31, 2004</b>	69,886,111	\$ 2,029.8
Issued on exchange of Exchangeable Shares	91,871	1.7
Issued pursuant to Distribution Reinvestment Plan	262,347	7.9
Issued pursuant to Premium Distribution Plan	932,142	27.4
Issued pursuant to Long-Term Incentive Plan	487,421	1.3
Issued pursuant to conversion of Debentures	7,301,654	193.5

Trust Units	Number of Units	Amounts (\$ millions)
Issued pursuant to Optional Trust Unit Purchase Plan	704,806	20.4
<b>Balance December 31, 2005</b>	<b>79,666,352</b>	<b>\$ 2,282.0</b>

(1) Restated – see note 3

The weighted average number of Trust Units and Exchangeable Shares outstanding for the twelve months ended December 31, 2005 was 75,808,919 (2004 – 59,482,034). For purposes of calculating diluted net income per Trust Unit, 3,247,742 (2004 – 1,868,995) and 2,286,791 Trust Units (2004-1,247,551) issuable pursuant to the conversion of the Series I and Series II Debentures outstanding respectively and 1,220,958 Trust Units (2004 – 525,129) issuable pursuant to the LTIP were added to the weighted average number.

#### PRIMEWEST EXCHANGEABLE CLASS A SHARES

PrimeWest has an unlimited number of Exchangeable Shares. The Exchangeable Shares are exchangeable into Trust Units at any time up to March 29, 2010, based on an exchange ratio that adjusts each time the Trust makes distribution to its Unitholders. The exchange ratio, which was 1:1 on the date that the Shares were issued, is based on the total monthly distribution, divided by the closing unit price on the distribution payment date. The exchange ratio on December 31, 2005 was 0.56399:1 (2004 – 0.50408:1).

Exchangeable Shares	Number of Units	Amounts (\$ millions)
Balance, December 31, 2003	3,041,123	\$ 28.0
Issued for Special Employee Retention Plan	94,340	1.2
Exchanged for Trust Units	(1,841,072)	(17.0)
Balance, December 31, 2004	1,294,391	\$ 12.2
Issued for Special Employee Retention Plan	94,340	1.8
Exchanged for Trust Units	(169,396)	(1.7)
Balance, December 31, 2005	1,219,335	\$ 12.3

#### TRUST UNITS AND EXCHANGEABLE SHARES ISSUED & OUTSTANDING

Number of Shares	2005	2004
Trust Units issued and outstanding	<b>79,666,352</b>	69,886,111
Exchangeable Shares		
Class A Shares		
(2005 – 1,219,335 shares exchangeable at 0.56399;		
2004 – 1,294,391 shares exchangeable at 0.50408)	<b>687,693</b>	652,477
Total Trust Units and Exchangeable Shares issued and outstanding	<b>80,354,045</b>	70,538,588
Convertible Unsecured Subordinated Debentures		
Series I	<b>1,246,981</b>	5,649,849
Series II	<b>874,717</b>	3,773,585
Unit Appreciation Rights	<b>1,220,958</b>	525,129
Total Trust Units and Exchangeable Shares issued and outstanding and Trust Units issuable pursuant to the conversion of the Convertible Unsecured Subordinated Debentures and the Long-Term Incentive Plan	<b>83,696,701</b>	80,487,151

## 12. Contributed Surplus

Contributed surplus includes the accumulated unit-based compensation charge in respect of PrimeWest's unexercised Unit Appreciation Rights granted under the LTIP on or after January 1, 2002. Upon exercise of the UARs and delivery of the Trust Units, the contributed surplus account is reduced and the amount is transferred to net capital contributions.



(\$ millions)	
Balance, December 31, 2003	\$ 3.6
Non-cash general and administrative expense	3.3
Unit Appreciation Rights exercised	(0.5)
Balance, December 31, 2004	\$ 6.4
Non-cash general and administrative expense	3.6
Unit Appreciation Rights exercised	(1.3)
Balance, December 31, 2005	\$ 8.7

### 13. Long-Term Incentive Plan

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

Effective January 1, 2005, PrimeWest adopted the fair value method of accounting for its LTIP with respect to UARs granted on or after January 1, 2002. Under this method of accounting, the fair value of the UARs is estimated using a recognized options pricing model on the grant date and is amortized over the vesting period with the amortized amount recorded in non-cash G&A expense offset by an increase to contributed surplus. When the UARs are exercised, contributed surplus is decreased and net capital contributions are increased.

PrimeWest recorded \$3.6 million (2004 - \$3.3 million) in non-cash G&A expense related to the LTIP.

For the twelve months ended December 31, 2005, PrimeWest used the Black-Scholes Options Pricing Model to calculate the estimated fair value of outstanding UARs issued on or after January 1, 2002. The following assumptions were used to arrive at the estimated fair value:

Weighted Average Assumptions	2005	2004
Risk-free interest rate	3.18%	3.49%
Expected volatility in Trust Unit price	19.8%	22.0%
Expected time until exercise	3 years	3 years
Expected forfeiture rate	13%	13%
Expected annual dividend yield	zero	zero

Summary of Changes	Number of UARs	Weighted Average Exercise Price
Balance outstanding at December 31, 2003	2,046,436	\$28.03
Granted	1,495,373	27.94
Forfeited/expired	(141,989)	(29.02)
Exercised	(166,328)	(27.37)
Balance outstanding at December 31, 2004	3,233,492	\$28.77
Granted	1,517,674	30.40
Forfeited/expired	(122,873)	(28.44)
Exercised	(458,618)	(28.42)
Balance outstanding at December 31, 2005	4,169,675	\$29.09

## SUMMARY OF UARS OUTSTANDING AT DECEMBER 31, 2005

Year of Grant	UARS Issued and Outstanding	UARS Vested	Range of Exercise Prices	Expiry Date
2002 grants	602,526	600,732	\$ 25.90 – 33.94	2008
2003 grants	805,641	516,356	25.25 – 32.24	2009
2004 grants	1,303,893	489,681	24.24 – 32.49	2010
2005 grants	1,457,615	138,464	28.90 – 40.51	2011
Total grants	4,169,675	1,745,233	\$ 24.24 – 40.51	

**14. Cash Distributions**

(\$ millions)	2005	2004	2003
Cash flow from operations	\$ 414.1	\$ 266.8	\$ 216.6
Deduct amounts to reconcile to distribution:			
Cash retained from cash available for distribution <sup>(1)</sup>	(129.9)	(64.0)	(15.3)
Contributed to reclamation fund	(7.6)	(6.7)	(8.7)
	\$ 276.6	\$ 196.1	\$ 192.6
Cash distributions to Trust Unitholders	\$ 276.6	\$ 196.1	\$ 192.6
Cash distributions per Trust Unit	\$ 3.66	\$ 3.30	\$ 4.32

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

**15. Related Party Transactions**

Under the Special Employee Retention Plan (SERP), PrimeWest agreed to issue 94,340 Exchangeable Shares to certain executive officers on each of the second, third, fourth and fifth anniversaries of the completion of the internalization transaction, which closed on November 6, 2002. In November 2005, 94,340 exchangeable shares were issued relating to the SERP. For the twelve months ended December 31, 2005, \$1.8 million (2004 - \$0.9 million) was recorded in non-cash G&A expense related to the SERP.

**16. Income Taxes**

PrimeWest and its subsidiaries had no taxable income for 2005, 2004 and 2003, as tax pool deductions and the royalty payable were sufficient to reduce taxable income in these entities to nil.

The future income tax asset and liability result from temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases.

(\$ millions)	2005	2004
Derivative liabilities	\$ 3.9	\$ -
Future income tax asset	\$ 3.9	\$ -

(\$ millions)	2005	2004 Restated
Loss carry forwards	\$ (1.2)	\$ (1.4)
Capital assets	224.8	236.9
Foreign exchange gain on long-term debt	4.8	3.7
Asset retirement obligation	(13.6)	(13.5)
Future income tax liability	\$ 214.8	\$ 225.7

The provisions for income taxes varies from the amounts that would be computed by applying the combined Canadian federal and provincial income tax rates for the following reasons:

(\$ millions)	2005	2004 Restated	2003 Restated
Income before taxes	\$ 195.5	\$ 74.4	\$ 31.1
Computed income tax expense (recovery) at the Canadian statutory rate of 37.62% (2004 – 38.87%; 2003 – 40.62%)	73.5	28.9	12.6
Increase (decrease) resulting from:			
Non-deductible Crown royalties and other payments, net of ARTC	0.3	0.3	0.3
Federal resource allowance	(12.3)	(9.2)	(17.4)
Change in income tax rate	(2.7)	(7.0)	(42.4)
Foreign exchange gain on long-term debt	(0.9)	(2.2)	(2.4)
Amounts included in Trust income and other	(72.7)	(45.1)	(26.1)
Future income tax recovery	\$ (14.8)	\$ (34.3)	\$ (75.4)

## 17. Financial Instruments

### a) Commodity Price Risk Management

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

A summary of these contracts in place at December 31, 2005 follows:

#### CRUDE OIL

Period	Volume (bbls/day)	Type	WTI Price (US\$/bbl)
Jan – Mar 2006	1000	Costless Collar	35.00/49.90
Jan – Mar 2006	500	Costless Collar	40.00/60.25
Jan – Mar 2006	500	Costless Collar	40.00/71.75
Jan – Mar 2006	500	Costless Collar	50.00/70.00
Jan – Mar 2006	500	Costless Collar	50.00/75.00
Jan – Mar 2006	1000	Costless Collar	50.00/82.80
Apr – Jun 2006	500	Costless Collar	40.00/71.25
Apr – Jun 2006	500	Costless Collar	50.00/70.00
Apr – Jun 2006	500	Costless Collar	50.00/75.70
Apr – Jun 2006	1000	Costless Collar	50.00/82.75
Apr – Jun 2006	500	Costless Collar	50.00/75.05
Jul – Sep 2006	500	Costless Collar	50.00/75.30
Jul – Sep 2006	1000	Costless Collar	50.00/82.05
Jul – Sep 2006	500	Costless Collar	50.00/76.05
Oct – Dec 2006	500	Costless Collar	50.00/75.03
Oct – Dec 2006	1000	Costless Collar	50.00/81.50
Oct – Dec 2006	500	Costless Collar	50.00/75.00
Jan – Mar 2007	500	Costless Collar	50.00/76.00
Apr – Jun 2007	500	Costless Collar	50.00/80.00

#### NATURAL GAS

Period	Volume (mmcf/day)	Type	AECO Price (Cdn\$/Mcf)
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Period	Volume (mmcf/day)	Type	AECO Price (Cdn\$/Mcf)
Jan – Mar 2006	10	Costless Collar	6.33/9.96
Jan – Mar 2006	10	Costless Collar	6.33/10.22
Jan – Mar 2006	5	Costless Collar	6.33/10.42
Jan – Mar 2006	10	Costless Collar	6.33/10.55
Jan – Mar 2006	5	Costless Collar	6.33/11.61
Jan – Mar 2006	5	Costless Collar	6.33/12.66
Jan – Mar 2006	5	Costless Collar	6.33/13.13
Jan – Mar 2006	5	Costless Collar	6.33/14.03
Jan – Mar 2006	5	Costless Collar	7.39/14.51
Jan – Mar 2006	10	Costless Collar	7.39/14.56
Jan – Mar 2006	5	Costless Collar	10.34/16.88
Jan – Mar 2006	5	Costless Collar	10.55/26.11
Jan – Mar 2006	5	Costless Collar	11.61/22.42
Apr – Jun 2006	5	Costless Collar	6.33/8.91
Apr – Jun 2006	10	Costless Collar	6.86/10.55
Apr – Jun 2006	5	Costless Collar	6.86/10.63
Apr – Jun 2006	5	Costless Collar	7.39/13.72
Apr – Jun 2006	5	Costless Collar	8.44/12.98
Apr – Jun 2006	5	Costless Collar	8.44/15.30
Apr – Jun 2006	10	Costless Collar	8.44/16.62
Jul – Sep 2006	10	Costless Collar	6.86/10.55
Jul – Sep 2006	5	Costless Collar	6.86/10.68
Jul – Sep 2006	5	Costless Collar	7.39/13.56
Jul – Sep 2006	5	Costless Collar	8.44/13.98
Jul – Sep 2006	5	Costless Collar	8.44/15.72
Jul – Sep 2006	5	Costless Collar	8.44/15.83
Jul – Sep 2006	10	Costless Collar	8.44/16.30
Oct – Dec 2006	5	Costless Collar	6.86/11.92
Oct – Dec 2006	10	Costless Collar	6.86/12.66
Oct – Dec 2006	5	Costless Collar	7.39/15.83
Oct – Dec 2006	5	Costless Collar	8.44/15.83
Oct – Dec 2006	5	Costless Collar	8.44/17.94
Oct – Dec 2006	5	Costless Collar	8.44/18.99
Oct – Dec 2006	10	Costless Collar	8.44/19.25
Jan – Mar 2007	5	Costless Collar	8.44/18.46
Jan – Mar 2007	5	Costless Collar	8.44/21.10
Jan – Mar 2007	5	Costless Collar	8.44/21.21

In 2005, the financial impact of contracts settling in the year was a decrease in sales revenues of \$44.3 million (2004 - \$28.2 million decrease in sales revenue).

The mark-to-market value of the hedges in place as at December 31, 2005 is an \$11.5 million loss of which \$9.2 million is attributable to natural gas and \$2.3 million is attributable to crude oil.

b) Fair Value of Financial Instruments

Financial instruments include cash, accounts receivable, accounts payable and accrued liabilities, accrued distributions to Unitholders and long-term debt. As at December 31, 2005, 2004, and 2003, the fair market value of these financial instruments, other than long-term debt, approximate their carrying value, due to the short-term maturity of these instruments. The fair value of long-term debt approximates its carrying value in all material respects, because the cost of borrowing approximates the market rate for similar borrowings.

**18. Commitments and Contingencies**

a) PrimeWest has lease commitments relating to office buildings. The estimated annual minimum operating lease rental payments for the buildings, after deducting sublease income will be \$3.7 million in 2006, \$3.5 million in 2007, \$3.4 million in 2008 and \$0.9 million in 2009.

b) As part of PrimeWest's internalization transaction which closed on November 6, 2002 PrimeWest agreed to issue 377,340 Exchangeable Shares to certain executive officers as a SERP. The SERP issued 94,340 Exchangeable shares on each of November 6, 2004 and 2005 and will issue an additional 94,340 shares on November 6, 2006 and 2007. For the twelve months ended December 31, 2005, \$1.8 million was recorded in non-cash general and administrative expense related to the SERP.

c) PrimeWest has various pipeline transportation commitments that run through 2011. The estimated annual payments are \$7.2 million in 2006, \$3.2 million in 2007, \$0.5 million in 2008, \$0.3 million in 2009, \$0.2 million in 2010 and \$0.1 million in 2011.

d) PrimeWest is engaged in a number of matters of litigation, none of which could reasonably be expected to result in any material adverse consequence.

**19. Prior Years' Comparative Numbers**

Certain prior years' comparative numbers have been restated to conform to the current year's presentation.

**TRADING PERFORMANCE**

For the quarter ended	Dec 31/05	Sep 30/05	Jun 30/05	Mar 31/05	Dec 31/04
TSX Trust Unit Prices (Cdn\$ per Trust Unit)					
High	\$ 37.68	\$ 36.42	\$ 31.68	\$ 32.00	\$ 28.33
Low	\$ 30.55	\$ 30.86	\$ 28.35	\$ 26.15	\$ 25.06
Close	\$ 35.90	\$ 36.40	\$ 30.66	\$ 28.99	\$ 26.62
Average daily traded volume	199,849	183,469	202,225	269,714	255,944

For the quarter ended	Dec 31/05	Sep 30/05	Jun 30/05	Mar 31/05	Dec 31/04
NYSE Trust Unit Prices (US\$ per Trust Unit)					
High	\$ 32.57	\$ 31.37	\$ 25.59	\$ 26.60	\$ 22.98
Low	\$ 25.71	\$ 25.15	\$ 22.50	\$ 21.30	\$ 20.85
Close	\$ 30.92	\$ 31.33	\$ 25.05	\$ 23.96	\$ 22.18
Average daily traded volume	480,603	445,338	377,264	536,170	542,483
Number of Trust Units outstanding including Exchangeable Shares (millions of Trust Units)	80.4	79.1	77.2	72.9	70.5
Distribution paid per Trust Unit	\$ 0.96	\$ 0.90	\$ 0.90	\$ 0.90	\$ 0.90

TOTAL COMPOUND ANNUAL RETURN (%)<sup>(1)</sup>

	PrimeWest	TSX Oil & Gas index	TSX S&P	S&P 500 Cdn\$	S&P 500 US\$	S&P/TSX CDN Energy Trust Index
Five year	19.0	25.8	6.7	(4.5)	0.5	30.7
Three year	28.6	38.5	21.7	3.7	13.2	41.8
One year	51.4	63.7	24.3	1.5	4.9	49.5

(1) Total return = Unit price plus distributions re-invested.

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