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# NEWS RELEASE

August 2, 2007

## Enerplus announces 2007 second quarter operating and financial results

TSX: ERF.un
NYSE: ERF

CALGARY, Aug. 2 /CNW/ - Enerplus Resources Fund ("Enerplus") is pleased to announce our results from operations for the period ending June 30, 2007. Highlights are as follows:

- Our activities focused on the successful execution of our capital development program, managing our conventional operations and advancing our oil sands business. Our balanced portfolio of development prospects in Canada and the U.S. continues to benefit us by providing flexibility in the allocation of our spending to maximize the economic returns of our program. As well, the diversification of our production by commodity will also provide additional stability in our cash flows as oil prices have stayed strong while natural gas prices have recently declined.

- Daily production volumes and capital spending are both essentially on track with our guidance for the year with production volumes averaging 82,478 BOE/day reflecting normal plant maintenance. Year-to-date production volumes averaged 84,244 BOE/day and we continue to expect we will meet both our average annual and exit rate production targets of 85,000 BOE/day and 86,000 BOE/day respectively.

- Monthly cash distributions to Unitholders were maintained at $0.42 per unit per month, paying a total of $1.26 per unit during the quarter with a payout ratio of 68% after working capital.

- Wet weather in the month of June throughout western Canada impacted our drilling activity during the quarter. We invested approximately $80.4 million on both our Canadian and U.S. properties and drilled 97 gross wells (35.7 net). Year-to-date, we have invested approximately $190.4 million through our capital development program and we continue to anticipate full year spending of approximately $415 million.

- Our Canadian conventional capital program continues to provide attractive returns from a diverse portfolio of opportunities with 84 gross wells (28.6 net) drilled during the quarter. Our highest concentration of spending was once again at our Sleeping Giant property in the U.S. where we invested approximately $33 million and drilled 13 gross wells (7.1 net) continuing with our 3rd well per section program. With continued strong crude oil prices, the rising Canadian dollar and the robust economics surrounding our U.S. capital program, we are reallocating a further $10 million from our Canadian budget to the Sleeping Giant capital program in 2007 and now expect to invest approximately $110 million in the U.S. this year. Drilling and related service costs in Canada have decreased since the beginning of the year and as a result, we expect to see modest savings on our total Canadian development capital program this year.

- Increased facility maintenance and costs associated with the implementation of training programs to enhance our operational efficiencies, combined with lower production volumes, were the main drivers in operating costs averaging $9.69 per BOE. Given the increases experienced in the first half of the year along with the increase in electricity costs expected in the second part of the year, we now expect full year operating costs will average approximately $9.00 per BOE up from our previous guidance of $8.45 per BOE.

- We acquired the remaining 10% working interest in the Kirby Oil Sands Partnership on June 22, for $20.3 million taking our working interest to 100%.

- We continue to advance our portfolio of oil sands projects which consists of working interests in our operated Kirby SAGD project and our non-operated Joslyn project which includes both mining and SAGD projects, and our equity investment in Laricina Energy. We have line of sight to over 60,000 bbls/day of future oil sands production to add to our 85,000 bbls/day of conventional production over the next 10 years as well as over 460 million barrels of contingent resources to potentially add to our 443 million barrels of booked reserves.

- Safety performance continued to improve during the quarter with only one contractor lost time incident. June marks the eleventh consecutive month where no employee has suffered a lost time injury.

- Our balance sheet remains one of the strongest in the sector with a debt to cash flow ratio of 0.7 times.

- Subsequent to the quarter on July 18, Enerplus was included in the S&P/TSX 60 Index which is a market weighted index of 60 of the largest Canadian public companies. We believe this is beneficial as it will provide increased liquidity, visibility and broader institutional ownership for Enerplus.

SUMMARY FINANCIAL AND OPERATING HIGHLIGHTS

All amounts are stated in Canadian dollars unless otherwise specified. In accordance with Canadian practice, production volumes, reserve volumes and revenues are reported on a gross basis, before deduction of Crown and other royalties, unless otherwise stated. Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE. The BOE rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. Use of BOE in isolation may be misleading. Certain prior year amounts have been restated to reflect current year presentation. Readers are also urged to review the Management's Discussion & Analysis (MD&A) and Audited Financial Statements for more fulsome disclosure on our operations. These reports can be found on our website at www.enerplus.com, our SEDAR profile at www.sedar.com and as part of our SEC filings available on www.sec.gov.

SELECTED FINANCIAL RESULTS

| For the six months ended June 30, | 2007 | 2006 |
|---|---|---|
| Financial (000's) | | |
| Net Income | $ 147,957 | $ 273,306 |
| Cash Flow from Operating Activities | 430,663 | 387,685 |
| Cash Distributions to Unitholders(1) | 320,278 | 304,593 |
| Cash Withheld for Acquisitions and Capital Expenditures | 110,385 | 83,092 |
| Debt Outstanding (net of cash) | 657,945 | 603,919 |
| Development Capital Spending | 190,398 | 236,421 |
| Acquisitions | 267,394 | 42,257 |
| Divestments | 5,473 | 20,806 |
| Financial per Unit(2) | | |
| Net Income | $ 1.18 | $ 2.27 |
| Cash Flow from Operating Activities | 3.42 | 3.22 |
| Cash Distributions to Unitholders(1) | 2.54 | 2.53 |
| Cash Withheld for Acquisitions and Capital Expenditures | 0.88 | 0.69 |
| Payout Ratio(3) | 74% | 79% |
| Selected Financial Results per BOE(4) | | |
| Oil & Gas Sales(5) | $ 50.00 | $ 51.88 |
| Royalties | (9.43) | (10.27) |
| Commodity Derivative Instruments | 0.45 | (2.54) |
| Operating Costs | (9.16) | (7.94) |
| General and Administrative | (1.93) | (1.64) |
| Interest and Foreign Exchange | (1.34) | (0.91) |
| Taxes | (0.35) | (0.65) |
| Restoration and Abandonment | (0.48) | (0.36) |
| Cash Flow from Operating Activities before changes in non-cash working capital | $ 27.76 | $ 27.57 |
| Weighted Average Number of Trust Units Outstanding (thousands) | 125,849 | 120,311 |
| Debt/Trailing 12 Month Cash Flow Ratio | 0.7x | 0.7x |

SELECTED OPERATING RESULTS

| For the six months ended June 30, | 2007 | 2006 |
|---|---|---|
| Average Daily Production | | |
| Natural gas (Mcf/day) | 270,300 | 269,922 |
| Crude oil (bbls/day) | 34,869 | 36,122 |
| NGLs (bbls/day) | 4,325 | 4,634 |
| Total (BOE/day) (6:1) | 84,244 | 85,743 |
| % Natural gas | 53% | 52% |
| Average Selling Price(5) | | |
| Natural gas (per Mcf) | $ 7.13 | $ 7.27 |
| Crude oil (per bbl) | $ 59.56 | $ 62.09 |
| NGLs (per bbl) | $ 48.55 | $ 51.50 |
| US$ exchange rate | 0.88 | 0.88 |
| Net Wells Drilled | 75 | 159 |

| | | |
|---|---|---|
| Success Rate | 99% | 100% |

(1) Calculated based on distributions paid or payable. Cash distributions to unitholders per unit will not correspond to the actual cumulative monthly distributions of $2.52 as a result of using the weighted average trust units outstanding for the period.
(2) Based on weighted average trust units outstanding for the period.
(3) Calculated as Cash Distributions to Unitholders divided by Cash Flow from Operating Activities.
(4) Non-cash amounts have been excluded.
(5) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

| TRUST UNIT TRADING SUMMARY for the six months ended June 30, 2007 | TSX - ERF.un (CDN$) | NYSE - ERF (US$) |
|---|---|---|
| High | $53.70 | $50.75 |
| Low | $46.50 | $39.53 |
| Close | $50.07 | $47.08 |

| 2007 CASH DISTRIBUTIONS PER TRUST UNIT | | CDN$ | US$ |
|---|---|---|---|
| Production Month | Payment Month | | |
| First Quarter Total | | $1.26 | $1.12 |
| April | June | $0.42 | $0.39 |
| May | July | 0.42 | 0.40 |
| June | August | 0.42 | 0.39(*) |
| Second Quarter Total | | $1.26 | $1.18 |
| Total Year-to-Date | | $2.52 | $2.30 |

(*) Calculated using an exchange rate of 1.07

2007 Development Activity

| | 2nd Quarter | | | Year to date | | |
|---|---|---|---|---|---|---|
| | Capital Spending | Wells Drilled | | Capital Spending | Wells Drilled | |
| Play Type | ($millions) | Gross | Net | ($millions) | Gross | Net |
| Shallow Gas & CBM | $ 6.9 | 49.0 | 19.6 | $ 10.1 | 65.0 | 27.2 |
| Crude Oil Waterfloods | 9.8 | 2.0 | 2.0 | 27.0 | 18.0 | 15.3 |
| Bakken Oil | 33.1 | 13.0 | 7.1 | 70.9 | 22.0 | 13.7 |
| Oil Sands (SAGD/Mining) | 9.0 | - | - | 19.1 | - | - |
| Other Conventional Oil & Gas | 21.6 | 33.0 | 7.0 | 63.3 | 98.0 | 19.2 |
| Total | $ 80.4 | 97.0 | 35.7 | $190.4 | 203.0 | 75.4 |

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Oil Sands Activity

We continue to advance our portfolio of oil sands projects which consists of working interests in our operated Kirby SAGD project and our non-operated Joslyn project which includes both mining and SAGD projects, and our equity investment in Laricina Energy. Our oil sands business is complimentary to our existing conventional business in western Canada and the U.S. and further diversifies our portfolio of oil and gas assets. We have line of sight to over 60,000 bbls/day of future oil sands production to add to our 85,000 bbls/day of conventional production over the next 10 years as well as over 460 million barrels of contingent resources to potentially add to our 443 million barrels of booked reserves.

On April 10, 2007, we completed the acquisition of a 90% working interest in the Kirby Oil Sands Partnership ("Kirby") located in the heart of the Athabasca oil sands fairway. On June 22, Enerplus acquired the remaining 10% working interest in Kirby for $20.3 million and as a result, now owns a 100% working interest in this operated steam assisted gravity drainage ("SAGD") project. In aggregate, our Kirby acquisitions represent a total contingent resource estimate of 244 million barrels. Our development plans for Kirby include a 10,000 bbl/day SAGD project with first production expected in 2011 and potential expansion to a total of 30,000 to 40,000 bbls/day of bitumen production. Our plans for this year include a winter core hole drilling program to further delineate the lease. In addition, preparatory engineering, stakeholder consultation and other activities are planned that will advance our regulatory application which we expect to file in 2008.

Development plans continue to advance on our 15% working interest in the Joslyn lease. The Operator has contracted Norwest Corporation to conduct a fulsome mining review of the lease which will be coupled with an internal SAGD assessment and optimization work expected to be completed in late 2008. The mining area may be expanded and this could limit the development of SAGD Phase III which is a 15,000 bbl/day expansion currently planned for production in 2010. Should we convert some of the SAGD area to mining, we could expect to possibly double the reserve recovery and increase the targeted production from the mine area.

Joslyn SAGD Phase II continues to run behind schedule as a result of the steam release which occurred in May 2006 with current production at approximately 2,000 bbls/day from 11 well pairs. Three well pairs may be permanently shut in as a result of the steam release. Of the remaining four well pairs, steam is being circulated in three and approval is awaited to start steaming the fourth. Even with best efforts to enhance artificial lift and operating practices we do not expect to achieve the initial estimate for peak production of 600 bbls/day per well pair. We are currently assessing performance and it is too early to determine peak production from the existing well pairs however, we will require additional well pairs to achieve the planned 10,000 bbl/day production level.

The Operator has provided an update on the North mine regulatory application which confirms our current timing estimates however capital cost estimates have increased as expected. The Operator is currently expecting first production in 2013 and peak production of 100,000 bbls/day (15,000 bbls/day net to Enerplus) in 2014 for a total initial capital cost of $2.9 billion ($435 million net to Enerplus) excluding any costs associated with an upgrader. A design basis memorandum and more rigorous cost estimates are expected to be completed in 2008.

We continue to examine our alternatives regarding financing our growing oil sands business as well as investigating various marketing options for our future production. We expect to announce these plans as they develop.

Update on Canadian Tax Legislation

Bill C-52, which implements the previously announced tax on income trusts, has passed reading in the House of Commons and the Senate and has now received Royal Assent. As a result of the tax legislation becoming enacted, we recorded a non-cash future income tax expense of approximately $78 million during the quarter. We also filed a material change report on SEDAR and EDGAR that reflects the changes to the estimated after tax net present value of future revenues from our oil and gas reserves, and related information, in accordance with Canadian National Instrument 51-101.

Additional details of the legislation remain to be clarified and further tactical decisions will be made over time. However, we intend to maintain our yield-oriented distribution model given our belief that investor demographics, the demand for yield product support such a model with a premium valuation. Our lower risk energy production, long life and low decline assets, and large scalable resource plays support this approach and are consistent with a successful oil and gas business. We will continue our disciplined acquisition strategy as the normal growth parameters outlined in the legislation and the strength of our balance sheet support active involvement in the M&A market in the U.S., Canada, and potentially internationally. We see value in the four-year tax exemption period and would be hesitant to make major changes to our structure during this period without compelling reasons that we do not currently foresee. As of December 2006, we had tax pools of approximately $1.9 billion. We expect to preserve and possibly build those pools in the next four years in order to maximize the tax shelter available post 2010.

## MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A")

The following discussion and analysis of financial results is dated August 1, 2007 and is to be read in conjunction with:

- the MD&A and audited consolidated financial statements as at and for the years ended December 31, 2006 and 2005; and
- the unaudited interim consolidated financial statements as at June 30, 2007 and for the three and six months ended June 30, 2007 and 2006.

All amounts are stated in Canadian dollars unless otherwise specified. All references to GAAP refer to Canadian generally accepted accounting principles. All note references relate to the notes included with the consolidated financial statements. In accordance with Canadian practice revenues are reported on a gross basis, before deduction of crown and other royalties, unless otherwise stated. Oil and natural gas reserves and production are presented on a company interest basis which is not a term defined or recognized under NI 51-101. Therefore, our company interest reserves may not be comparable to similar measures presented by other issuers. Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE. The BOE rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. Use of BOE in isolation may be misleading. Certain prior year amounts have been restated to reflect current year presentation.

The following MD&A contains forward-looking information and statements. We refer you to the end of the MD&A for our disclaimer on forward-looking statements and information.

### Non-GAAP Measures

Throughout the MD&A we use the term "payout ratio" to analyze operating performance, leverage and liquidity. We calculate payout ratio by dividing cash distributions to unitholders ("cash distributions") by cash flow from operating activities ("cash flow"), both of which appear on our consolidated statements of cash flows. The term "payout ratio" does not have a standardized meaning or definition as prescribed by GAAP and therefore may not be comparable with the calculation of similar measures by other entities.

Refer to the Liquidity and Capital Resources section of the MD&A for further information on cash flow, cash distributions and payout ratio.

Update on Canadian Government Announcement on Intention to Tax Trusts

On June 22, 2007 Bill C-52, which contains legislative provisions to implement the proposals to tax publicly traded income trusts in Canada, was passed by the Senate, given Royal Assent and became law. As a result, our second quarter future income tax provision includes a future income tax expense of $78.1 million related to this legislation. This non-cash expense relates to temporary differences between the accounting and tax basis of the Fund's assets and liabilities and has no immediate impact on cash flow.

We are currently evaluating alternatives to determine the optimal structure for our unitholders. However, we see value in the four-year tax exempt period through 2010 as a distributing entity and would hesitate to make major structural changes during this period without compelling reasons which we do not currently foresee.

Overview

Strong commodity prices helped deliver solid cash flow of $237.5 million for the quarter. As we expected, downtime from scheduled facility maintenance reduced our average daily production to 82,478 BOE/day. Operating costs for the quarter increased to $9.69/BOE due to lower production as well as increased field training costs and unexpected repairs and maintenance expenses. As a result of operating costs experienced to date, along with anticipated increases in electricity costs, we are increasing our annual operating cost guidance to approximately $9.00/BOE. On April 10, 2007 we acquired a 90% interest in the Kirby Oil Sands Partnership ("Kirby") for consideration of $182.8 million, consisting of $128.1 million in cash and $54.7 million in equity. In a subsequent transaction on June 22, 2007 we acquired the remaining 10% interest for cash consideration of $20.3 million resulting in a total purchase price of $203.1 million. In conjunction with the acquisition, we closed an equity offering on April 10, 2007 consisting of 4.25 million trust units raising gross proceeds of $210.6 million.

Results of Operations

Production

Production averaged 82,478 BOE/day during the second quarter of 2007, a decrease of 4% from 86,028 BOE/day during the first quarter of 2007. As expected, our production volumes were lower during the quarter given normal maintenance and turn-around activity which occurs during this time of year.

For the three and six months ended June 30, 2007 production decreased by 4% and 2%, respectively, compared to the same periods in 2006. The majority of the decrease was due to natural reservoir declines, partially offset by additional production from our development capital program and our acquisition of gross-overriding royalty interests in the Jonah natural gas field in Wyoming ("Jonah") that closed on January 31, 2007.

Our average production during the second quarter was weighted 54% natural gas and 46% crude oil and natural gas liquids on a BOE basis. Average production volumes for the three and six months ended June 30, 2007 and 2006 are outlined below:

| | Three months ended | Six months ended |
|---|---|---|

| | Three months ended June 30, | | | Six months ended June 30, | | |
|---|---|---|---|---|---|---|
| Daily Production Volumes | 2007 | 2006 | % Change | 2007 | 2006 | % Change |
| Natural gas (Mcf/day) | 264,946 | 269,088 | (2)% | 270,300 | 269,922 | -% |
| Crude oil (bbls/day) | 34,178 | 36,388 | (6)% | 34,869 | 36,122 | (3)% |
| Natural gas liquids (bbls/day) | 4,143 | 4,856 | (15)% | 4,325 | 4,634 | (7)% |
| Total daily sales (BOE/day) | 82,478 | 86,092 | (4)% | 84,244 | 85,743 | (2)% |

Based on our year-to-date results we are maintaining our annual production estimate of 85,000 BOE/day and 2007 exit rate of 86,000 BOE/day.

Pricing

The prices received for our natural gas and crude oil production directly impact our earnings, cash flow and financial condition. The following tables compare our average selling prices and benchmark price indices for the three and six months ended June 30, 2007 and June 30, 2006.

| | Three months ended June 30, | | | Six months ended June 30, | | |
|---|---|---|---|---|---|---|
| Average Selling Price(1) | 2007 | 2006 | % Change | 2007 | 2006 | % Change |
| Natural gas (per Mcf) | $ 7.04 | $ 6.22 | 13% | $ 7.13 | $ 7.27 | (2)% |
| Crude oil (per bbl) | $61.93 | $68.80 | (10)% | $59.56 | $62.09 | (4)% |
| Natural gas liquids (per bbl) | $53.34 | $52.33 | 2% | $48.55 | $51.50 | (6)% |
| Per BOE | $50.96 | $51.50 | (1)% | $50.00 | $51.88 | (4)% |

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

| | Three months ended June 30, | | | Six months ended June 30, | | |
|---|---|---|---|---|---|---|
| Average Benchmark Pricing | 2007 | 2006 | % Change | 2007 | 2006 | % Change |
| AECO natural gas - monthly index (CDN$/Mcf) | $ 7.37 | $ 6.27 | 18% | $ 7.42 | $ 7.77 | (5)% |
| AECO natural gas - daily index (CDN$/Mcf) | $ 7.07 | $ 6.01 | 18% | $ 7.23 | $ 6.79 | 6% |
| NYMEX natural gas - monthly NX3 index (US$/Mcf) | $ 7.56 | $ 6.82 | 11% | $ 7.26 | $ 7.95 | (9)% |
| NYMEX natural gas - monthly NX3 index CDN$ equivalent (CDN$/Mcf) | $ 8.31 | $ 7.66 | 8% | $ 8.25 | $ 9.03 | (9)% |
| WTI crude oil (US$/bbl) | $65.03 | $70.70 | (8)% | $61.65 | $67.09 | (8)% |
| WTI crude oil CDN$ equivalent (CDN$/bbl) | $71.46 | $79.44 | (10)% | $70.06 | $76.24 | (8)% |
| US$/CDN$ exchange rate | 0.91 | 0.89 | 2% | 0.88 | 0.88 | -% |

We realized an average price on our natural gas of $7.04/Mcf (net of transportation) during the three months ended June 30, 2007 an increase of 13% from $6.22/Mcf for the same period in 2006. For the six months ended June 30, 2007 we realized a 2% decrease in our average price of $7.13/Mcf compared to the same period in 2006. We sell approximately one third of our natural gas to aggregators, with the remainder sold under month and day AECO index contracts and NYMEX monthly index contracts. Although our realized average natural gas price fluctuates from month to month, it remains within the range of the movement of the benchmark indices as the volume of natural gas sold on each index can vary each month. Overall our 13% increase and 2% decrease for the three and six months ended June 30, 2007 compared to the same periods in 2006 are within the range of the combined changes experienced by the AECO and NYMEX indices.

The average price we received for our crude oil during the three months ended June 30, 2007 decreased 10% to $61.93/bbl (net of transportation) from $68.80/bbl during the same period in 2006. Similarly, the West Texas Intermediate ("WTI") crude oil benchmark price, after adjusting for the change in the US$ exchange rate, also decreased 10% from the corresponding period in 2006. For the six months ended June 30, 2007, relative to the same period in 2006, our crude oil price fell 4%, while the WTI crude oil benchmark price fell 8%. This difference was largely due to improved pricing differentials during the first half of 2007 for our sour and heavy crude oil.

While the Canadian dollar strengthened significantly against the U.S. dollar during the quarter, the average exchange rate, for both the three and six month periods in 2007 was only moderately higher than for the comparable periods in 2006. As most of our crude oil and natural gas is priced in reference to U.S. dollar denominated benchmarks, this movement in the exchange rate reduced the Canadian dollar prices that we would have otherwise realized.

The Canadian/U.S. dollar exchange rate at June 30, 2007 was 0.94 which is one of the highest levels in recent years. The forward market is forecasting the exchange rate to approximate par by the end of 2007 with marginal weakening in 2008. If the current strength in the Canadian dollar persists our future Canadian dollar revenues realized from our oil and gas production will be reduced. We expect every $0.01 change in the Canadian/U.S. dollar exchange rate to have a $0.10 annualized per trust unit impact on cash flow.

## Price Risk Management

Natural gas prices fell in the second quarter with rising levels of inventory, aggressive drilling in the U.S., and increased liquefied natural gas imports to North America. Although there remains some threat of increased hurricane activity this summer, unless there is sustained heat in the U.S., there is potential for natural gas prices to remain depressed through the third quarter. With respect to crude oil prices, global demand continues to remain strong. Demand, combined with lower than expected non-OPEC production levels and geopolitical uncertainty, contributed to a steady climb in prices throughout the second quarter.

We have developed a price risk management framework to respond to the volatile price environment in a prudent manner. Consideration is given to our overall financial position together with the economics of our development capital program and acquisitions. Consideration is also given to the upfront costs of our risk management program as we seek to limit our exposure to price downturns while maintaining participation should commodity prices increase.

Given our price risk management framework, we entered into additional commodity contracts during the second quarter of 2007. Considering all of the financial contracts transacted as of July 25, 2007, we have protected a portion of our natural gas and crude oil sales for the period July 2007 through December 2008. We have also protected a portion of our exposure to rising electricity costs in the Alberta power market for the period July 2007 through September 2008. See Note 10 for a detailed list of our current price risk management positions.

The following is a summary of the physical and financial contracts in place at July 25, 2007 as a percentage of our forecasted net production volumes:

| | Natural Gas (CDN$/Mcf) | | | Crude Oil (US$/bbl) | |
|---|---|---|---|---|---|
| | July 1, 2007- October 31, 2007 | November 1, 2007- March 31, 2008 | April 1, 2008- October 31, 2008 | July 1, 2007- December 31, 2007 | January 1, 2008- December 31, 2008 |
| Floor Protection Price (puts) | $ 7.32 | $ 8.54 | $ 7.54 | $68.93 | $66.73 |
| % (net of royalties) | 32% | 11% | 3% | 33% | 12% |
| Fixed Price (swaps) | $ 7.58 | $ 8.81 | $ 8.18 | $66.24 | $73.15 |
| % (net of royalties) | 13% | 3% | 2% | 8% | 5% |
| Upside Capped Price (calls) | $ 9.07 | $10.97 | $ 9.50 | $ - | $83.13 |
| % (net of royalties) | 28% | 11% | 3% | - | 12% |

Based on weighted average price (before premiums), average annual production of 85,000 BOE/day and assuming a 19% royalty rate.

### Accounting for Price Risk Management

During the second quarter of 2007, our commodity price risk management program generated cash losses of $1.1 million and non-cash gains of $19.1 million, compared to cash gains of $7.9 million and non-cash losses of $33.5 million during the first quarter of 2007. The change in cash costs is primarily due to the increase in the WTI crude oil benchmark price during the second quarter of 2007. The impact of lower forward natural gas prices on our natural gas floor protection at the end of the second quarter resulted in a non-cash gain. This was partially offset by the impact of higher forward crude oil prices at the end of the second quarter.

Compared to the second quarter of 2006 our crude oil cash costs decreased by $15.7 million from $16.0 million and our natural gas cash costs increased by $0.2 million from $0.6 million. The decrease in crude oil cash costs is the result of the expiration of contracts that existed during the second quarter of 2006 that had ceiling prices between US$35.35/bbl and US$45.80/bbl on 4,500 bbls/day.

At June 30, 2007 the fair value of our commodity derivative instruments, net of premiums, represents a gain of $9.2 million and is recorded on our balance sheet as a deferred financial asset. In comparison at March 31, 2007 the fair value of our commodity derivative instruments represented a loss of $9.9 million and was recorded on our balance sheet as a deferred financial credit. As the forward markets for natural gas and crude oil fluctuate, and new contracts are executed and existing contracts are realized, changes in fair value ($19.1 million during the second quarter of 2007) are reflected as a non-cash charge or increase to earnings. See Note 3 for details.

The following table summarizes the effects of our commodity derivative instruments on income.

| Risk Management Costs ($ millions, except per unit amounts) | Three months ended June 30, 2007 | | Three months ended June 30, 2006 | |
|---|---|---|---|---|
| Cash losses: | | | | |
| Crude oil | $ 0.3 | $ 0.10/bbl | $ 16.0 | $ 4.82/bbl |
| Natural gas | 0.8 | $ 0.03/Mcf | 0.6 | $ 0.03/Mcf |
| Total Cash losses | $ 1.1 | $ 0.15/BOE | $ 16.6 | $ 2.12/BOE |
| Non-cash (gains)/losses: | | | | |
| Change in fair value -financial contracts | $(19.1) | $(2.54)/BOE | $(22.2) | $(2.84)/BOE |
| Amortization of deferred financial assets | - | $ - /BOE | 18.4 | $ 2.35/BOE |
| Total Non-cash (gains) | $(19.1) | $(2.54)/BOE | $ (3.8) | $(0.48)/BOE |
| Total (gains)/ losses | $(18.0) | $(2.39)/BOE | $ 12.8 | $ 1.64/BOE |

| Risk Management Costs ($ millions, except per unit amounts) | Six months ended June 30, 2007 | | Six months ended June 30, 2006 | |
|---|---|---|---|---|
| Cash (gains)/losses: | | | | |
| Crude oil | $ (8.1) | $(1.28)/bbl | $ 28.9 | $ 4.41/bbl |
| Natural gas | 1.3 | $ 0.03/Mcf | 10.6 | $ 0.22/Mcf |
| Total Cash (gains)/losses | $ (6.8) | $(0.45)/BOE | $ 39.5 | $ 2.54/BOE |
| Non-cash (gains)/losses: | | | | |
| Change in fair value -financial contracts | $ 14.4 | $ 0.95/BOE | $(62.5) | $(4.03)/BOE |
| Amortization of deferred financial assets | - | $ - /BOE | 36.7 | $ 2.37/BOE |
| Total Non-cash losses/(gains) | $ 14.4 | $0.95/BOE | $(25.8) | $(1.66)/BOE |
| Total losses | $ 7.6 | $0.50/BOE | $ 13.7 | $ 0.88/BOE |

Revenues

Crude oil and natural gas revenues during the second quarter of 2007 were comparable with the first quarter of 2007 as improved crude oil prices offset the impact of lower production and natural gas prices.

Crude oil and natural gas revenues for the three months ended June 30, 2007 were $382.5 million ($387.9 million, net of $5.4 million transportation) compared to $403.5 million ($409.1 million, net of $5.6 million transportation) for the same period in 2006. For the six months ended June 30, 2007 revenues were $762.5 million ($773.8 million, net of $11.3 million transportation) compared to $805.2 million ($816.9 million, net of $11.7 million transportation) during the same period in 2006.

The decrease in revenues of $21.0 million or 5% for the three months ended June 30, 2007 compared to the same period in 2006 was due to lower production and crude oil prices, offset by increased natural gas prices. The decrease in revenues of $42.7 million or 5% for the six months ended June 30, 2007 compared to the same period in 2006 was due to decreased production along with slightly lower commodity prices.

The following table summarizes the changes in sales revenue:

| Analysis of Sales Revenue(1) ($ millions) | Crude Oil | NGLs | Natural Gas | Total |
|---|---|---|---|---|
| Quarter ended June 30, 2006 | $ 227.8 | $ 23.1 | $ 152.6 | $ 403.5 |
| Price variance(1) | (21.3) | 0.4 | 19.5 | (1.4) |
| Volume variance | (13.9) | (3.4) | (2.3) | (19.6) |
| Quarter ended June 30, 2007 | $ 192.6 | $ 20.1 | $ 169.8 | $ 382.5 |

| ($ millions) | Crude Oil | NGLs | Natural Gas | Total |
|---|---|---|---|---|
| Year-to-date ended June 30, 2006 | $ 406.0 | $ 43.2 | $ 356.0 | $ 805.2 |
| Price variance(1) | (16.0) | (2.3) | (7.9) | (26.2) |
| Volume variance | (14.1) | (2.9) | 0.5 | (16.5) |
| Year-to-date ended June 30, 2007 | $ 375.9 | $ 38.0 | $ 348.6 | $ 762.5 |

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

Other Income

Other income for the three and six months ended June 30, 2007 was $0.3 million and $14.4 million, respectively compared to $0.2 million and $1.3 million for the same periods in 2006. During the first quarter of 2007 we sold certain marketable securities which resulted in a gain of $14.1 million. These marketable securities were historically recorded in other current assets at a cost of $2.4 million.

Royalties

Royalties are paid to various government entities and other land and mineral rights owners. For the three and six months ended June 30, 2007 royalties were $72.2 million and $143.8 million, respectively, both approximately 19% of oil and gas sales, net of transportation. For the three and six months ended June 30, 2006 royalties were $78.0 million and $159.4 million, approximately 19% and 20% of oil and gas sales, net of transportation, respectively. Decreases in royalties for the three and six months ended June 30, 2007 of $5.8 million and $15.6 million, respectively, compared to the same periods in 2006 were the result of slightly lower, weighted average commodity prices.

For 2007 we expect royalties to be approximately 19% of oil and gas sales, net of transportation costs. The Alberta government is currently conducting a review of the oil and gas royalty regime which may impact royalties in the future. Alberta Crown royalties represented approximately 45% of total royalties incurred during the first half of 2007.

Operating Expenses

Operating expenses during the second quarter of 2007 were $9.69/BOE or 14% higher than the first quarter of 2007. This increase was due to lower production resulting from scheduled maintenance and the incremental expenditures associated with these turn-around activities.

Operating expenses for the three months ended June 30, 2007 were $72.8 million or $9.69/BOE compared to $65.1 million or $8.31/BOE for the second quarter of 2006. For the six months ended June 30, 2007 operating costs were $138.8 million or $9.10/BOE compared to $123.3 million or $7.94/BOE for the same period in 2006. These increases resulted from unexpected incremental repairs and maintenance, supplies and labour, and well servicing expenses at our non-operated Mitsue and operated Gleneath and Giltedge areas. A field training initiative directed at optimizing production and reducing the time required to bring new wells on stream also contributed to the cost increase. We expect many of these costs to moderate over the remainder of the year.

As a result of the costs incurred to date and increased electricity costs expected in the second half of 2007, we are revising our annual operating cost guidance from $8.45/BOE to approximately $9.00/BOE.

General and Administrative Expenses

General and administrative ("G&A") expenses for the second quarter of 2007 were 3% lower than the first quarter of 2007. G&A expenses for the three months ended June 30, 2007 were $16.7 million or $2.22/BOE compared to $14.6 million or $1.86/BOE for the second quarter of 2006. G&A expenses totaled $33.8 million or $2.21/BOE for the six months ended June 30, 2007 compared to $27.9 million or $1.80/BOE for the same period in 2006. As expected, G&A increased over the prior year mainly due to overall compensation costs associated with retaining experienced staff. Costs to date in 2007 are in line with our expectations.

For the three and six months ended June 30, 2007 our G&A expenses included non-cash charges of $2.1 million or $0.28/BOE and $4.2 million or $0.28/BOE respectively compared to $1.3 million or $0.17/BOE and $2.5 million or $0.16/BOE for the same periods in 2006. These amounts relate solely to our trust unit rights incentive plan and are determined using a binomial lattice option-pricing model. The volatility of our trust unit price combined with the increased number of rights outstanding associated with additional employees have increased the non-cash cost of the plan.

The following table summarizes the cash and non-cash expenses recorded in G&A:

| General and Administrative Costs ($ millions) | Three months ended June 30, 2007 | Three months ended June 30, 2006 | Six months ended June 30, 2007 | Six months ended June 30, 2006 |
|---|---|---|---|---|
| Cash | $ 14.6 | $ 13.3 | $ 29.6 | $ 25.4 |

| | | | | |
|---|---|---|---|---|
| Non-cash trust unit rights incentive plan | 2.1 | 1.3 | 4.2 | 2.5 |
| Total G&A | $ 16.7 | $ 14.6 | $ 33.8 | $ 27.9 |

| (Per BOE) | | | | |
|---|---|---|---|---|
| Cash | $ 1.94 | $ 1.69 | $ 1.93 | $ 1.64 |
| Non-cash trust unit rights incentive plan | 0.28 | 0.17 | 0.28 | 0.16 |
| Total G&A | $ 2.22 | $ 1.86 | $ 2.21 | $ 1.80 |

We are maintaining our guidance for G&A expenses at $2.40/BOE, including non-cash G&A costs of approximately $0.30/BOE.

Interest Expense

Interest expense in the second quarter of 2007 was $3.7 million or 46% higher than the first quarter of 2007 due to changes in non-cash charges. The first quarter of 2007 included a non-cash gain of $1.6 million while the second quarter of 2007 included a non-cash loss of $2.1 million. These non-cash amounts result from the mark-to-market change on our interest rate swaps and the interest component on our cross currency interest rate swap ("CCIRS") as well as the amortization of the premium on our US$175 million senior unsecured notes. After consideration of these non-cash items, interest expense for the second quarter of 2007 was comparable to the first quarter of 2007.

Interest expense increased to $11.8 million for the second quarter of 2007 from $7.1 million during the same period in 2006. Interest expense increased to $20.0 million for the six months ended June 30, 2007 from $15.0 million during the same period in 2006. These increases are due to higher average indebtedness and interest rates during 2007 combined with the non-cash losses recorded during the three and six months ended June 30, 2007 of $2.1 million and $0.5 million respectively.

The following table summarizes the cash and non-cash interest expense recorded.

| Interest Expense ($ millions) | Three months ended June 30, 2007 | 2006 | Six months ended June 30, 2007 | 2006 |
|---|---|---|---|---|
| Cash | $ 9.7 | $ 7.1 | $ 19.5 | $ 15.0 |
| Non-cash | 2.1 | - | 0.5 | - |
| Total Interest Expense | $ 11.8 | $ 7.1 | $ 20.0 | $ 15.0 |

At June 30, 2007 20% of our debt was based on fixed interest rates while 80% had floating interest rates.

Capital Expenditures

We spent $80.4 million and $190.4 million on development drilling and facilities for the three and six months ended June 30, 2007, respectively, compared to $107.7 million and $236.4 million during the same periods in 2006. We achieved a 100% success rate with our second quarter drilling program as 35.7 net wells were drilled. Year-to-date, 75.4 net wells were drilled compared to 159 in 2006. Development in 2007 continues to focus primarily on Sleeping Giant Bakken oil and crude oil waterfloods. Despite the reduction in the total number of wells drilled in 2007 compared to 2006, our capital spending is in line with our expectations as the costs associated with drilling oil wells are higher than those for shallow natural gas.

Property acquisitions were $204.0 million and $267.4 million for the three and six months ended June 30, 2007, compared to $12.2 million and $42.2 million for the same periods in 2006. On April 10, 2007 we acquired the initial 90% of Kirby for $182.8 million and subsequently on June 22, 2007 we acquired the remaining 10% of Kirby for $20.3 million. The total combined consideration for 100% of Kirby amounted to $203.1 million. During the first quarter of 2007 we acquired Jonah for total consideration of approximately $61 million.

Property dispositions were $5.5 million for both the three and six months ended June 30, 2007 compared to $1.1 million and $20.8 million for the same periods in 2006. The majority of the $20.8 million divestment in 2006 related to the sale of a 1% interest in the Joslyn project.

Total net capital expenditures for 2007 and 2006 are outlined below.

| Capital Expenditures ($ millions) | Three months ended June 30, 2007 | Three months ended June 30, 2006 | Six months ended June 30, 2007 | Six months ended June 30, 2006 |
|---|---|---|---|---|
| Development expenditures | $ 69.4 | $ 90.3 | $ 160.2 | $ 188.0 |
| Plant and facilities | 11.0 | 17.4 | 30.2 | 48.4 |
| Development Capital | 80.4 | 107.7 | 190.4 | 236.4 |
| Office | 1.6 | 0.5 | 3.0 | 1.3 |
| Sub-total | 82.0 | 108.2 | 193.4 | 237.7 |
| Acquisitions of oil and gas properties(1) | 204.0 | 12.2 | 267.4 | 42.2 |
| Dispositions of oil and gas properties(1) | (5.5) | (1.1) | (5.5) | (20.8) |
| Total Net Capital Expenditures | $ 280.5 | $ 119.3 | $ 455.3 | $ 259.1 |
| Total Capital Expenditures financed with cash flow | $ 74.9 | $ 44.1 | $ 110.4 | $ 83.1 |
| Total Capital Expenditures financed with debt and equity | 205.6 | 75.2 | 344.9 | 195.5 |
| Total non-cash consideration for 1% sale of Joslyn project | - | - | - | (19.5) |
| Total Net Capital Expenditures | $ 280.5 | $ 119.3 | $ 455.3 | $ 259.1 |

(1) Net of post-closing adjustments.

We are maintaining our 2007 annual guidance of $415 million for development capital spending and are reallocating $10 million from our Canadian capital budget to our U.S. Bakken oil property for the second half of 2007.

Depletion, Depreciation, Amortization and Accretion ("DDA&A")

DDA&A of property, plant and equipment is recognized using the unit-of-production method based on proved reserves.

For the three months ended June 30, 2007, DDA&A increased to $15.58/BOE compared to $15.47/BOE during the corresponding period in 2006. For the six months ended June 30, 2007 DDA&A increased to $15.48/BOE compared to $15.00/BOE during the corresponding period in 2006. The increases in DDA&A per BOE are attributable to the continuing higher cost of capital additions in recent years combined with a slightly greater share of U.S. production which has a higher depletion rate per BOE.

No impairment of the Fund's assets existed at June 30, 2007 using year-end reserves updated for acquisitions, divestitures, production and management's estimates of future prices.

Asset Retirement Obligations

The following chart compares the amortization of the asset retirement costs, accretion of the asset retirement obligation, and actual site restoration costs incurred.

| ($ millions) | Three months ended June 30, 2007 | Three months ended June 30, 2006 | Six months ended June 30, 2007 | Six months ended June 30, 2006 |
|---|---|---|---|---|
| Amortization of the asset retirement cost | $ 3.3 | $ 3.1 | $ 6.7 | $ 6.1 |
| Accretion of the asset retirement obligation | 1.6 | 1.6 | 3.3 | 3.1 |
| Total Amortization and Accretion | $ 4.9 | $ 4.7 | $ 10.0 | $ 9.2 |
| Asset Retirement Obligations Settled | $ 3.8 | $ 2.5 | $ 7.1 | $ 5.6 |

The timing of actual asset retirement costs will differ from the timing of amortization and accretion charges. Actual asset retirement costs will be incurred over the next 66 years with the majority between 2036 and 2045. For accounting purposes, the asset retirement cost is amortized using a unit-of-production method based on proved reserves before royalties while the asset retirement obligation accretes until the time the obligation is settled.

Taxes

Future Income Taxes

Future income taxes arise from differences between the accounting and tax bases of assets and liabilities. A portion of the future income tax liability that is recorded on the balance sheet will be recovered through earnings before 2011. The balance will be realized when future income tax assets and liabilities are realized or settled.

For the three months ended June 30, 2007 a future income tax expense of $71.0 million was recorded in income compared to a recovery of $44.8 million for the same period in 2006. For the six months ended June 30, 2007 a future income tax expense of $47.2 million was recorded in income compared to a future income tax recovery of $46.6 million during the same period in 2006. The changes in future income taxes for the quarter and year-to-date are attributed to the following:

- During the second quarter of 2007, the Federal Government enacted a new tax on distributions from publicly traded income trusts and limited partnerships (specified investment flow-through entities, or "SIFTs"). The 31.5% SIFT tax will be applicable to the Fund effective January 1, 2011 provided that, until that time, the Fund complies with the "normal growth" guidelines regarding equity capital as outlined by the government. This tax rate change results in a future income tax expense of $78.1 million being recorded in the second quarter of 2007.
- During the second quarter of 2007, the Federal Government also enacted a decrease in the corporate rate of tax from 19.0% to 18.5% effective January 1, 2011. The effect of this rate change is a future income tax recovery of $1.2 million recorded in the second quarter of 2007.
- A future income tax recovery of $32.2 million was included in the second quarter of 2006 due to a reduction in the federal and provincial corporate tax rates enacted in that quarter.

After consideration of the above items, the future income tax provisions were comparable between the periods.

Current Income Taxes

In our current structure, payments are made between the operating entities and the Fund which ultimately transfers both income and future income tax liability to our unitholders. As a result, no cash income taxes have been paid by our Canadian operating entities. However, effective January 1, 2011 Enerplus will be subject to the SIFT tax at a rate of 31.5%.

For the three and six months ended June 30, 2007 our U.S. operations incurred current income related taxes in the amounts of $3.2 million and $5.3 million respectively, compared to $6.1 million and $10.0 million during the same periods in 2006.

The amount of current taxes recorded throughout the year is dependant upon the timing of both capital expenditures and repatriation of the funds to Canada. We continue to expect current income and withholding taxes to be approximately 15% of cash flow from U.S. operations in 2007 assuming all funds available after U.S. development capital spending are repatriated to Canada.

Net Income

Net income for the second quarter of 2007 was $40.1 million or $0.31 per trust unit compared to $146.0 million or $1.19 per trust unit for the second quarter of 2006. Net income for the six months ended June 30, 2007 was $148.0 million or $1.18 per trust unit compared to $273.3 million or $2.27 per trust unit for the same period in 2006. The decrease during the three and six months ended June 30, 2007 is due to increased future income tax expense as a result of the enactment of the SIFT tax, lower oil and gas sales and increased operating and G&A costs, partially offset by lower royalties and reduced commodity derivative losses.

Cash Flow from Operating Activities

Cash flow for the three and six months ended June 30, 2007 was $237.5 million and $430.7 million respectively, compared to $198.4 million and $387.7 million for the three and six months ended June 30, 2006. These increases were primarily a result of movements in non-cash working capital between the periods.

Selected Financial Results

| Per BOE of production (6:1) | Three months ended June 30, 2007 Operating Cash Flow(1) | Non-Cash & Other Items | Total | Three months ended June 30, 2006 Operating Cash Flow(1) | Non-Cash & Other Items | Total |
|---|---|---|---|---|---|---|
| Production per day | | | 82,478 | | | 86,092 |
| Weighted average sales price(2) | $ 50.96 | $ - | $ 50.96 | $ 51.50 | $ - | $ 51.50 |
| Royalties | (9.63) | - | (9.63) | (9.96) | - | (9.96) |
| Commodity derivative instruments | (0.15) | 2.54 | 2.39 | (2.12) | 0.48 | (1.64) |
| Operating costs | (9.80) | 0.11 | (9.69) | (8.31) | - | (8.31) |
| General and administrative | (1.94) | (0.28) | (2.22) | (1.69) | (0.17) | (1.86) |
| Interest expense, net of interest | (1.25) | (0.29) | (1.54) | (0.88) | - | (0.88) |
| Foreign exchange gain/(loss) | (0.11) | 0.64 | 0.53 | (0.05) | 0.36 | 0.31 |
| Current income tax | (0.43) | - | (0.43) | (0.78) | - | (0.78) |
| Restoration and abandon-ment cash costs | (0.51) | 0.51 | - | (0.32) | 0.32 | - |
| Depletion, depreciation, amortization and accretion | - | (15.58) | (15.58) | - | (15.47) | (15.47) |
| Future income tax (expense)/ recovery | - | (9.45) | (9.45) | - | 5.73 | 5.73 |
| Gain on sale of marketable securities | - | - | - | - | - | - |
| Total per BOE | $ 27.14 | $(21.80) | $ 5.34 | $ 27.39 | $ (8.75) | $ 18.64 |

(1) Cash Flow from Operating Activities before changes in non-cash working capital.
(2) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

| Per BOE of production (6:1) | Six months ended June 30, 2007 Operating Cash Flow(1) | Non-Cash & Other Items | Total | Six months ended June 30, 2006 Operating Cash Flow(1) | Non-Cash & Other Items | Total |
|---|---|---|---|---|---|---|

| | | | | | | |
|---|---|---|---|---|---|---|
| Production per day | | | 84,244 | | | 85,743 |
| Weighted average sales price(2) | $ 50.00 | $ - | $ 50.00 | $ 51.88 | $ - | $ 51.88 |
| Royalties | (9.43) | - | (9.43) | (10.27) | - | (10.27) |
| Commodity derivative instruments | 0.45 | (0.95) | (0.50) | (2.54) | 1.66 | (0.88) |
| Operating costs | (9.16) | 0.06 | (9.10) | (7.94) | - | (7.94) |
| General and administrative | (1.93) | (0.28) | (2.21) | (1.64) | (0.16) | (1.80) |
| Interest expense, net of interest | (1.25) | (0.03) | (1.28) | (0.88) | - | (0.88) |
| Foreign exchange gain/ (loss) | (0.09) | 0.32 | 0.23 | (0.03) | 0.18 | 0.15 |
| Current income tax | (0.35) | - | (0.35) | (0.65) | - | (0.65) |
| Restoration and abandon-ment cash costs | (0.48) | 0.48 | - | (0.36) | 0.36 | - |
| Depletion, depreciation, amortization and accretion | - | (15.48) | (15.48) | - | (15.00) | (15.00) |
| Future income tax (expense)/ recovery | - | (3.10) | (3.10) | - | 3.00 | 3.00 |
| Gain on sale of marketable securities (3) | - | 0.92 | 0.92 | - | - | - |
| Total per BOE | $ 27.76 | $(18.06) | $ 9.70 | $ 27.57 | $ (9.96) | $ 17.61 |

(1) Cash Flow from Operating Activities before changes in non-cash working capital.
(2) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(3) Gain on sale of marketable securities was a cash item however it is included in cash flow from investing activities not cash flow from operating activities.

Selected Canadian and U.S. Financial Results

The following tables provide a geographical analysis of key operating and financial results for the three and six months ended June 30, 2007 and 2006.

| (CDN$ millions, except per unit amounts) | Three months ended June 30, 2007 | | |
|---|---|---|---|
| | Canada | U.S. | Total |

| | | | |
|---|---|---|---|
| Daily Production Volumes | | | |
| Natural gas (Mcf/day) | 254,122 | 10,824 | 264,946 |
| Crude oil (bbls/day) | 24,563 | 9,615 | 34,178 |
| Natural gas liquids (bbls/day) | 4,143 | - | 4,143 |
| Total daily sales (BOE/day) | 71,059 | 11,419 | 82,478 |
| Pricing(1) | | | |
| Natural gas (per Mcf) | $ 7.03 | $ 7.37 | $ 7.04 |
| Crude oil (per bbl) | $ 59.59 | $ 67.94 | $ 61.93 |
| Natural gas liquids (per bbl) | $ 53.34 | $ - | $ 53.34 |
| Capital Expenditures | | | |
| Development capital and office | $ 49.1 | $ 32.9 | $ 82.0 |
| Acquisitions of oil and gas properties | $ 204.5 | $ (0.5) | $ 204.0 |
| Dispositions of oil and gas properties | $ (5.5) | $ - | $ (5.5) |
| Revenues | | | |
| Oil and gas sales(1) | $ 315.8 | $ 66.7 | $ 382.5 |
| Royalties | $ (58.9) | $(13.3)(2) | $ (72.2) |
| Commodity derivative instruments | $ 18.0 | $ - | $ 18.0 |
| Expenses | | | |
| Operating | $ 70.6 | $ 2.2 | $ 72.8 |
| General and administrative | $ 14.9 | $ 1.8 | $ 16.7 |
| Depletion, depreciation, amortization and accretion | $ 89.5 | $ 27.4 | $ 116.9 |
| Current income taxes | $ - | $ 3.2 | $ 3.2 |

| (CDN$ millions, except per unit amounts) | Three months ended June 30, 2006 Canada | U.S. | Total |
|---|---|---|---|
| Daily Production Volumes | | | |
| Natural gas (Mcf/day) | 263,265 | 5,823 | 269,088 |
| Crude oil (bbls/day) | 25,912 | 10,476 | 36,388 |
| Natural gas liquids (bbls/day) | 4,856 | - | 4,856 |
| Total daily sales (BOE/day) | 74,645 | 11,447 | 86,092 |
| Pricing(1) | | | |
| Natural gas (per Mcf) | $ 6.17 | $ 8.25 | $ 6.22 |
| Crude oil (per bbl) | $ 67.30 | $ 72.50 | $ 68.80 |
| Natural gas liquids (per bbl) | $ 52.33 | $ - | $ 52.33 |
| Capital Expenditures | | | |
| Development capital and office | $ 80.8 | $ 27.4 | $ 108.2 |
| Acquisitions of oil and gas properties | $ 12.2 | $ - | $ 12.2 |
| Dispositions of oil and gas properties | $ (1.1) | $ - | $ (1.1) |
| Revenues | | | |
| Oil and gas sales(1) | $ 330.0 | $ 73.5 | $ 403.5 |
| Royalties | $ (64.1) | $(13.9)(2) | $ (78.0) |
| Commodity derivative instruments | $ (12.8) | $ - | $ (12.8) |
| Expenses | | | |
| Operating | $ 63.4 | $ 1.7 | $ 65.1 |
| General and administrative | $ 13.2 | $ 1.4 | $ 14.6 |
| Depletion, depreciation, amortization and accretion | $ 92.4 | $ 28.8 | $ 121.2 |

| | | | |
|---|---|---|---|
| Current income taxes | $ - | $ 6.1 | $ 6.1 |

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(2) Royalties include U.S. state production tax.

| | Six months ended June 30, 2007 | | |
|---|---|---|---|
| (CDN$ millions, except per unit amounts) | Canada | U.S. | Total |
| Daily Production Volumes | | | |
| Natural gas (Mcf/day) | 260,051 | 10,249 | 270,300 |
| Crude oil (bbls/day) | 24,946 | 9,923 | 34,869 |
| Natural gas liquids (bbls/day) | 4,325 | - | 4,325 |
| Total daily sales (BOE/day) | 72,613 | 11,631 | 84,244 |
| Pricing(1) | | | |
| Natural gas (per Mcf) | $ 7.12 | $ 7.33 | $ 7.13 |
| Crude oil (per bbl) | $ 57.24 | $ 65.41 | $ 59.56 |
| Natural gas liquids (per bbl) | $ 48.55 | $ - | $ 48.55 |
| Capital Expenditures | | | |
| Development capital and office | $ 122.6 | $ 70.8 | $ 193.4 |
| Acquisitions of oil and gas properties | $ 206.6 | $ 60.8 | $ 267.4 |
| Dispositions of oil and gas properties | $ (5.5) | $ - | $ (5.5) |
| Revenues | | | |
| Oil and gas sales(1) | $ 631.4 | $ 131.1 | $ 762.5 |
| Royalties | $(117.7) | $(26.1)(2) | $(143.8) |
| Commodity derivative instruments | $ (7.6) | $ - | $ (7.6) |
| Expenses | | | |
| Operating | $ 134.5 | $ 4.3 | $ 138.8 |
| General and administrative | $ 29.7 | $ 4.1 | $ 33.8 |
| Depletion, depreciation, amortization and accretion | $ 181.0 | $ 55.0 | $ 236.0 |
| Current income taxes | $ - | $ 5.3 | $ 5.3 |

| | Six months ended June 30, 2006 | | |
|---|---|---|---|
| (CDN$ millions, except per unit amounts) | Canada | U.S. | Total |
| Daily Production Volumes | | | |
| Natural gas (Mcf/day) | 264,304 | 5,618 | 269,922 |
| Crude oil (bbls/day) | 26,124 | 9,998 | 36,122 |
| Natural gas liquids (bbls/day) | 4,634 | - | 4,634 |
| Total daily sales (BOE/day) | 74,809 | 10,934 | 85,743 |
| Pricing(1) | | | |
| Natural gas (per Mcf) | $ 7.25 | $ 8.42 | $ 7.27 |
| Crude oil (per bbl) | $ 59.47 | $ 68.92 | $ 62.09 |
| Natural gas liquids (per bbl) | $ 51.50 | $ - | $ 51.50 |
| Capital Expenditures | | | |
| Development capital and office | $ 182.8 | $ 54.9 | $ 237.7 |
| Acquisitions of oil and gas properties | $ 27.6 | $ 14.6 | $ 42.2 |
| Dispositions of oil and gas properties | $ (20.8) | $ - | $ (20.8) |
| Revenues | | | |
| Oil and gas sales(1) | $ 671.9 | $ 133.3 | $ 805.2 |

| | | | |
|---|---|---|---|
| Royalties | $ (134.1) | $(25.3)(2) | $(159.4) |
| Commodity derivative instruments | $ (13.7) | $ - | $ (13.7) |
| Expenses | | | |
| Operating | $ 119.9 | $ 3.4 | $ 123.3 |
| General and administrative | $ 25.7 | $ 2.2 | $ 27.9 |
| Depletion, depreciation, amortization and accretion | $ 178.0 | $ 54.7 | $ 232.7 |
| Current income taxes | $ - | $ 10.0 | $ 10.0 |

(1) Netof oil and gas transportation costs, but before the effects of commodity derivative instruments.
(2) Royalties include U.S. state production tax.

Quarterly Financial Information - 2005 to 2007

Oil and gas sales for the second quarter of 2007 were consistent with oil and gas sales for the first quarter of 2007. Overall oil and gas sales increased during 2005 due to increased crude oil production and higher commodity prices, but decreased throughout 2006 as a result of softening natural gas prices.

Net income for the second quarter of 2007 was lower than net income for the first quarter of 2007 mainly due to an increased future income tax expense resulting from the enactment of the SIFT tax during the second quarter of 2007. Net income has been affected by fluctuating commodity prices and risk management costs, the fluctuating Canadian dollar, higher operating and G&A costs, changes in future income tax provisions as well as changes to accounting policies adopted during 2005 and 2007. Furthermore, changes in the fair value of our commodity derivative instruments along with changes in fair value of other financial instruments cause net income to fluctuate between quarters.

Quarterly information is summarized in the following table:

| Quarterly Financial Information ($ millions, except per trust unit amounts) | Oil and Gas Sales(1) | Net Income | Net Income per trust unit Basic | Net Income per trust unit Diluted |
|---|---|---|---|---|
| 2007 | | | | |
| Second Quarter | $ 382.5 | $ 40.1 | $ 0.31 | $ 0.31 |
| First Quarter | 380.0 | 107.9 | 0.88 | 0.87 |
| 2006 | | | | |
| Fourth Quarter | $ 369.5 | $ 110.2 | $ 0.90 | $ 0.89 |
| Third Quarter | 398.0 | 161.3 | 1.31 | 1.31 |
| Second Quarter | 403.5 | 146.0 | 1.19 | 1.19 |
| First Quarter | 401.7 | 127.3 | 1.08 | 1.07 |
| Total | $1,572.7 | $ 544.8 | $ 4.48 | $ 4.47 |
| 2005 | | | | |
| Fourth Quarter | $ 503.2 | $ 150.9 | $ 1.29 | $ 1.28 |
| Third Quarter | 398.7 | 107.1 | 0.97 | 0.97 |
| Second Quarter | 320.0 | 108.8 | 1.04 | 1.04 |
| First Quarter | 301.8 | 65.2 | 0.63 | 0.62 |
| Total | $1,523.7 | $ 432.0 | $ 3.96 | $ 3.95 |

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(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

Liquidity and Capital Resources

Sustainability of our Distributions and Asset Base

As an oil and gas trust we have a declining asset base and therefore rely on ongoing development activities and acquisitions to replace production and add additional reserves. Our future oil and natural gas production and reserves are highly dependent on our success in exploiting our asset base and acquiring additional reserves. To the extent we are unsuccessful in these activities our cash distributions could be reduced.

Development activities and acquisitions may be funded internally by withholding a portion of cash flow or through external sources of capital such as debt or the issuance of equity. To the extent that we withhold cash flow to finance these activities, the amount of cash distributions may be reduced. Should external sources of capital become limited or unavailable, our ability to make the necessary development expenditures and acquisitions to maintain or expand our asset base may be impaired and ultimately reduce the amount of cash distributions.

Distribution Policy

The amount of cash distributions is proposed by management and approved by the Board of Directors. We continually assess distribution levels with respect to forecasted cash flows, debt levels and capital spending plans. The level of cash withheld has historically varied between 10% and 40% of annual cash flow from operating activities and is dependent upon numerous factors, the most significant of which are the prevailing commodity price environment, our current levels of production, debt obligations, our access to equity markets and funding requirements for our development capital program.

At December 31, 2006 we changed our methodology for calculating payout ratio to cash distributions to unitholders divided by cash flow from operating activities (after changes in non-cash working capital) as presented on our Consolidated Statements of Cash Flows. As a result, fluctuations in non-cash changes in operating working capital will continue to impact our payout ratio from quarter to quarter.

Although we intend to continue to make cash distributions to our unitholders, these distributions are not guaranteed. To the extent there is taxable income at the trust level determined in accordance with the Canadian Income Tax Act, the distribution of that taxable income is non-discretionary.

Cash Flow from Operating Activities, Cash Distributions and Payout Ratio

Cash flow from operating activities and cash distributions are reported on the Consolidated Statements of Cash Flows. During the second quarter of 2007 cash distributions of $162.6 million were funded entirely through cash flow of $237.5 million. Our payout ratio, which is calculated as cash distributions divided by cash flow, was 68% for the three months ended June 30, 2007 compared to 78% for the same period in 2006. For the six months ended June 30, 2007 our cash distributions were $320.3 million and were funded entirely through cash flow of $430.7 million. Our payout ratio for the six months ended June 30, 2007 was 74% compared to 79% for the six months ended June 30, 2006.

After consideration of cash distributions, the balance of our second quarter cash flow of $74.9 million was used to fund 93% of our $80.4 million in development capital spending. The balance of our development capital expenditures and our property acquisitions (which primarily related to the Kirby acquisition), were financed through a combination of debt and a portion of the proceeds raised in our equity issue of $210.6 million which closed April 10, 2007.

In aggregate, our 2007 second quarter cash distributions of $162.6 million and our development capital spending of $80.4 million totaled $243.0 million, or approximately 102% of our cash flow of $237.5 million. We rely on access to capital markets to the extent cash distributions and net capital expenditures exceed cash flow. Over the long term we would expect to support our distributions and capital expenditures with our cash flow; however, we would continue to fund acquisitions and growth through additional debt and equity. There will be years, especially when we are investing capital in opportunities that do not immediately generate cash flow (such as our Joslyn and Kirby oil sands projects) that this relationship will vary. In the oil and gas sector, because of the nature of reserve reporting, the natural reservoir declines and the risks involved in capital investment, it is not possible to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities. Therefore we do not disclose maintenance capital separate from development capital spending.

For the three months ended June 30, 2007 our cash distributions exceeded our net income by $122.5 million (2006 - $8.3 million) however net income includes $167.4 million of non-cash items (2006 - $71.1 million) that do not impact our cash flow. For the six months ended June 20, 2007 our cash distributions exceeded our net income by $172.3 million (2006 - $31.3 million) which includes $296.5 million of non-cash items (2006 - $160.2 million) that do not impact our cash flow. Future income taxes can fluctuate from period to period as a result of changes in tax rates (such as the enactment of the SIFT tax during the second quarter of 2007), or changes in the royalty, interest and dividends from our operating subsidiaries paid to the Fund. In addition, other non-cash charges such as DDA&A are not a good proxy for the cost of maintaining our productive capacity as they are based on the historical costs of our PP&E and not the fair market value of replacing those assets within the context of the current commodity price environment. The level of investment in a given period may not be sufficient to replace productive capacity given the natural declines associated with oil and natural gas assets. In these instances a portion of the cash distributions paid to unitholders may represent a return of the unitholders' capital.

The following table compares cash distributions to cash flow and net income.

| ($ millions, except per unit amounts) | Three months ended June 30, 2007 | Three months ended June 30, 2006 | Six months ended June 30, 2007 | Six months ended June 30, 2006 |
|---|---|---|---|---|
| Cash flow from operating activities: | $ 237.5 | $ 198.4 | $ 430.7 | $ 387.7 |
| Use of cash flow: | | | | |
| Cash distributions | $ 162.6 | $ 154.3 | $ 320.3 | $ 304.6 |
| Capital expenditures | 74.9 | 44.1 | 110.4 | 83.1 |
| | $ 237.5 | $ 198.4 | $ 430.7 | $ 387.7 |
| Excess of cash flow over cash distributions | $ 74.9 | $ 44.1 | $ 110.4 | $ 83.1 |
| Net income | $ 40.1 | $ 146.0 | $ 148.0 | $ 273.3 |
| Shortfall of net income over cash distributions | $ (122.5) | $ (8.3) | $ (172.3) | $ (31.3) |

| | | | | |
|---|---|---|---|---|
| Cash distributions per weighted average trust unit | $ 1.27 | $ 1.26 | $ 2.54 | $ 2.53 |
| Payout ratio(1) | 68% | 78% | 74% | 79% |

(1) Based on cash distributions divided by cash flow from operating activities.

Long-Term Debt

Long-term debt at June 30, 2007 which was comprised of $412.9 million of bank indebtedness and $247.1 million of senior unsecured notes, decreased to $660.0 million from $679.8 million at December 31, 2006. With the adoption of the financial instrument accounting standards (see Note 2) on January 1, 2007 we adjusted the carrying value of our US$175 million senior unsecured notes to fair value of $208.2 million from their previous carrying value of $268.3 million, a decrease of $60.1 million. Subsequent to this adoption entry, our total long term debt has increased by approximately $40.3 million from December 31, 2006. Increases in long-term debt resulting from the Jonah and Kirby acquisitions more than offset decreases resulting from the April 2007 equity issue and the foreign exchange impact of the strengthening Canadian dollar against the U.S. dollar on our U.S. denominated senior notes.

We continue to maintain a conservative balance sheet with a long-term debt to trailing cash flow ratio of 0.7 times as demonstrated below:

| Financial Leverage and Coverage | June 30, 2007 | December 31, 2006 |
|---|---|---|
| Long-term debt to trailing cash flow | 0.7x | 0.8x |
| Cash flow to interest expense | 24.4x | 26.8x |
| Long-term debt to long-term debt plus equity | 19% | 20% |

Long-term debt is measured net of cash.
Cash flow and interest expense are 12-months trailing.

There has been no change to our $850 million bank credit facility or our senior unsecured notes during the quarter. Payments with respect to the bank facilities, senior unsecured notes and other third party debt have priority over claims of and future distributions to the unitholders. Unitholders have no direct liability should cash flow be insufficient to repay this indebtedness. The agreements governing these bank facilities and senior unsecured notes stipulate that if we default or fail to comply with certain covenants, the ability of the Fund's operating subsidiaries to make payments to the Fund and consequently the Fund's ability to make distributions to the unitholders may be restricted. At June 30, 2007 we are in compliance with our debt covenants, the most restrictive of which limits our long term debt to 3 times trailing cash flow reflecting acquisitions on a pro forma basis. Refer to "Debt of Enerplus" in our 2006 Annual Information Form for a detailed description of these covenants.

Principal payments on Enerplus' senior unsecured notes are required commencing in 2010 and 2011 and are more fully discussed in Note 7.

We anticipate that we will continue to have adequate liquidity to fund planned development capital spending during 2007 through a combination of cash flow retained by the business and debt. A portion of our $415 million development capital budget for 2007 is discretionary and could be revised downward in the event of a commodity price downturn or similar economic event.

Trust Unit Information

We had 129,205,000 trust units outstanding at June 30, 2007 compared to 122,582,000 trust units at June 30, 2006 and 123,151,000 at December 31, 2006.

The weighted average basic number of trust units outstanding for the six months ended June 30, 2007 was 125,849,000 (2006 - 120,311,000). At July 31, 2007 we had 129,359,000 trust units outstanding.

For the three months ended June 30, 2007, 416,000 trust units (2006 - 350,000) were issued pursuant to the Trust Unit Monthly Distribution Reinvestment and Unit Purchase Plan ("DRIP") and the trust unit rights plan. This resulted in $18.6 million (2006 - $14.6 million) of additional equity to the Fund. For the six months ended June 30, 2007, 699,000 trust units ($31.7 million additional equity) were issued pursuant to DRIP and the trust unit options and rights plans compared to 673,000 trust units ($28.0 million) during the same period in 2006. For further details see Note 9.

On April 10, 2007, in conjunction with the acquisition of Kirby we issued 1,105,000 trust units as part of the purchase price consideration representing $54.8 million and also closed a public offering of 4,250,000 trust units for net proceeds of $199.6 million.

Canadian and U.S. Taxpayers

Enerplus estimates that approximately 95% of cash distributions paid to Canadian unitholders and 90% of cash distributions paid to U.S. unitholders will be taxable in 2007 and the remaining 5% and 10% respectively will be treated as a tax deferred return of capital. Actual taxable amounts may vary depending on actual distributions which are dependent upon production, commodity prices and cash flow experienced throughout the year.

For U.S. taxpayers the taxable portion of cash distributions are considered to be a dividend for U.S. tax purposes. For most U.S. taxpayers this should be a "Qualified Dividend" eligible for the reduced tax rate. This preferential rate of tax for "Qualified Dividends" is set to expire at the end of 2010. On March 24, 2007, Bill 1672 was introduced into the U.S. House of Representatives which, if enacted as presented, would make dividends from Canadian income funds such as Enerplus ineligible for treatment as a "Qualified Dividend". The dividends would then become a "non-qualified dividend from aforeign corporation" subject to the normal rates of tax commencing with dividends received after the date of enactment. The proposed bill still requires the approval of the House of Representatives, the Senate and the President prior to it being enacted. Therefore, we are unable to determine when or even if the bill will become enacted as presented.

In July 2007, Enerplus estimated its non-resident ownership to be approximately 70%.

Recent Canadian Accounting Pronouncements

CICA Section 3862 - Financial Instruments - Disclosures

This standard requires entities to provide disclosures in their financial statements that enable users to evaluate the significance of financial instruments to the entity's financial position and performance. It also requires that entities disclose the nature and extent of risks arising from financial instruments and how the entity manages those risks.

This standard is effective for January 1, 2008 and will result in additional disclosures for our financial instruments.

CICA Section 3863 - Financial Instruments - Presentation

This standard establishes presentation guidelines for financial instruments and non-financial derivatives and deals with the classification of financial instruments, from the perspective of the issuer, between liabilities and equity, the classification of related interest, dividends, losses and gains, and the circumstances in which financial assets and financial liabilities are offset.

This standard is effective for January 1, 2008 and should have a minimal impact on our reporting.

CICA Section 1535 - Capital Disclosures

This section details disclosures that must be made regarding an entities capital and how it is managed. The standard requires qualitative information about an entity's objectives, policies and processes for managing capital and quantitative data about what the entity regards as capital. It requires disclosure of compliance with any capital requirements and consequences of any non-compliance.

This standard is effective for January 1, 2008 and will result in additional disclosures around managing capital.

Internal Controls and Procedures

There were no changes in our internal control over financial reporting during the quarter ended June 30, 2007 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Additional Information

Additional information relating to Enerplus Resources Fund, including the Fund's Annual Information Form, is available under the Fund's profile on the SEDAR website at www.sedar.com and at www.enerplus.com

Forward-Looking Statements and Information

This management's discussion and analysis ("MD&A") contains certain forward-looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this MD&A contains forward-looking information and statements pertaining to the following: the amount, timing and tax treatment of cash distributions to unitholders; future payout ratios; future tax treatment of income trusts such as the Fund; future structure of the Fund and its subsidiaries; the Fund's tax pools; the volumes and estimated value of the Fund's oil and gas reserves and resources; the volume and product mix of the Fund's oil and gas production; future oil and natural gas prices and the Fund's commodity risk management programs; the amount of future asset retirement obligations; future liquidity and financial capacity; future results from operations, cost estimates and royalty rates; future development, exploration, and acquisition and development activities and related expenditures, including with respect to both our conventional and oil sands activities.

The forward-looking information and statements contained in this MD&A reflect several material factors and expectations and assumptions of the Fund including, without limitation: that the Fund will continue to conduct its operations in a manner consistent with past operations; the general continuance of current industry conditions; the continuance of existing and in certain circumstances, proposed tax and royalty regimes; the accuracy of the estimates of the Fund's reserve volumes; and certain commodity price and other cost assumptions. The Fund believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information and statements included in this MD&A are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information or statements including, without limitation: changes in commodity prices; unanticipated operating results or production declines; changes in tax or environmental laws or royalty rates; increased debt levels or debt service requirements; inaccurate estimation of the Fund's oil and gas reserves volumes; limited, unfavourable or no access to capital markets; increased costs; the impact of competitors; and certain other risks detailed from time to time in the Fund's public disclosure documents including, without limitation, those risks identified in this MD&A, our MD&A for the year ended December 31, 2006, and in the Fund's annual information form.

The forward-looking information and statements contained in this MD&A speak only as of the date of this MD&A, and none of the Fund or its subsidiaries assumes any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable laws.

CONSOLIDATED BALANCE SHEETS

| (CDN$ thousands) (Unaudited) | June 30, 2007 | December 31, 2006 |
|---|---|---|
| Assets | | |
| Current assets | | |
| Cash | $ 2,050 | $ 124 |
| Accounts receivable | 146,408 | 175,454 |
| Deferred financial assets (Note 3) | 12,664 | 23,612 |
| Other current | 2,875 | 6,715 |
| | 163,997 | 205,905 |
| Property, plant and equipment (Note 4) | 3,891,161 | 3,726,097 |
| Goodwill | 206,358 | 221,578 |
| Other assets | 57,633 | 50,224 |
| | $ 4,319,149 | $ 4,203,804 |
| Liabilities | | |
| Current liabilities | | |
| Accounts payable | $ 243,520 | $ 284,286 |
| Distributions payable to unitholders | 54,272 | 51,723 |
| Deferred financial credits (Note 3) | 86,686 | - |
| | 384,478 | 336,009 |
| Long-term debt (Note 7) | 659,995 | 679,774 |
| Future income taxes | 362,157 | 331,340 |
| Asset retirement obligations (Note 6) | 123,709 | 123,619 |
| | 1,145,861 | 1,134,733 |
| Equity | | |
| Unitholders' capital (Note 9) | 4,003,318 | 3,713,126 |
| Accumulated deficit | (1,149,130) | (971,085) |
| Accumulated other comprehensive loss (Note 2) | (65,378) | (8,979) |
| | 2,788,810 | 2,733,062 |

| | | |
|---|---|---|
| | $ 4,319,149 | $ 4,203,804 |

CONSOLIDATED STATEMENTS OF ACCUMULATED DEFICIT

| (CDN$ thousands) (Unaudited) | Three months ended June 30, 2007 | 2006 | Six months ended June 30, 2007 | 2006 |
|---|---|---|---|---|
| Accumulated income, beginning of period | $ 2,055,109 | $ 1,535,470 | $ 1,952,960 | $ 1,408,178 |
| Adjustment for adoption of financial instruments standards (Note 2) | - | - | (5,724) | - |
| Revised Accumulated income, beginning of period | 2,055,109 | 1,535,470 | 1,947,236 | 1,408,178 |
| Net income | 40,084 | 146,014 | 147,957 | 273,306 |
| Accumulated income, end of period | $ 2,095,193 | $ 1,681,484 | $ 2,095,193 | $ 1,681,484 |
| Accumulated cash distributions, beginning of period | $(3,081,716) | $(2,459,950) | $(2,924,045) | $(2,309,705) |
| Cash distributions | (162,607) | (154,348) | (320,278) | (304,593) |
| Accumulated cash distributions, end of period | $(3,244,323) | $(2,614,298) | $(3,244,323) | $(2,614,298) |
| Accumulated deficit, end of period | $(1,149,130) | $ (932,814) | $(1,149,130) | $ (932,814) |

CONSOLIDATED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

| (CDN$ thousands) (Unaudited) | Three months ended June 30, 2007 | 2006 | Six months ended June 30, 2007 | 2006 |
|---|---|---|---|---|
| Balance, beginning of period | $ (15,525) | $ (12,509) | $ (8,979) | $ (15,568) |
| Transition adjustments (Note 2): | | | | |
| Cash flow hedges | - | - | 660 | - |
| Available for sale marketable securities | - | - | 14,252 | - |

| | | | | |
|---|---|---|---|---|
| Other comprehensive loss | (49,853) | (26,708) | (71,311) | (23,649) |
| Balance, end of period | $ (65,378) | $ (39,217) | $ (65,378) | $ (39,217) |

CONSOLIDATED STATEMENTS OF INCOME

| (CDN$ thousands except per trust unit amounts) (Unaudited) | Three months ended June 30, 2007 | 2006 | Six months ended June 30, 2007 | 2006 |
|---|---|---|---|---|
| Revenues | | | | |
| Oil and gas sales | $ 387,926 | $ 409,078 | $ 773,797 | $ 816,916 |
| Royalties | (72,214) | (77,983) | (143,762) | (159,389) |
| Commodity derivative instruments (Notes 3 and 10) | 17,954 | (12,837) | (7,652) | (13,732) |
| Other income | 272 | 222 | 14,432 | 1,290 |
| | 333,938 | 318,480 | 636,815 | 645,085 |
| Expenses | | | | |
| Operating | 72,756 | 65,106 | 138,786 | 123,271 |
| General and administrative (Note 9) | 16,660 | 14,560 | 33,770 | 27,865 |
| Transportation | 5,453 | 5,615 | 11,317 | 11,727 |
| Interest on long-term debt | 11,847 | 7,110 | 19,962 | 15,006 |
| Foreign exchange gain (Note 8) | (3,956) | (2,408) | (3,474) | (2,254) |
| Depletion, depreciation, amortization and accretion | 116,909 | 121,183 | 236,000 | 232,734 |
| | 219,669 | 211,166 | 436,361 | 408,349 |
| Income before taxes | 114,269 | 107,314 | 200,454 | 236,736 |
| Current taxes | 3,227 | 6,147 | 5,291 | 10,009 |
| Future income tax expense / (recovery) | 70,958 | (44,847) | 47,206 | (46,579) |
| Net Income | $ 40,084 | $ 146,014 | $ 147,957 | $ 273,306 |
| Net income per trust unit | | | | |
| Basic | $ 0.31 | $ 1.19 | $ 1.18 | $ 2.27 |
| Diluted | $ 0.31 | $ 1.19 | $ 1.18 | $ 2.26 |
| Weighted average number of trust units outstanding (thousands) | | | | |

| | | | | |
|---|---|---|---|---|
| Basic | 128,361 | 122,379 | 125,849 | 120,311 |
| Diluted | 128,419 | 122,845 | 125,904 | 120,747 |

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

| (CDN$ thousands) (Unaudited) | Three months ended June 30, 2007 | 2006 | Six months ended June 30, 2007 | 2006 |
|---|---|---|---|---|
| Net income | $ 40,084 | $ 146,014 | $ 147,957 | $ 273,306 |
| Other comprehensive income / loss, net of tax: | | | | |
| Unrealized gains/ (losses) on marketable securities | 2,502 | - | (654) | - |
| Realized gains on marketable securities included in net income | - | - | (11,654) | - |
| Gains and losses on derivatives designated as hedges in prior periods included in net income | (176) | - | (380) | - |
| Change in cumulative translation adjustment | (52,179) | (26,708) | (58,623) | (23,649) |
| Other comprehensive loss | (49,853) | (26,708) | (71,311) | (23,649) |
| Comprehensive (loss) / income (Note 2) | $ (9,769) | $ 119,306 | $ 76,646 | $ 249,657 |

CONSOLIDATED STATEMENTS OF CASH FLOWS

| (CDN$ thousands) (Unaudited) | Three months ended June 30, 2007 | 2006 | Six months ended June 30, 2007 | 2006 |
|---|---|---|---|---|
| Operating Activities | | | | |
| Net income | $ 40,084 | $ 146,014 | $ 147,957 | $ 273,306 |
| Non-cash items add/ (deduct): | | | | |
| Depletion, depreciation, amortization | | | | |

| | | | | |
|---|---|---|---|---|
| and accretion | 116,909 | 121,183 | 236,000 | 232,734 |
| Change in fair value of derivative instruments (Note 3) | (1,394) | (3,774) | 33,453 | (25,759) |
| Unit based compensation (Note 9) | 2,107 | 1,339 | 4,218 | 2,526 |
| Foreign exchange on translation of senior notes (Note 8) | (20,808) | (2,813) | (23,690) | (2,748) |
| Future income tax | 70,958 | (44,847) | 47,206 | (46,579) |
| Amortization of senior notes premium | (159) | - | (328) | - |
| Reclassification adjustments from AOCI to net income | (176) | - | (380) | - |
| Gain on sale of marketable securities | - | - | (14,055) | - |
| Asset retirement costs incurred (Note 6) | (3,803) | (2,521) | (7,117) | (5,584) |
| | 203,718 | 214,581 | 423,264 | 427,896 |
| Decrease/(Increase) in non-cash working capital | 33,764 | (16,177) | 7,399 | (40,211) |
| Cash flow from operating activities | 237,482 | 198,404 | 430,663 | 387,685 |
| Financing Activities | | | | |
| Issue of trust units, net of issue costs (Note 9) | 218,204 | 14,564 | 231,224 | 268,244 |
| Cash distributions to unitholders | (162,607) | (154,348) | (320,278) | (304,593) |
| (Decrease)/Increase in bank credit facilities | (35,992) | 80,255 | 64,350 | (52,599) |
| Decrease in non-cash financing working capital | 180 | 131 | 2,549 | 2,131 |
| Cash flow from financing activities | 19,785 | (59,398) | (22,155) | (86,817) |
| Investing Activities | | | | |
| Capital expenditures | (82,000) | (108,133) | (193,354) | (237,693) |
| Property acquisitions | (149,266) | (12,230) | (212,644) | (42,257) |
| Property dispositions | (1,107) | 1,089 | (1,152) | 1,278 |
| Proceeds on sale of marketable securities | - | - | 16,467 | - |
| Increase in non-cash investing working capital | (20,627) | (19,076) | (14,497) | (30,509) |
| Cash flow from investing activities | (253,000) | (138,350) | (405,180) | (309,181) |

| | | | | |
|---|---|---|---|---|
| Effect of exchange rate changes on cash | (2,311) | (1,269) | (1,402) | (1,128) |
| Change in cash | 1,956 | (613) | 1,926 | (9,441) |
| Cash, beginning of period | 94 | 1,265 | 124 | 10,093 |
| Cash, end of period | $ 2,050 | $ 652 | $ 2,050 | $ 652 |
| | | | | |
| Supplementary Cash Flow Information | | | | |
| Cash income taxes paid | $ 4,005 | $ 3,516 | $ 7,246 | $ 3,770 |
| Cash interest paid | $ 14,644 | $ 10,238 | $ 20,730 | $ 14,761 |

ENERPLUS RESOURCES FUND
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Tabular amounts in thousands of Canadian dollars and thousands of units except per unit amounts) (Unaudited)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The interim consolidated financial statements of Enerplus Resources Fund ("Enerplus" or the "Fund") have been prepared by management following the same accounting policies and methods of computation as the consolidated financial statements for the fiscal year ended December 31, 2006, except as identified in Note 2. The note disclosure requirements for annual statements provide additional disclosure to that required for these interim statements. Accordingly, these interim statements should be read in conjunction with the Fund's consolidated financial statements for the year ended December 31, 2006. The disclosures provided below are incremental to those included in the 2006 annual consolidated financial statements of the Fund.

2. CHANGES IN ACCOUNTING POLICIES

Financial Instruments

Effective January 1, 2007, the Fund adopted three new accounting standards that were issued by the Canadian Institute of Chartered Accountants ("CICA"): Handbook Section 1530, Comprehensive Income, Handbook Section 3855, Financial Instruments - Recognition and Measurement, and Handbook Section 3865, Hedges. These standards were adopted prospectively pursuant to their respective adoption provisions, and therefore there is no effect on prior periods.

Comprehensive Income

CICA Handbook Section 1530 introduces comprehensive income, which consists of net income and other comprehensive income ("OCI"). OCI represents changes in equity during a period arising from transactions and other events with non-owner sources and includes unrealized gains and losses on marketable securities classified as available-for-sale along with unrealized foreign currency translation gains or losses arising from self-sustaining foreign operations, among other things. The Consolidated Statements of Comprehensive

Income include a calculation of comprehensive income, while the cumulative changes in OCI are included in the Statements of Accumulated Other Comprehensive Income (AOCI).

Financial Instruments - Recognition and Measurement

CICA Handbook Section 3855 establishes the criteria for recognizing and measuring financial assets, financial liabilities and non-financial derivatives. Under this standard, all financial instruments are required to be measured at fair value on recognition except for certain related party transactions. Measurement in subsequent periods depends on whether the financial instrument has been classified as held-for-trading, available-for-sale, held-to-maturity, loans and receivables, or other financial liabilities.

Financial assets and financial liabilities classified as held-for-trading are measured at fair value with changes in fair value recognized in net income. Financial assets classified as loans and receivables along with financial liabilities classified as other liabilities are measured at amortized cost using the effective interest rate method. Financial assets classified as available-for-sale are measured at fair value with changes in fair value recognized in OCI. Investments in equity instruments classified as available-for-sale that do not have a quoted price in an active market are measured at cost. Transaction costs or fees attributable to the acquisition, issue, or disposal of a financial asset or liability are expensed immediately to net income.

Derivative instruments are recorded on the consolidated balance sheets at fair value, including those derivatives that are embedded in financial or non-financial contracts that are not closely related to the host contracts. Changes in the fair values of derivative instruments are recognized in net income with the exception of derivatives that are designated as effective cash flow hedges. Refer to the Hedges section for further detail.

Hedges

CICA Handbook Section 3865 specifies the criteria and method of accounting for each of the designated hedging strategies.

When hedge accounting is discontinued for a cash flow hedge, the amounts previously recognized in AOCI are reclassified to net income over the remaining term of the hedged item.

When hedge accounting is discontinued for a fair value hedge, the carrying value of the hedged item is no longer adjusted. Any difference between the carrying value and the face value or principal amount of the hedged item is amortized to net income over the remaining term of the original hedging relationship using the effective interest method.

Impact upon Adoption of Sections 1530, 3855 and 3865

As a result of the adoption of these standards on January 1, 2007 the Fund elected to stop designating its interest rate and electricity swaps as cash flow hedges and recorded these items on the consolidated balance sheet at their fair values with the offset recorded to opening accumulated other comprehensive income. In addition, the Fund elected to stop designating its cross currency and interest rate swap ("CCIRS") as a fair value hedge and recorded the CCIRS on the consolidated balance sheet at fair value with the offset recorded to opening accumulated deficit. In conjunction, the underlying US$175,000,000 senior unsecured notes were recorded at fair value with the offset recorded to opening accumulated deficit.

The Fund's investments in marketable securities have been classified as available-for-sale and were therefore recorded on the consolidated balance sheet at fair value with the offset recorded to opening AOCI.

Deferred charges of $1,523,000 associated with issuance of the senior unsecured notes were recorded to the opening accumulated deficit.

Amounts previously recorded in the cumulative translation adjustment were reclassified into opening AOCI. Our prior year comparative statements have been restated to reflect this change.

The Fund has recorded the following transition adjustments as of January 1, 2007 in the Consolidated Financial Statements: (a) an increase of $1,494,000 to deferred financial assets to record the electricity swaps at fair value; (b) an increase to other current assets of $14,493,000 to record publicly traded marketable securities at fair value; (c) an increase of $1,708,000 to other assets, consisting of $3,231,000 to record publicly traded marketable securities at fair value less $1,523,000 to write-off the deferred charges associated with the issuance of the senior unsecured notes; (d) an increase of $65,675,000 to deferred financial credits to record the CCIRS and interest rates swaps at fair value; (e) a decrease to long-term debt of $60,111,000 to record the US$175,000,000 senior unsecured note at fair value; (f) an increase to future income taxes of $ 2,943,000 to reflect the tax impact of the adoption entries; (g) an increase of $5,724,000, net of taxes, to the opening accumulated deficit; (h) recognition in AOCI of $14,912,000, net of taxes, related to the net gains on marketable securities classified as available-for-sale along with the fair value of the interest rate and power swaps formerly designated as cash flow hedges. In addition, the Fund reclassified to AOCI $8,979,000 of net unrealized foreign currency losses that were previously presented as a separate item in equity. These transition adjustments are summarized below.

Impact of transition adjustment on selected consolidated balance sheets line items:

| (CDN$ thousands) | Transition adjustment as at January 1, 2007 |
|---|---|
| Deferred financial assets | $1,494 |
| Other current assets | 14,493 |
| Other assets | 1,708 |
| Deferred credits | 65,675 |
| Long-term debt | (60,111) |
| Future income taxes | 2,943 |
| Accumulated deficit | (5,724) |
| Cumulative translation adjustment | 8,979 |
| Accumulated other comprehensive income | 5,933 |

As a result of these changes, net income decreased by $956,000 ($1,347,000 before future income taxes of $391,000) and $89,000 ($126,000 before future income taxes of $37,000 for the three and six months ended June 30, 2007 respectively. Both the basic and diluted net income per trust unit calculations for the three months ended June 30, 2007 decreased by $0.01 and were unchanged for the six months ended June 30, 2007.

## 3. DEFERRED FINANCIAL ASSETS AND CREDITS

The deferred financial assets and credits result from recording our derivative financial instruments at fair value. The deferred financial asset relating to crude oil and natural gas instruments of $9,182,000 at June 30, 2007 consists of the fair value of the financial instruments of $22,749,000 less the related deferred premiums of $13,567,000.

| ($ thousands) | Interest Rate Swap | Cross Currency Interest Rate Swaps | Electricity Swaps | Commodity Derivative Instruments | Total |
|---|---|---|---|---|---|
| Deferred financial assets/(credits) as at December 31, 2006 | $ - | $ - | $ - | $ 23,612 | $ 23,612 |
| Adoption of financial instruments standards(1) | (673) | (65,002) | 1,494 | - | (64,181) |
| Change in fair value asset/ (credits) | 2,100(2) | (21,684)(3) | 561(4) | (14,430)(5) | (33,453) |
| Deferred financial assets/(credits) as at June 30, 2007 | $ 1,427 | $(86,686) | $ 2,055 | $ 9,182 | $(74,022) |

(1) The adoption of the financial instruments standards on January 1, 2007 resulted in a decrease to the deferred financial assets balance. See Note 2 for further details.
(2) Recorded in interest expense.
(3) Recorded in foreign exchange expense (loss of $18,774) and interest expense (loss of $2,910).
(4) Recorded in operating expense.
(5) Recorded in commodity derivative instruments (see below).

The following table summarizes the income statement effects of commodity derivative instruments:

| Commodity Derivative Instruments ($ thousands) | Three months ended June 30, 2007 | Three months ended June 30, 2006 | Six months ended June 30, 2007 | Six months ended June 30, 2006 |
|---|---|---|---|---|
| Change in fair value | $(19,052) | $(22,218) | $ 14,430 | $(62,499) |
| Amortization of deferred financial assets | - | 18,444 | - | 36,740 |
| Realized cash costs/(gains), net | 1,098 | 16,611 | (6,778) | 39,491 |
| Commodity derivative | | | | |

| | | | | |
|---|---|---|---|---|
| instruments | $(17,954) | $ 12,837 | $ 7,652 | $ 13,732 |

4. PROPERTY, PLANT AND EQUIPMENT

| ($ thousands) | June 30, 2007 | December 31, 2006 |
|---|---|---|
| Property, plant and equipment | $ 6,237,441 | $ 5,855,511 |
| Accumulated depletion, depreciation and accretion | (2,346,280) | (2,129,414) |
| Net property, plant and equipment | $ 3,891,161 | $ 3,726,097 |

Capitalized development G&A of $8,158,000 (2006 - $6,696,000) is included in property, plant and equipment ("PP&E") for the six months ended June 30, 2007. Excluded from PP&E for the purpose of the depletion and depreciation calculation is $99,376,000 (2006 - $57,799,000) related to the Joslyn development project and $203,083,000 (2006 - nil) related to the Kirby development project, both of which have not yet commenced commercial production.

5. PROPERTY ACQUISITION

On April 10, 2007 the Fund acquired a 90% interest in the Kirby Oil Sands Partnership ("Kirby") for total consideration of $182,800,000 consisting of $128,050,000 in cash and the issuance of 1,104,945 trust units at a price of$49.55 per unit ($54,750,000 of equity). On June 22, 2007, the Fund acquired the remaining 10% interest in Kirby for cash consideration of $20,276,000. The acquisition of Kirby has been accounted for as an asset acquisition pursuant to the guidance in the Emerging Issues Committee Abstract 124.

6. ASSET RETIREMENT OBLIGATIONS

The following table reconciles the Fund's asset retirement obligations:

| ($ thousands) | Six months ended June 30, 2007 | Year ended December 31, 2006 |
|---|---|---|
| Asset retirement obligations, beginning of period | $ 123,619 | $ 110,606 |
| Changes in estimates | 3,653 | 12,757 |
| Acquisition and development activity | 969 | 5,574 |
| Dispositions | (759) | (45) |
| Asset retirement obligations settled | (7,117) | (11,514) |
| Accretion expense | 3,344 | 6,241 |
| Asset retirement obligations, end of period | $ 123,709 | $ 123,619 |

## 7. LONG-TERM DEBT

| ($ thousands) | June 30, 2007 | December 31, 2006 |
|---|---|---|
| Bank credit facilities (a) | $ 412,870 | $ 348,520 |
| Senior notes (b) | | |
| US$175 million (issued June 19, 2002) | 189,701 | 268,328 |
| US$54 million (issued October 1, 2003) | 57,424 | 62,926 |
| Total long-term debt | $ 659,995 | $ 679,774 |

(a) Unsecured Bank Credit Facility

Enerplus has an $850,000,000 unsecured covenant based three year term facility. The facility is extendible each year with a bullet payment required at the end of the three year term. Various borrowing options are available under the facility including prime rate based advances and bankers' acceptance loans. This facility carries floating interest rates that are expected to range between 55.0 and 110.0 basis points over bankers' acceptance rates, depending on Enerplus' ratio of senior debt to earnings before interest, taxes and non-cash items. The effective interest rate on the facility for the six months ended June 30, 2007 was 4.9% (2006 - 4.6%).

(b) Senior Unsecured Notes

On October 1, 2003 Enerplus issued US$54,000,000 senior unsecured notes that mature October 1, 2015. The notes have a coupon rate of 5.46% priced at par with interest paid semi-annually on April 1 and October 1 of each year. Principal payments are required in five equal installments beginning October 1, 2011 and ending October 1, 2015. The notes are subject to fluctuations in foreign exchange rates and are translated into Canadian dollars using the period end foreign exchange rate.

On June 19, 2002 Enerplus issued US$175,000,000 senior unsecured notes that mature June 19, 2014. The notes have a coupon rate of 6.62% priced at par, with interest paid semi-annually on June 19 and December 19 of each year. Principal payments are required in five equal installments beginning June 19, 2010 and ending June 19, 2014. Concurrent with the issuance of the notes on June 19, 2002, the Fund entered into a cross currency interest rate swap ("CCIRS") with a syndicate of financial institutions. Under the terms of the swap, the amount of the notes was fixed for purposes of interest and principal repayments at a notional amount of CDN$268,328,000. Interest payments are made on a floating rate basis, set at the rate for three-month Canadian bankers' acceptances, plus 1.18%.

On January 1, 2007 in conjunction with the adoption of CICA Sections 3855 and 3865, the Fund elected to stop designating the CCIRS as a fair value hedge on the US$175,000,000 senior notes. As a result, the Fund recorded the senior notes at their fair value of US$178,681,000 (CDN $208,217,000) with the offset to opening accumulated deficit. In addition, the Fund recorded a liability of $65,002,000 with the offset to opening accumulated deficit, which represented the fair value of the CCIRS. The premium amount of US$3,681,000, representing the difference between the January 1, 2007 fair value and the face amount of the senior notes, will be amortized to net income over the remaining term of the notes using the effective interest method. The effective interest rate over the remaining term of the senior notes is 6.16%. The senior notes are carried at amortized cost and are translated into Canadian dollars using the period end foreign exchange rate. At June 30, 2007 the amortized cost of the US$175,000,000 senior notes was US$178,391,000.

## 8. FOREIGN EXCHANGE

| ($ thousands) | Three months ended June 30, 2007 | Three months ended June 30, 2006 | Six months ended June 30, 2007 | Six months ended June 30, 2006 |
|---|---|---|---|---|
| Unrealized foreign exchange gain on translation of U.S. dollar denominated senior notes | $(20,808) | $ (2,813) | $(23,690) | $ (2,748) |
| Unrealized foreign exchange loss on cross currency interest rate swap | 15,998 | - | 18,774 | - |
| Realized foreign exchange loss | 854 | 405 | 1,442 | 494 |
| Foreign exchange gain | $ (3,956) | $ (2,408) | $ (3,474) | $ (2,254) |

The US$54,000,000 and US$175,000,000 senior unsecured notes are exposed to foreign currency fluctuations and are translated into Canadian dollars at the exchange rate in effect at the balance sheet date. Foreign exchange gains and losses are included in the determination of net income for the period.

## 9. FUND CAPITAL

(a) Unitholders' Capital

Trust Units
Authorized: Unlimited number of trust units

| Issued: (thousands) | Six months ended June 30, 2007 Units | Six months ended June 30, 2007 Amount | Year ended December 31, 2006 Units | Year ended December 31, 2006 Amount |
|---|---|---|---|---|
| Balance before Contributed Surplus, beginning of period | 123,151 | $3,706,821 | 117,539 | $3,407,567 |
| Issued for cash: | | | | |
| Pursuant to public offerings | 4,250 | 199,558 | 4,370 | 240,287 |
| Pursuant to rights plans | 118 | 4,153 | 640 | 22,974 |
| Trust unit rights incentive plan (non-cash) - exercised | - | 1,141 | - | 3,065 |
| DRIP(*), net of redemptions | 581 | 27,513 | 602 | 32,928 |
| Issued for acquisition of property interests (non-cash) | 1,105 | 54,750 | - | - |

| | | | | |
|---|---|---|---|---|
| | 129,205 | 3,993,936 | 123,151 | 3,706,821 |
| Contributed Surplus (Trust Unit Rights Plan) | - | 9,382 | - | 6,305 |
| Balance, end of period | 129,205 | $4,003,318 | 123,151 | $3,713,126 |

(*) Distribution Reinvestment and Unit Purchase Plan

| Contributed Surplus ($ thousands) | Six months ended June 30, 2007 | Year ended December 31, 2006 |
|---|---|---|
| Balance, beginning of period | $ 6,305 | $ 3,047 |
| Trust unit rights incentive plan (non-cash) - exercised | (1,141) | (3,065) |
| Trust unit rights incentive plan (non-cash) - expensed | 4,218 | 6,323 |
| Balance, end of period | $ 9,382 | $ 6,305 |

On April 10, 2007 the Fund closed an equity offering of 4,250,000 trust units at a price of $49.55 per unit for gross proceeds of $210,588,000 ($199,558,000 net of issuance costs). These trust units were eligible for the April 20, 2007 cash distribution paid to unitholders of record at the close of business on April 10, 2007.

In conjunction with the acquisition of Kirby on April 10, 2007, the Fund issued 1,105,000 trust units at a price of $49.55 per unit for gross proceeds of $54,750,000.

(b) Trust Unit Rights Incentive Plan

As at June 30, 2007, a total of 3,473,000 rights issued pursuant to the Trust Unit Rights Incentive Plan ("Rights Plan") with an average exercise price of $48.37 were outstanding. This represents 2.7% of the total trust units outstanding of which 1,062,000 rights with an average exercise price of $42.87 were exercisable. Under the Rights Plan, distributions per trust unit to Enerplus unitholders in a calendar quarter which represent a return of more than 2.5% of the net PP&E of Enerplus at the end of such calendar quarter may result in a reduction in the exercise price of the rights. Results for the first and second quarters of 2007 reduced the exercise price of the outstanding rights by $0.51 per trust unit (effective July 2007) and $0.51 per trust unit (effective October 2007).

Activity for the rights issued pursuant to the Rights Plan is as follows:

| | Six months ended June 30, 2007 | | Year ended December 31, 2006 | |
|---|---|---|---|---|
| | Number of Rights (000's) | Weighted Average Exercise Price(1) | Number of Rights (000's) | Weighted Average Exercise Price(1) |

| | | | | |
|---|---|---|---|---|
| Trust unit rights outstanding | | | | |
| Beginning of period | 3,079 | $48.53 | 2,621 | $42.80 |
| Granted | 638 | 49.85 | 1,473 | 54.49 |
| Exercised | (118) | 35.11 | (640) | 35.94 |
| Cancelled | (126) | 50.62 | (375) | 46.35 |
| End of period | 3,473 | 48.37 | 3,079 | 48.53 |
| Rights exercisable at the end of the period | 1,062 | $42.87 | 809 | $39.81 |

(1) Exercise price reflects grant prices less reduction in strike price discussed above.

The Fund uses a binomial option-pricing model to calculate the estimated fair value of rights under the plan. Non-cash compensation costs for the three and six months ended June 30, 2007 were $2,107,000 ($0.02 per unit) and $4,218,000 ($0.03 per unit) respectively. The non-cash compensation costs for the three and six months ended June 30, 2006 were $1,339,000 ($0.01 per unit) and $2,526,000 ($0.02 per unit) respectively.

(c) Basic and Diluted per Trust Unit Calculations

Net income per trust unit has been determined based on the following:

| (thousands) | Six months ended June 30, 2007 | 2006 |
|---|---|---|
| Weighted average units | 125,849 | 120,311 |
| Dilutive impact of rights | 55 | 436 |
| Diluted trust units | 125,904 | 120,747 |

(d) Cash Distributions to Unitholders

Cash distributions to unitholders for the three months ended June 30, 2007 were $162,607,000 (2006 - $154,348,000). Cash distributions to unitholders for the six months ended June 30, 2007 were $320,278,000 (2006 - $304,593,000). Cash distributions are determined by the Board of Directors in accordance with the Trust indenture and are paid monthly.

10. FINANCIAL INSTRUMENTS

(a) Fair Value of Financial Instruments

As a result of the adoption of the new financial instrument and hedging accounting standards described in Note 2, certain financial instruments are now measured and reported on the balance sheet at fair value which were previously reported at amortized cost.

The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's-length transaction between knowledgeable, willing parties who are under no compulsion to act. Fair values are determined by reference to quoted bid or ask prices, as appropriate, in the most advantageous active market for that instrument to which we have immediate access. Where bid and ask prices are unavailable, we would use the closing price of the most recent transaction for that instrument. In the absence of an active market, we determine fair values based on prevailing market rates for instruments with similar characteristics. Fair values may also be determined based on internal and external valuation models, such as option pricing models and discounted cash flow analysis, that use observable market based inputs and assumptions.

(b) Carrying Value and Fair Value of Financial Instruments

i. Cash

Cash is classified as held-for-trading and is reported at fair value.

ii. Accounts Receivable

Accounts receivable are classified as loans and receivables are reported at amortized cost. At June 30, 2007 the carrying value of accounts receivable approximated their fair value.

iii. Marketable Securities

Marketable securities with a quoted market price in an active market are classified as available-for-sale and are reported at fair value, with changes in fair value recorded in other comprehensive income. As at June 30, 2007 the Fund reported investments in marketable securities of publicly traded marketable securities at a fair value of $12,308,000. For the three months ended June 30, 2007, the change in fair value of these investments represented a gain $3,538,000 ($2,502,000 net of tax). For the six months ended June 30, 2007 the change in fair value of these investments represented a loss of $923,000 ($654,000 net of tax).

Marketable securities without a quoted market price in an active market are reported at amortized cost. As at June 30, 2007 the Fund reported investments in marketable securities of private companies at an amortized cost of $45,325,000.

During the first quarter of 2007 the Fund disposed of certain marketable securities which resulted in a gain of $14,493,000 ($11,654,000 net of tax) being reclassified from accumulated other comprehensive income to net income.

Marketable securities are included in other current assets or other assets on the Consolidated Balance Sheet. Realized gains and losses on marketable securities are included in other income.

iii. Accounts Payable & Distributions Payable to Unitholders

Accounts payable as well as Distributions payable to unitholders are classified as other liabilities and are reported at amortized cost. At June 30, 2007 the carrying value of these accounts approximated their fair value.

iv. Long-term debt

Bank Credit Facilities

The bank credit facilities are classified as other liabilities and are reported at amortized cost. At June 30, 2007 the carrying value of the bank credit facilities approximated their fair value.

US$54 million senior notes

The US$54,000,000 million senior notes, which are classified as other liabilities, are reported at their amortized cost of US$54,000,000 and are translated into Canadian dollars at the period end exchange rate. At June 30, 2007 the Canadian dollar amortized cost of the senior notes was approximately $57,424,000.

US$175 million senior notes

The US$175,000,000 million senior notes, which are classified as other liabilities, are reported at amortized cost of US$178,391,000 and are translated to Canadian dollars at the period end exchange rate. At June 30, 2007 the Canadian dollar amortized cost of the senior notes was approximately $189,701,000.

v. Derivative Financial Instruments

Interest Rate Swaps

The Fund has entered into interest rate swaps on $75,000,000 of notional debt at rates varying from 4.10% to 4.61% before banking fees that are expected to range between 0.55% and 1.10%. These interest rate swaps mature between June 2011 and January 2012. The interest rate swaps are classified as held-for-trading and are reported at fair value. At June 30, 2007 the fair value of the interest rate swaps represented an asset of $1,427,000. For the three months ended June 30, 2007, the change in fair value of these contracts represented an unrealized gain of $1,919,000.

Cross Currency Interest Rate Swap (CCIRS)

Concurrent with the issuance of the notes on June 19, 2002, the Fund entered into a CCIRS with a syndicate of financial institutions. Under the terms of the swap, the amount of the notes was fixed for purposes of interest and principal repayments at a notional amount of CDN$268,328,000. Interest payments are made on a floating rate basis, set at the rate for three-month Canadian bankers' acceptances, plus 1.18%. The CCIRS is classified as held-for-trading and is reported at fair value. At June 30, 2007 the fair value of the CCIRS represented a liability of $86,686,000. For the three months ended June 30, 2007, the change in fair value of the CCIRS represented an unrealized loss of $20,191,000.

Crude Oil Instruments

Enerplus has entered into the following financial option contracts to reduce the impact of a downward movement in crude oil prices. These contracts are classified as held-for-trading and are reported at fair value. At June 30, 2007 the fair value of these contracts represented a liability of $8,285,000. For the three months ended June 30, 2007, the change in fair value of these contracts represented an unrealized loss of $6,327,000.

The net premium cost of the crude oil instruments entered into as of June 30, 2007 is $11,212,000.

The following table summarizes the Fund's crude oil risk management positions at July 25, 2007:

| | | WTI US$/bbl | | | |
|---|---|---|---|---|---|
| | Daily Volumes bbls/day | Sold Call | Purchased Put | Sold Put | Fixed Price and Swaps |
| Term | | | | | |
| July 1, 2007 - December 31, 2007 | | | | | |
| Put | 5,000 | - | $71.00 | - | - |
| Put | 2,500 | - | $68.00 | - | - |
| Put | 2,500 | - | $65.70 | - | - |
| Swap | 2,500 | - | - | - | $66.24 |
| January 1, 2008 - December 31, 2008 | | | | | |
| Collar | 750 | $77.00 | $67.00 | - | - |
| 3-Way option(1) | 1,000 | $84.00 | $66.00 | $50.00 | - |
| 3-Way option(1) | 1,000 | $84.00 | $66.00 | $52.00 | - |
| 3-Way option(1) | 1,000 | $86.00 | $68.00 | $52.00 | - |
| Swap(2) | 750 | - | - | - | $72.94 |
| Swap(2) | 750 | - | - | - | $73.35 |

(1) Financial contracts entered into during the second quarter of 2007.
(2) Financial contracts entered into subsequent to June 30, 2007.

Natural Gas Instruments

Enerplus has certain physical and financial contracts outstanding as at July 25, 2007 on its natural gas production that are detailed below. In addition, the Fund has outstanding physical natural gas contracts that provide the Fund a premium of $0.40/Mcf on 23.5MMcf/day for the month of July 2007.

These contracts are classified as held-for-trading and are reported at fair value. At June 30, 2007 the fair value of these contracts represented an asset of $17,467,000. For the three months ended June 30, 2007, the change in fair value of these contracts represented an unrealized gain of $25,379,000.

The net premium cost of the financial natural gas instruments entered into as of June 30, 2007 is $2,355,000.

The following table summarizes the Fund's natural gas risk management positions at July 25, 2007:

| | | AECO CDN$/Mcf | | | |
|---|---|---|---|---|---|
| | Daily Volumes MMcf/day | Sold Call | Purchased Put | Sold Put | Fixed Price and Swaps |
| Term | | | | | |
| July 1, 2007 - October 31, 2007 | | | | | |
| Collar | 6.6 | $10.02 | $7.50 | - | - |

| | | | | | |
|---|---|---|---|---|---|
| Collar | 6.6 | $9.00 | $7.50 | - | - |
| Collar | 9.5 | $9.10 | $7.10 | - | - |
| Collar | 9.5 | $9.15 | $7.14 | - | - |
| Collar | 9.5 | $9.50 | $7.20 | - | - |
| Costless Collar | 4.7 | $8.02 | $7.17 | - | - |
| Costless Collar | 4.7 | $8.23 | $7.28 | - | - |
| Costless Collar | 4.7 | $8.20 | $7.50 | | |
| 3-Way option | 4.7 | $9.50 | $7.75 | $5.49 | - |
| Put | 4.7 | - | $7.28 | - | - |
| Swap | 6.6 | - | - | - | $7.60 |
| Swap | 4.7 | - | - | - | $7.33 |
| Swap | 2.4 | - | - | - | $7.84 |
| Swap | 2.4 | - | - | - | $7.96 |
| Swap | 7.1 | - | - | - | $7.17 |
| Swap | 2.4 | - | - | - | $7.70 |
| Swap | 2.4 | - | - | - | $7.53 |
| Swap | 2.4 | - | - | - | $8.35 |
| November 1, 2007 - March 31, 2008 | | | | | |
| Collar | 2.4 | $9.95 | $8.00 | - | - |
| Collar(1) | 2.4 | $10.15 | $8.00 | - | - |
| 3-Way option | 4.7 | $10.50 | $8.20 | $5.70 | - |
| 3-Way option | 4.7 | $11.61 | $8.97 | $6.33 | - |
| 3-Way option(1) | 4.7 | $11.61 | $8.97 | $6.33 | - |
| 3-Way option(1) | 4.7 | $11.08 | $8.55 | $6.01 | - |
| Swap | 4.7 | - | - | - | $8.70 |
| Swap(1) | 2.4 | - | - | - | $9.01 |
| April 1, 2008 - October 31, 2008 | | | | | |
| 3-Way option(1) | 5.7 | $9.50 | $7.54 | $5.28 | - |
| Swap(1) | 4.7 | - | - | - | $8.18 |
| 2007 - 2010 | | | | | |
| Physical (escalated pricing) | 2.0 | - | - | - | $2.52 |

(1) Financial contracts entered into during the second quarter of 2007.
(*) There were no financial contracts entered into subsequent to June 30, 2007.

Electricity Instruments

The Fund has entered into electricity swaps that fix the price of electricity. These contracts are classified as held-for-trading and are reported at fair value. At June 30, 2007 the fair value of these contracts represented an asset of $2,055,000. For the three months ended June 30, 2007, the change in fair value of these contracts represented an unrealized gain of $614,000.

Unrealized gains or losses resulting from changes in fair value along with realized gains or losses on settlement of the electricity contracts are recognized as operating costs.

The following table summarizes the Fund's electricity management positions at July 25, 2007.

| Term | Volumes MWh | Price CDN$/MWh |
|---|---|---|

| | | |
|---|---|---|
| July 1, 2007 - December 31, 2007 | 5.0 | $61.50 |
| July 1, 2007 - December 31, 2007 | 4.0 | $62.90 |
| April 1, 2008 - September 30, 2008 | 4.0 | $63.00 |

The Fund did not enter into any new electricity contracts in the second quarter of 2007.

This news release contains certain forward-looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this news release contains forward-looking information and statements pertaining to the following: the amount, timing and tax treatment of cash distributions to unitholders; future payout ratios; future tax treatment of income trusts such as the Fund; the volumes and estimated value of the Fund's future oil and gas reserves; the volume and product mix of the Fund's oil and gas production; future oil and natural gas prices and the Fund's commodity risk management programs; the amount of future asset retirement obligations; future liquidity and financial capacity; future results from operations, cost estimates and royalty rates; future development, exploration, acquisition and development activities, and related expenditures, including with respect to both our conventional and oil sands activities.

The forward-looking information and statements contained in this news release reflect several material factors and expectations and assumptions of the Fund including, without limitation: that the Fund will continue to conduct its operations in a manner consistent with past operations; the general continuance of current industry conditions; the continuance of existing (and in certain circumstances, proposed) tax and royalty regimes; the accuracy of the estimates of the Fund's reserve volumes; and certain commodity price and other cost assumptions. The Fund believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information and statements included in this news release are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information or statements including, without limitation: changes in commodity prices; unanticipated operating results or production declines; changes in tax or environmental laws or royalty rates; increased debt levels or debt service requirements; inaccurate estimation of the Fund's oil and gas reserves volumes; limited, unfavourable or no access to capital markets; increased costs; the impact of competitors; and certain other risks detailed from time to time in the Fund's public disclosure documents (including, without limitation, those risks identified in this news release and in the Fund's annual information form).

The forward-looking information and statements contained in this news release speak only as of the date of this news release, and none of the Fund or its subsidiaries assumes any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable laws.

Gordon J. Kerr
President & Chief Executive Officer