



PRIMEWEST

FOR IMMEDIATE RELEASE

February 20, 2003

PrimeWest Announces Fourth Quarter and Full Year 2002 Results

CALGARY (TSX: PWL.UN, PWX; NYSE: PWI) – PrimeWest Energy Trust (PrimeWest) today announced financial and operating results for the fourth quarter and the year-ended December 31, 2002.

FINANCIAL HIGHLIGHTS – FOURTH QUARTER (thousands of dollars except per-BOE and per-trust-unit amounts)

	Dec. 31, 2002	Three months ended	
		Sep. 30, 2002	Dec. 31, 2001
Net revenue	\$ 68,794	\$ 63,814	\$ 78,477
Per BOE	25.20	23.00	26.00
Cash flow from operations	41,570	40,841	53,246
Per BOE	15.22	14.71	17.64
Royalty expense	17,267	13,997	13,591
Per BOE	6.32	5.04	4.50
Operating expenses	16,809	14,931	17,188
Per BOE	6.16	5.38	5.69
G&A expenses - Cash	3,295	2,436	2,532
Per BOE	1.21	0.88	0.84
- UAR's ⁽¹⁾	(93)	(940)	2,815
Per BOE	(0.03)	(0.34)	0.93
Interest expense	3,192	3,014	3,172
Per BOE	1.17	1.09	1.05
Internalization costs - Cash	3,598	-	-
Per BOE	1.52	-	-
Management fees - Cash	-	1,300	1,666
Per BOE	-	0.47	0.55
- Non-cash	-	449	419
Per BOE	-	0.16	0.14
Cash distributed to unitholders	40,337	38,818	53,628
Per Trust Unit	1.20	1.20	1.76
Cash flow from operations			
Per Trust Unit ⁽²⁾	1.21	1.26	1.69
Net debt ⁽³⁾	225,436	270,859	224,431
Per Trust Unit	5.79	8.01	6.85

(1) Unit Appreciation Rights

(2) Based on trust units at date of distribution

(3) Net debt is long-term debt plus negative working capital

(4) Per trust unit figures restated to reflect four to one trust unit consolidation

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OPERATING HIGHLIGHTS – FOURTH QUARTER	Three months ended	
	Dec. 31, 2002	Sep. 30, 2002
Daily sales volumes		
Natural gas (<i>MMcf/day</i>)	114.2	115.5
Crude oil (<i>bbls/day</i>)	8,766	8,975
Natural gas liquids (<i>bbls/day</i>)	1,878	1,950
Total (<i>BOE/day</i>)	29,678	30,169
Realized Commodity Prices ⁽¹⁾ (<i>Cdn \$</i>)		
Natural gas (<i>\$/Mcf</i>)	5.09	4.07
Crude oil (<i>\$/bbl</i>)	33.26	35.97
Natural gas liquids (<i>\$/bbl</i>)	32.48	28.09
Total (<i>\$ per BOE</i>)	31.46	28.09

(1) Includes hedging gains (losses)

Fourth quarter highlights:

- Cash flow from operations of \$41.6 million (\$1.13 per trust unit) compared to \$40.8 million (\$1.21 per trust unit) for the third quarter;
- Unitholders approve management internalization effective October 1, 2002; non-recurring cash costs of internalization of \$3.6 million in the fourth quarter;
- NYSE listing November 19, 2002; non-recurring costs associated with the listing were approximately \$0.7 million (\$0.26 per BOE) in the quarter;
- Production averaged 29,678 barrels of oil equivalent per day (BOE/day) for the fourth quarter, 1.6% below the third quarter results;
- Operating costs increased to \$6.16 per BOE for the fourth quarter compared to \$5.38 for the third quarter. Fourth quarter costs included a number of adjustments related to activities in prior quarters and escalating power costs; and
- Net debt reduced to \$225.4 million at December 31, 2002 compared to \$270.9 million at September 30, 2002. A bought deal equity financing of 4.2 million trust units at \$26.20 for net proceeds of \$104.5 million closed on November 13, 2002.

Subsequent Events:

- Closed acquisition of Caroline/Peace River Arch properties for \$206.1 million on January 23, 2003. Added 6,800 BOE/day of production, 83% natural gas, and approximately 17.6 million BOE of established reserves;
- Increases PrimeWest's expected production for 2003 by 20% to approximately 36,000 BOE/day from 30,189 in 2002;
- Increases gas weighting to 68% expected for 2003 compared to 62% for 2002; and
- Closed a bought deal equity financing on February 13, 2003 for 6 million trust units at \$25.75 for net proceeds of \$146.8 million.



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FINANCIAL AND OPERATING HIGHLIGHTS – FULL YEAR

(thousands of dollars except per BOE, per trust unit and multiple amounts)

FINANCIAL	2002	Per BOE	2001	Per BOE
Gross revenues before hedging	\$ 292,623	\$ 26.56	\$ 340,191	\$ 31.30
Hedging revenues	28,121	2.55	39,480	3.63
Royalty expense	(56,496)	(5.13)	(73,156)	(6.73)
Operating expense	(60,773)	(5.52)	(58,951)	(5.42)
Operating margin	203,475	18.46	247,564	22.78
General and administrative expense	(11,281)	(1.02)	(10,394)	(0.96)
Cash management fees	(3,982)	(0.36)	(6,431)	(0.59)
Interest expense	(10,788)	(0.98)	(13,800)	(1.27)
Capital taxes	(2,887)	(0.26)	(2,429)	(0.22)
Contribution to reclamation fund	(4,078)	(0.37)	(3,499)	(0.32)
Cash internalization costs	(3,598)	(0.33)	-	-
Cash flow available for distribution	\$ 166,861	\$ 15.14	\$ 211,011	\$ 19.42
Per trust unit ⁽¹⁾	\$ 4.89		\$ 8.23	
Cash distributed to unitholders	\$ 157,951		\$ 234,465	
Per trust unit ⁽¹⁾	\$ 4.80		\$ 9.24	
Net debt ⁽²⁾	\$ 225,436		\$ 224,431	
Net debt to cash flow from operations multiple	1.32		1.05	
Trust units and exchangeable shares issued and outstanding				
Year End	38,944,386		32,785,085	
Weighted Average	34,134,230		25,633,250	
OPERATING	2002		2001	
Daily sales volume				
Natural gas (MMcf/day)	113.5		104.8	
Crude oil (bbls/day)	9,239		10,033	
Natural gas liquids (bbls/day)	2,030		2,273	
Total (BOE/day)	30,189		29,774	

(1) All unit and per unit figures have been restated to reflect the 4 for 1 unit consolidation effective August 16, 2002.

(2) Net debt is long term debt plus working capital.

FINANCIAL AND OPERATING HIGHLIGHTS – FULL YEAR

- Production stable throughout 2002 at approximately 30,000 BOE per day;
- Operating margin of \$18.46 per BOE for 2002, down 19% from 2001 primarily due to lower prices for natural gas;
- Hedging gains of \$28.1 million (\$2.55 per BOE) in 2002, compared to gains of \$39.5 million (\$3.63 per BOE) in 2001;
- Royalties per BOE down 24% compared to 2001 primarily due to significantly lower natural gas prices year over year;
- General and administrative expenses increased over 2001 reflecting \$0.8 million of non-recurring costs in 2002 related to listing the trust units on the New York Stock Exchange;



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- Cash management fees down 39% compared to 2001 primarily due to the internalization of management effective October 1, 2002, at a cost of \$26.3 million, and lower net revenue driven by lower natural gas prices in 2002;
- Interest expense down 22% from 2001 as a result of lower average debt and lower interest rates in 2002 compared to 2001;
- Distributions of \$4.80 per trust unit in 2002 compared to \$9.24 in 2001 reflecting reduced cash flow in 2002 due to lower natural gas prices and a 95% payout ratio in 2002 compared to 111% in 2001; and
- Capital development program of \$63.1 million added 8.7 million BOE of established reserves at \$7.27 per BOE.

The preceding and the following information constitute management's discussion and analysis (MD&A) of PrimeWest's operating and financial results for the year ended December 31, 2002 compared with 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, 2002 and 2001, together with accompanying notes. The notes to the Consolidated Financial Statements are available on PrimeWest's website at www.primewestenergy.com, except the United States / Canadian GAAP reconciliation which will be provided at a later date.

Consolidation of Trust Units

On August 16, 2002 the Trust Units of PrimeWest began trading on a four to one consolidated basis on the TSX. All per Trust Unit amounts have been restated to conform to the four to one consolidated basis.

Currency

All financial information contained in this MD&A is reported in Canadian dollars, unless otherwise indicated.

Natural Gas Conversion Equivalent

All calculations required to convert natural gas to a crude oil equivalent (BOE) have been made using a ratio of 6 thousand cubic feet of natural gas to 1 barrel of crude oil.

Reserves and Production Information

Established reserves include 100% of proved reserves and 50% of probable reserves. All production information is reported before the deduction of crown and freehold royalties.

Notes to Consolidated Financial Statements

Please refer to PrimeWest's website at www.primewestenergy.com for the notes to the Consolidated Financial Statements, except the United States / Canadian GAAP reconciliation which will be provided at a later date. If you wish to receive a hard copy of these notes, please contact us at the numbers listed on page 1 of this release.

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 size of our reserves;
- The timing and amount of future production;
- Prices for oil and natural gas 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; and
- Our treatment under governmental regulatory regimes.

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;
- 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; and
- The other factors discussed under "Operational and Other Business Risks" in this MD&A.

These factors should not be construed as exhaustive. We undertake no obligation to publicly update or revise any forward-looking statements.



CASH FLOW RECONCILIATION

The following table shows a reconciliation of 2002 cash flow from operations to the prior year.

Increase (Decrease) in Cash Flow

	(in thousands of dollars)	
2001 Cash flow from operations	\$	214,511
Effect of:		
production volumes		3,452
natural gas price		(55,317)
hedging gas(1)		(4,100)
crude oil price		12,414
hedging crude oil(1)		(7,300)
natural gas liquids price		(3,253)
royalty expense		16,660
other		(6,128)
2002 Cash flow from operations	\$	170,939

(1) Reflects change from previous year (i.e. reduced hedging gains in 2002 compared to 2001). See 2002 Hedging Results.

Capital Spending

Capital expenditures, including corporate acquisitions, totaled approximately \$124.1. million in 2002 as summarized in the following table:

<i>(thousands of dollars)</i>	2002	2001	2000
Land and lease	\$ 5,663	\$ 6,831	\$ 545
Geological and geophysical	1,814	4,048	817
Development drilling	34,488	47,766	16,416
Plant and facilities	21,182	21,802	5,665
Head office (includes capitalized G&A)	5,908	3,457	2,348
Total property, plant and equipment	69,055	83,904	25,791
Acquisitions	59,606	822,598	118,656
Total additions	128,661	906,502	144,447
Property dispositions	(4,529)	(78,144)	(855)
Net additions	\$ 124,132	\$ 828,358	\$ 143,592

In 2002, PrimeWest completed \$45.6 million in property acquisitions adding 5.7 million barrels of oil equivalent of established reserves and approximately 1,550 BOE per day of production.

Acquisitions includes \$13.2 million to acquire the 1% retained royalty as part of the internalization of management plus \$0.8 million in capitalized costs to effect the internalization.

For 2002, PrimeWest added 8.7 million BOE of established reserves at a cost of \$7.27 per BOE from \$63.1 million of development activities (2001 – \$80.4 million; 2000 - \$23.4 million).



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Outlook for Capital Spending

On November 25, 2002, PrimeWest announced its intention to acquire production and reserves at Caroline and Peace River Arch for \$206.1 million, including \$15 million for certain natural gas processing midstream assets. Established reserves were approximately 17.6 million BOE and production as of January 1, 2003 was approximately 6,800 BOE per day. At December 31, 2002, \$14.2 million had been incurred to effect the acquisition. The transaction closed on January 23, 2003.

PrimeWest plans to spend \$70 to \$100 million in 2003 on capital development programs.

Reserve Reconciliation

2002	TOTAL PROVED RESERVES				Net Change (%)
	Oil (Mbbls)	Sales Gas (mmcf)	NGL (mmbbls)	BOE ⁽¹⁾ (mboe)	
Opening Balance	24,719	349,310	7,830	90,767	
Additions, Extensions, Discoveries	182	31,910	796	6,296	7%
Acquisitions	373	23,840	862	5,208	6%
Divestments	(512)	(6,710)	(158)	(1,789)	(2%)
Revision	27	(7,440)	(138)	(1,351)	(2%)
2002 Production	(3,372)	(41,440)	(741)	(11,020)	(12%)
Closing Balance	21,416	349,470	8,451	88,112	(3%)
Reserve Life Index	7.1	8.7	11.2	8.4	

Numbers may not add due to rounding

(1) Natural gas to crude oil converted on a 6:1 basis

2002	TOTAL ESTABLISHED RESERVES				Net Change (%)
	Oil (Mbbls)	Sales Gas (mmcf)	NGL (mmbbls)	BOE ⁽¹⁾ (mboe)	
Opening Balance	28,545	413,710	9,546	107,043	
Additions, Extensions, Discoveries	234	43,910	1,133	8,685	8%
Acquisitions	437	26,310	925	5,746	5%
Divestments	(633)	(7,800)	(186)	(2,119)	(2%)
Revision	(751)	(16,220)	(486)	(3,940)	(4%)
2002 Production	(3,372)	(41,440)	(741)	(11,020)	(10%)
Closing Balance	24,460	418,470	10,191	104,396	(3%)
Reserve Life Index	8.1	10.4	13.5	10.0	

Numbers may not add due to rounding

(1) Natural gas to crude oil converted on a 6:1 basis

Summary of Daily Production Volumes by Core Property

Core Property	BOE / Day	
	2002	2001
NorthWest	4,569	4,763
Dawson	6,312	6,008
SouthEast	7,063	7,356
Central	7,797	8,853
Caroline	1,463	1,875
Other Properties	1,290	(882)
GORR	1,695	1,801
Total	30,189	29,774

Production Summary

	2002	%	2001	%	Change
Natural Gas (<i>MMcf per day</i>)	113.5	62	104.8	59	8%
Crude Oil (<i>barrels per day</i>)	9,239	31	10,033	34	(8%)
Natural Gas Liquids (<i>barrels per day</i>)	2,030	7	2,273	7	(11%)
Total Oil Equivalent (BOE per day)	30,189	100	29,774	100	1%

Development success, particularly at Dawson, contributed to the increase in natural gas production volumes in 2002 compared to 2001. Crude oil volume declined in 2002 compared to 2001 as a significant majority of the 2002 capital development program was focused on the development of natural gas reserves and production.

Outlook for Production Volumes

Our target for 2003 is to produce an average of approximately 36,000 BOE per day, approximately 68% natural gas. Our natural decline rate for production is 15% - 20% per year. Our capital development program of \$70 to \$100 million for 2003 is expected to significantly offset the impact of natural decline.

Commodity Prices

Average Realized Sales Prices ⁽¹⁾ (Canadian dollars)	2002	2001	Change
Natural Gas (\$ per Mcf)	\$ 4.55	\$ 6.16	(26%)
Crude Oil (\$ per barrel)	33.53	32.21	4%
Natural Gas Liquids (\$ per barrel)	26.56	30.96	(14%)
Total Oil Equivalent ⁽²⁾ (\$ per BOE)	\$ 29.16	\$ 34.80	(16%)

(1) Includes hedging gains / losses

(2) Excludes sulphur

Natural gas, using the AECO daily index as the benchmark, entered 2002 at \$3.67 per Mcf and exited 2002 at \$6.02 per Mcf, an increase of 64%. High natural gas storage levels depressed natural gas prices for much of the year, particularly in the first and third quarters with the AECO price averaging \$3.30 per Mcf. Natural gas prices rose in the second quarter on the prospect for a warmer than normal summer of 2002 and fourth quarter natural gas prices strengthened on the prospect for reduced supply combined with cold weather in the major U.S. natural gas consuming areas.

For 2001, the price for natural gas reached record levels in the first quarter of the year with an average AECO price of \$10.91 per Mcf. Prices fell through the remainder of 2001 and averaged \$6.30 for the year, also a record high.



Crude oil, using West Texas Intermediate (WTI) as the benchmark, entered 2002 at \$US 19.84 per barrel, fell to a low of \$US 17.97 per barrel on January 17, 2002 then reached a high of \$US 32.72 per barrel on December 27, 2002, and exited 2002 at \$US 31.20 per barrel. The threat of military action in the Middle East combined with a general strike in Venezuela has driven the market to recent highs.

Sales Revenue

Gross sales revenues fell by 15% in 2002 compared to 2001. Total sales revenue was influenced both by production volumes which increased year-over-year, and natural gas prices, which decreased year-over-year as discussed above.

Revenue (\$ millions)	2002	%	2001	%	Change
Natural Gas	\$ 187.7	59	\$ 234.5	62	(20%)
Crude Oil	113.1	35	118.0	31	(4%)
Natural Gas Liquids	19.7	6	25.7	7	(23%)
	\$ 320.5	100	\$ 378.2	100	(15%)

Natural Gas Revenues

Average daily production of natural gas was 8% higher in 2002 than 2001, reflecting the significant weighting to natural gas of the 2002 capital development program. The 26% drop in the average realized natural gas prices in 2002 compared to 2001, significantly outweighed the benefits of the production increase, resulting in a 20% decrease in revenue from natural gas sales in 2002 compared to 2001.

Crude Oil Revenues

Reduced crude oil production was partially offset by higher average crude oil prices comparing 2002 to 2001.

Natural Gas Liquids Revenues

An 11% decrease in production volumes and a 14% decrease in prices, resulted in a 23% decrease in natural gas liquids revenues in 2002 compared to 2001. PrimeWest does not hedge its natural gas liquids prices.

2002 Hedging Results

During 2002, PrimeWest actively protected against the risk of falling prices on a major portion of its production by either fixing the price or protecting the downside risk through put or collar arrangements. In aggregate, total average sales prices were higher by \$2.55 per BOE in 2002 (2001 - \$3.63 per BOE) than would otherwise have been the case if PrimeWest had not entered into price protection arrangements.

	Crude Oil \$/bbl		Natural Gas \$/Mcf		BOE ⁽¹⁾	
	2002	2001	2002	2001	2002	2001
Unhedged Price	\$ 34.25	\$ 30.86	\$ 3.81	\$ 5.26	\$ 26.61	\$ 31.17
Hedging Gain	(0.72)	1.35	0.74	0.90	2.55	3.63
Realized Price	\$ 33.53	\$ 32.21	\$ 4.55	\$ 6.16	\$ 29.16	\$ 34.80

(1) Excludes sulphur



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	2002		2001	
	Hedging Gain (Loss)		Hedging Gain	
	% Hedged	(\$ million)	% Hedged	(\$ million)
Natural Gas	71%	\$ 30.5	78%	\$ 34.6
Crude Oil	69%	(2.4)	84%	4.9
Total Gain		\$ 28.1		\$ 39.5

2003 / 2004 Hedging Summary

Approximate percentage of 2003 anticipated production volumes hedged as at December 31, 2002 net of anticipated royalties, reflecting full production declines with no offsetting additions:

2003	Q1	Q2	Q3	Q4	Full Year
Crude Oil	65%	38%	27%	28%	40%
Natural Gas	69%	60%	60%	31%	55%

As at December 31, 2002, the mark-to-market loss for 2003 hedges totals \$13.8 million, \$1.9 million for crude oil and \$11.9 million for natural gas.

For 2004, PrimeWest has none of its crude oil production and 12% of its natural gas production hedged with a combination of swaps, and option based instruments. As at December 31, 2002 there is no material gain or loss on a mark-to-market valuation of these hedges.

Price Outlook

Natural Gas

Natural gas is a commodity that moves through pipelines at high pressure and as such is affected by supply and demand forces within North America. New gas supply is added primarily by drilling, re-working of existing wells, and additions to capital infrastructure. Disruptions to supply can come from extreme weather conditions such as extreme cold hindering operations, extreme heat reducing pipeline and compression efficiencies, and hurricane activity affecting offshore operations. Demand comes from use of natural gas for central heating, to generate electricity, and as a feedstock for commercial or industrial use. Gas is currently stored in the summer months when heating demand is down and gas is withdrawn in winter when heating demand is high.

After a year of robust pricing in 2001 (AECO gas averaged \$6.30/mcf), the year 2002 started off with much more modest pricing (\$3.67/mcf for the first nine months). The result was a significant drop in industry drilling activity through the year that has resulted in a reduction of North American supply capability in the near term. In addition, significant hurricane activity in the Gulf of Mexico through the summer and into early fall caused significant supply disruptions. On the demand side, economic activity has not rebounded, but hot weather in North America over the summer resulted in additional gas fired electricity demand and very cold weather in the central and northeast parts of the continent so far this winter have resulted in significant year over year demand increases.

Early in 2003, natural gas in storage is at historically low levels and concerns are being raised about the ability to re-fill storage to adequate levels by the end of the summer in time for the next winter heating season due to supply declines. Pricing year to date has been exceptionally strong and is expected to remain so for the next several years.



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Crude Oil

Crude oil can be transported by pipeline, tank truck, and ocean tanker. As such, oil is truly a world commodity and is influenced by global supply and demand fundamentals. World supply is dominated by the OPEC cartel and by production changes within a few key non-OPEC exporting countries (e.g. Russia and other former Soviet Union nations, Norway). World demand fluctuates with the global economies.

Oil entered 2002 with comfortable inventories and the prospect of global oversupply. As the year progressed, overall tightening of OPEC quotas and supply, combined with several global supply disruptions (a delay in renewing the Iraq oil for food program, hurricane activity in the Gulf of Mexico, a general strike in Venezuela) significantly reduced inventories.

Early in 2003, crude oil inventories have been reduced further and the potential for hostilities in the Middle East remains high. Crude oil prices have increased to levels not seen since the 1990 Gulf War.

Royalties (Net of ARTC)

	2002	2001	% Change
Royalty Expense (Net of ARTC) (\$ millions)	\$ 56.5	\$ 73.2	(23%)
Per BOE	\$ 5.13	\$ 6.73	(24%)
Royalties as % of Sales Revenues			
-with hedging revenue	17.6%	19.3%	(9%)
-excluding hedging revenue	19.3%	21.5%	(10%)

Lower royalties are the direct result of lower revenues. The overall decrease in the royalty rate is due to lower natural gas prices year-over-year. Hedging gains, that do not attract royalties and result in lower royalty expense as a percentage of sales, were substantial for both 2002 and 2001 as previously discussed.

Operating Expenses

	2002	2001	% Change
Operating Expenses (\$ millions)	\$ 60.8	\$ 59.0	3%
Per BOE	\$ 5.52	\$ 5.42	2%

The year-over-year increase of \$1.8 million is due, in part, to the 1% increase in production volumes. On a BOE basis, operating expenses increased 2% over the 2001 level. PrimeWest continues as a low cost producer among the seven largest oil and gas royalty trusts.

Operating Margin

\$ per BOE	2002	2001	% Change
Sales Price and Other Revenue ⁽¹⁾	\$ 29.11	\$ 34.93	(17%)
Royalties	(5.13)	(6.73)	(24%)
Operating Expenses	(5.52)	(5.42)	2%
Operating Margin	\$ 18.46	\$ 22.78	(19%)

(1) Includes hedging and sulphur

The decrease in operating margin reflects lower natural gas prices in 2002 compared to 2001 and PrimeWest's 62% natural gas production weighting in 2002, partially offset by lower royalty expense. In 2001, record high prices for natural gas benefited natural gas weighted producers including PrimeWest.



General & Administrative Expenses

	2002	2001	% Change
General & administrative expense (\$ millions)	\$ 11.3	\$ 10.4	9%
Per BOE	\$ 1.02	\$ 0.96	6%

Excluding \$0.8 million of 2002 expenses related to the NYSE listing, the full year 2002 result would have been \$10.5 million or \$ 0.95 per BOE.

Unit Appreciation Rights Expense

Unit Appreciation Rights (UAR) expense of \$6.1 million (2001 - \$4.2 million) relates to PrimeWest's long-term incentive program for employees, directors and officers. The program rewards employees based on total unitholder return, which is comprised of cumulative distributions on a reinvested basis plus growth in unit price. Total unitholder return was 19.5% in 2002 (2001 - a loss of 6%). No benefit accrues to employees with respect to the first 5% of total unitholder return. Expenses related to the UAR plan 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, over the six year life of the unit appreciation rights.

Unit appreciation rights in a trust are similar to stock options in a corporation. The intent is to align employee and unitholder interests. The outcome is expected to be a modest dilution to unitholders' positions over time.

Effective January 1, 2002 the method of accounting for the long-term incentive plan was changed to comply with new CICA accounting standard 3870. The calculation of the long-term incentive liability now includes vested and unvested UARs. Previously, only vested UARs were included. The Trust has the option of paying cash to settle the long-term incentive liability. The long-term incentive liability has been reclassified as equity on the balance sheet as the Trust intends to settle the liability in the form of Trust Units.

Costs Outlook

PrimeWest's operating costs in 2002 and 2001 were among the lowest of the seven largest conventional oil and gas royalty trusts. The acquisition of low cost production at Caroline and North West Alberta effective January 1, 2003, is expected to reinforce our low cost position. We are targeting stabilization in our cost structure in 2003 as follows:

Operations:

- Per BOE costs of approximately \$5.50 reflecting:
 - lower costs associated with the Caroline and North West Alberta properties,
 - continued rationalization of operations, particularly at Caroline, offset partially by higher costs associated with third party processing of natural gas

General and Administrative:

- per BOE costs of less than \$0.90. Increases in the cost of employee benefits and corporate governance are expected to be offset by continued process improvements.

At PrimeWest, we are committed to contain costs during all phases of the commodity price cycle.



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Management Fees / Internalization Costs

	2002	2001
Cash management fees	\$ 4.0	\$ 6.4
Non-cash management fees	1.4	1.9
Non-cash internalization costs	13.1	-
Acquisition / disposition fees	0.4	13.0
1% retained royalty	1.3	3.4
Purchase of 1% retained royalty	13.2	-
	\$ 33.4	\$ 24.7

On November 4, 2002, unitholders voted, by a 92% majority, to internalize management at a cost of \$26.3 million. Approximately \$13.2 million of cash consideration related to the acquisition of the 1% retained royalty and was recorded as an acquisition. The balance of the consideration was paid in the form of Class A exchangeable shares of PrimeWest Energy Inc., exchangeable for approximately 491,000 trust units as at the effective date, and was charged to expense. In addition, the internalization transaction included retention provisions for senior management of \$3.5 million payable in the form of Class A Exchangeable Shares over a five year vesting period, and payment of \$1.5 million to terminate a management incentive program.

From inception in 1996 through September 30, 2002 PrimeWest Management Inc. received a management fee of 2.5% of net production revenue as well as a quarterly allocation of Trust Units and a 1% retained royalty. The 1% retained royalty was based on the net cash flow from operations and the proceeds from property dispositions.

In addition, PrimeWest Management Inc. was also entitled to an acquisition fee representing 1.5% of capital spent on asset or corporate acquisitions and a disposition fee representing 1.25% of proceeds received from asset dispositions.

The \$13.0 million of acquisition / disposition fees in 2001 related primarily to the Cypress acquisition.

Interest Expense

Interest expense decreased to \$10.8 million in 2002 compared to \$13.8 million in 2001. Lower year-over-year average debt levels and lower interest rates contributed to the decrease.

	2002	2001
Interest Expense (million)	\$ 10.8	\$ 13.8
Year End Net Debt Level (million)	\$ 225.4	\$ 224.4
Year End Debt Level per Trust Unit	\$ 5.79	\$ 6.84
Average Cost of Debt	4.6%	5.4%

Depletion, Depreciation and Amortization

The 2002 depletion, depreciation and amortization (DD&A) rate was \$16.51 per BOE compared to \$14.66 per BOE for 2001. The 2002 rate reflects a full year of production from the Cypress properties acquired on March 29, 2001.

The 2002 and 2001 DD&A rates are inflated relative to the acquisition cost of reserves due to the requirement to account for future income tax liabilities associated with these reserves. Absent this tax adjustment, the 2002 DD&A rate would have been lower by approximately \$5.00 per BOE. (See also Income Taxes – Trust.)



Ceiling Test

PrimeWest performs a ceiling test at each balance sheet date which compares the book value of capital assets (i.e. the value of capital assets reflected on the balance sheet, net of DD&A) with an estimate of the future net revenue from proved reserves (as determined by independent engineers) less estimated future general and administrative costs, debt servicing costs, management fees, and applicable income taxes.

Performing this test at December 31, 2002, using commodity prices of AECO \$5.59 per Mcf for natural gas and \$US 29.39 per barrel WTI for crude oil, a ceiling test surplus of \$900 million results.

Site Reclamation and Restoration Reserve

To fund future costs related to well abandonment and site cleanup, PrimeWest contributed \$0.37 per BOE, totaling \$4.1 million for 2002, to a segregated fund. This fund is used to pay for reclamation and abandonment costs as they are incurred. In 2002, a total of \$3.9 million was paid out of the reserve, leaving a balance of \$0.01 million in the fund at year end.

A provision of \$4.0 million was made for site reclamation and abandonment during 2002, compared to \$3.5 million for 2001. The provision is based on site reclamation and abandonment cost estimates made by both PrimeWest and external engineers and is charged to depletion, depreciation and amortization expense on a unit of production basis.

The 2003 contribution rate has been set at \$0.50 per BOE which is expected to be sufficient to meet the funding requirements for the future.

Income Taxes – Trust

Current income tax expense of \$2.9 million for 2002 (2001 - \$2.4 million) is comprised of the Federal Large Corporations Tax and other capital taxes payable by PrimeWest Energy Inc.

PrimeWest Energy Inc. manages its operating and financing activities such that it is not subject to current tax payable, other than the capital taxes noted above.

Future income taxes are recorded on corporate acquisitions to the extent that the book value of capital assets acquired exceeds the tax pools acquired. These future taxes increase the cost basis of the capital assets acquired and are recovered over time as royalties are paid to the Trust. The income statement for the year ended December 31, 2002 reflects a future income tax recovery of \$32.3 million (2001 - \$30.3 million), due primarily to the drawdown of future income tax liability of \$376.3 million recorded as part of the Cypress acquisition. The future income tax liability was \$339.9 million at December 31, 2002 (\$362.6 million at December 31, 2001).

The unitholders of the Trust are allocated taxable income based on the amount of royalty revenue, interest and revenue from direct investments earned (essentially distributions before crown royalty charges), less certain tax deductions such as Canadian Oil and Gas Property Expense (COGPE), resource allowance, unit issue expenses and other direct costs.

Income Taxes – Unitholders

For the 2002 taxation year, unitholders of the Trust were paid \$4.80 per Trust Unit in distributions. Of these distributions, 45%, or \$2.16 per Trust Unit, is a tax deferred return of capital and 55%, or \$2.64 per Trust Unit is taxable to unitholders as other income (taxed at the same rate the same as interest income). The tax deferred return of capital reduces the unitholder's adjusted cost base for purposes of calculating a capital gain or loss upon ultimate



disposition of their Trust Units. It should be noted that this represents the tax treatment for Canadian residents.

For unitholders resident in the United States, taxability of distributions is calculated using U.S. tax rules which allow for the deduction of crown royalties and accounting based depletion. As a result, none of the 2002 distribution is taxable as dividends, 100% of the 2002 distributions are a tax deferred reduction to the cost of units for tax purposes.

Unitholders contemplating a disposition may wish to consult the “Unitholder Info” section on PrimeWest’s website and use the adjusted cost base calculator.

Unitholders should always seek independent competent tax advice.

Income Taxes – Unitholders – Outlook

Based on current expectations for cash flow for 2003, it is anticipated that approximately 55% of 2003 distributions will be taxable and 45% will be tax deferred, for unitholders resident in Canada. For residents of the United States, Canadian withholding tax applies to 55% of the distribution.

Net Asset Value

Net asset value (NAV) is a measure of the worth of PrimeWest’s 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%, from these reserves, as independently assessed by Gilbert Laustsen Jung Associates Ltd. (GLJ) as at January 1, 2003. The commodity price forecast used in this assessment is based on the arithmetic average of three independent consultants’ price forecasts. 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, 2003 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. Value is delivered to unitholders through such monthly distributions.

The following table sets forth the calculation of net asset value:

As at January 1 (\$ million except per Trust Unit amounts)

	2003	2002
Assets		
Present value of net cash flow from established reserves discounted at 10%	\$ 923.0	\$ 872.6
Hedging mark-to-market	(13.6)	50.5
Unproved lands	44.2	55.7
Reclamation fund	-	0.8
	953.6	979.6
Liabilities		
Working capital deficiency	\$ (0.4)	\$ (29.4)
Long-term debt	(225.0)	(195.0)
	(225.4)	(224.4)
Total net asset value	\$728.2	\$ 755.2
Net asset value pre-tax per Trust Unit	\$ 18.71	\$ 23.03
Reference prices		
- Oil (\$US WTI/bbl)	\$ 25.83	\$ 19.68
- Exchange rate (\$US/\$Cdn)	\$ 0.64	\$ 0.63
- Natural gas (\$Cdn/Mcf)	\$ 5.85	\$ 4.03

The NAV calculation is based on the above reference prices as of January 1, 2003 and 2002 and is highly sensitive to changes in price forecasts over time. Also, the NAV calculation assumes a “blow down” scenario whereby existing reserves are produced without being replaced by acquisitions. A major cornerstone of PrimeWest’s strategy is to replace reserves through accretive acquisitions and capital development.

Net Income

	2002	2001
Net income	\$ 0.6	\$ 79.5

Net income declined by \$78.9 million as a result of significantly lower natural gas prices, increased DD&A reflecting a full year of Cypress volumes and costs of \$16.7 million associated with the internalization of management.

Liquidity and Capital Resources

Long Term Debt

At December 31, 2002, long-term debt, net of working capital was \$225.4 million or \$5.79 per Trust Unit, compared to \$224.4 million, or \$6.85 per Trust Unit at the end of 2001.

(thousands of dollars)	2002	2001
Long-term debt	\$ 225,000	\$ 195,000
Working capital deficit	436	29,431
Net debt	225,436	224,431
Market value of Trust Units and exchangeable shares outstanding (1)	965,000	834,053
Total capitalization	1,190,436	1,058,484
Net debt as a percentage of total capitalization	19%	21%

(1) Based on December 31 closing price



Outlook – Long Term Debt

Long-term debt net of working capital in 2003 is expected to increase as a result of the 2003 capital development program, and the Caroline / Peace River Arch acquisition which closed on January 23, 2003, partially offset by the net proceeds of the equity issue which closed on February 13, 2003.

Unitholders' Equity

On August 16, 2002, Trust Units were consolidated on a 4 to 1 basis in anticipation of the November 19, 2002 listing on the New York Stock Exchange.

The Trust had 37,004,522 Trust Units outstanding at December 31, 2002 compared to 31,491,402 Trust Units at the end of 2001. In addition, there are 5,179,278 million exchangeable shares (see below) outstanding at year end, exchangeable into a total of 1,939,864 Trust Units. The weighted average number of Trust Units, including those issuable by the exchange of exchangeable shares, was 34,134,230 Trust Units for 2002 compared to 25,633,250 for 2001.

During 2002, PrimeWest issued 979,210 Trust Units for \$24.1 million pursuant to the Distribution Reinvestment and Optional Trust Unit Purchase Plans (441,424 Trust Units, \$14.1 million in 2001), 153,749 pursuant to the Long-Term Incentive Plan for employees and 66,853 to PrimeWest Management Inc. pursuant to the Management Agreement.

Dividends declared were \$1.3 million in 2002, compared to \$4.1 million in 2001. Dividends were paid to PrimeWest Management Inc. in conjunction with the Management Agreement (see discussion under Management Fees).

PrimeWest completed a bought deal financing which closed on November 13, 2002, raising net proceeds of \$104.5 million on the issuance of 4.2 million Trust Units at \$26.20 per Trust Unit. Proceeds were used to fund the Caroline/Ells acquisitions announced in October of 2002 and to reduce outstanding indebtedness.

Exchangeable Shares

Exchangeable shares were issued in connection with both the Venator acquisition in April 2000 and the Cypress acquisition in March 2001. These shares were issued to provide a tax-deferred rollover of the adjusted cost base from the shares being exchanged to the exchangeable shares of PrimeWest. A tax deferral is not permitted by Canadian tax law when shares are exchanged for Trust Units.

A further 1,363,714 exchangeable shares were issued in the fourth quarter of 2002 in connection with the management internalization transaction previously discussed.

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, 2002, there were 5.2 million exchangeable shares outstanding. The exchange ratio on these shares was 0.37454 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 in 2002 totaled \$158.0 million, or \$4.80 per Trust Unit, compared to \$234.5 million, or \$9.24 per Trust Unit in 2001. Commencing in 2003, PrimeWest pays distributions to registered U.S. unitholders in U.S. funds, upon request. Payments to U.S. unitholders are subject to 15% Canadian withholding tax, which applies to the taxable portion of the distribution under Canadian tax law, estimated at 55% for 2003.

Since inception in October of 1996 to December 31, 2002, PrimeWest has distributed \$35.92 per Trust Unit (through December 31, 2001 - \$31.12 per Trust Unit).

Outlook for Cash Distributions

PrimeWest distributed \$0.40 per unit per month for January and February of 2003 and has committed to distributing \$0.40 per Trust Unit per month for March and April of 2003, subject to revision should there be a material change to expected cash flows during this period. Beyond this time frame, the Board of Directors will establish a distribution level commensurate with cash flow expectations and any foreseen internal requirements.

Cash Flow Sensitivities

Impact on 2003 cash available for distribution per unit (increase/decrease):

Crude Oil Price (\$US 1.00 per barrel WTI increase)	0.10 ⁽¹⁾
Natural Gas Price (\$0.10 per Mcf increase)	0.09 ⁽¹⁾
Interest Rate (1% increase)	(0.04)
Exchange Rate (\$US 0.01 increase)	(0.14)
Production (1,000 BOE per day increase)	0.20

(1) Without the effect of price protection

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 U.S.;
- weather conditions that influence the demand for natural gas and heating oil;
- the Canadian/U.S. exchange rate that affects the price received for crude oil as the price of crude oil is referenced in U.S. dollars;



- transportation availability and costs;
- price differentials among world and North American markets based on transportation costs to major markets and quality of production.

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

Beyond our hedging strategy, PrimeWest also mitigates risk by having a well-diversified marketing portfolio and by transacting with a number of counter-parties and limiting exposure to each counter-party. In 2002, approximately 30% of natural gas production was sold to aggregators and 70% 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 U.S. 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 2002, PrimeWest added \$28.1 million (\$0.82 per Trust Unit) to our cash flow through various physical and financial hedging transactions. In total, PrimeWest hedged 69% of full year crude oil production and 71% of full year natural gas production net of royalties.

Operational and Other Business Risks

PrimeWest is also exposed to a number of risks related to its activities within the oil and gas industry that 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.
<i>We mitigate by:</i>	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
<i>We mitigate by:</i>	Hedging. See 2002 Hedging Results and 2003 / 2004 Hedging Summary earlier in this MD&A.
Transportation	Market risk related to the availability of transportation to market and potential disruption in delivery systems.
<i>We mitigate by:</i>	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



PRIMEWEST

sufficient to replace annual production declines.

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

As a royalty trust, we concentrate on acquiring large pool, mature and lower decline properties where high risk capital programs are not normally required to mitigate annual production declines.

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.

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

We mitigate by: Contracting our reserves evaluation to a reputable third party consultant, Gilbert Laustsen Jung Associates Ltd. (GLJ). The work and independence of GLJ is reviewed by the Audit and Reserves Committee of the Board of Directors of PrimeWest. Our strategy is to invest in mature, longer life properties having a high 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 Nominating Committee of the Board, which acts as PrimeWest's Environmental, Health and Safety Committee.

Regulation, Tax, 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



PRIMEWEST

Liability to
unitholders

We mitigate by:

have on our operations.

There is no statutory protection for unitholders from liabilities of the trust.

Limiting the business of the trust to the right to receive the net cash flow of PrimeWest Energy Inc. All of the oil and gas business operations of PrimeWest are conducted by PrimeWest Energy Inc. PrimeWest Energy Inc. has a vigorous EH&S program as well as significant insurance protection.



CONSOLIDATED BALANCE SHEETS

As at December 31
(in thousands of Canadian dollars)

	2002	2001	2000
ASSETS			
Current Assets			
Accounts Receivable	\$ 71,635	\$ 60,609	\$ 40,561
Prepaid Expenses	9,759	9,112	4,398
Inventory	2,204	3,173	840
	83,598	72,894	45,799
Cash Reserved for Site Restoration and Reclamation	12	755	398
Property, Plant and Equipment	1,404,463	1,448,661	395,376
Other Assets	14,179	-	-
	\$ 1,502,252	\$ 1,522,310	\$ 441,573
LIABILITIES AND UNITHOLDERS' EQUITY			
Current Liabilities			
Bank Overdraft	\$ 3,057	\$ 14,613	\$ 834
Accounts Payable	43,109	26,207	19,057
Accrued Liabilities	23,950	39,350	13,440
Accrued Distributions to Unitholders	13,918	11,980	9,961
Due to Related Company	-	10,108	2,057
Current Portion of Long-term Debt	-	67	106
	84,034	102,325	45,455
Long-term Debt	225,000	195,000	78,940
Future Income Taxes	339,888	362,595	16,596
Site Restoration and Reclamation Provision	6,232	6,113	1,958
	655,154	666,033	142,949
Unitholders' Equity			
Net Capital Contributions	1,299,968	1,152,551	435,342
Capital Issued but Not Distributed	884	1,035	614
Long Term Incentive Plan Equity	10,068	7,932	8,930
Accumulated Income	123,170	122,550	43,014
Accumulated Cash Distributions	(578,934)	(420,983)	(186,518)
Accumulated Dividends	(8,058)	(6,808)	(2,758)
	847,098	856,277	298,624
	\$ 1,502,252	\$ 1,522,310	\$ 441,573

Commitments and Contingencies

CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY

For the Years Ended December 31 (in thousands of Canadian dollars)	2002	2001	2000
Unitholders' Equity - Beginning of Year, as previously reported	\$ 856,277	\$ 298,624	\$ 200,039
Future Income Tax Accounting Change	-	-	(10,219)
Net Income for the Year	620	79,536	55,612
Capital Contributions, Net of Costs	147,417	717,209	124,293
Cash Distributions	(157,951)	(234,465)	(79,033)
Dividends	(1,250)	(4,050)	(1,612)
Long Term Incentive Plan Equity	2,136	(998)	8,930
Capital Issued but Not Distributed	(151)	421	614
Unitholders' Equity - End of Year	\$ 847,098	\$ 856,277	\$ 298,624

CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31 (in thousands of Canadian dollars, except per unit amounts)	2002	2001	2000
REVENUES			
Sales of Crude Oil, Natural Gas & Natural Gas Liquids	\$ 320,517	\$ 378,155	\$ 191,339
Crown & Other Royalties, Net of ARTC	(56,496)	(73,156)	(35,157)
Other Income	227	1,516	379
	264,248	306,515	156,561
EXPENSES			
Depletion, Depreciation & Amortization	181,956	159,332	42,865
Operating	60,773	58,951	30,174
General & Administrative	11,281	10,394	4,140
Unit Appreciation Rights	6,125	4,158	10,296
Interest	10,788	13,800	6,359
Cash Management Fees	3,982	6,431	3,277
Non-Cash Management Fees	1,414	1,819	731
Cash Internalization Costs	3,598	-	-
Non-Cash Internalization Costs	13,124	-	-
	293,041	254,885	97,842
Income / (Loss) Before Taxes for the Year	(28,793)	51,630	58,719
Income and Capital Taxes	2,887	2,428	549
Future Taxes (Recovery) (Note 11)	(32,300)	(30,334)	2,558
	(29,413)	(27,906)	3,107
Net Income	\$ 620	\$ 79,536	\$ 55,612
Net Income per Trust Unit			
Basic	\$ 0.02	\$ 3.12	\$ 5.00
Diluted	\$ 0.02	\$ 3.08	\$ 4.84



CONSOLIDATED STATEMENTS OF CASH DISTRIBUTIONS

For the Years Ended December 31
(in thousands of Canadian dollars, except per
unit amounts)

	2002	2001	2000
Net Income for the Year	\$ 620	\$ 79,536	\$ 55,612
Add Back (Deduct)			
Depletion, Depreciation & Amortization	181,956	159,332	42,865
Cash (Retained) / Paid from Cash Available for Distribution	(7,315)	25,822	(29,266)
Contribution to Reclamation Fund	(4,078)	(3,499)	(2,964)
Management Fees Paid in Trust Units	1,414	1,819	731
Internalization Costs Paid in Trust Units	13,124	-	-
Unit Appreciation Rights Expense	6,125	4,158	10,296
Future Income Taxes (Recovery)	(32,300)	(30,334)	2,558
	\$ 159,546	\$ 236,834	\$ 79,832
Cash Distributions to Trust Unitholders (99%)	\$ 157,951	\$ 234,465	\$ 79,033
Cash Distributions per Trust Unit ⁽¹⁾	\$ 4.80	\$ 9.24	\$ 7.08

(1) After giving effect to 4 for 1 trust unit consolidation on August 16, 2002.



PRIMEREST

CONSOLIDATED STATEMENTS OF CASH FLOW

For the Years Ended December 31 (in thousands of Canadian dollars)	2002	2001	2000
OPERATING ACTIVITIES			
Net Income for the Year	\$ 620	\$ 79,536	\$ 55,612
Add: (Deduct) Items Not Involving Cash Flow from Operations			
Depletion, Depreciation & Amortization	181,956	159,332	42,865
Non-Cash Internalization Costs	13,124	-	-
Unit Appreciation Rights Expense	6,125	4,158	10,296
Non-Cash Management Fees	1,414	1,819	731
Future Income Taxes	(32,300)	(30,334)	2,558
Cash Flow from Operations	170,939	214,511	112,062
Expenditures on Site Restoration & Reclamation	(3,909)	(3,769)	(3,561)
Change in Non-Cash Working Capital	(10,729)	(20,487)	(15,570)
	156,301	190,255	92,931
FINANCING ACTIVITIES			
Proceeds from Issue of Trust Units, Net of Costs	118,333	159,542	38,036
Acquisition of Trust Units pursuant to Normal Course Issuer Bid	-	-	(926)
Cash Distributions to Unitholders	(145,887)	(223,658)	(77,173)
Dividends Paid	(1,250)	(602)	(1,612)
Increase (Decrease) in Long-Term Debt	29,933	(62,980)	(41,449)
Change in Non-Cash Working Capital	1,797	2,019	6,291
	2,926	(125,679)	(76,833)
INVESTING ACTIVITIES			
Expenditures on Property, Plant & Equipment	(69,055)	(84,206)	(25,791)
Acquisition of Capital/Corporate Assets	(59,606)	(84,054)	(6,306)
Proceeds on Disposition Property Plant and Equipment	4,529	78,144	855
Expenditures for Future Acquisition	(14,179)	-	-
Cash Reserved for Future Site Restoration & Reclamation	743	(357)	661
Proceeds on Disposition of Short Term Investments	-	-	174
Change in Non-Cash Working Capital	(10,103)	12,118	7,971
	(147,671)	(78,355)	(22,436)
Increase (Decrease) in Cash for the Year	11,556	(13,779)	(6,338)
Cash (Bank Overdraft), Beginning of Year	(14,613)	(834)	5,504
(Bank Overdraft), End of Year	\$ (3,057)	\$ (14,613)	\$ (834)
Cash Interest Paid	\$ 10,275	\$ 13,159	\$ 6,872
Cash Taxes Paid	\$ 3,960	\$ 460	\$ 453



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Notes to Consolidated Financial Statements

Please refer to PrimeWest's website at www.primewestenergy.com for the notes to the Consolidated Financial Statements, except the United States / Canadian GAAP reconciliation which will be provided at a later date. If you wish to receive a hard copy of these notes, please contact us at the numbers listed on page 1 of this release.

FOURTH QUARTER AND YEAR END CONFERENCE CALL AND WEBCAST

PrimeWest will be conducting a conference call and Web cast for interested analysts, brokers, investors and media representatives about its fourth quarter and 2002 year end results and 2003 outlook at 9:00 a.m. Mountain standard time (11:00 a.m. Eastern standard time) on Friday, February 21, 2002.

Callers may dial 1-888-881-4892 a few minutes prior to start and request the PrimeWest conference call. The call also will be available for replay by dialing 1-877-289-8525, and entering pass code 231507 followed by the pound (#) key.

Interested users of the Internet are invited to listen to the webcast at <http://www.newswire.ca/webcast/viewEventCNW.html?eventID=453860> for the live Web cast and/or replay or access the Web cast at the PrimeWest Web site, www.primewestenergy.com

PrimeWest is a Calgary-based conventional oil and gas royalty trust that actively acquires, develops, produces, and sells natural gas, crude oil, and natural gas liquids for the generation of monthly cash distributions to unitholders. Trust units of PrimeWest are traded on the Toronto Stock Exchange (TSX) under the symbol "PWI.UN" and on the New York Stock Exchange under the symbol "PWI". Exchangeable shares of PrimeWest Energy Inc. are listed on the TSX under the symbol "PWX".

Learn more about PrimeWest on our Web site, www.primewestenergy.com.