PrimeWest Energy Trust

For the fourth quarter and twelve months ended December 31, 2004

CALGARY, February 24, 2005 (TSX: PWI.UN; PWX; PWI.DB.A; PWI.DB.B; NYSE: PWI) -- PrimeWest Energy Trust (PrimeWest or the Trust) today announced interim operating and financial results for the fourth quarter and year ended December 31, 2004. Unless otherwise noted, all figures contained in this report are in Canadian dollars.

PRIMEWEST ENERGY TRUST ANNOUNCES FOURTH QUARTER AND FULL YEAR 2004 RESULTS

Fourth Quarter Highlights:

- In the fourth quarter PrimeWest closed non-core asset sales for net proceeds of $88.1 million. These funds were used to reduce the amount drawn on the bank credit facility. In addition another $5.4 million of assets were held for sale and closed in February 2005.
- Year-end net debt to annualized fourth quarter 2004 cash flow is 1.7 times.
- Fourth quarter production averaged 44,368 barrels of oil equivalent (BOE) per day, compared to the third quarter 2004 rate of 35,460 BOE/day.
- Distributions of $0.90 per unit represent a payout ratio of approximately 76%, compared to third quarter 2004 distributions of $0.83 per unit, representing a payout ratio of approximately 74%.
- Cash flow from operations of $81.8 million ($1.07 per unit) compared to $68.3 million ($1.06 per unit) in the third quarter of 2004, primarily due to a continued strong commodity price environment and increased production volumes from the Calpine asset acquisition.
- Year end Proved plus Probable Reserve Life Index increased to 10.3 years from 9.8 years at the end of 2003.

Subsequent Events

- On January 26, 2005 Standard and Poors announced the inclusion of income trusts in the S&P/TSX Composite Index, Canada’s benchmark stock index. Specifics regarding the inclusion process, including the impact on PrimeWest is expected to be announced by mid-year 2005.
- On January 27, 2005 the unitholders of Calpine Natural Gas Trust approved the business combination of Calpine Natural Gas Trust and Viking Energy Royalty Trust. As a result PrimeWest’s 25% unit ownership of Calpine Natural Gas Trust has been converted into an 8.3% ownership of Viking Energy Trust. As of February 24, 2005, PrimeWest has sold its 8.3% ownership of Viking Energy Trust and has received gross proceeds of $95.8 million.

Legislative Changes

On December 6, 2004, the Government of Canada suspended legislation that would have restricted the non-resident ownership of income trusts. The Government proceeded with the proposed changes to non-resident withholding tax and non-resident unitholders are encouraged to contact their tax advisors.

Forward Looking Information

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

The use of any of the words "anticipate, "continue, "estimate", "expect", "may", "will", "project", "should", "believe", "outlook" and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in our forward-looking statements. We believe the expectations reflected in those forward-looking statements are reasonable. However, we cannot assure you that these expectations will prove to be correct. You should not unduly rely on forward-looking statements included in this report. These statements speak only as of the date of this MD&A.

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

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

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

- Volatility in market prices for oil and natural gas;
- The impact of weather conditions on seasonal demand;
- Risks inherent in our oil and gas operations;
- Uncertainties associated with estimating reserves;
- Competition for, among other things; capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- Incorrect assessments of the value of acquisitions;
- Geological, technical, drilling and processing problems;

- General economic conditions in Canada, the United States and globally;
- Industry conditions, including fluctuations in the price of oil and natural gas;
- Royalties payable in respect of PrimeWest's oil and gas production;
- Governmental regulation of the oil and gas industry, including environmental regulation;
- Fluctuation in foreign exchange or interest rates;
- Unanticipated operating events that can reduce production or cause production to be shut-in or delayed;
- Failure to obtain industry partner and other third party consents and approvals, when required;
- Stock market volatility and market valuations;
- OPEC's ability to control production to balance global supply and demand of crude oil at desired prices 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 "Operational and Other Business Risks" in this MD&A.

These factors should not be construed as exhaustive.

Management's Discussion and Analysis

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

Financial and Operating Highlights – Fourth Quarter

Financial Highlights	**Three Months Ended**		
($ millions, except per BOE and per Trust Unit amounts)	**Dec 31, 2004**	Sep 30, 2004	Dec 31, 2003
Gross revenue (net of transportation)	**169.3**	125.4	97.1
per BOE(1)	**41.46**	38.43	32.88
Cash flow from operations	**81.8**	66.8	43.2
per BOE	**20.05**	20.48	14.62
per Trust Unit(2)	**1.07**	1.04	0.86
Royalty expense	**41.8**	28.9	21.1
per BOE	**10.24**	8.86	7.13
Operating expenses	**28.3**	21.4	21.2
per BOE	**6.94**	6.56	7.18
G&A expenses - Cash	**7.9**	3.4	4.1
per BOE	**1.93**	1.03	1.37
G&A expenses - Non-cash	**2.3**	14.1	8.5
per BOE	**0.56**	4.31	2.88
Interest expense (3)	**11.7**	4.4	4.1
per BOE	**2.86**	1.35	1.37
Distributions to unitholders	**62.6**	50.4	46.3
per Trust Unit(4)	**0.90**	0.83	0.96
Net debt(5)	**552.0**	464.8	255.9
per Trust Unit(6)	**7.77**	5.84	5.07

(1) All calculations required to convert natural gas to a crude oil equivalent (BOE) have been made using a ratio of 6,000 cubic feet of natural gas to one barrel of crude oil. BOE's may be misleading, particularly if used in isolation. The BOE conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(2) Weighted Average Trust Units, Exchangeable Shares, Convertible Unsecured Subordinated Debentures and Trust Units issuable pursuant to Long-Term Incentive Plan (diluted). Cash flow is increased to adjust for the interest on Convertible Unsecured Subordinated Debentures.

(3) Interest expense includes the interest on the Convertible Unsecured Subordinated Debentures.

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

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

(6) Trust Units and Exchangeable Shares outstanding and Trust Units issuable pursuant to the Long-Term Incentive Plan December 31, 2004.

Operating Highlights	**Three Months Ended**		
	Dec 31, 2004	Sep 30, 2004	Dec 31, 2003
Daily Sales Volumes			
Natural gas *(mmcf/day)*	**187.2**	143.5	126.9
Crude oil *(bbls/day)*	**9,108**	8,447	8,189
Natural gas liquids *(bbls/day)*	**4,059**	3,096	2,779
Total *(BOE/day)*	**44,368**	35,460	32,111

Outlook – 2005

PrimeWest expects full year 2005 production volumes to average approximately 41,000 BOE/day. Full year operating costs are expected to be approximately $6.60/BOE. PrimeWest expects to invest approximately $125 million in its capital development program with the focus on further development of our Alberta natural gas assets. Approximately $50 million will be invested in development of tight gas assets at Caroline and Columbia; $20 million will be invested in developing shallow gas assets in southeastern Alberta; and $55 million will be invested in development of natural gas at Crossfield and conventional development. The Trust plans to begin evaluating Coal Bed Methane potential on our land holdings in the Horseshoe Canyon fairway.

Cash Flow Reconciliation

($ millions)	
Third quarter 2004 cash flow from operations	$ 66.8
Volumes	32.3
Commodity prices	10.1
Net hedging change from prior quarter	1.3
Operating expenses	(6.9)
Royalties	(12.9)
General and administrative expenses	(4.5)
Interest Expense	(7.3)
Other	2.9
Fourth quarter 2004 cash flow from operations	81.8

The above table includes non-GAAP measurements that may not be comparable to other companies. Refer to the section on Non-GAAP Measures.

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

Taxability of Distributions

Canadian Unitholders

The Trust has determined that 45% of distributions declared, or $1.49 per Trust Unit are deemed a tax-deferred return of capital and 55% or $1.81 per Trust Unit are taxable to Canadian unitholders as "other income" (taxed at the same rate as interest income.)

United States and Other Non-Resident Unitholders

For unitholders resident in the United States, the taxability of distributions is derived using US tax rules, which permit the deduction of Crown royalties and accounting-based depletion. In the case of a US resident, 45% of the distributions are taxable as a "qualified dividend" with the remaining 55% treated as a tax-deferred return of capital.

Investors who do not qualify as residents of Canada for income tax purposes should seek advice from a qualified tax advisor in their country of residency regarding the tax treatment of the distributions paid by PrimeWest. Monthly distributions payable to non-residents of Canada are normally subject to a withholding tax of 25% as prescribed by the Canadian Income Tax Act. However, the level of withholding tax may be reduced in accordance with reciprocal tax treaties. In the case of the Canada – United States Tax Convention, US residents are subject to a 15% withholding tax on the distributions paid by PrimeWest.

For further information on taxability of distributions paid by PrimeWest, please refer to the Taxation section of our website at www.primewestenergy.com and your qualified tax advisor.

Capital Expenditures

($ millions)	Three Months Ended **Dec 31, 2004**	Sep 30, 2004	Dec 31, 2003
Land & lease acquisitions	**$ 1.8**	$ 2.0	$ 2.1
Geological and geophysical	**2.4**	3.3	4.4
Drilling and completions	**30.1**	12.0	16.9
Investment in facilities			
Equipping & tie-in	**4.3**	1.0	3.4
Compression & processing	**0.9**	1.3	0.5
Gas gathering	**1.9**	1.8	1.4
Production facilities	**5.0**	3.6	2.2
Capitalized G&A	**0.4**	0.4	0.2
Development capital	**46.8**	25.4	31.1
Corporate/property acquisitions	**1.4**	767.0	23.9
Dispositions	**(88.1)**	(6.3)	(1.5)
Leasehold improvements, furniture and equipment	**3.2**	0.6	1.2
Total	**$ (36.7)**	$ 786.7	$ 54.7

During the fourth quarter of 2004, PrimeWest's net capital expenditures totaled $(36.7) million as proceeds from dispositions exceeded capital expenditures. Development capital of $46.8 million invested in the fourth quarter 2004 included $34.4 million or 74% for drilling, completions and tie-ins that contribute to new reserve additions and help offset natural production decline. In the fourth quarter, PrimeWest's capital spending was focused primarily in the areas of Caroline, Columbia, Brant Farrow, Boundary Lake and Princess. Gross wells drilled in the fourth quarter totaled 69 (38.6 net wells), with a success rate of 97%.

Compared to the third quarter of 2004, development capital spending of $46.8 million in the fourth quarter of 2004 was higher due to a higher level of drilling activity as a result of the Calpine acquisition.

During the fourth quarter of 2004, PrimeWest incurred leasehold improvement expenditures on office space acquired to accommodate additional staff, resulting from the Calpine acquisition.

In the fourth quarter PrimeWest engaged in a divestiture program targeting non-core assets which resulted in proceeds of $88.1 million. An additional $5.4 million of assets were held for sale at year-end and closed in February 2005. These asset sales reduced production volumes by approximately 2,700 BOE/day, however, due to the timing of the sales the fourth quarter average daily production volume impact was a reduction of 400 BOE/day.

Production Volumes

	Three Months Ended		
	Dec 31, 2004	Sep 30, 2004	Dec 31, 2003
Natural gas (mmcf/day)	**187.2**	143.5	126.9
Crude oil (bbls/day)	**9,108**	8,447	8,189
Natural gas liquids (bbls/day)	**4,059**	3,096	2,779
Total (BOE/day)	**44,368**	35,460	32,111
Gross Overriding Royalty volumes included above (BOE/day)	**1,643**	1,404	1,595

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

PrimeWest's production volumes in the fourth quarter 2004 are higher when compared with the third quarter of 2004 and the fourth quarter of 2003 primarily due to volumes contributed by the Calpine assets. PrimeWest's development activity also added volumes, which partially offset natural production decline.

In the second quarter of 2004, the Alberta Energy and Utilities Board ruled on the natural gas over bitumen issue, which resulted in approximately 330 BOE/day of PrimeWest production at Ells being permanently shut-in effective July 1, 2004. In October 2004, the Government of Alberta enacted amendments to the Natural Gas Royalty Regulations of 2002 specifically with respect to gas production in the affected area. This amendment provides for a technical change to the royalty calculation for gas producers adversely affected by the EUB shut-in orders. This technical change to the calculation of royalties represents a reduction in royalties paid by PrimeWest to the Province of Alberta. PrimeWest is evaluating the change to the royalty calculation and its impact as well as any further steps to be taken in relation to the gas over bitumen issue.

PrimeWest expects full year 2005 production to average approximately 41,000 BOE/day. This estimate incorporates PrimeWest's expected natural production declines and volume shut-in, offset by volume additions from the 2005 capital development program.

Average Realized Sales Prices

	Three Months Ended		
(Canadian Dollars)	**Dec 31, 2004**	Sep 30, 2004	Dec 31, 2003
Natural gas ($/Mcf)(1)(2)	**7.00**	**6.14**	5.52
Without hedging	**6.98**	**6.31**	5.50
Crude oil ($/bbl)(1)	**36.45**	**39.95**	31.27
Without hedging	**46.03**	**48.58**	33.43
Natural gas liquids ($/bbl)	**47.32**	**45.30**	34.49
Total Oil Equivalent ($/BOE)	**41.37**	**38.31**	32.78
Without hedging	**43.24**	**41.06**	33.25
Realized hedging loss included in prices above ($/BOE)	**1.87**	**2.75**	0.47

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

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

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

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

PrimeWest's cash flow from operations is directly impacted by the volatility in commodity prices, but the use of hedging can reduce the impact of the price volatility by locking in prices in advance. This can increase or decrease the prices realized by the Trust. In the fourth quarter of 2004, PrimeWest reported a $7.6 million hedging loss representing the amount of additional revenue that could have been earned without hedging. This compared to a loss of $9.0 million in the third quarter of 2004 and a loss of $1.4 million for the same period in 2003.

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

Benchmark Commodity Prices	**Past Four Quarters (Actual)**				**Next Four Quarters (Forward Markets)[1]**			
	Q1 2004	Q2 2004	Q3 2004	Q4 2004	Q1 2005	Q2 2005	Q3 2005	Q4 2005
Natural gas								
NYMEX *(US$/mcf)*	5.69	5.97	5.84	6.87	6.23	6.10	6.19	6.55
AECO *(Cdn$/mcf)*	6.61	6.80	6.66	7.09	6.28	6.24	6.40	6.88
Crude oil WTI *(US$/bbl)*	35.15	38.32	43.88	48.28	43.54	42.97	42.25	41.65

(1) As December 31, 2004

Financial and Operating Highlights – Full Year

	2004	2003	Change (%)
FINANCIAL ($ millions, except per BOE and per Trust Unit amounts)			
Gross revenue (net of transportation expense)	**513.7**	434.6	18
per BOE[1]	**39.45**	35.74	10
Cash flow from operations	**266.8**	216.6	23
per BOE	**20.49**	17.82	15
per Trust Unit[2][6]	**4.33**	4.67	(7)
Royalty expense	**119.8**	101.9	18
per BOE	**9.20**	8.38	10
Operating expenses	**88.9**	79.4	12
per BOE	**6.83**	6.53	5
G&A expenses - Cash	**19.0**	14.5	31
per BOE	**1.46**	1.20	22
G&A expenses - Non-cash	**9.4**	14.4	(35)
per BOE	**0.73**	1.19	(39)
Interest expense [3]	**20.6**	15.1	36
per BOE	**1.58**	1.24	27

Net income	**103.4**	95.9	8
Per Trust Unit – diluted	**1.74**	2.07	(16)
Distributions to unitholders	**196.1**	192.6	2
per Trust Unit[(4)]	**3.30**	4.32	(24)
Net debt[(5)]	**552.0**	255.9	116
per Trust Unit[(6)]	**7.77**	5.07	53

(1) All calculations required to convert natural gas to a crude oil equivalent (BOE) have been made using a ratio of 6,000 cubic feet of natural gas to one barrel of crude oil. BOE's may be misleading, particularly if used in isolation. The BOE conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(2) Weighted Average Trust Units, Exchangeable Shares, Convertible Unsecured Subordinated Debentures and Trust Units issuable pursuant to Long-Term Incentive Plan (diluted). Cash flow is increased to adjust for the interest on Convertible Unsecured Subordinated Debentures.

(3) Interest expense includes the interest on the Convertible Unsecured Subordinated Debentures.

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

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

(6) Trust Units and Exchangeable Shares outstanding and Trust Units issuable pursuant to the Long-Term Incentive Plan December 31, 2004.

Operating

	2004	2003	Change (%)
Daily Sales Volume			
Natural gas (mmcf/day)	**145.1**	134.1	8
Crude oil (bbls/day)	**8,282**	8,116	2
Natural gas liquids (bbls/day)	**3,107**	2,855	9
Total (BOE/day)	**35,578**	33,316	7

Realized Commodity Prices

(Canadian Dollars)	**2004**	2003	Change (%)
Natural gas ($/Mcf)[(1)(2)]	**6.61**	6.05	9
Without hedging	**6.70**	6.51	3
Crude oil ($/bbl)[(1)]	**36.83**	33.94	9
Without hedging	**44.46**	36.55	22
Natural gas liquids ($/bbl)	**43.69**	35.34	24
Total Oil Equivalent [(1)] ($/BOE)	**39.35**	35.63	10
Without hedging	**41.51**	38.14	9

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

Financial and Operating Highlights – Full Year

- Production in 2004 averaged 35,578 BOE/day, up 7% from 2003 level of 33,316 BOE/day as a result of the Calpine and Seventh Energy acquisitions and development capital volume additions, offset by natural production declines.
- Operating margin of $23.47/BOE for 2004, up 14% from 2003 primarily due to higher commodity prices throughout the year, offset by higher operating costs in 2004.
- Distributions of $3.30 per Trust Unit in 2004 compared to $4.32 in 2003 due partially to a lower payout ratio of 74% in 2004 compared to 89% in 2003.
- Hedging loss of $28.2 million ($2.16/BOE) in 2004, compared to losses of $30.5 million ($2.51/BOE) in 2003 and gains of $28.1 million ($2.55/BOE) in 2002.
- Capital development program of $125.1 million added 10.3 mmBOE of Proved plus Probable reserves on a Company Interest basis at $12.15/BOE, which excludes $0.92/BOE for future development capital. (Refer to the "Reserves and Production" section later in this release for reserve definitions).
- In 2004, PrimeWest's corporate and asset acquisitions which included Seventh Energy and the Calpine assets were $807.4 million.
- Operating expenses at $6.83/BOE were 5% higher on a per BOE basis in 2004 compared to 2003, primarily due to rising industry costs.
- Company Interest Proved plus Probable reserves of 155.2 mmBOE at December 31, 2004, represents an increase of 45% from 106.8 mmBOE reported as at December 31, 2003. PrimeWest's current Reserve Life Index (RLI) is 10.3 years on a Company Interest Proved plus Probable basis. Company Interest Proved Producing reserves of 105.8 mmBOE at December 31, 2004, represent an increase of 37% over the December 31, 2003 Company Interest Proved Producing reserves of 77.5 mmBOE. The Company Interest Proved Producing RLI is 7.6 years.
- Cash general and administrative expenses increased $4.5 million over 2003 reflecting higher salaries, higher short-term incentive bonuses, increased information technology expenditures, one-time consulting costs associated with potential acquisitions, and increased board of directors costs. These increases were partially offset by increases in overhead recoveries.
- Interest expense during 2004 is 36% higher compared to 2003 as a result of higher average debt levels during the fourth quarter due to the acquisition of the Calpine assets.
- The Distribution Reinvestment, Premium Distribution and Optional Trust Unit Purchase Plans added $60.0 million of proceeds that were used for the capital development program and to repay debt.

Non-GAAP Measures

The 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 unit basis;
- Distributions per trust unit;
- 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 is calculated using cash flow and adding back the interest expense on the convertible unsecured subordinated debentures, divided by the diluted weighted average units outstanding in the year. The diluted weighted average units outstanding consists of the weighted average Trust Units and Exchangeable Shares outstanding, and includes the Trust Units that would be issued pursuant to the conversion of the Convertible Unsecured Subordinated Debentures, and Trust Units issuable pursuant to the Long-Term Incentive Plan. 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 2004 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 less working capital, excluding derivative assets and liabilities, divided by the number of Trust Units and exchangeable shares outstanding and Trust Units issuable pursuant to the Long Term Incentive Plan at December 31, 2004.

The Trust's cash flow from operations, distributions per Trust Unit and net debt per Trust Unit may not be directly comparable to similar measures presented by other companies or Trusts.

Evaluation of Disclosure Controls and Procedures

The Chief Executive Officer, Don Garner, and Chief Financial Officer, Dennis Feuchuk, evaluated the effectiveness of PrimeWest Energy's disclosure controls and procedures as of December 31, 2004, and concluded that PrimeWest Energy's disclosure controls and procedures were effective to ensure that information PrimeWest is required to disclose in its filings with the Securities and Exchange Commission under the Securities Exchange Act of 1934 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.

Changes to Internal Controls and Procedures for Financial Reporting

There were no significant changes to PrimeWest's internal controls or in other factors that could significantly affect these controls subsequent to December 31, 2004.

Vision, Core Business and Strategy

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

Maximizing total return to unitholders, in the form of cash distributions and change in unit price, is PrimeWest's overriding objective. Our strategies for asset management and growth, financial management and corporate governance are outlined in this MD&A, along with a discussion of our performance in 2004 and our goals for 2005 and beyond.

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

Asset Management and Growth

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

Financial Management

PrimeWest strives to maintain a conservative debt position, to allow us to fund smaller acquisitions without tapping into the capital markets and to fund ongoing development activities. Our long-term debt is comprised of bank credit facilities through a bank syndicate, senior secured notes and convertible unsecured subordinated debentures. Our diversified debt instruments help to reduce our reliance on the bank syndicate, as well as afford additional foreign exchange protection because a portion of our debt, the senior secured notes, are denominated in US dollars. PrimeWest's commodity hedging approach helps to stabilize cash flow, reduce volatility, and protect transaction economics.

PrimeWest continues to target a payout ratio between 70% and 90% of annual cash flow from operations to increase the Trust's financial flexibility. The 2004 payout ratio was approximately 74%, and the retained cash flow was utilized to fund the Trust's capital spending program and repay debt. PrimeWest's net debt to cash flow level is 1.7 times at 2004 year end using annualized fourth quarter cash flows.

PrimeWest's dual listing on both the Toronto Stock Exchange (TSX) and New York Stock Exchange (NYSE) provide increased liquidity and a broadened investor base. The NYSE listing enables 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 unitholders, PrimeWest offers participation in the Distribution Reinvestment Plan (DRIP), Premium Distribution Plan (PREP), and Optional Trust Unit Purchase Plan (OTUPP), which represent a convenient way to maximize an investment in PrimeWest. For alternate investment styles, PrimeWest also has Exchangeable Shares and Convertible Unsecured Subordinated Debentures available, which permit participation in PrimeWest without the ongoing tax implications associated with receiving a distribution.

Corporate Governance

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

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

Outlook – 2005

PrimeWest expects 2005 production volumes to average approximately 41,000 BOE/day. Full year operating costs are expected to be approximately $6.60/BOE, while full year G&A costs are expected to be approximately $1.25/BOE. PrimeWest expects to invest approximately $125 million in its capital development program with the focus on further development of our Alberta natural gas assets. Approximately $50 million will be invested in development of tight gas assets at Caroline and Columbia; $20 million will be invested in developing shallow gas assets in southeastern Alberta; and approximately $55 million will be invested in development of natural gas at Crossfield and conventional development opportunities. The Trust plans to being evaluating Coal Bed Methane potential on our land holdings in the Horseshoe Canyon fairway.

Cash Flow Reconciliation

($ millions)		
2003 cash flow from operations	$	216.6
Production volumes		33.1
Commodity prices		43.8
Net hedging change from prior year		2.3
Operating expenses		(9.5)
Royalties		(17.9)
Interest		(5.5)
G&A		(4.5)
Other		8.4
2004 cash flow from operations	$	266.8

The above table includes non-GAAP measurements (see Section on Non-GAAP Measures)

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 expenses, interest, 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 not controllable by PrimeWest. Other factors that are to a certain extent controllable by PrimeWest include production levels and operating expenses, as well as interest and general and administrative (G&A) expenses.

Capital Spending

Capital expenditures, including development, acquisitions and divestitures totaled approximately $837.6 million in 2004, versus $334.4 million in 2003.

($ millions, except per BOE)	**2004**	2003
Land & lease acquisitions	**$ 8.3**	$ 6.0
Geological and geophysical	**8.2**	5.8
Drilling and completions	**69.8**	58.4
Equipping and tie-in	**12.1**	19.0
Compression and processing	**4.7**	6.3
Gas gathering	**4.4**	2.3
Production facilities	**15.8**	5.7
Capitalized G&A	**1.8**	1.0
Development capital	**$ 125.1**	$ 104.5
Corporate/property acquisitions	**807.4**	230.9
Dispositions	**(99.5)**	(2.3)
Leasehold improvements, furniture and capital	**4.6**	1.3
Total	**$ 837.6**	$ 334.4

In 2004 PrimeWest completed $807.4 million of corporate and property acquisitions that included the Calpine assets and Seventh Energy. Total capital and corporate acquisitions added 46.5 mmBOE of Company Interest Proved reserves and 58.3 mmBOE of Company Interest Proved plus Probable reserves. Property dispositions of $104.9 million, including assets held for sale of $5.4 million resulted in a reduction of the Company Interest Proved Plus Probable reserves of 5.1 mmBOE.

PrimeWest's 2004 capital development program totaled $125.1 million (2003 - $104.5 million). The program focused on core areas of Caroline, Columbia, Princess, Boundary Lake, Brant Farrow and Valhalla. The development program added 7.3 mmBOE of Company Interest Proved reserves and 10.3 mmBOE of Company Interest Proved plus Probable reserves.

Leasehold improvements during 2004 of $2.5 million were incurred as a result of additional office space requirements associated with the Calpine acquisition.

	2004	2003
Development Program:		
Proved reserve additions (mmBOE)	**7.3**	6.9
Average cost ($/BOE)[(1) (3)]	**$ 17.76**	$ 15.98
Proved plus Probable reserve additions (mmBOE)	**10.3**	7.9
Average cost ($/BOE)[(1) (3)]	**$ 13.07**	$ 14.29
Acquisition Program:[(2)]		
Proved reserve additions (mmBOE)	**42.4**	12.7
Average cost ($/BOE)	**$ 16.57**	$ 18.84
Proved plus Probable reserve additions (mmBOE)	**53.2**	15.6
Average cost ($/BOE) [(3)]	**$ 13.20**	$ 15.71

(1) Under NI 51-101 the implied methodology to be used to calculate FD&A costs includes incorporating future development capital (FDC) required to bring the Company Interest Proved Undeveloped and Probable reserves to production. The average cost per BOE from

Company Interest Proved reserve additions includes FDC of $0.62/BOE ($0.84/BOE for 2003), and the average cost per BOE from Company Interest Proved plus Probable reserve additions includes FDC of $0.92/BOE ($1.06/BOE for 2003).

(2) Net of dispositions

(3) The aggregate of the costs incurred under the capital development program incurred in 2004 and the estimated future development costs generally will not reflect the total finding and development costs related to reserve additions for that year.

Drilling, completions and tie-in spending represent 65% of development capital that contributed to new reserve additions. 20% or $24.9 million of the development capital was invested in facilities that represents debottlenecking, increasing capacity or other activities that contribute to future production volumes.

In 2005, PrimeWest plans to invest approximately $125 million on its capital development programs. The 2005 program will focus on further development of our Alberta natural gas assets.

Given that production volumes will decline naturally over time as oil or gas reservoirs are depleted, PrimeWest is always striving to offset this natural production 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 stringent 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, multi-zone suite of assets stretching from northeast B.C., and 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 core areas.

Reserves and Production

National Instrument 51-101 (NI 51-101) was introduced by the Alberta Securities Commission in 2003 to improve the standards and quality of reserve reporting and to achieve a higher industry consistency. Under NI 51-101, “Proved” reserves are those reserves that can be estimated with a high degree of certainty to be recoverable (i.e. it is likely that the actual remaining quantities recovered will exceed the estimated Proved reserves). In accordance with this definition, the level of certainty targeted by the reporting company should result in at least a 90% probability that the quantities actually recovered will equal or exceed the estimated reserves. In the case of “Probable” reserves, which are obviously 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 reporting company must believe that there is at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved plus Probable reserves.

In accordance with NI 51-101, six thousand cubic feet (6 mcf) of natural gas and one barrel of natural gas liquids (1 bbl NGL) each equal one barrel of oil equivalent (BOE). This conversion rate is not based on price or energy content. As such, BOE’s may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 mcf of natural gas to 1 barrel of crude oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

The following table sets forth a reconciliation of light, medium and heavy crude oil, natural gas, natural gas liquids and barrels of oil equivalent of the Company Interest Reserves of PrimeWest for the year ended December 31, 2004 derived from the report of the independent reserve evaluators, Gilbert Lausten Jung Associated Ltd. (GLJ) using Consultant's Average Forecast Price and Cost estimates, and reconciled to December 31, 2003. PrimeWest's Company Interest Reserves include working interest and royalties receivable. This definition is consistent with the basis on which Reserves were reported in prior years.

Company Interest Reserves – Consultant's Average Pricing

	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**
December 31, 2003	18,854.0	19,554.6	3,324.4	22,879.0	304.9	343.2	89.0	432.2
Capital additions	680.3	704.9	545.4	1,250.3	10.5	19.8	5.6	25.4
Improved Recovery	356.1	329.1	20.1	349.2	11.9	13.2	6.7	19.9
Technical Revisions	1,233.5	1,193.9	107.1	1,301.0	(6.3)	(3.2)	(7.7)	(10.9)
Acquisitions	3,033.7	3,306.1	600.4	3,906.5	194.2	224.7	58.7	283.4
Dispositions	(2,074.3)	(2,292.3)	(459.4)	(2,751.7)	(6.6)	(10.1)	(3.1)	(13.2)
Economic Factors [1]	-	-	-	-	(5.0)	(5.1)	(0.3)	(5.4)
Production	(3,031.3)	(3,031.3)	-	(3,031.3)	(53.4)	(53.4)	-	(53.4)
December 31, 2004	**19,052.0**	**19,765.0**	**4,138.0**	**23,903.0**	**450.2**	**529.2**	**148.7**	**677.9**

	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**
December 31, 2003	7,798.0	8,975.1	2,887.7	11,862.8	77.5	85.7	21.1	106.8
Capital additions	259.1	294.0	61.3	355.3	2.7	4.3	1.5	5.8
Improved Recovery	398.3	458.6	311.1	769.7	2.7	3.0	1.4	4.4
Technical Revisions	(365.4)	(243.5)	(349.0)	(592.5)	(0.2)	0.4	(1.5)	(1.1) [1]
Acquisitions	4,838.6	5,706.4	1,406.0	7,112.4	40.3	46.5	11.8	58.3
Dispositions	(52.3)	(65.3)	(35.1)	(100.4)	(3.2)	(4.0)	(1.1)	(5.1)
Economic Factors [2]	-	-	-	-	(0.8)	(0.9)	-	(0.9)
Production	(1,137.3)	(1,137.3)	-	(1,137.3)	(13.1)	(13.1)	-	(13.1)
December 31, 2004	**11,739.0**	**13,988.0**	**4,282.0**	**18,270.0**	**105.8**	**121.9**	**33.3**	**155.2**

Columns may not add due to rounding

[1] Approximately 0.8 mmboe of this amount is attributable to the cessation of liquids stripping, resulting in a higher heat content gas stream.

[(2)] Economic factors relate to reserves that have been shut-in due to the EUB gas over bitumen issue. Due to the uncertainty of their future production these reserves have been removed from the corporate total.

The following table sets forth a reconciliation of PrimeWest's Net Reserves for the year ended December 31, 2004 derived from the report of the independent reserve evaluators, GLJ, using Consultant's Average Forecast Price and Cost estimates. These year-end reserves are reconciled to December 31, 2003 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.

Net Reserves – Consultant's Average Pricing

	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
December 31, 2003	14,284	14,829	2,504	17,333	2,856	2,959	435	3,394
Extensions	460	482	427	909	-	-	-	-
Improved Recovery	312	286	17	303	4	4	1	5
Technical Revisions	126	5	69	74	(40)	(1)	(14)	(15)
Discoveries	82	82	28	110	-	-	-	-
Acquisitions	2,415	2,602	458	3,060	297	352	74	426
Dispositions	(1,331)	(1,417)	(454)	(1,871)	(454)	(570)	(136)	(706)
Economic Factors [(1)]	268	276	49	325	762	763	143	906
Production	(1,849)	(1,849)	-	(1,849)	(884)	(884)	-	(884)
December 31, 2004	**14,767**	**15,296**	**3,098**	**18,394**	**2,541**	**2,623**	**503**	**3,126**

	Associated and Non-Associated Gas (Natural Gas) (bcf)				Natural Gas Liquids (mbbls)			
	Proved Producing	Total Proved	Probable	Proved Plus Probable	Proved Producing	Proved	Probable	Proved Plus Probable
December 31, 2003	240.7	269.9	70.1	339.9	5,570	6,381	2,051	8,433
Extensions	7.3	14.9	4.1	19.1	174	205	40	245
Improved Recovery	9.5	10.6	5.3	15.9	278	320	214	534
Technical Revisions	(0.8)	1.8	(6.1)	(4.4)	(305)	(189)	(259)	(448)
Discoveries	0.9	1.2	0.4	1.6	3	6	2	8
Acquisitions	154.5	179.0	46.6	225.6	3,405	4,021	980	5,001
Dispositions	(9.3)	(12.1)	(2.9)	(15.0)	(37)	(46)	(23)	(69)
Economic Factors [(1)]	(2.4)	(2.6)	0.1	(2.4)	20	13	2	15
Production	(42.2)	(42.2)	0.0	(42.2)	(800)	(800)	-	(800)
December 31, 2004	**358.2**	**420.4**	**117.6**	**538.0**	**8,308**	**9,911**	**3,008**	**12,919**

	Total (mmboe)			
	Proved Producing	Proved	Probable	Proved Plus Probable
December 31, 2003	62.8	69.1	16.7	85.8
Extensions	1.9	3.2	1.2	4.3
Improved Recovery	2.2	2.4	1.1	3.5
Technical Revisions	(0.4)	0.1	(1.2)	(1.1)[1]
Discoveries	0.2	0.3	0.1	0.4
Acquisitions	31.9	36.8	9.3	46.1
Dispositions	(3.4)	(4.1)	(1.1)	(5.2)
Economic Factors [2]	0.6	0.6	0.2	0.8
Production	(10.6)	(10.6)	0.0	(10.6)
December 31, 2004	**85.3**	**97.9**	**26.2**	**124.1**

Columns may not add due to rounding

(1) Approximately 0.8 mmboe of this amount is attributable to the cessation of liquids stripping, resulting in a higher heat content gas stream.

(2) Economic factors relate to reserves that have been shut-in due to the EUB gas bitumen issue. Due to the uncertainty of their future production these reserves have been removed from the corporate total.

Forecast Prices and Costs

The following tables provide Reserves data and a breakdown of Future Net Revenue by component and production group using Forecast Prices and Costs on a Company Interest, Gross and Net basis.

Summary of Oil and Natural Gas Reserves and Net Present Values of Future Net Revenue as of December 31, 2004 Forecast Prices and Costs

	RESERVES					
	Light And Medium Crude Oil (mbbl)			Heavy Oil (mbbl)		
RESERVES CATEGORY	Company Interest	Gross	Net	Company Interest	Gross	Net
PROVED						
Developed Producing	16,272	14,701	14,767	2,780	2,766	2,541
Developed Non-Producing	267	267	249	61	61	54
Undeveloped	354	335	280	32	32	28
TOTAL PROVED	16,893	15,303	15,296	2,872	2,859	2,623
PROBABLE	3,587	3,295	3,098	551	548	503
TOTAL PROVED PLUS PROBABLE	20,480	18,597	18,394	3,423	3,407	3,126

Columns may not add due to rounding

	RESERVES					
	Natural Gas (Bcf)			Natural Gas Liquids (mbbl)		
RESERVES CATEGORY	Company Interest	Gross	Net	Company Interest	Gross	Net
PROVED						
Developed Producing	450.2	440.8	358.2	11,739	11,494	8,308
Developed Non-Producing	38.1	38.0	30.2	1,089	1,089	808
Undeveloped	40.9	40.9	32.0	1,160	1,160	795
TOTAL PROVED	529.2	519.8	420.4	13,988	13,743	9,911
PROBABLE	148.7	147.3	117.6	4,282	4,243	3,008
TOTAL PROVED PLUS PROBABLE	677.9	667.0	538.0	18,270	17,986	12,919

Columns may not add due to rounding

	RESERVES		
	Total (mboe)		
RESERVES CATEGORY	Company Interest	Gross	Net
PROVED			
Developed Producing	105,825	102,431	85,316
Developed Non-Producing	7,761	7,753	6,143
Undeveloped	8,368	8,349	6,441
TOTAL PROVED	121,954	118,533	97,900
PROBABLE	33,208	32,629	26,207
TOTAL PROVED PLUS PROBABLE	155,162	151,162	124,107

Columns may not add due to rounding

	NET PRESENT VALUES OF FUTURE NET REVENUE									
	BEFORE FUTURE INCOME TAX EXPENSES DISCOUNTED AT (%)					AFTER FUTURE INCOME TAX EXPENSES DISCOUNTED AT (%)				
RESERVES CATEGORY	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)
PROVED										
Developed Producing	2,263.6	1,655.8	1,331.5	1,129.6	990.8	2,263.6	1,655.8	1,331.5	1,129.6	990.8
Developed Non-Producing	165.2	99.4	71.7	56.6	47.2	165.2	99.4	71.7	56.6	47.2
Undeveloped	137.5	84.1	56.4	40.0	29.2	137.5	84.1	56.4	40.0	29.2
TOTAL PROVED	2,566.2	1,839.3	1,459.6	1,226.1	1,067.2	2,566.2	1,839.3	1,459.6	1,226.1	1,067.2
PROBABLE	731.8	392.1	254.8	184.9	143.3	731.8	392.1	254.8	184.9	143.3
TOTAL PROVED PLUS PROBABLE	3,298.1	2,231.4	1,714.4	1,411.0	1,210.5	3,298.1	2,231.4	1,714.4	1,411.0	1,210.5

Columns may not add due to rounding

Production Volumes

	2004	2003	Change (%)
Natural gas (mmcf/day)	**145.1**	134.1	8
Crude oil (bbls/day)	**8,282**	8,116	2
Natural gas liquids (bbls/day)	**3,107**	2,855	9
Total (BOE/day)	**35,578**	33,316	7
Gross Overriding Royalty volumes included above (BOE/day)	**1,440**	1,604	(10)

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

The 7% increase in production volumes year-over-year is due to the acquisition of Seventh Energy and the Calpine assets during the year, combined with development additions, and offset by asset divestitures and natural decline. During 2004, approximately 2,900 BOE/day of annualized incremental production was brought on-line from development activities to mitigate decline. Approximately 1,900 BOE/day of new production remained behind pipe at the end of 2004.

The acquisition of the Calpine assets, with current production volumes of approximately 14,360 BOE/day, added the equivalent of 4,759 BOE/day to 2004 average daily production volumes. Assets acquired from Seventh Energy contributed 1,198 BOE/day to 2004 average daily production volumes.

Production from PrimeWest's non-operated Ells property in Northeast Alberta was shut-in by the Alberta Energy and Utilities Board effective July 1, 2004, as a result of the gas over bitumen issue. The gas over bitumen issue refers to the announcement on June 3, 2003 by the Alberta Energy and Utilities Board ("EUB") proposing a change in policy respecting gas production from the Wabiskaw and McMurray formations in the Athabasca Oil Sands area of Northeastern Alberta. The process outlined by the EUB resulted in the shut-in of approximately 330 BOE/day of PrimeWest's production. In October 2004, the Government of Alberta enacted amendments to the Natural Gas Royalty Regulations of 2002 specifically with respect to gas production in the affected area. This amendment provides for a technical change to the royalty calculation for gas producers adversely affected by the EUB shut-in orders. This technical change to the calculation of royalties represents a reduction of royalties paid by PrimeWest to the Province of Alberta. PrimeWest is evaluating the change to the royalty calculation and its impact as well as any further steps to be taken in relation to the gas over bitumen issue.

An additional shut-in of 300 BOE/day at PrimeWest's non-operated Whiskey Creek area is as a result of the limited capacity at the Quirk Creek gas plant. With no alternate facilities in the area, PrimeWest's production will remain behind-pipe until processing capacity becomes available at the Quirk Creek facility, which is expected to be mid-2005.

PrimeWest expects production for full year 2005 to be approximately 41,000 BOE/day. This estimate incorporates PrimeWest's expected natural decline rate, and production volume shut-ins, offset by production additions resulting from the capital development program.

Commodity Prices

Benchmark Prices	**2004**	2003	Change (%)
Natural gas			
NYMEX (US$/mcf)	**$ 6.09**	$ 5.44	12
AECO (Cdn$/mcf)	**$ 6.79**	$ 6.70	1
Crude oil WTI (US$/bbl)	**$ 41.40**	$ 31.04	33

Average Realized Sales Prices [1]

(Canadian Dollars)	**2004**	2003	Change (%)
Natural gas ($/mcf)[2]	**$ 6.61**	$ 6.05	9
Crude oil ($/bbl)	**$ 36.83**	$ 33.94	9
Natural gas liquids ($/bbl)	**$ 43.69**	$ 35.34	24
Total Oil Equivalent ($/BOE)	**$ 39.35**	$ 35.63	10
Realized hedging loss included in prices above ($/BOE)	**$ (2.16)**	$ (2.51)	(14)

(1) Includes hedging gains/losses.

(2) Excludes sulphur.

Commodity prices were generally higher in 2004 than in 2003, with the average realized selling price per BOE of PrimeWest's production increasing by 10% before hedging impact. The effect of hedging reduced PrimeWest's 2004 realized price by $2.16/BOE, compared to a reduction of $2.51/BOE in 2003. The use of financial hedges is designed to reduce the impact of commodity price volatility and improve the predictability of cash flow from operations.

The realized Canadian selling price that PrimeWest receives for its oil production is also impacted by currency exchange rates. Canadian oil prices are benchmarked in U.S. dollars, therefore a stronger Canadian dollar translates into lower realized prices and revenue, when measured in Canadian dollars.

Crude Oil Prices

Crude oil prices rose strongly in 2004, reflecting higher global demand and continued concerns over supply amidst political uncertainty in a number of the producing regions around the world. Strong economic growth in China and India, together with a recovering U.S. economy, has significantly increased oil consumption and tightened the supply/demand balance. On the supply side, the anticipated increase in Iraqi export capability did not occur due to continued violence and sabotage of production and pipeline infrastructures within the country. With rising demand, excess production capacity that existed within OPEC was used up, leaving Saudi Arabia, Kuwait and UAE as the only OPEC members with surplus capability to increase production quickly to offset any supply disruptions that may occur in other parts of the world. As a result, prices fluctuated in response to world events and weather conditions. During 2004, oil prices increased from US$32.50/Bbl at the beginning of the year to a historical high of US$55.17/Bbl on October 22, before dropping back to US$43.45/Bbl by year-end.

As at December 31, 2004, the forward market for crude oil indicated a gradual lessening of prices over the next 12 months to approximately US$41.50/Bbl by next year-end. However, prices rebounded once again in late January 2005, nearing US$50.00/Bbl, reflecting continued market nervousness with potential supply disruptions. Key factors that could influence prices in 2005 include: potential for a slow down in demand growth in Asia in response to higher prices, particularly in China and India; OPEC's ability to control production to balance supply and demand at their desired price levels; Iraq's ability to restore oil export capability; non OPEC production growth and the impact of higher oil prices on world consumption.

Canadian companies that produce crude oil of a heavier grade will be required to contend with the widening of the price differential versus lighter, sweet crude oil. As the majority of the new crude production brought into the markets is of heavier and sourer quality that requires special refinery handling capability, the price differential has increased over the course of 2004. In addition, the realized price for heavy oil producers has been negatively affected by the large premium being priced into the cost of diluents, natural gas by-products that are used to blend heavier crude oil to improve transportability. PrimeWest's crude oil production consists of 70% light and 30% medium to slightly heavy grade. The medium to slightly heavy grade oil does not require any diluent blending and attracts a better pricing differential than the heavier crude oil production.

Natural Gas Prices

PrimeWest's realized natural gas price increased approximately 3% from a 2003 average of $6.51/mcf to $6.70/mcf during 2004. Industry outlook for natural gas prices was bullish at the beginning of 2004 as North American gas storage levels were being drawn down to below historical averages due to late cold winter weather. Even though gas storage recovered and exceeded historical levels later in the year, higher crude oil prices helped sustain gas prices in the summer. However, cool summer temperatures that reduced electricity demand coupled with mild winter weather during the latter part of 2004 dampened previously bullish gas price expectations. North American gas storage levels at 2004 year-end were higher than the 5-year average. As of December 31, 2004, forward gas prices had also retracted from previous high levels, with the NYMEX price increasing only slightly from US$6.15/Mmbtu at 2004 year-end to US$6.88/Mmbtu by December 2005. However, it should be noted that this forward price curve is still considerably higher than the forward curve at 2003 year-end.

Early in 2005, gas prices have partly recovered from the more bearish view at year end with brief periods of cold weather in many of the US gas consuming regions. Although gas storage levels remain high by historical standards, the market will likely accept higher storage levels going forward as the operating norm for fear of shortages during extreme weather conditions. A continued buoyant crude oil market should also serve as a support for gas prices. Based on energy equivalent, natural gas is currently trading at the low end of the price range established by distillates and fuel oil. With demand remaining strong after adjusting for weather related factors, the upside potential for gas price is favourable. Key factors which will influence gas prices in 2005 include: North American weather patterns in the upcoming summer and winter seasons; the ability of producers in Canada and the US to replace and add to production levels with increased drilling; the growth of gas demand in the electricity sector; the impact of government regulations; and the market response to conservation.

Sales Revenue

Revenue ($ millions)[2]	2004	% of total	2003	% of total	Change (%)
Natural gas [1]	**$ 351.0**	69	$ 297.3	68	18
Crude oil	**111.7**	22	100.5	23	11
Natural gas liquids	**49.7**	9	36.8	9	35
Total	**$ 512.4**		$ 434.6		
Hedging loss included above	**$ (28.2)**	100	$ (30.5)	100	(8)

(1) Excludes sulphur.

(2) Net of transportation expense.

Revenues for 2004 were $512.4 million compared to $434.6 million in the previous year, including the effect of hedging. Higher gas sales volumes as a result of the Calpine asset and Seventh Energy acquisitions completed in 2004 along with higher crude oil and natural gas liquids prices were the major contributors to the increased revenue in 2004.

Based on the forward markets, the overall outlook for commodity prices in 2005 is lower, and has been reflected in PrimeWest's internal price forecasts. If the pricing environment softens in 2005, and the Canadian dollar remains strong, oil and gas revenues will be negatively impacted. Since a greater portion of PrimeWest's revenues (69%) is derived from natural gas, the Trust has greater sensitivity to changes in natural gas prices than crude oil prices.

2004 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, protect acquisition economics and stabilize cash flow against the unpredictable commodity price environment. 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)**		**BOE ($/BOE)[1]**	
	2004	2003	**2004**	2003	**2004**	2003
Unhedged price	**$ 44.46**	$ 36.55	**$ 6.70**	$ 6.51	**$ 41.51**	$ 38.14
Hedging loss	**(7.63)**	(2.61)	**(0.09)**	(0.46)	**(2.16)**	(2.51)
Realized price	**$ 36.83**	$ 33.94	**$ 6.61**	$ 6.05	**$ 39.35**	$ 35.63

(1) Excludes sulphur

	2004 Hedge Loss		2003 Hedge Loss	
	% Hedged	**$ millions**	% Hedged	$ millions
Crude oil	**58%**	**$ 23.1**	65%	$ 7.7
Natural gas	**54%**	**5.1**	61%	22.8
Total loss		**$ 28.2**		$ 30.5

The table below shows the approximate percentage of future anticipated production volumes hedged at December 31, 2004, net of anticipated royalties, reflecting full production declines with no offsetting additions:

2005	**Q1**	**Q2**	**Q3**	**Q4**	**Full Year**
Crude Oil	72%	68%	47%	41%	57%
Natural Gas	59%	56%	49%	49%	53%
2006					
Crude Oil	17%	0%	0%	0%	4%
Natural Gas	35%	0%	0%	0%	9%

A summary of hedging contracts in place as at December 31, 2004 is available under Note 16 in the Notes to the Consolidated Financial Statements.

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

The 2004 income statement shows an unrealized gain of $0.1 million on derivatives resulting from the change in the mark-to-market valuation of the derivative financial instruments during the period. The gain was comprised of an $8.9 million loss for crude oil hedges, a $9.1 million gain for natural gas hedges and a $0.1 million loss for electrical power hedges.

For the year ended December 31, 2004 the cash impact of contracts settling was a $28.1 million loss comprised of a $23.1 million loss in crude oil, a $5.1 million loss in natural gas, a $0.8 million gain on electrical power and a $0.7 million loss in interest rate swaps.

Royalties (Net of ARTC)

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

($ millions, except per BOE)	**2004**	2003	Change (%)
Royalty expense (net of ARTC)	**$ 119.8**	$ 101.9	18
Per BOE	**$ 9.20**	$ 8.38	10
Royalties as % of sales revenues			
With hedge revenue	**23%**	24%	(4%)
Excluding hedge revenue	**22%**	22%	0%

Royalty expense in 2004 was 18% higher than in 2003 due to higher revenues year over year. The crown royalty system is based on a sliding scale structure that increases the royalty rates as commodity prices rise.

Because of the sliding scale crown royalty system, future changes to prices will be accompanied by changes in royalty rates and royalty expense.

Operating Expenses

($ millions, except per BOE)	**2004**	2003	Change (%)
Operating expense	**$ 88.9**	$ 79.4	12
Per BOE	**$ 6.83**	$ 6.53	5

Operating expenses for 2004 are $9.5 million higher than 2003. A primary contributor to the increase in operating expense was the increased production volume from the Seventh Energy and Calpine asset acquisitions in 2004. On a per BOE basis, operating expenses increased 5% over the 2003 level reflecting the impact on costs of high activity in the industry.

Operating expenses are primarily impacted by labour and power costs, which represent approximately 29% of PrimeWest's costs. Other costs that are difficult to influence, including partner-operated expenses, property taxes and lease rentals, make up approximately 32% of our costs. PrimeWest is targeting 2005 operating expenses at approximately $6.60/BOE.

Operating Margin

($/BOE)	**2004**	2003	Change (%)
Sales price and other revenue [1]	**$ 40.13**	$ 36.20	11
Transportation Expense	**(0.63)**	(0.68)	(7)
Royalties	**(9.20)**	(8.38)	10
Operating expenses	**(6.83)**	(6.53)	5
Operating margin	**$ 23.47**	$ 20.61	14

[1] Includes hedging and sulphur

Operating margins increased 14% from 2003 on a per BOE basis. The increase in 2004 compared to 2003 is primarily due to higher sales prices, offset by higher unit operating expenses and higher royalties. Operating margin measures the level of cash flow per barrel of oil equivalent at the field level and before head office expenses.

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

General & Administrative Expense

($ millions, except per BOE)	**2004**	2003	Change (%)
Cash G&A expense	**$ 19.0**	$ 14.5	31
Per BOE	**$ 1.46**	$ 1.20	22
Non-cash G&A expense	**$ 9.4**	$ 14.4	(35)
Per BOE	**$ 0.73**	$ 1.19	(39)

Cash general and administrative expenses increased $4.5 million over 2003 reflecting higher salaries, higher short-term incentive bonuses, increased information technology expenditures, one-time consulting costs associated with potential acquisitions, and increased board of directors costs. These increases were partially offset by increases in overhead recoveries.

Included in non-cash G&A expense is $8.5 million relating to the change in the value of the Unit Appreciation Rights (UARs), granted under the Long-Term Incentive Plan (LTIP). UARs in a Trust are similar to stock options in a corporation. The program is 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. Expenses related to the LTIP are recorded on a mark-to-market basis, whereby increases or decreases in the valuation of the UAR liability are reported quarterly, as a charge to the income statement. Also included in non-cash G&A expense is $0.9 million related to the special employee retention plan. See note 14 to the consolidated financial statements.

Interest Expense

($ millions, except per Trust Unit)	**2004**	2003	Change (%)
Interest expense	**$20.6**	$15.1	36
Period end net debt level	**$552.0**	$255.9	116
Debt per Trust Unit	**$7.77**	$5.07	53
Average cost of debt	**4.8%**	4.7%	

Interest expense, representing interest on bank debt, the senior secured notes, and the convertible unsecured subordinated debentures increased to $20.6 million from $15.1 million in 2003 due to higher average debt balances in 2004 compared to 2003. Debt levels increased in the third quarter of 2004 with the issuance of additional bank debt and the Convertible Debentures to fund the acquisition of the Calpine assets.

The average cost of debt has increased due to the issuance of the convertible unsecured subordinated debentures in the third quarter 2004. The $150 million Series I and $100 million Series II debentures bear annual interest at 7.5% and 7.75% respectively.

Foreign Exchange Gain

The foreign exchange gain of $11.7 million results from the translation of the US dollar denominated senior secured notes and related interest payable. The notes were issued at 1.3923:1 Canadian to US dollars, and the close rate on December 31, 2004 was 1.2020:1 Canadian to US dollars.

Depletion, Depreciation and Amortization

The 2004 DD&A rate of $15.15/BOE is lower than the 2003 rate of $16.70/BOE due to the January 1, 2004 ceiling test write down of $309 million offset by the impact of the Calpine asset acquisition.

Ceiling Test

Effective January 1, 2004, PrimeWest adopted CICA Accounting Guideline 16 (AcG-16), "Oil and Gas Accounting - Full Cost".

The guideline is effective for fiscal years beginning on or after January 1, 2004. The cost impairment test is a two-stage process that 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.

Performing this test at January 1, 2004, using consultant's average prices as at January 1, 2004 of AECO $5.90 per Mcf for natural gas and US$ 29.21 per barrel WTI for crude oil resulted in a before tax impairment of $308.9 million, and an after tax impairment of $233.3 million. The write down was booked to accumulated income in the first quarter of 2004.

Performing this test at December 31, 2004, using consultant's average prices as at January 1, 2005, of AECO $6.79 per mcf for natural gas and US$ 42.76 per barrel WTI for crude oil results in a ceiling test surplus.

Site Reclamation and Restoration Reserve

Since the inception of the Trust, PrimeWest has maintained a site reclamation fund to pay for future costs related to well abandonment and site clean up. The fund is used to pay for such costs as they are incurred. The 2004 contribution rate for the fund was unchanged from 2003 at $0.50 per BOE, which was expected to be sufficient to meet expenditure requirements for the future. As at December 31, 2004, the site reclamation fund had a balance of $10.3 million.

The reclamation and abandonment costs incurred for 2004 were $4.6 million, compared to $2.2 million in 2003.

The 2005 contribution rate has been set at $0.50 per BOE.

Asset Retirement Obligation

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

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, 2005. 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 costs and general and administrative costs.

This calculation is a “snapshot” in time and is heavily dependent upon future commodity price expectations at the point in time the “snapshot” is taken. Accordingly, the NAV as at January 1, 2005 may not reflect fairly the equity market trading value of PrimeWest. It is also significant to note that NAV reduces as reserves are produced and net operating cash flow is distributed to unitholders. Value is delivered to unitholders through such monthly distributions.

The following table sets forth the calculation of NAV:

	2004 Consultant’s Average	2003 Consultant’s Average
As at December 31		
($ millions except per Trust Unit Amounts)	**2004**	2003
Assets		
PV $_{10}$ of future cash flow [(1)(3)]	**$ 1,714.4**	$ 904.6
Market value of Calpine Trust units	**91.0**	-
Mark to market value of hedging contracts	**0.1**	(0.5)
Unproved lands	**103.9**	36.0
Reclamation fund	**10.3**	8.2
	1,919.7	948.3
Liabilities		
Debt and working capital deficiency [(2)]	**(378.5)**	(255.9)
Net Asset Value	**$ 1,541.2**	$ 692.4
Outstanding Trust Units – millions, diluted	**80.5**	50.4
NAV per Trust Unit	**$ 19.15**	$ 13.74

(1) 100% of Proved Plus Probable reserves

(2) Debt excludes convertible unsecured subordinated debentures

(3) Refer to Summary of Oil and Natural Gas Reserves and Net Present Values of Future Net Revenue Table under the Section “Reserves and Production”).

Pricing Assumptions	**2004 Consultant’s Average**	2003 Consultant’s Average
Edmonton Par Oil – Cdn. $/bbl		
2004	-	$37.81
2005	$50.37	$34.10
2006	$47.46	$32.79
2007	$43.88	$32.72
2008	$40.89	$32.89
2009	$39.20	-
Spot Gas at AECO-C – Cdn. $/mcf		
2004	-	$5.90
2005	$6.79	$5.33

2006	$6.52	$4.98
2007	$6.25	$4.95
2008	$5.95	$4.92
2009	$5.79	-

The NAV calculation is based on the above reference prices as of December 31, 2004 and 2003 and is highly sensitive to changes in price forecasts over time as well as the exchange rate. In addition, the year-over-year change is impacted by the cash distributions made throughout the year, which totaled $196.1 million or $3.30 per trust unit. 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)	**2004**	2003	Change (%)
Income and capital taxes	**$ 3.3**	$ 3.8	(13)
Future income taxes recovery	**(37.6)**	(79.9)	(53)
	$ (34.3)	$ (76.1)	(55)

The Alberta Government enacted a tax rate reduction of 1% in the first quarter of 2004, reducing the rate from 12.5% to 11.5% effective April 1, 2004.

During 2003, the Canadian Government enacted Federal income tax changes for the oil and gas resource sector. The Federal income tax changes effectively reduced the statutory tax rates for current and future periods. Specifically, the 100% deductibility of the resource allowance will be completely phased out by the year 2007. During the same time frame, Crown charges will become 100% deductible and resource tax rates will decline from the current 27% to 21%. These tax rate reductions contributed to the large future tax recovery in 2003 of $83.0 million.

Cash taxes paid include tax installments for current and prior years and payments for taxes owing upon the filing of year end tax returns. Cash taxes paid in 2004 include $1.3 million relating to prior years. Income and capital tax expense includes the estimate of the current year’s taxes and any adjustments resulting from prior year tax assessments. The year ending December 31, 2004 includes $0.5 million related to prior years.

Net Income

($ millions)	**2004**	2003
Net Income	**$ 103.4**	$ 95.9

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 foreign exchange gains, depletion, depreciation, and amortization (DD&A) and future taxes.

Net income of $103.4 million exceeded 2003 net income of $95.9 million due to higher revenues offset by increased operating expenses, royalties, general and administrative expenses and lower future tax recoveries.

Liquidity & Capital Resources

Long-term Debt

($ millions)	2004	2003	Change (%)
Long-term debt	**$ 656.3**	**$ 250.1**	162
Working capital deficit/(surplus)	**(104.3)**	**5.8**	1,898
Net debt	**$ 552.0**	**$ 255.9**	116
Market value of Trust Units and exchangeable shares outstanding (1)	**1,877.7**	**1,380.7**	36
Total capitalization	**$ 2,429.7**	**$ 1,636.6**	48
Net debt as a % of total capitalization	**23%**	**16%**	44

(1) Based on December 31 Trust Unit closing price of $26.62 and exchangeable ratio of 0.50408:1

Long-term debt is comprised of bank credit facilities, senior secured notes and Convertible Unsecured Subordinated Debentures of $264.0 million, $150.3 million and $242.0 million respectively.

PrimeWest had a borrowing base of $625 million at year end 2004. The bank credit facilities consist of an available revolving term loan of $437.5 million, and an operating facility of $25 million with the balance being the maximum amount of the Senior Secured Notes of $162.5 million. In addition to amounts outstanding under the facility, PrimeWest has outstanding letters of credit in the amount of $4.9 million (2003 - $5.1 million). The credit facility revolves until June 30, 2005, by which time the lenders will have conducted their annual borrowing base review.

The Senior 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 7.5% (Series I) and 7.75% (Series II) convertible unsecured subordinated 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 PrimeWest Trust Units.

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

PrimeWest has early adopted CICA Handbook Section 3860 – “Financial Instruments”. In accordance with this new section, the Convertible Unsecured Subordinated Debentures were initially recorded at their fair value of $147.0 million (Series I) and $94.9 million (Series II). The difference between the fair value and the issue proceeds of $8.1 million was recorded in unitholders’ equity ($3.0 million Series I and $5.1 million Series II).

Unitholders’ Equity

The Trust had 69,886,111 Trust Units outstanding at December 31, 2004 compared to 48,751,883 Trust Units at the end of 2003. In addition, there were 1,294,391 exchangeable shares (see below) outstanding at year end, exchangeable into a total of 652,477 Trust Units. The weighted average number of Trust Units, including those issuable by the exchange of exchangeable shares, was 59,482,034 Trust Units for 2004 compared to 46,015,519 for 2003.

During 2004, 116,233 Trust Units were issued to employees pursuant to the LTIP.

In 2004, PrimeWest completed two equity offerings. The first closed on April 22, 2004 raising net proceeds of $134.9 million on the issuance of 5.4 million Trust Units at $26.30 per Trust Unit. Proceeds were used to reduce the indebtedness of PrimeWest under its credit facility. The second offering closed on September 2, 2004 raising net proceeds of $285.1 million on the issuance of 12.3 million Trust Units at $24.40 per Trust Unit. Proceeds were used in the acquisition of the Calpine assets.

Under the Distribution Reinvestment Plan (DRIP), in 2004 PrimeWest issued 268,677 Trust Units for $6.5 million (465,969 Trust Units, $11.4 million in 2003), 1,311,462 Trust Units for $32.0 million pursuant to the Premium Distribution (PREP) component (134,629 Trust Units, $3.4 million in 2003) and 894,167 Trust Units for $21.5 million pursuant to the Optional Trust Unit Purchase Plan component (OTUPP) (721,209 Trust Units, $17.6 million in 2003).
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 DRIP gives Canadian unitholders the chance to reinvest their monthly distributions at a 5% discount to the volume weighted average market price of the Trust Units, while the OTUPP gives Canadian unitholders an opportunity to purchase additional Trust Units directly from PrimeWest at the same 5% discount to the volume weighted average market price. The DRIP and PREP components are mutually exclusive, and participation in the OTUPP requires enrollment in either the DRIP or PREP.

These plan components benefit the unitholders by offering alternatives to maximize their investment in PrimeWest, while providing the Trust with an inexpensive method to raise additional capital. The Trust expects interest in these plans in 2005 to be similar to 2004. 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 PrimeWest’s Plan Agent, Computershare Trust Company of Canada at 1-800-564-6253 or visit PrimeWest’s website at 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 of PrimeWest. Canadian law does not permit a tax deferral when shares are exchanged for Trust Units.

In 2004, 94,340 exchangeable shares were issued pursuant to the special employee retention plan. During 2003, 161,717 exchangeable shares were issued in relation to the termination of the management incentive program of PrimeWest Management Inc. (see Note 14 in the 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, 2004, there were 1,294,391 exchangeable shares outstanding. The exchange ratio on the shares was 0.50408:1 Trust Units for each exchangeable share as 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

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

Cash distributions for 2004 were $196.1 million or $3.30 per Trust Unit representing a payout ratio of approximately 74% versus 2003 amounts of $192.6 million or $4.32 per Trust Unit representing a payout ratio of approximately 89%.

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

Cash Flow Sensitivities

The table below is designed to provide the directional impact on 2005 annual cash available for distribution per unit (increase/decrease) depending on changes in the following:

	$/Trust Unit (1)
Crude oil price (US$1.00/bbl WTI increase)	0.04
Natural gas price ($0.10/mcf increase)	0.06
Exchange rate (US$0.01 decrease)	0.03
Interest rate (1% decrease)	0.02
Production (1,000 BOE/day increase)	0.12

(1) Without the effect of hedging

The figures in this table are provided for directional information only and are based on the units outstanding as at December 31, 2004. 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, lease rental commitments that run from 2005 through 2009 and various pipeline transportation commitments that run through 2010. The details of the timing of these contractual obligations are included in the following table.

As at December 31, 2004	Payments due by period ($ millions)				
	Total	Less than 1 year	1-3 years	4-5 years	More than 5 years
Long-term debt obligations	**414.2**	-	339.1	75.1	-
Series I and II convertible unsecured subordinated debentures	**250.0**	-	-	150.0	100.0
Lease rental obligations	**14.7**	3.6	10.3	0.8	-
Pipeline transportation obligations	**15.1**	7.1	7.6	0.4	-
Total contractual obligations	**694.0**	10.7	357.0	226.3	100.0

As part of PrimeWest's internalization transaction (see Note 14 in the Consolidated Financial Statements) PrimeWest agreed to issue 377,360 Exchangeable Shares pursuant to a Special Employee Retention Plan. One quarter of the Exchangeable Shares were issued to the executive officers of PrimeWest on November 6, 2004. One third of the remaining exchangeable shares will be issued on each of the third, fourth and fifth anniversary of transaction closing, November 6, 2002. As at December 31, 2004, $0.2 million has been accrued in non-cash general and administrative expenses related to the Special Employee Retention Plan.

Critical Accounting Estimates

PrimeWest's financial statements have been prepared in accordance with Canadian generally accepted accounting principles. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The following discussion reviews such accounting policies and is included in Management's Discussion and Analysis to aid the reader in assessing the critical accounting policies and practices of the Trust and the likelihood of materially different results being reported. PrimeWest's management reviews its estimates regularly, but new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates.

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

Proved and Probable Oil and Gas Reserves

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

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

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

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

Full Cost Accounting For Oil and Gas Activities

PrimeWest adopted CICA Accounting Guideline 16 (AcG-16), "Oil and Gas Accounting – Full Costs" on January 1, 2004. The new guideline modifies how the ceiling test is performed and requires that cost centers be tested for recoverability using undiscounted future cash flows from Proved reserves, which are determined by using forward indexed prices. When the carrying amount of a cost center is not recoverable, the cost center must be 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 be capitalized whether successful or not. The aggregate of net capitalized costs and estimated future development costs less estimated salvage values is amortized using the unit of production method based on estimated Proved oil and gas reserves. An increase in estimated proved oil and gas reserves would result in a corresponding reduction in depletion expense. A decrease in estimated future development costs would result in a corresponding reduction in depletion expense.

Fair Value of Derivative Instruments

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

The estimation of the fair value of certain hedging derivatives requires considerable judgment. The estimation of the fair value of commodity price hedges requires sophisticated financial models that incorporate forward price and volatility data and, which when compared with PrimeWest's outstanding hedging contracts, produce cash inflow or outflow variances over the contract period.

Asset Retirement Obligations

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

PrimeWest, under the current policy, is required to provide for future removal and site restoration costs. PrimeWest must estimate these costs in accordance with existing laws, contracts or other policies. These estimated costs are charged to earnings and the appropriate liability account over the expected service life of the asset.

Legal, Environmental Remediation and Other Contingent Matters

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

Income Tax Accounting

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

Business Combinations

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

This methodology is also used to value unproved oil and gas reserves. The valuation of these reserves, by their nature, is less certain than the valuation of Proved reserves.

Goodwill

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

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 EIC 151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts." The EIC 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 the financial statements.

Variable Interest Entities

In June 2003 the CICA issued Accounting Guideline 15 "Consolidation of Variable Interest Entities" which deals with the consolidation of entities that are subject to control on a basis other than ownership of voting interests. This guideline is effective for annual and interim periods beginning on or after November 1, 2004. The Trust has determined that this new guideline is not applicable based on the current structure of the Trust and therefore will have no impact on the financial statements of the Trust.

Business Risks

PrimeWest's operations are affected by a number of underlying risks, both internal and external to the Trust. These risks are similar to those affecting others in both the conventional oil and gas royalty trust sector and the conventional oil and gas producers sector. The Trust's financial position, results of operations, and cash available for distribution to unitholders are directly impacted by these factors. These factors are discussed under two broad categories – Commodity Price, Foreign Exchange and Interest Rate Risk; and Operational and Other Business Risks.

Commodity Price, Foreign Exchange And Interest Rate Risk

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

- world market forces, specifically the actions of OPEC and other large crude oil producing countries including Russia, and their implications on the supply of crude oil;
- world and North American economic conditions which influence the demand for both crude oil and natural gas and the level of interest rates set by the governments of Canada and the US;
- weather conditions that influence the demand for natural gas and heating oil;
- the Canadian/US exchange rate that 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 actively monitored by the Board.

Beyond our hedging strategy, PrimeWest also mitigates risk by having a well-diversified marketing portfolio and by transacting with a number of counter-parties and limiting exposure to each counter party. In 2004, approximately 25% of 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 objective of our commodity risk management program is to reduce the volatility of our cash distributions, to lock in the economics on major acquisitions and to protect our capital structure when commodity prices cycle downwards. In 2004, PrimeWest recognized a commodity hedging loss of $28.2 million ($0.45 per Trust Unit), compared to a loss of $30.5 million ($0.66 per Trust Unit) in 2003.

Operational And Other Business Risks

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

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

We mitigate by:
Performing regular and proactive protective well, facility and pipeline maintenance supported by telemetry, physical inspection and diagnostic tools.

Commodity Price
Fluctuations in natural gas, crude oil and natural gas liquid prices

We mitigate by:
Hedging. Refer to page 21 of this MD&A.

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

We mitigate by:
Diversifying the transportation systems on which we rely to get our product to market.

Natural decline
Development risk associated with capital enhancement activities undertaken – the risk that capital spending on activities such as drilling, well completions, well workovers and other capital activities will not result in reserve additions or in quantities sufficient to replace annual production declines.

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

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

We mitigate by:
Continually scanning the marketplace for opportunities to acquire assets. Our technical acquisition specialists evaluate potential corporate or property acquisitions and identify areas for value enhancement through operational efficiencies or capital investment. All prospects are subjected to rigorous economic review against established acquisition and economic hurdle rates. In some cases we may also hedge commodity prices to protect the acquisition economics in the near term period.

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

We mitigate by:
Contracting our reserves evaluation to a reputable third party consultant, GLJ. The Operations and Reserves Committee of the Board of Directors of PrimeWest review the work and independence of GLJ. Our strategy is to invest in mature, longer life properties having a higher proved producing component where the reserve risk is generally lower and cash flows are more stable and predictable.

Environmental Health and Safety (EH&S)
Environmental, health and safety risks associated with oil and gas properties and facilities.

We mitigate by:
Establishing and adhering to strict guidelines for EH&S including training, proper reporting of incidents, supervision and awareness. PrimeWest has active community involvement in field locations including regular meetings with stakeholders in the area. PrimeWest carries adequate insurance to cover property losses, liability and business interruption.

These risks are reviewed regularly by the Corporate Governance and EH&S Committee of the Board, which acts as PrimeWest's Environmental, Health and Safety Committee.

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

We mitigate by:
Keeping informed of proposed changes in regulations and laws to properly respond to and plan for the effects that these changes may have on our operations.

Liability to unitholders is uncertain
Because of uncertainties in the law relating to investment trusts, there is a risk that a Unitholder could be held personally liable for obligations of the Trust.

Mitigated by:
On July 1, 2004 a new statute entitled the *Income Trusts Liability Act* (Alberta) was proclaimed in force, creating a statutory limitation on the liability of unitholders of Alberta income trusts such as PrimeWest. The legislation provides that a Unitholder is not, as a beneficiary, liable for any act, default, obligation or liability of the Trust that arises after July 1, 2004. Similar legislation was proclaimed in force in Ontario in December of 2004.

Income Taxes – Unitholders – 2004

For the 2004 taxation year, Canadian unitholders of PrimeWest were paid $3.30 Canadian per Trust Unit in distributions. Of this distribution amount, 45% or $1.49 per Trust Unit is deemed a tax deferred return of capital, and 55% or $1.81 per Trust Unit is taxable to unitholders as other income (taxed at the same rate as interest income).

For unitholders resident in the United States, the taxability of distributions is calculated using US tax rules which allow for the deduction of crown royalties and accounting based depletion. As a result of these deductions, distributions are taxable as dividends and 45% of the 2004 distributions are taxable as a "qualified dividend" with the remaining 55% 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.

For both Canadian and United States unitholders, the tax deferred return of capital portion reduces the unitholders' 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.

Quarterly Performance – Selected Measures

($ millions, except per Trust Unit amounts)	**2004**				2003				2002
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Net Revenues	**126.8**	97.2	84.9	85.7	73.0	77.3	85.6	94.0	68.8
Net Income	**40.6**	20.2	22.4	20.1	0.7	8.8	63.0	23.4	(7.3)
Net Income Per Unit - Basic	**0.57**	0.31	0.41	0.40	0.01	0.19	1.38	0.56	(0.20)
Net Income Per Unit – Diluted	**0.56**	0.31	0.40	0.40	0.01	0.19	1.37	0.55	(0.20)

The above table highlights PrimeWest's performance by selected measures for the fourth quarter ended 2004, and the preceding eight quarters through 2003 and 2002.

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

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

Questions

PrimeWest Energy Trust welcomes questions from unitholders and potential investors; call Investor Relations at 403-234-6600 or toll-free in Canada and the US at 1-877-968-7878; or visit us on the Internet at our website, www.primewestenergy.com. We make every effort to reply within 2 business days, but during periods of heavy call volume, our response time may increase.

Don Garner
President and Chief Executive Officer

February 24, 2005

Consolidated Balance Sheets

As at December 31 ($ millions)	2004	2003 (restated)
ASSETS		
Current assets		
Cash and cash equivalents	**$ 54.4**	$ 2.5
Marketable securities (note 4)	**68.6**	-
Accounts receivable	**96.9**	65.4
Assets held for sale (note 6)	**5.4**	-
Prepaid expenses	**10.9**	6.5
Inventory	**5.8**	2.1
	242.0	76.5
Cash reserved for site restoration and reclamation (note 10)	**10.3**	8.2
Other assets and deferred charges (note 7)	**10.9**	1.5
Derivative asset (note 16)	**0.6**	-
Property, plant and equipment (note 6)	**1,908.6**	1,548.2
Goodwill (note 5)	**68.5**	56.1
	$ 2,240.9	$ 1,690.5
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities		
Accounts payable	**$ 47.7**	$ 26.7
Accrued liabilities	**72.3**	45.3
Derivative liability (note 16)	**0.5**	-
Accrued distributions to unitholders	**17.7**	10.3
	138.2	82.3
Long-term debt (note 8)	**656.3**	250.1
Future income taxes (note 15)	**211.2**	313.2
Asset retirement obligation (note 9)	**40.3**	19.7
	1,046.0	665.3
UNITHOLDERS' EQUITY		
Net capital contributions (note 11)	**2,049.9**	1,565.9
Capital issued but not distributed	**3.3**	5.2
Convertible unsecured subordinated debentures (note 8)	**8.1**	-
Long-term incentive plan equity (note 12)	**20.1**	14.6
Accumulated income	**89.2**	219.1
Accumulated cash distributions	**(967.7)**	(771.6)
Accumulated dividends	**(8.0)**	(8.0)
	1,194.9	1,025.2
	$2,240.9	$ 1,690.5

Commitments and Contingencies (Note 17)

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

Consolidated Statements of Unitholders’ Equity

For the years ended December 31 ($ millions)	2004	2003 (restated)	2002 (restated)
Unitholders’ equity, beginning of year	**$ 1,025.2**	$ 847.1	$ 856.3
Adjustment to unitholder’s equity at beginning of period to adopt:			
New asset retirement obligation	**-**	-	1.2
New oil and gas accounting standard	**(233.3)**	-	-
Net income for the year	**103.4**	95.9	(0.6)
Net capital contributions	**484.0**	265.9	147.4
Capital issued but not distributed	**(1.9)**	4.3	(0.1)
Convertible unsecured subordinated debentures	**8.1**	-	-
Long-term incentive plan equity	**5.5**	4.6	2.1
Cash distributions	**(196.1)**	(192.6)	(158.0)
Dividends	**-**	-	(1.2)
Unitholders’ equity, end of year	**$ 1,194.9**	$ 1,025.2	$ 847.1

Consolidated Statements of Cash Flow

For the years ended December 31

($ millions)	2004	2003 (Restated)	2002 (Restated)
OPERATING ACTIVITIES			
Net income for the year	**$ 103.4**	$ 95.9	$ (0.6)
Add/(deduct):			
Items not involving cash from operations			
Depletion, depreciation and amortization	**197.3**	197.4	183.2
Non-cash general & administrative	**9.4**	14.4	6.1
Non-cash foreign exchange gain	**(11.9)**	(12.1)	-
Cash distributions from marketable securities	**4.1**	-	-
Non-cash management fees	**-**	-	1.4
Non-cash internalization	**-**	-	13.1
Unrealized gain on derivatives	**(0.1)**	-	-
Future income taxes recovery	**(37.6)**	(79.9)	(33.2)
Accretion on asset retirement obligation	**2.0**	1.2	0.9
Other non-cash items	**0.2**	(0.3)	-
Cash flow from operations	**266.8**	216.6	170.9
Expenditures on site restoration and reclamation	**(4.6)**	(2.2)	(3.9)
Change in non-cash working capital	**11.9**	5.3	(10.7)
	$ 274.1	$ 219.7	$ 156.3
FINANCING ACTIVITIES			
Proceeds from issue of Trust Units (net of costs)	**$ 441.0**	$ 240.3	$ 118.3
Proceeds from issue of debentures	**250.0**	-	-
Net cash distributions to unitholders (note 13)	**(159.6)**	(172.5)	(145.1)
Dividends	**-**	-	(1.2)
Increase (decrease) in bank credit facilities	**166.0**	(137.0)	29.9
Increase in senior secured notes	**-**	174.0	-
Increase in deferred charges	**(10.0)**	(1.5)	-
Change in non-cash working capital	**10.9**	(3.6)	1.0
	$ 698.3	$ 99.7	$ 2.9
INVESTING ACTIVITIES			
Expenditures on property, plant & equipment	**$ (129.7)**	$ (105.8)	$ (69.1)
Acquisition of capital/corporate assets	**(807.4)**	(210.1)	(59.6)
Proceeds on disposal of property, plant & equipment	**96.5**	2.3	4.5
Investment in marketable securities	**(72.7)**	-	-
(Increase) decrease in cash reserved for future site restoration and reclamation	**(2.1)**	(6.6)	0.7
Expenditures on future acquisitions	**-**	-	(14.1)
Change in non-cash working capital	**(5.1)**	6.4	(10.1)
	$ (920.5)	$ (313.8)	$ (147.7)
INCREASE IN CASH FOR THE YEAR	**$ 51.9**	$ 5.6	$ 11.5
CASH (BANK OVERDRAFT) BEGINNING OF THE YEAR	**2.5**	(3.1)	(14.6)
CASH (BANK OVERDRAFT) END OF THE YEAR	**$ 54.4**	$ 2.5	$ (3.1)
CASH INTEREST PAID	**$ 15.0**	$ 13.1	$ 10.3
CASH TAXES PAID	**$ 3.8**	$ 3.9	$ 4.0

Consolidated Statements of Income

For the years ended December 31 (millions of dollars, except per Trust Unit amounts)	2004	2003 (Restated)	2002 (Restated)
REVENUES			
Sales of crude oil, natural gas and natural gas liquids	**$ 521.9**	$ 442.9	$ 326.8
Transportation expenses	**(8.2)**	(8.3)	(6.3)
Crown and other royalties, net of ARTC	**(119.8)**	(101.9)	(56.5)
Unrealized gain on derivatives	**0.1**	-	-
Other income	**0.6**	(2.8)	0.3
	394.6	329.9	264.3
EXPENSES			
Operating	**88.9**	79.4	60.8
Cash general and administrative	**19.0**	14.5	11.3
Non-cash general and administrative	**9.4**	14.4	6.1
Interest	**20.6**	15.1	10.8
Depletion, depreciation and amortization	**197.3**	197.4	183.2
Cash management fees (note 14)	**-**	-	4.0
Cash internalization costs	**-**	-	3.6
Non-cash management fees (note 14)	**-**	-	1.4
Non-cash internalization costs (note 14)	**-**	-	13.1
Accretion on asset retirement obligation	**2.0**	1.2	0.9
Foreign exchange gain	**(11.7)**	(11.9)	-
	325.5	310.1	295.2
Income (loss) before taxes for the year	**69.1**	19.8	(30.9)
Income and capital taxes	**3.3**	3.8	2.9
Future income taxes recovery (note 15)	**(37.6)**	(79.9)	(33.2)
	(34.3)	(76.1)	(30.3)
Net income for the year	**$ 103.4**	$ 95.9	$ (0.6)
Net income per Trust Unit	**$ 1.74**	$ 2.08	$ (0.02)
Diluted net income per Trust Unit	**$ 1.74**	$ 2.07	$ (0.02)

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 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 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. is a wholly owned subsidiary of PrimeWest Energy Inc.

On November 4, 2002, unitholders voted, by a 92% majority, to internalize management. PrimeWest Management Inc. and its shareholders received a total of $26.3 million in connection with that transaction. Approximately $13.2 million related to the acquisition of the 1% retained royalty and was recorded as an acquisition in property, plant and equipment. The balance was charged to non-cash internalization expense. In addition, retention provisions for senior management to receive 94,340 exchangeable shares on each of the second, third, fourth and fifth anniversaries of the completion of the internalization transaction were agreed to and $1.5 million was accrued relating to the termination of the management incentive program (see Note 14).

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 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 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

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% to 30%.

Joint Venture Accounting

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

Long-Term Incentive Plan

Liabilities under the Trust's Long-term Incentive Plan are estimated at each balance sheet date, based on the amount of Unit Appreciation Rights that are in the money using the unit price as at that date. Expenses are recorded through non-cash general and administrative costs, with an offsetting amount in long-term incentive plan equity. As Trust Units are issued under the plan, the exercise value is recorded in net capital contributions.

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 gas reserves or the economic lives and future cash flows from related assets.

3. Changes in Accounting Policies

Full Cost Accounting

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

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

Consultant's Average Price Forecasts	Year				
	2004	2005	2006	2007	2008
WTI (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 new standard requires the recognition of the liability associated with the future site reclamation costs of tangible long-lived assets. This liability would be comprised of the Trust's net ownership interest in producing wells and processing plant facilities. The liability for future retirement obligations is to be recorded in the financial statements at the time the liability is incurred.

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

The adoption of CICA Handbook section 3110 allows for the cumulative effect of the change in accounting policy to be recorded to accumulated income with retroactive restatement of prior period comparatives. At January 1, 2004, this resulted in an increase to the asset retirement obligation of $19.7 million (2003 - $15.3 million, 2002 - $11.8 million), an increase to PP&E of $10.6 million (2003 - $9.0 million, 2002 $7.7 million), a $5.6 million (2003 - $0.04 million, 2002 - $1.2 million) increase to accumulated income, a decrease of site restoration provision of $17.8 million (2003 - $6.2 million, 2002 - $6.1 million) and an increase to the future tax liability of $3.1 million (2003 – $(0.03) million, 2002 - $0.9 million). See Note 10 for the reconciliation of the asset retirement obligation.

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

Financial Derivatives

Effective January 1, 2004, the Trust has implemented CICA Accounting Guideline (AcG-13), "Hedging Relationships", which is effective for fiscal years beginning on or after July 1, 2003. AcG-13 addresses the identification, designation, documentation and effectiveness of hedging transactions for the purposes of applying hedge accounting. It also established conditions for applying or discontinuing hedge accounting. Under the new guideline, hedging transactions must be documented and it must be demonstrated that the hedges are sufficiently effective in order to continue accrual accounting for position hedges with derivatives. The trust is not applying hedge accounting to its hedging relationships.

As of January 1, 2004, the Trust recorded $6.0 million for the mark-to-market value of the outstanding hedges as a derivative liability and a $6.0 million deferred derivative loss, to be realized upon settlement of the corresponding derivative instrument. The deferred loss at January 1, 2004 was comprised of a $3.9 million loss for crude oil, $2.1 million loss for natural gas, $0.6 million loss for interest rate swaps and a gain of $0.6 million for electrical power. See Note 9 for the reconciliation of the derivative liability.

4. Marketable Securities

($ millions)	**2004**	2003
Investment in Calpine Natural Gas Trust	**$ 68.6**	$ --

As at December 31, 2004, PrimeWest had a 25% ownership in Calpine Natural Gas Trust. The investment is accounted for using the cost method. The market value of the investment at December 31, 2004 is $91.0 million.

5. Acquisitions

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

Net Assets Acquired at Assigned Values	($ millions)	Consideration Paid	($ millions)
Petroleum and natural gas assets	$ 746.9		
Inventory	4.2	Cash	$ 747.0
Working capital	2.9	Net closing adjustments	(10.3)
Asset Retirement Obligation	(12.0)	Costs associated with acquisition	5.3
	$ 742.0		$ 742.0

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

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

c) On January 23, 2003, PrimeWest Gas Inc. completed the acquisition of two private Canadian oil and gas companies. Subsequent to the transaction, PrimeWest Gas Inc. was wound up into PrimeWest Energy Inc. The acquired companies were 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	$ 220.9		
Goodwill	56.1		
Working capital, including cash of $3.9	0.7		
Site restoration provision	(5.4)	Cash	$ 212.7
Future income taxes	(53.2)	Costs associated with acquisition	6.4
	$ 219.1		$ 219.1

6. Property, Plant and Equipment

2004 ($ millions)	Cost	Accumulated depletion depreciation and amortization	Net book value
Property acquisition oil and 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

2003 ($ millions)	Cost	Accumulated depletion depreciation and amortization	Net book value
Property acquisition oil and gas rights	$ 1,933.3	$ (612.3)	$ 1,321.0
Drilling and completion	208.0	(52.1)	155.9
Production facilities and equipment	91.0	(23.1)	67.9
Head office furniture and equipment	8.0	(4.6)	3.4
	$ 2,240.3	$ (692.1)	$ 1,548.2

Unproved land costs of $103.9 million (2003 – $36.0 million) are excluded from costs subject to depletion and depreciation.

PrimeWest capitalized $2.9 million of general and administrative costs in 2004 (2003 - $2.5 million).

On February 4, 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.

PrimeWest has performed a ceiling test as at December 31, 2004. The impairment test was calculated using the consultant's average prices at January 1 for the years 2005 to 2009 as follows:

Consultant's Average Price Forecasts	Year				
	2005	2006	2007	2008	2009
WTI ($U.S./bbl)	**42.76**	40.37	37.36	34.82	33.45
AECO ($Cdn/Mcf)	**6.79**	6.52	6.25	5.95	5.79

The December 31, 2004, ceiling test resulted in a surplus.

A ceiling test was performed at December 31, 2003 in accordance with CICA Accounting Guideline 5 (AcG-5), "Full Cost Accounting in the Oil and Gas Industry", using December 31, 2003 commodity prices of AECO $6.09/mcf for natural gas and WTI US$ 32.52/bbl for crude oil. The December 31, 2003 ceiling test resulted in a surplus.

7. Other Assets and Deferred Charges

($ millions)	**2004**	2003
Deferred charges	**$ 10.6**	$ 1.3
Other assets	**0.3**	0.2
	$ 10.9	$ 1.5

8. Long-Term Debt

($ millions)	**2004**	2003
Bank credit facility	**$ 264.0**	$ 88.0
Senior secured notes	**150.3**	162.1
Convertible unsecured subordinated debentures	**242.0**	-
	$ 656.3	$ 250.1

Long-term debt is comprised of bank credit facilities, senior secured notes and Convertible Unsecured Subordinated Debentures of $264.0 million, $150.3 million and $242.0 million respectively.

PrimeWest has a maximum borrowing base of $625 million at December 31, 2004 (2003 - $390 million) as established by the lenders. The bank credit facilities consist of a revolving term loan to a maximum of $437.5 million and an operating facility of $25 million with the balance of $162.5 million being the maximum amount of the Senior Secured Notes. In addition to amounts outstanding under the facility, PrimeWest has outstanding letters of credit in the amount of $4.9 million (2003 - $5.1 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 2004, the effective interest rate on the facilities was 4.0% (2003 – 4.7%).

The bank credit facility revolves until June 30, 2005, 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 lender has the right to extend the revolving period for a further 364-day period or to convert the facility to a term facility. If the lender converts 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 Senior Secured Notes (the "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 Notes and the bank 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 under the bank credit facility and Notes have agreed to share the security interests on a *pari passu* basis.

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

The 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) Convertible Unsecured Subordinated 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 to Trust Units at a conversion price of $26.50 per Trust Unit. PrimeWest has the option to redeem the Series I Debentures at a price of $1,050 per Series I Debenture after September 30, 2007 and on or before September 30, 2008, and at a price of $1,025 per Series I Debenture after September 30, 2008 and before maturity. On redemption or maturity the Trust may elect to satisfy its obligation to repay the principal by issuing PrimeWest Trust Units.

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

Debenture issue costs of $10.0 million are 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 $94.9 million (Series II). The difference between the fair value and proceeds of $8.1 million was recorded in unitholders’ 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. As at December 31, 2004, $0.3 million of the Series I Debentures had been converted to equity and $0.2 million of accretion was realized. Series II accretion was $0.2 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 gas properties:

Asset Retirement Obligation ($ millions)	2004	2003
Asset Retirement Obligation, January 1	**$ 19.7**	**$ 15.3**
Liabilities incurred	13.1	5.4
Liabilities settled	(4.6)	(2.2)
Accretion expense	2.0	1.2
Acquisition of capital assets	12.0	-
Disposal of capital assets	(2.4)	-
Acquisition of Seventh Energy	0.5	-
Asset Retirement Obligation December 31	**$ 40.3**	**$ 19.7**

As at December 31, 2004, the undiscounted amount of estimated cash flows required to settle the obligation is $238.6 million. The estimated cash flow has been discounted using a credit-adjusted risk free rate of 7.0 percent and an inflation rate of 1.5 percent. Although the expected period until settlement ranges from a minimum of 1 year to a maximum of 50 years, the costs are expected to be paid over an average of 33.2 years. These future asset retirement costs will be funded from the cash reserved for site restoration and reclamation. This cash reserve of $10.3 million is currently funded at $0.50 per BOE from PrimeWest’s operations.

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 per BOE produced for 2004 and 2003). The cash amount contributed, including interest earned, was $6.7 million in 2004 (2003 – $8.7 million). Actual costs of site restoration and abandonment totaling $4.6 million were paid out of this cash reserve for the year ended December 31, 2004 (2003 – $2.2 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)
Balance, December 31, 2002	37,004,522	$ 1,252.2
Issued for cash	9,100,000	234.8
Issue expenses	-	(12.1)
Issued on exchange of exchangeable shares	964,897	21.2
Issued pursuant to Distribution Reinvestment Plan	600,598	14.8
Issued pursuant to Long-Term Incentive Plan	360,608	9.4
Issue of units due to odd lot program	38	-
Issue of fractional units due to 4 to 1 consolidation	11	-
Issued pursuant to Optional Trust Unit Purchase Plan	721,209	17.6
Balance, December 31, 2003	**48,751,883**	**$ 1,537.9**
Issued for cash	17,700,000	420.0
Issue expenses	-	(0.5)
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	3.0
Issue pursuant to conversion of debentures	10,527	0.3
Issued pursuant to Optional Trust Unit Purchase Plan	894,167	21.5
Balance, December 31, 2004	**69,886,111**	**$ 2,037.7**

The weighted average number of Trust Units and exchangeable shares outstanding in 2004 was 59,482,034 (2003 – 46,015,519). For purposes of calculating diluted net income per Trust Unit 1,868,995 and 1,247,551 Trust Units issuable pursuant to the conversion of the Series I and Series II Convertible Unsecured Subordinated Debentures respectively and 525,129 Trust Units (2003 – 345,278) issuable pursuant to the long-term incentive plan were added to the weighted average number. The per unit cash distribution amounts paid or declared reflects distributions paid or declared to Trust Units outstanding on the record dates.

PrimeWest Exchangeable Class A Shares

PrimeWest has an unlimited number of exchangeable shares. The exchangeable shares are exchangeable into PrimeWest Trust Units at any time up to March 29, 2010; based on an exchange ratio that adjusts each time the Trust makes distribution to its unitholders. The exchange ratio, which was 1:1 on the date of the initial exchangeable share offering, is based on the total monthly distribution, divided by the closing unit price on the distribution payment date. The exchange ratio on December 31, 2004 was 0.50408:1 (2003 – 0.44302:1).

Exchangeable Shares	# of shares	($ millions)
Balance, December 31, 2002	**5,179,278**	**$ 47.7**
Issued for management incentive program	161,717	1.5
Exchanged for Trust Units	(2,299,872)	(21.2)
Balance, December 31, 2003	**3,041,123**	**28.0**
Issued for special employee incentive program	94,340	1.2
Exchanged for Trust Units	(1,841,072)	(17.0)
Balance, December 31, 2004	**1,294,391**	**$ 12.2**

Trust Units and Exchangeable Shares Issued & Outstanding

# of Shares	**2004**	2003
Trust Units issued & outstanding	**69,886,111**	48,751,883
Exchangeable shares		
Class A Shares		
(2004 – 1,294,391 shares exchangeable at 0.50408; 2003 - 3,041,123 shares exchangeable at 0.44302)	**652,477**	1,347,277
Total units and exchangeable shares issued & outstanding	**70,538,588**	50,099,160
Convertible Unsecured Subordinated Debentures		
Series I	**5,649,849**	-
Series II	**3,773,585**	-
Unit Appreciation Rights	**525,129**	345,278
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.	**80,487,151**	50,444,438

12. Long-Term Incentive Plan

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

As at December 31, 2004

Year of Grant	UARs issued & outstanding	UARs vested	Current return per "in the money" UARs	Total equity ($ millions)	Trust Unit dilution
1999	35,919	35,919	$ 38.55	$ 1.4	52,020
2000	110,985	110,985	19.42	2.2	80,979
2001	323,235	322,444	10.11	3.3	122,424
2002	825,982	585,423	7.67	6.3	160,042
2003	962,043	382,801	6.48	5.0	90,987
2004	**1,445,467**	**163,912**	**$ 2.87**	**1.9**	**18,677**
Total	**3,703,631**	**1,601,484**		**$ 20.1**	**525,129**

As at December 31, 2003

Year of Grant	UARs issued & outstanding	UARs vested	Current return per "in the money" UARs	Total equity ($ millions)	Trust Unit dilution
1998	10,391	10,391	$ 49.98	$ 0.5	18,844
1999	55,160	55,160	34.92	1.9	69,892
2000	120,137	119,387	16.40	2.0	71,007
2001	383,424	265,645	7.81	3.0	74,891
2002	961,405	447,562	6.09	4.7	86,694
2003	1,085,031	141,896	$ 4.75	2.5	23,950
Total	2,615,548	1,040,041		$ 14.6	345,278

Cumulative to December 31, 2004, 1,287,601 UARs have been exercised (cumulative to December 31, 2003 – 1,030,850), resulting in the issuance of 835,213 Trust Units from treasury (cumulative to December 31, 2003 – 719,374).

13. Cash Distributions

($ millions)	**2004**	2003	2002
Cash flow from operations	**$ 266.8**	$ 216.6	$ 170.9
Deduct amounts to reconcile to distribution:			
Cash retained from cash available for Distribution[1]	**(64.0)**	(15.3)	(7.3)
Contribution to reclamation fund	**(6.7)**	(8.7)	(4.1)
	$ 196.1	$ 192.6	$ 159.5
Cash Distributions to Trust Unitholders	**$ 196.1**	$ 192.6	$ 158.0
Cash Distributions per Trust Unit	**$ 3.30**	$ 4.32	$ 4.80

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

14. Related-Party Transactions

On September 26, 2002, the Trust announced the planned elimination, effective October 1, 2002, of its external management structure and all related management, acquisition and disposition fees, as well as the acquisition of the right to mandatory quarterly dividends commonly referred to as the “1% retained royalty”. The transaction was approved by the unitholders and the holders of Exchangeable Shares on November 4, 2002 and closed November 6, 2002. The transaction resulted in the elimination of the 2.5% management fee on net production revenue, quarterly incentive payments payable in the form of Trust Units, the 1.5% acquisition fee and the 1.25% disposition fee, which resulted in payments to PrimeWest Management Inc. in 2002 totaling $5.8 million. In addition, the amount of the 1% retained royalty paid in 2002 was $1.3 million.

The internalization transaction was achieved through the purchase by PrimeWest of all of the issued and outstanding shares of PrimeWest Management Inc. for a total consideration of approximately $26.3 million comprised of a cash payment of $13.2 million and the issuance of Exchangeable Shares exchangeable, based on an agreed exchange ratio, for approximately 491,000 Trust Units and valued at approximately $13.1 million based on the closing price of the Trust Units on the TSX on September 26, 2002. The $13.2 million that related to the acquisition of the 1% retained royalty was capitalized; an additional $9.5 million was capitalized with an offset to future tax liability as a result of the property, plant and equipment having no tax basis. In addition, PrimeWest agreed to issue Exchangeable Shares valued at $1.5 million to certain executive officers to terminate a management incentive program of PrimeWest Management Inc. and to create a special employee retention plan for those executive officers which provides for long-term incentive bonuses in the form of Exchangeable Shares. Under the special employee retention plan, PrimeWest agreed to issue 94,340 exchangeable shares on each of the second, third, fourth and fifth anniversaries of the completion of the internalization transaction. In November 2004, 94,340 exchangeable shares were issued relating to the special employee retention plan at a value of $1.2 million. As at December 31, 2004, $0.2 million has been accrued in non-cash general and administrative expenses related to the special employee retention plan.

15. Income Taxes

PrimeWest and its subsidiaries had no taxable income for 2004, 2003, and 2002, as tax pool deductions and the royalty payable were sufficient to reduce taxable income in these entities to nil.

The future tax provision results from temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases.

($ millions)	**2004**	2003
Loss carry forwards	**$ (1.4)**	$ -
Capital assets	**230.2**	318.9
Foreign exchange gain on long-term debt	**3.7**	2.1
Asset retirement obligation	**(13.5)**	(2.9)
Long-term incentive liability	**(6.8)**	(4.9)
	$ 212.2	$ 313.2

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

($ millions)	**2004**	2003	2002
Net income (loss) before taxes	**$ 69.1**	$ 19.8	$ (30.9)
Computed income tax expense (recovery) at the Canadian statutory rate of 38.87% (2003 – 40.62%; 2002 – 42.12%)	**26.9**	7.6	(13.0)
Increase (decrease) resulting from:			
Non-deductible crown royalties and other payments, net of ARTC	**0.3**	0.3	5.7
Federal resource allowance	**(8.9)**	(16.2)	(3.5)
Change in income tax rate	**(8.6)**	(43.1)	(4.2)
Foreign exchange gain on long-term debt	**(2.2)**	(2.4)	-
Amounts included in trust income and other	**(45.1)**	(26.1)	(18.2)
Future income taxes	**$ (37.6)**	$ (79.9)	$ (33.2)

16. Financial Instruments

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

A summary of these derivative financial instruments, options and swaps in place at December 31, 2004 follows:

CRUDE OIL

Period	Volume (bbls/d)	Type	WTI Price (US$/bbl)
Jan – Mar 2005	500	Swap	27.25
Jan – Mar 2005	500	Swap	28.60
Jan – Mar 2005	500	Swap	30.00
Jan – Mar 2005	500	Costless Collar	28.00/34.35
Jan – Mar 2005	500	3 Way	25.00/30.00/35.50
Jan – Mar 2005	500	Costless Collar	35.00/49.80
Jan – Mar 2005	500	Costless Collar	35.00/50.00
Jan – Mar 2005	500	Costless Collar	40.00/51.50
Jan – Mar 2005	500	Costless Collar	40.00/57.60
Jan – Mar 2005	500	Costless Collar	40.00/65.80
Apr – Jun 2005	500	Swap	27.07
Apr – Jun 2005	500	Swap	28.50
Apr – Jun 2005	500	Swap	30.00
Apr – June 2005	500	3 Way	25.00/30.00/36.75
Apr – June 2005	500	Costless Collar	35.00/47.00
Apr – June 2005	500	Costless Collar	35.00/46.90
Apr – June 2005	500	Costless Collar	37.50/50.90
Apr – June 2005	500	Costless Collar	37.50/56.70
Apr – June 2005	500	Costless Collar	40.00/60.75
Jul – Sep 2005	500	Swap	27.05
Jul – Sep 2005	500	Swap	28.50
Jul – Sep 2005	500	Costless Collar	35.00/44.90

Jul – Sep 2005	500	Costless Collar	35.00/44.35
Jul – Sep 2005	500	Costless Collar	35.00/51.30
Jul – Sep 2005	500	Costless Collar	35.00/56.50
Oct – Dec 2005	500	Swap	27.18
Oct – Dec 2005	500	Costless Collar	35.00/42.80
Oct – Dec 2005	500	Costless Collar	35.00/42.40
Oct – Dec 2005	500	Costless Collar	35.00/48.05
Oct – Dec 2005	500	Costless Collar	35.00/53.25
Jan – Mar 2006	1000	Costless Collar	35.00/49.90

NATURAL GAS (AECO)

Period	Volume (mmcf/day)	Type	AECO Price (Cdn$/mcf)
Nov 2004 - Mar 2005	4.7	Costless Collar	5.80/7.91
Nov 2004 - Mar 2005	4.7	Swap	6.71
Nov 2004 – Mar 2005	4.7	Costless Collar	6.33/11.87
Nov 2004 – Mar 2005	4.7	Costless Collar	6.86/11.61
Jan 2005 – Mar 2005	10.0	Costless Collar	6.33/11.18
Jan 2005 – Mar 2005	10.0	Costless Collar	6.33/10.76
Jan 2005 – Mar 2005	10.0	Costless Collar	6.33/10.55
Jan 2005 – Mar 2005	10.0	Costless Collar	6.33/12.13
Jan 2005 – Mar 2005	5.0	3 Way	5.28/6.33/10.44
Jan 2005 – Mar 2005	5.0	3 Way	5.28/6.33/10.35
Jan 2005 – Mar 2005	5.0	3 Way	5.28/6.33/12.53
Jan 2005 – Mar 2005	5.0	Costless Collar	6.33/16.40
Feb 2005 – Mar 2005	5.0	Costless Collar	6.33/10.76
Apr 2005 – Jun 2005	10.0	Costless Collar	6.33/7.75
Apr 2005 – Jun 2005	10.0	Costless Collar	6.33/7.63
Apr 2005 – Jun 2005	10.0	Costless Collar	6.33/7.49
Apr 2005 – Jun 2005	10.0	Costless Collar	6.33/7.84
Apr 2005 – Jun 2005	5.0	Costless Collar	6.33/7.85
Apr 2005 – Jun 2005	5.0	Costless Collar	6.33/6.99
Apr 2005 – Jun 2005	5.0	Costless Collar	6.33/7.09
Apr 2005 – Jun 2005	5.0	Costless Collar	6.33/7.44
Apr 2005 – Jun 2005	5.0	Costless Collar	6.33/8.56
Apr 2005 – Jun 2005	5.0	Costless Collar	6.33/8.97
Apr 2005 – Jun 2005	5.0	Costless Collar	6.33/8.33
Jul 2005 – Sep 2005	10.0	Costless Collar	6.33/7.81
Jul 2005 – Sep 2005	10.0	Costless Collar	6.33/7.66
Jul 2005 – Sep 2005	10.0	Costless Collar	6.33/7.53
Jul 2005 – Sep 2005	10.0	Costless Collar	6.33/7.86
Jul 2005 – Sep 2005	2.4	Costless Collar	6.33/7.88
Jul 2005 – Sep 2005	5.0	Costless Collar	6.33/7.50
Jul 2005 – Sep 2005	5.0	Costless Collar	6.33/7.60
Jul 2005 – Sep 2005	5.0	Costless Collar	6.33/7.79
Jul 2005 – Sep 2005	5.0	Costless Collar	6.33/9.28

Oct 2005 – Dec 2005	10.0	Costless Collar	6.33/8.97
Oct 2005 – Dec 2005	10.0	Costless Collar	6.33/8.71
Oct 2005 – Dec 2005	10.0	Costless Collar	6.33/8.60
Oct 2005 – Dec 2005	10.0	Costless Collar	6.33/8.96
Oct 2005 – Dec 2005	5.0	3 Way	5.28/6.33/9.92
Oct 2005 – Dec 2005	5.0	3 Way	5.28/6.33/9.76
Oct 2005 – Dec 2005	5.0	3 Way	5.28/6.33/10.04
Oct 2005 – Dec 2005	5.0	Costless Collar	6.33/10.90
Jan 2006 – Mar 2006	10.0	Costless Collar	6.33/10.55
Jan 2006 – Mar 2006	10.0	Costless Collar	6.33/10.22
Jan 2006 – Mar 2006	10.0	Costless Collar	6.33/9.96
Jan 2006 – Mar 2006	5.0	Costless Collar	6.33/10.42
Jan 2006 – Mar 2006	5.0	Costless Collar	6.33/13.13

A 3 Way option is like a traditional collar, except that PrimeWest has resold the put at a lower price. Utilizing the first 3 Way natural gas contract above as an example, PrimeWest has sold a call at $10.44, purchased a put at $6.33, and resold the put at $5.28. Should the market price drop below $6.33 PrimeWest will receive $6.33 until the price is less than $5.28, at which time PrimeWest would then receive market price plus $1.05. However, should market prices rise above $10.44, PrimeWest would receive a maximum price of $10.44. Should the market price remain between $6.33 and $10.44 PrimeWest would receive the market price.

In 2004, the financial impact of contracts settling in the year was a decrease in sales revenues of $28.2 million (2003 - $30.5 million decrease in sales revenues; 2002 - $28.1 million increase in sales revenues).

The mark-to-market value of the hedges in place as at December 31, 2004 is a $0.2 million gain of which $9.1 million gain is attributable to natural gas and an $8.9 million loss is attributable to crude oil.

Electrical Power

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

The mark to market value of the hedges at December 31, 2004 is a $0.1 million loss.

b) Fair Value Of Financial Instruments

Financial instruments include cash, marketable securities, accounts receivable, accounts payable and accrued liabilities, accrued distributions to unitholders, long-term debt and financial hedges. As at December 31, 2004, 2003, and 2002, the fair market value of the financial instruments, other than long-term debt and financial hedges, 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.

17. 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 $3.6 million in 2005, $3.6 million in 2006 and $3.4 million in 2007, $3.3 million in 2008 and $0.8 million in 2009.

b) As part of PrimeWest's internalization transaction (see Note 15), PrimeWest agreed to issue 377,360 exchangeable shares as a special employee retention plan. One quarter of the exchangeable shares (94,340) were issued to the executive officers of PrimeWest on November 6, 2004. An additional 94,340 exchangeable shares will be issued each on November 6, 2005, November 6, 2006 and November 6, 2007. As at December 31, 2004 $0.2 million has been accrued in non-cash general and administrative expenses related to the special employee retention plan.

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

d) PrimeWest has various pipeline transportation commitments that run through 2010. The estimated annual payments are $7.1 million in 2005, $4.1 million in 2006, $2.9 million in 2007, $0.4 million in 2008 and $0.2 million in 2009.

e) Pursuant to the purchase of the Calpine assets, PrimeWest entered into a natural gas purchase and sale agreement where the purchaser has the right to purchase natural gas in an amount based on a notional quantity of natural gas produced from certain of the Calpine Assets. The gas purchase and sale arrangement is on a firm basis for a seven-year term, based on a monthly index price, with predetermined declining quantities. As part of the arrangement, the purchase obligations will be secured by credit support acceptable to PrimeWest provided by the purchaser. The parties will share in the proceeds of sale of the natural gas subject to this purchase and sale arrangement realized between December 31, 2004 and December 31, 2006. The sale proceeds will only be shared if gas prices exceed an agreed forward strip pricing prevailing at the time that the Purchase and Sale Agreement was executed, plus $1.00/mcf, and the maximum amount that will be paid by PrimeWest Gas under that price sharing mechanism is $2,500,000 in any calendar quarter to a maximum aggregate amount of $25,000,000.

18. Prior Years' Comparative Numbers

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

19. Differences Between Canadian And United States Generally Accepted Accounting Principles

PrimeWest's financial statements are prepared in accordance with generally accepted accounting principles (GAAP) in Canada, which, in some respects, differ from those generally accepted in the United States (US). The following are those policies that result in significant measurement differences.

1. Property, Plant And Equipment

PrimeWest adopted CICA Accounting Guideline 16 (AcG-16), "Oil and Gas Accounting – Full Costs" on January 1, 2004. The new guideline modifies how the ceiling test is performed and requires that cost centers be tested for recoverability using undiscounted future cash flows from Proved reserves, which are determined by using forward indexed prices. When the carrying amount of a cost center is not recoverable, the cost center must be 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.

In accordance with the full cost method of accounting under U.S. GAAP, the net carrying value is limited to a standardized measure of discounted future cash flows, before financing and general administrative costs. Where the amount of a ceiling test write down under Canadian GAAP differs from the amount of a write down under U.S. GAAP, the charge for depreciation and depletion under U.S. and Canadian GAAP will differ in subsequent years.

Under Canadian GAAP, depletion charges are calculated by reference to proved reserves estimated using future prices and estimated future costs. Under US GAAP, depletion charges are calculated by reference to proved reserves using constant prices.

2. Asset Retirement Obligation

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. The change in accounting policy is recorded as an adjustment to accumulated income with retroactive restatement of prior period comparatives.

The Trust is required to provide for asset retirement obligations. These costs are estimated in accordance with existing laws, contracts and other policies and charged to earnings and the appropriate liability account over the expected service life of the asset.

This change in accounting policy is consistent with the Trust's adoption of FAS 143 Accounting for Asset Retirement Obligations effective January 1, 2003. The new standard requires the recognition of the liability associated with the future site reclamation costs of the long-lived assets. The liability for future retirement obligations is to be recorded in the financial statements at the time the liability is incurred.

The asset retirement obligation is initially recorded at the estimated fair value as a long-term liability with a corresponding increase to property, plant and equipment. The depreciation of property, plant and equipment is allocated to expense on the unit-of-production basis.

The adoption of FAS 143 allows for the cumulative effect of the change in accounting policy to be booked as a transitional adjustment to net income with no restatement of prior period comparatives. At January 1, 2003, this resulted in an increase to the asset retirement obligation of $15.3 million, an increase to PP&E of $8.4 million in 2003, a $0.4 million decrease to net income after tax, a decrease in the site restoration provision of $6.2 million and a decrease to future tax liability of $0.3 million.

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

3. Marketable Securities

PrimeWest follows the cost method of accounting for the investment in marketable securities as established by the CICA. Under this accounting policy, the investment is initially recorded at cost with the corresponding distributions received in excess of earnings recorded as a reduction to the carrying amount of the investment. Under U.S. GAAP, the marketable securities are considered held for trading and recorded on the balance sheet at fair value. The corresponding after tax difference between the cost method and fair value is recorded to earnings in the current year and results in a Canadian / U.S. GAAP difference.

Recent US Accounting Pronouncements Issued But Not Implemented

Share-Based Payment

On December 15, 2004 the Financial Accounting Standards Board (FASB) in the United States issued FASB Statement No. 123R "Share-Based Payment". The standard mandates that a public entity measure the cost of equity based service awards based on the fair value of the award at grant date. That cost will be recognized over the period during which an employee is required to provide service in exchange for the award or the requisite service period. No compensation cost is recognized for equity instruments for which employees do not render the requisite service. The public entity will initially measure the cost of the liability based service awards based on its current fair value. The fair value of that award will be re-measured subsequently at each reporting date through the settlement date. Changes in fair value during the requisite service period will be recognized as compensation cost over that period. The Trust is currently assessing the impact of the pronouncement on the financial statements.

The following tables set out the significant differences in the consolidated financial statements using U.S. GAAP.

a) Consolidated Net Income

($ millions, except per Trust Unit amounts)	**2004**	2003	2002
Net income/(loss) as reported	**$ 103.4**	$95.9	$ (0.6)
Adjustments			
Depletion and depreciation	**(4.2)**	35.4	67.3
FAS 115 adjustment	**22.6**	-	-
FAS 133 adjustment	**5.4**	6.1	(55.8)
Accretion of asset retirement obligation	**-**	-	0.9
Future income tax expense	**(4.3)**	(42.3)	(1.4)
Adjusted net income before change in accounting policy	**122.9**	95.1	10.4
Cumulative effect of change in accounting policy, net of tax of $0.3 million	**-**	(0.4)	–
Adjusted net income	**$ 122.9**	$ 94.7	$10.4
Net income per Trust Unit			
U.S. GAAP – basic	**$ 2.07**	$ 2.01	$0.30
– diluted	**$2.05**	$ 1.99	$ 0.30
Cumulative effect of change in accounting policy per Trust Unit			
U.S. GAAP – basic	**-**	$ 0.01	–
– diluted	**-**	$ 0.01	–

b) Pro Forma Consolidated Net Income

U.S. GAAP requires the cumulative impact of a change in accounting policy to be presented in the current year's consolidated statement of income with no restatement of the comparative prior periods. The following table illustrates the pro forma impact on the Trust's 2002 net income under U.S. GAAP had the prior period been restated.

($ millions, except per Trust Unit amounts)	**2002**
Net income	
As reported	$10.4
As restated	$11.2
Net income per Trust Unit (Basic)	
As reported	$0.30
As restated	$0.33
Net income per Trust Unit (Diluted)	
As reported	$0.30
As restated	$0.32
Asset retirement obligation at January 1, 2002	$ 11.8

c) Consolidated Unitholders' Equity

($ millions)	**2004**	2003
Unitholders' Equity as reported	**$ 1,194.9**	$ 1,025.2
Adjustments		
Depletion and depreciation	**(270.3)**	(493.6)
FAS 115 adjustment	**22.6**	--
FAS 133 adjustment	**-**	(5.4)
Future income tax recovery	**119.2**	127.0
	$ 1,066.4	$ 653.2

d) Consolidated Balance Sheets

($ millions)	**2004**		2003	
	Cdn GAAP	**U.S. GAAP**	Cdn GAAP	U.S. GAAP
Property, plant and equipment (net)	**$ 1,908.6**	**$ 1,699.4**	$ 1,548.2	$ 1,042.1
Marketable securities	**68.6**	**91.2**	-	-
Derivative liability	**0.5**	**0.5**	-	5.4
Future income tax liability	**211.2**	**153.2**	313.2	183.0
Accumulated income/(deficit)	**89.2**	**(39.3)**	219.1	(162.2)

e) Consolidated Cash Flows

The consolidated statements of cash flows prepared in accordance with Canadian GAAP conform in all material respects with U.S. GAAP, except that Canadian GAAP allows for the presentation of operating cash flow before changes in non-cash working capital items in the consolidated statement of cash flows. This total cannot be presented under U.S. GAAP.

FAS 69 Supplemental Reserve Information (Unaudited)

The following data supplements oil and gas disclosure in the Trust's Annual Report, and is provided in accordance with the provisions of FAS 69.

Oil and Gas Reserves

Users of this information should be aware that the process of estimating quantities of "Proved" and "Proved developed" crude oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of the numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Canadian provincial royalties are determined based on a graduated percentage scale, which varies with prices and production volumes. Canadian reserves, as presented on a net basis, assume prices and royalty rates in existence at the time the estimates were made, and the Trust's estimate of future production volumes. Future fluctuations in prices, production rates, or changes in political or regulatory environments could cause the Trust's share of future production from Canadian reserves to be materially different from that presented.

Subsequent to December 31, 2004, no major discovery or other favorable or adverse event is believed to have caused a material change in the estimates of Proved or Proved developed reserves as of that date.

Results of Oil and Gas Operations

($ millions)	**2004**	2003	2002
Revenues	**$394.6**	$329.9	$ 264.3
Expenses			
Production costs	**88.9**	79.4	60.8
Depreciation, depletion and amortization	**201.5**	170.3	113.5
Accretion	**2.0**	1.2	–
Tax recovery	**(30.0)**	(39.9)	(26.0)
	262.4	211.0	148.3
Results of operations from oil and gas operations	**$132.2**	$ 118.9	$ 116.0

Costs Incurred

($ millions)	**2004**	2003	2002
Property acquisition costs			
Proved properties	**$ 770.5**	**$ 202.4**	$ 57.7
Unproved properties	**52.1**	**34.0**	5.7
Exploration costs	**16.0**	**5.7**	1.8
Development costs	**123.6**	**101.5**	56.8
	$ 962.2	**$ 343.6**	$ 122.0

Acquisition costs include costs incurred to purchase, lease, or otherwise acquire oil and gas properties.

Development costs include the costs of drilling and equipping development wells and facilities to extract, treat and gather and store oil and gas, along with an allocation of overhead.

There were no oil and gas property costs not being amortized in any of the years presented.

Capitalized Costs

($ millions)	**2004**	2003	2002
Proved properties	**$2,599.1**	$ 2,189.0	$ 1,838.8
Unproved properties	**103.9**	36.0	44.2
	2,703.0	2,225.0	1,883.0
Less related accumulated depreciation, depletion and amortization	**(1,010.0)**	(1,186.2)	(1,011.6)
	$1,693.0	$ 1,038.8	$ 871.4

Proved Oil & Gas Reserve Quantities

	2004	**2004**	2003	2003	2002	2002
	Crude Oil & Natural Gas Liquids (mbbls)	**Natural Gas (mmcf)**	Crude Oil & Natural Gas Liquids (mbbls)	Natural Gas (mmcf)	Crude Oil & Natural Gas Liquids (mbbls)	Natural Gas (mmcf)
Opening balance	**25,643**	**272,897**	25,989	279,106	26,657	267,371
Revision of previous estimates	**(806)**	**2,640**	225	(33,640)	1,737	5,700
Purchase of reserves in place	**6,940**	**180,914**	1,640	50,389	954	18,929
Sale of reserves in place	**(2,120)**	**(8,027)**	(28)	(803)	(568)	(5,328)
Discoveries and extensions	**791**	**16,018**	941	14,742	736	25,337
Production	**(2,649)**	**(42,215)**	(3,124)	(36,897)	(3,527)	(32,903)
Closing Balance	**27,799**	**422,227**	25,643	272,897	25,989	279,106

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves

The standardized measure for calculating the present value of future net cash flows from Proved oil and gas reserves is based on current costs and prices and a ten percent discount factor as prescribed by FASB 69.

Accordingly, the estimated future net cash inflows were computed by applying prevailing selling prices at year end to the estimated future production of Proved reserves. Estimated future expenditures are based on future development costs.

Although these calculations have been prepared according to the standards described above, it should be emphasized that due to the number of assumptions and estimates required in the calculation, the amounts are not indicative of the amount of net revenue that the Trust expects to receive in future years. They are also not indicative of the current value or future earnings that may be realized from the production of Proved reserves, nor should it be assumed that they represent the fair market value of the reserves or of the oil and gas properties.

Although the calculations are based on existing economic conditions at each year end, such economic conditions have changed and may continue to change significantly due to events such as the continuing changes in the natural gas market and changes in government policies and regulations. While the calculations are based on the Trust's understanding of the established FASB guidelines, there are numerous other equally valid assumptions under which these estimates could be made that would produce significantly different results.

Standardized Measure

($ millions)	**2004**	2003	2002
Future cash inflows	**$ 4,187.1**	$ 2,631.1	$ 2,890.5
Future production costs	**(1,186.6)**	(804.9)	(699.0)
Future development costs	**(72.0)**	(69.4)	(73.4)
Other related future costs	**(37.1)**	(42.1)	(43.4)
Future net cash flows	**2,891.4**	1,714.7	2,074.7
Discount at 10%	**(1,242.7)**	(721.6)	(919.4)
Standardized measure of discounted future net cash flow related to proved reserves	**$ 1,648.7**	$ 993.1	$ 1,155.3

Summary of Changes in the Standardized Measure During the Year

($ millions)	**2004**	2003	2002
Sales of oil and gas produced, net of production costs	**$ (312.2)**	$ (255.0)	$ (203.5)
Net change in sales and transfer prices, net of development and production costs	**144.4**	(106.2)	672.6
Sales of reserves in place	**(54.4)**	(2.3)	(4.5)
Purchases of reserves in place	**630.4**	156.4	45.6
Extensions, discoveries and improved recovery, less related costs	**106.7**	48.5	52.3
Changes in timing of future net cash flows and other	**37.1**	(60.6)	(93.6)
Revisions of previous quantity estimates	**4.3**	(58.5)	28.3
Accretion of discount	**99.3**	115.5	59.8
Net change	**655.6**	(162.2)	557.0
Balance at beginning of year	**993.1**	1,155.3	598.3
Balance at end of year	**$ 1,648.7**	$ 993.1	$ 1,155.3

Trading Performance

For the quarter ended	**Dec 31/04**	Sep 30/04	Jun 30/04	Mar 31/04	Dec 31/03
TSX Trust Unit prices ($ per Trust Unit)					
High	**$ 28.33**	$ 26.70	$ 26.80	$ 28.35	$ 27.34
Low	**$ 25.06**	$ 23.29	$ 22.18	$ 22.70	$ 24.48
Close	**$ 26.62**	$ 26.70	$ 23.25	$ 26.65	$ 24.51
Average daily traded volume	**255,944**	259,219	187,767	256,922	184,428

For the quarter ended	**Dec 31/04**	Sep 30/04	Jun 30/04	Mar 31/04	Dec 31/03
NYSE Trust Unit prices (US$ per Trust Unit)					
High	**$ 22.98**	$ 21.16	$ 20.44	$ 22.14	$ 21.48
Low	**$ 20.85**	$ 17.65	$ 16.00	$ 17.31	$ 18.67
Close	**$ 22.18**	$ 21.16	$ 17.43	$ 20.31	$ 21.27
Average daily traded volume	**542,483**	329,862	279,882	469,694	243,921

Number of Trust Units outstanding including exchangeable shares (millions of units)	**70.5**	69.7	56.8	50.87	50.10
Distribution paid per Trust Unit	**$0.90**	$0.83	$0.75	$0.82	$0.96

Total Compound Annual Return (%) [(1)]

	PrimeWest	TSX Oil and Gas Index	TSX S&P	S&P 500 $Cdn	S&P 500 US$	S&P TSX Cdn Energy Trust Index
Five Year	21.5%	23.4%	3.6%	(5.9)%	(2.3)%	13.4%
Three Year	18.5%	24.9%	7.7%	(6.5)%	2.9%	15.7%
One Year	9.7%	40.5%	14.4%	2.8%	10.8%	29.6%

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

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