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NEWS RELEASE

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Enerplus announces 2006 year-end results

TSX: ERF.un
NYSE: ERF

CALGARY, Feb. 22 /CNW/ - Enerplus is pleased to announce our 2006 year-end results with highlights summarized as follows:

- Annual average production exceeded our guidance and grew to 85,779 BOE/day primarily as a result of our internal capital program. Our exit rate volumes were in line with expectations at 87,500 BOE/day.

- We executed the largest development capital program in our history spending $491.2 million, essentially in line with our target of $485.0 million.

- Cash flow increased 11% to $863.7 million from $774.6 million in the previous year.

- Net income increased 26% to $544.8 million. On a trust unit basis, this resulted in an increase of 13% to $4.48 per unit reflecting the increase in units outstanding.

- Cash distributions increased in 2006 by 23% to $614.3 million or 11% per unit compared to 2005.

- Cash distributions to unitholders were maintained at $0.42 per unit throughout 2006 resulting in total distributions of $5.04 per unit.

- Our payout ratio averaged 71%.

- Our Reserve Life Index ("RLI") continued to be one of the longest in the sector at 14.0 years on a proved plus probable basis and 10.1 years on a proved basis, including both conventional and non-conventional reserves.

- Proved plus probable reserves decreased 1% to 443.3 MMBOE and proved reserves decreased 4% to 299.8 MMBOE.

- We replaced 82% of our production without the benefit of any significant acquisitions.

- Successful drilling efforts resulted in 361 net wells drilled with a success rate of over 99%.

- We acquired 3.7 MMBOE of proved plus probable reserves at an attractive cost of $14.04/BOE.

- Our finding, development and acquisition costs ("FD&A") for the year were $23.19/BOE on a proved plus probable basis and $28.82/BOE on a proved basis including future development capital ("FDC"). Excluding FDC our proved plus probable FD&A costs were $20.45/BOE and $29.13/BOE on a proved basis. Our three-year proved plus probable FD&A costs were $14.90/BOE ($11.51/BOE excluding FDC).

- Operating costs averaged $8.02/BOE in 2006.

- G&A costs were $1.91/BOE, higher than our guidance of $1.85/BOE.

- We continue to maintain a conservative balance sheet as evidenced by a net debt to trailing 12 month cash flow ratio of 0.8x.

- Our future opportunity set increased significantly year-over-year to over $2 billion in attractive conventional capital projects (excluding oil sands).

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. All reserve figures are calculated based upon company interest reserves using forecast prices and costs. See "Reserve Reporting and Determination Methodologies" for additional information. 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), Audited Financial Statements and forthcoming Annual Information Form 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 Form 40-F that will be filed with the SEC and available on www.sec.gov.

FINANCIAL HIGHLIGHTS

For the years ended December 31,	2006	2005
Financial (000's)		
Net Income	$ 544,782	$ 432,041
Cash Flow from Operating Activities	863,696	774,633
Cash Distributions to Unitholders(1)	614,340	498,205
Cash Withheld for Acquisitions and Capital Expenditures	249,356	276,428
Debt Outstanding (net of cash)	679,650	649,825
Development Capital Spending	491,226	368,689
Acquisitions	51,313	704,028
Divestments	21,127	66,511
Financial per Unit(2)		
Net Income	$ 4.48	$ 3.96

Cash Flow from Operating Activities	7.10	7.10
Cash Distributions to Unitholders(1)	5.05	4.57
Cash Withheld for Acquisitions and Capital Expenditures	2.05	2.53
Payout Ratio(3)	71%	64%
Selected Financial Results per BOE(4)		
Oil & Gas Sales(5)	$ 50.23	$ 52.36
Royalties	(9.36)	(10.21)
Financial Contracts	(1.10)	(4.90)
Operating Costs	(8.02)	(7.45)
General and Administrative	(1.71)	(1.28)
Interest and Foreign Exchange	(0.93)	(0.64)
Taxes	(0.70)	(0.31)
Restoration and Abandonment	(0.37)	(0.27)
Cash Flow from Operating Activities before changes in non-cash working capital	$ 28.04	$ 27.30
Weighted Average Number of Trust Units Outstanding (thousands)	121,588	109,083
Debt/Trailing 12 Month Cash Flow Ratio	0.8x	0.8x

OPERATING HIGHLIGHTS

For the years ended December 31,	2006	2005
Average Daily Production		
Natural gas (Mcf/day)	270,972	274,336
Crude oil (bbls/day)	36,134	29,315
NGLs (bbls/day)	4,483	4,689
Total (BOE/day) (6:1)	85,779	79,727
% Natural gas	53%	57%
Average Selling Price(5)		
Natural gas (per Mcf)	$ 6.81	$ 8.41
Crude oil (per bbl)	61.80	55.93
NGLs (per bbl)	50.90	47.33
US$ exchange rate	0.88	0.83
Net Wells drilled	361	393
Success Rate	99%	99%
Proved Reserves (MMBOE)(6)	299.8	313.2
Probable Reserves (MMBOE)(6)	143.5	135.9
Total Proved plus Probable Reserves (MMBOE)(6)	443.3	449.1
FD&A Cost per BOE, excluding Future Development Capital(7)	$ 20.45	$ 13.98
FD&A Cost per BOE, including Future Development Capital(7)	$ 23.19	$ 17.18

Recycle Ratio(7)	1.4x	1.7x
Proved Reserve Life Index (years)	10.1	9.9
Proved plus Probable Reserve Life Index (years)	14.0	13.5

In some circumstances, presentation has been changed to minimize the use of non-GAAP measures.

(1) Calculated based on distributions paid or payable. Cash distributions to unitholders per unit will not correspond to the actual monthly distributions of $5.04 as a result of using the annual weighted average trust units outstanding.
(2) Based on annual weighted average trust units outstanding.
(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.
(6) Reserve figures are calculated based upon company interest reserves using forecast prices and costs.
(7) Based upon proved plus probable company interest reserves.

	TSX - ERF.un	NYSE - ERF
Trust Unit Trading Information	($CDN)	($US)
High	66.00	59.45
Low	43.86	38.50
Close	50.68	43.61
Volume (000's)	82,120	81,677

OPERATIONS REVIEW

2006 Production

In 2006, we were able to grow the production from our assets as a result of strong base performance and the successful execution of the largest development capital program in our history. Daily production averaged 85,800 BOE/day, a new high for Enerplus and slightly ahead of our guidance of 85,500 BOE/day. Strong base production performance from our U.S. and Canadian operations and production additions from our capital program resulted in an increase in our year-over-year exit rate from 85,000 in 2005 to 87,500 BOE/day in 2006, demonstrating our ability to grow production through internal development without the benefit of any significant acquisition activity.

Approximately 50% of our average daily production volumes are attributed to resource plays, with the Sleeping Giant project in Montana now our single largest producing property. We continue to operate approximately 64% of our daily production volumes.

We expect 2007 average production to remain essentially flat at 85,000 BOE/day with a reduced capital program of $410 million. We expect to exit 2007 with production of 86,000 BOE/day as a result of the timing of our capital expenditures which are back-end loaded this coming year. These targets are exclusive of any acquisition or divestment activity that may occur as a normal part of our business during the course of 2007.

2006 Capital Spending

Development capital spending of $491 million during 2006 was in line with

our guidance of $485 million despite inflationary pressures. Through this spending, we added approximately 21,400 BOE/day of initial production at an attractive on-stream cost of $23,000/BOE/day which is significantly better than our on-stream cost in 2005 and was slightly better than forecast. We achieved these results due to the strength of our opportunity set and our ability to allocate capital to our most attractive projects. Our capital high-grading in 2006 included increasing our Bakken oil spending and deferring some of our shallow gas and waterflood projects.

Key attributes of our 2006 capital program include:

- We achieved better than expected capital efficiencies despite inflationary pressures. Inflation averaged approximately 15%, meaningfully higher than anticipated. As a result we chose to defer approximately 10% of our planned activity to manage our capital spending while maintaining attractive capital efficiencies.

- Approximately 57% of our capital was directed to oil development while 43% was directed to natural gas opportunities reflecting the strength of the oil markets and the attractiveness of our Bakken oil development in the U.S.

- 64% of our capital spending was focused on resource plays which are marked by relatively predictable decline rates with low geologic risk.

- We also invested approximately $89 million (18% of our total capital) in longer-term opportunities in oil sands, land, seismic and higher risk drilling activities which did not add production or cash flow in the current year but positions us to add significant production and reserves over the next few years.

- Operated capital spending accounted for 73% of the total which is higher than last year due to higher spending on our U.S. Bakken oil projects.

Play type	2006 Initial Production Additions(*) (BOE/day)	2006 Capital ($millions)	2006 Cost of Production Additions ($/BOE/day)	2007 Estimated Capital ($millions)
Shallow Gas & CBM	3,200	$ 94	$ 29,400	$ 43
Waterflood	1,600	66	41,250	65
Bakken Oil	7,800	117	15,000	70
Oil Sands (SAGD/mine)	-	39	n/a	40
Other Conventional Oil & Gas	8,800	175	19,900	192
Total	21,400	$ 491	$ 23,000	$ 410

(*) 2006 production was not recorded for Joslyn as the operation has not reached commercial production levels. Initial production based on first month production rates.

2007 Capital Spending

We expect to reduce capital spending to $410 million for 2007 based on our current commodity price outlook. Should commodity prices change and/or if

we experience better success, our capital budget could increase or decrease. Our spending will continue to be focused on resource play development. We also expect to spend $84 million (20%) on longer-term opportunities in oil sands, land, seismic and higher risk drilling.

The most significant reductions in our program will occur in our shallow gas/CBM program and U.S. Bakken spending. The shallow gas/CBM program was deferred given potential risks we see with near-term gas prices although with continued gas price strength, these programs could be increased. Currently, we plan to continue with a base level program concentrating on our most profitable opportunities in this area as it is a core activity for us and represents a significant percentage of our future opportunity. The reduction in our U.S. Bakken spending reflects the completion of a majority of our drilling program of two wells per section. We are currently testing the benefits of a third well per section, exploring other zones in the area as well as extending the Bakken play into North Dakota. With success in these areas, we could increase our U.S. spending.

2006 Drilling Activity

In 2006, we participated in the drilling of 360.9 net wells, significantly less than our original guidance of 550 net wells, while maintaining our success rate of 99%. During the course of the year, we elected to defer a portion of our drilling program as a result of industry inflationary pressures and lower natural gas prices. We deferred the drilling of approximately 140 net shallow gas and CBM wells and approximately 30 net waterflood wells. Funds from these programs offset the inflationary pressures on the remainder of the drilling program and ensured the execution of other more profitable drilling programs such as those in our Bakken oil and other conventional drilling programs. In total we drilled 275.1 net natural gas wells and 85.8 net crude oil wells in 2006.

Bakken Oil Development

As our single largest producing property, the Sleeping Giant project represents approximately 13% of our production and 9% of our proved plus probable reserves. During 2006 we invested $117 million to drill 41 gross wells (26.5 net) to add 7,800 BOE/day of incremental production at an attractive on-stream cost of $15,000/BOE/day. As part of our 2006 activities, we initiated an increased density drilling program by drilling 6 gross wells (4 net) at 3 wells per section. Based upon results to date, 10 additional increased density wells have been planned for 2007. Continued success may lead to additional increased density wells.

To date, we have drilled 56 development wells with a 100% success rate and executed a successful re-fracture program resulting in production growth from 8,700 BOE/day upon acquisition to over 11,500 BOE/day at year-end 2006. These results are far better than we anticipated at the time of the acquisitions.

In 2007, we plan to invest $70 million to drill 26 gross (17 net) oil wells and re-fracture stimulate 12 gross (8 net) wells. This year's development activity will complete the second well per section program in the primary Bakken field area and focus on identifying and proving up new opportunities in the general area. We own 120,000 net acres of undeveloped land in Montana and North Dakota, portions of which we plan to test in 2007. The primary target on the undeveloped lands is the Bakken formation, however the lands are also prospective for the Ratcliffe, Mission Canyon, Birdbear, Duperow and Red River geological formations.

Oil Sands

Enerplus and Total E&P Canada ("Total"), the operator of the Joslyn

project, are continuing to review the lease development plans given the flexibility which exists for both SAGD and mining operations. Although meaningful progress was made in 2006, the complexities of determining the optimal development plan have extended the expected timeline. An extensive lease development plan is anticipated in 2007 and is not expected to impact current SAGD operations or the startup timing of the initial phase of the mine. The development plan will also provide an update of estimates relating to the future development capital associated with the mine development.

A summary of the expected production and timing for the various projects on the Joslyn lease are included in the table below. Not all dates are available given the uncertainty around the final full lease development plan.

Joslyn Project Development

	Project Production Throughput(1) (bbls/day)	Net Production Throughput (bbls/day)	Future Development Capital(2) ($millions)	Start Up(3)	Full Production (4)
Phase I & II SAGD	10,000	1,500	31	2006	2008
Phase III SAGD	15,000	2,250	284	TBD	TBD
North Mine	100,000	15,000	TBD	2013	2014
South Mine	100,000	15,000	TBD	2016	2017

(1) All production estimates are those of the Operator.
(2) Future development capital for SAGD based on independent third party reserve report dated December 31, 2006. Future development capital for mining is currently under full review by the Operator as the project definition advances and new investment estimates are anticipated toward the end of 2007.
(3) Start up for SAGD refers to first steam. Start up for mining refers to initial extraction.
(4) Full production refers to full project production throughput.

In addition to our Joslyn lease, Enerplus has assembled an internal oil sands team with significant experience in SAGD development. We are actively pursuing an operated SAGD project in which to deploy this team. Through our joint venture with Laricina Energy Ltd., we have invested approximately $3 million to acquire working interest in several land positions with SAGD potential.

Reserves

Independent reserves evaluation of the Joslyn lease indicates total proved reserves of 8.7 million BOE, and total proved plus probable reserves of 56.7 million BOE net to Enerplus in the SAGD area for Phases I - III. Independent contingent resource estimates for the North Mine indicate a "best estimate" of approximately 140 million BOE net to Enerplus, or over 900 million BOE gross. This is consistent with numbers filed in the North Mine regulatory application by the Operator. In addition, third party assessments estimate significant additional mining resources outside the North Mine area. Please see our 2006 Annual Information Form for further information on the resource disclosure including risks and uncertainties associated with our resource estimates associated with the mining potential contained within the Joslyn lease.

If current development plans are modified and a decision is made to mine some of the currently identified SAGD areas, existing SAGD Phase III probable

reserve bookings could be impacted. Although mining typically provides about twice the recovery of the original bitumen in place versus SAGD projects, there could be timing differences between reserves bookings associated with the existing SAGD Phase III development plans versus possible expansion of mine development plans. Although timing of the expected booking may extend through 2007, depending on the progress made over the next year, we may be in a position to book probable reserves associated with the North Mine at year-end.

2006 Capital Investment

In regard to the Joslyn lease, spending in 2006 reached $36 million to advance both the SAGD ($33 million) and the mining options ($3 million). In addition, $3 million was spent to acquire lands in conjunction with Laricina, resulting in a total oil sands investment of $39 million in 2006. This capital included the drilling of close to 280 gross additional delineation wells over both SAGD and mining areas and the 4.5 gross sections of land acquired in late 2005. Capital investment to progress the SAGD development included the completion of central plant facilities, the commissioning and start-up of the water treatment system, the initiation of steam injection into SAGD well pairs, and the completion of a 40 kilometre pipeline from Joslyn to the Athabasca Terminal. Total continues to expect Phase II to reach peak production of 10,000 bbls/day gross (1,500 bbls/day net to Enerplus) in 2008, however due to reduced operating pressures, this may require additional wells and capital in 2007 and 2008. We currently do not have any production volumes associated with this project included in our 2007 production estimates as commercial volumes are not expected until 2008. Investment on the mining side supported the application for regulatory approval of the North Mine, representing 100,000 bbls/day of potential gross bitumen production (15,000 bbls/day net to Enerplus).

2007 Oil Sands Capital Spending Outlook

Total capital spending on oil sands is expected to increase to approximately $40 million including:

- Joslyn SAGD development of $21 million, which includes the continued start-up and ramp-up of Phase II well pairs, and the possible addition of 10 new well pairs late in the year. The regulatory approval process continues for SAGD Phase III with approvals expected in the first quarter of 2007 assuming no change in the base development plan. Currently Phase III represents a 15,000 bbl/day expansion of the existing facilities to a potential of 25,000 bbls/day of gross SAGD production (3,750 bbls/day net to Enerplus).

- Mining investment of $13 million to advance the regulatory approval process and engineering, and to further delineate the mine.

- Investment of $6 million to further delineate the new Laricina lands in the first quarter of 2007.

These investments will enhance the value of our portfolio of oil sands assets. Our capital spending may increase further should we identify and execute on other attractive oil sands opportunities.

Crude Oil Waterfloods

Crude oil waterfloods are a significant part of the Enerplus portfolio representing 20% of our production and 24% of our proved plus probable

reserves. During 2006 we invested approximately $66 million on waterflood development including drilling 40 gross (29.7 net) wells. Pembina and Joarcam were our most active waterflood development areas in 2006. During 2007, we expect to maintain our investment activity in this area at approximately $65 million. This will include drilling 76 gross wells (41 net). Key development areas include Pembina, Joarcam, Virden as well as the Medicine Hat Glauconitic "C" East Unit. Although capital efficiency measures based on initial waterflood production may be higher, the low decline rates and long life nature of these projects provide attractive full-cycle returns.

Shallow Natural Gas and Coalbed Methane

Shallow gas and coalbed methane represent 22% of our reserves, with an attractive reserve life index of 17.2 years. Production volumes from these two resource plays represent 16% of our total production, with shallow gas representing the majority in this category. During 2006, we invested $94 million on shallow gas/CBM development, drilling 430 gross (249.5 net) wells and adding 3,200 BOE/day of incremental production at an average on-stream cost of $29,400/BOE/day. Key areas of shallow gas development include Hanna, Bantry and Shackleton, while CBM development efforts were focused at Bashaw, Joffre and Trochu. Currently, our inventory of shallow gas/CBM future drilling locations represents approximately six years of development at historical investment levels. However, for 2007 we have chosen to high grade our development program to $43 million, focusing on our most profitable programs given potential risks in near-term gas prices. Should gas price strength continue, the size of this program could increase.

Other Conventional Oil and Gas

We also have a diversified portfolio of other conventional opportunities in western Canada. These properties are diversified by commodity (67% natural gas, 33% liquids) and are mixed between operated (46%) and non-operated (54%). Conventional oil and gas represents approximately 51% of our production and 32% of our proved plus probable reserves. In 2006, we invested approximately $175 million in other conventional oil and gas development activities including the drilling of 275 gross wells (53.5 net). In 2007, we plan to invest $192 million in development activities at other conventional oil and gas properties including drilling approximately 200 gross wells (70 net). Actual capital may vary depending on the activity levels from industry partners on non-operated properties in which we participate.

FUTURE POTENTIAL

Enerplus has focused on building a large, diversified portfolio of economic, conventional and non-conventional capital projects that will support our operations in the years ahead through the addition of production and reserves. We currently have a conventional opportunity set of approximately $2 billion of capital projects representing approximately 2,500 net wells. The non-conventional opportunities are estimated at approximately $1 billion of capital projects associated with oil sands excluding any investments relating to an upgrader solution. This represents about five years of conventional future development potential at current capital spending levels assuming no new acquisitions, land deals, or new opportunity identification on our existing properties.

Our opportunity set includes significant potential across our entire asset base and capital projects which are both technically and economically viable at todayès commodity prices:

- Weighted 60% to natural gas and 40% to oil

- Resource plays comprise over 50% of the total

- Includes approximately $500 million of opportunity included in our third party reserve engineering reports

- $1 billion of ùbaseâ projects which we project to have a greater than 80% chance of technical success

- Approximately $500 million of risk-adjusted opportunities that have less than an 80% chance of success

We have excluded those projects from our opportunity set that are early stage ideas with greater technical/economic uncertainty.

ACQUISITIONS & DIVESTMENTS

2006 was a year our disciplined approach to acquisitions resulted in limited transactions despite actively pursuing numerous opportunities. As a result, we preserved our balance sheet and avoided the high cost acquisitions within Canada driven by an aggressive energy trust sector. Within the U.S. we tempered our activities as we built our U.S. operating group and executed an expanded internal development program which achieved strong internal production and reserve gains.

Given recent weakness in commodity markets and capital market uncertainty, we see an increasing number of attractive acquisitions at potentially more favourable pricing. This increased opportunity set comes at a time when our equity value is relatively stronger than the general trust sector, our balance sheet is strong and our U.S. execution capability is now in place.

During the year, through a series of small transactions, we increased our interests in core areas, notably at Sleeping Giant in Montana and at Gleneath in Saskatchewan. We acquired minor non-operated interests in a large block of land at Copton within the greater Deep Basin which has significant upside from relatively low risk drilling for deep, sweet natural gas. These properties were acquired at an attractive cost per BOE of $14 and a higher cost on a flowing barrel metric given the significant upside we see within the properties.

In early 2006, we sold a 1% working interest in our Joslyn oil sands lease in exchange for an equity stake in Laricina Energy Ltd. a private oil sands focused company. Given the low selling price of these reserves and the modest number of acquired reserves for the year, the resulting net acquisition metrics appear unattractive. However, the chart below offers more comparable per BOE and per flowing BOE metrics by excluding the Joslyn sale.

2006 Acquisition & Divestment Summary

	Cost/ Proceeds(*) ($ millions)	Proved plus Probable Reserves (MBOE)	Production (BOE/day)	Cost of Proved plus Probable Reserves ($/BOE)	Cost per Daily BOE
Acquired	$ 51.3	3,654	655	$ 14.04	$ 78,321
Divested(xx)	$ (1.4)	(63)	(26)	$ (22.22)	$ 53,846
Net excluding Joslyn	$ 49.9	3,591	629	$ 13.90	$ 79,332
Joslyn Divestment	$ (19.7)	(3,329)	n/a	$ (5.91)	n/a

Net including Joslyn	$ 30.2	262	629	$ 115.27	$ 48,013

(*) After adjustments for working capital and excluding future development capital.

(xx) Excludes sale of reserves of Joslyn for equity stake in Laricina.

Acquisition of Gross Overriding Royalty Interests

On January 31, 2007, Enerplus acquired various gross overriding royalty ("GORR") interests in the state of Wyoming for total consideration of US$52 million (CDN$60 million). This acquisition represents a modest addition to our assets in the United States and establishes a new area with significant gas development potential.

The assets produce natural gas from the EnCana Corporation operated Jonah gas field in Wyoming, which is one of the largest gas fields in the U.S. with an estimated original gas in place of 14 trillion cubic feet. We have acquired approximately 540 BOE/day of daily production and approximately 2.2 million BOE of proved reserves and 2.9 million BOE of proved plus probable reserves. This represents a GORR of about 0.5% on about 650 producing gas wells in the Jonah field. The proved plus probable reserve life index of the assets is 15.9 years, calculated using independent third party engineering reserve estimates and management's estimate of current production. We believe the field has a significant number of additional infill drilling locations that will provide growth potential for the future. Enerplus will not be required to expend any future development capital on the assets. We expect the net operating cash flow per BOE, net of all applicable U.S. taxes, to be significantly higher than that of our existing production due to the nature of the GORR which is not subject to deductions for operating costs and royalties.

RESERVES

Attractive reserve additions from our U.S. properties, oil sands and conventional Canadian operations were partially offset by unexpected capital inflation and negative revisions (mainly in the probable category) in our Canadian conventional areas. Enerplus achieved overall proved plus probable finding, development and acquisition costs including future development capital of $23.19/BOE in 2006 ($20.45/BOE excluding FDC) and a three-year average FD&A cost of $14.90/BOE ($11.51/BOE excluding FDC).

Other key points in our reserve assessment include:

- Reserve life index increased to 14 years in line with our historical performance.

- We replaced 82% of production without the benefit of any significant acquisitions. Over the last five years, we have averaged almost 200% reserve replacement inclusive of acquisition and divestment activity.

- Our U.S. operations added 7.3 million BOE at a one-year proved plus probable F&D cost of $13.78/BOE including FDC reflecting a 20% increase in reserves at December 31, 2005 as a result of our strong operational and development performance in the U.S.

- 6.9 million BOE were added to our oil sands reserves at a one-year proved plus probable F&D cost of $10.54/BOE ($5.67/BOE excluding FDC) reflecting another successful year of core hole drilling and analysis.

- No changes were made to the allocation of reserves associated with the SAGD portion of the Joslyn lease versus the mining portion. Total and Enerplus are in discussions on a potential change to the lease development plan which could impact the reserve allocation between the mine and SAGD portions of the lease and the timing of reserve bookings.

- There are no proved or probable mining reserves included in our year-end reserve summary. The current North Mine project continues to progress and there is the potential to book probable reserves associated with this project at year-end 2007.

- Canadian conventional development added over 19 million BOE excluding negative revisions, at a one-year proved plus probable F&D cost of $20.63/BOE ($17.17/BOE without FDC). This reflects the strong conventional drilling results we achieved in Canada which were partially offset by the negative revisions tied to existing Canadian operations.

- Proved and probable negative revisions of 7.5 million BOE were predominantly from the "probable" reserves category which has less certainty than "proved" reserves. These revisions represent less than 2% of our total year-end reserves and were mainly due to performance and economic factors in a few of our older Canadian conventional properties.

- No changes to the after-tax calculations have been included for our Canadian assets in connection with the proposed changes on taxability for trusts in the Canadian market. Should the proposed legislation be enacted, Enerplus would provide an updated analysis which would include the effect of any enacted tax legislation.

- Acquisition and divestment activity resulted in no significant change to our reserves. Minor acquisitions were offset by the sale of a 1% working interest in our Joslyn lease.

Reserve Reporting and Determination Methodologies

All reports, including our U.S. reserves, were evaluated using Canadian NI 51-101 rules. Three external, independent third party engineering firms were used to evaluate and review our reserves this year. Sproule Associates Limited ("Sproule"), our historical independent engineering evaluators, evaluated our Canadian conventional reserves. GLJ Petroleum Consultants Ltd. ("GLJ") evaluated the Joslyn SAGD bitumen reserves as they have previously performed such evaluations for the operator of the Joslyn project. DeGolyer and MacNaughton ("D&M") of Dallas, Texas, evaluated the reserves attributed to our assets in the United States. Sproule evaluated 90% of the total proved plus probable value (discounted at 10%) of our Canadian conventional year-end reserves and has reviewed the remainder of the reserves internally evaluated by Enerplus. Both GLJ and D&M evaluated 100% of the reserves in their respective areas. Both GLJ and D&M utilized Sproule's forecast price and cost assumptions as of December 31, 2006 in their evaluations to maintain consistency among our reserve reporting.

The following tables report company interest reserves that include gross working interest reserves plus owned royalty interest reserves using forecast prices. "Company interest" reserves are not a measure defined in NI 51-101 adopted by the Canadian securities regulators and does not have a standardized meaning under NI 51-101. Accordingly, our company interest reserves may not be comparable to reserves presented or disclosed by other issuers. Our reserves

statement, which includes complete disclosure of our oil and gas reserves and other oil and gas information in accordance with NI 51-101 is contained within our Annual Information Form which will be available on our website at www.enerplus.com and on our SEDAR profile at www.sedar.com Additionally, the Annual Information Form is part of our Form 40-F that will be filed with the SEC and available on www.sec.gov.

Probable reserves are evaluated and categorized by our third party engineering firms or our own internal evaluators under the review of the third party engineering firm. Care should be used when comparing U.S. and Canadian style reserves and production reporting between companies. Under U.S. reporting, reserve estimates are calculated using prices and costs held constant at amounts in effect at the date of the reserve report and typically only include net proved reserves. Additionally, proved reserve standards in the U.S. may not be comparable to the Canadian standards. Generally, Canadian standards for reporting proved reserves may be more conservative than U.S. standards.

All evaluations of future net production revenues set forth in the tables are stated after the provision for income taxes and exclude abandonment costs on wells and facilities where reserves are not assigned or associated general and administrative costs. These schedules have been prepared on the basis that Enerplus will not pay cash income taxes in Canada in the future due to Enerplus' current structure as an income trust and Canadian tax laws currently in effect. Under our current mutual fund structure and existing tax legislation in Canada, annual taxable income is transferred from our operating entities to the Fund through interest, royalty and other payments. We, in turn, make distributions to our unitholders and therefore currently do not incur any Canadian income tax. As a result, after tax future net revenues from Canadian oil and gas reserves are equal to before tax future net revenues from Canadian oil and gas reserves. Enerplus' U.S. operations are subject to cash income taxes, and as a result Enerplus' U.S. reserves are shown net of the effect of such taxes that we estimate would be payable after taking into account inter-company debt in our structure. The Canadian federal government has announced a proposal designed to effectively tax income trusts such as Enerplus at the same level as Canadian corporations, effective for the 2011 tax year. Such proposal has not yet been approved or put in force and it is uncertain as what form, if any, changes in Canadian income tax laws will take as a result of such proposal. Any changes in Canadian income tax laws that may result from such proposal could adversely affect the estimated future net revenues associated with Enerplus' oil and gas reserves. For additional information, investors should refer to disclosure that will be contained in Enerplus' Annual Information Form.

The net estimated present value of all future net revenues at December 31, 2006 was based upon crude oil and natural gas pricing assumptions prepared by Sproule as of December 31, 2006. These prices were applied to the reserves evaluated by Sproule, GLJ and D&M. The base reference prices and exchange rates used by Sproule are detailed below:

Sproule December 31, 2006 - Forecast Price Assumptions

WTI crude oil US$/bbl	Light crude(1) Edmonton CDN$/bbl	Hardisty Heavy 12 degree API CDN$/bbl	Differential Between Hardisty Heavy And Bitumen(2) (Oil Sands) CDN$/bbl	Henry Hub Price US$/ MMbtu	Natural Gas 30 day spot at AECO CDN$/ MMbtu	Exchange Rate CDN$/US$

2007	$ 65.73	$ 74.10	$ 42.98	$ 8.88	$ 7.85	$ 7.72	$ 0.87
2008	68.82	77.62	45.02	11.35	8.39	8.59	0.87
2009	62.42	70.25	40.74	12.83	7.65	7.74	0.87
2010	58.37	65.56	38.03	12.19	7.48	7.55	0.87
2011	55.20	61.90	35.90	11.66	7.63	7.72	0.87
Thereafter	2.0%	2.0%	2.0%	(xx)	(xx)	2.0%	0.87

(1) Edmonton refinery postings for 40 degree API, 0.4% sulphur content crude.
(2) The bitumen price is derived by GLJ from Sproule's forecasts of various stream prices.
(xx) Escalation varies after 2011.

Reserves Summary

The following table sets out our company interest volumes by production type and reserve category under a forecast price scenario. Under different price scenarios, these reserves could vary as a change in price can affect the economic limit and reserves associated with a property.

2006 Reserve Summary - Company Interest Volumes (Forecast Prices)

	OIL AND GAS RESERVES			
	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Oil Sands) (Mbbls)	Total Oil (Mbbls)
Proved developed producing				
Canada	66,458	28,932	2,479	97,869
United States	21,933	-	-	21,933
Total	88,391	28,932	2,479	119,802
Proved developed non-producing				
Canada	537	-	-	537
United States	871	-	-	871
Total	1,408	-	-	1,408
Proved undeveloped				
Canada	3,509	2,221	6,251	11,981
United States	587	-	-	587
Total	4,096	2,221	6,251	12,568
Total Proved				
Canada	70,504	31,153	8,730	110,387
United States	23,391	-	-	23,391

Total	93,895	31,153	8,730	133,778
Probable				
Canada	16,872	8,912	47,998	73,782
United States	8,637	-	-	8,637
Total	25,509	8,912	47,998	82,419
Proved plus Probable				
Canada	87,376	40,065	56,728	184,169
United States	32,028	-	-	32,028
Total	119,404	40,065	56,728	216,197

OIL AND GAS RESERVES

	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)
Proved developed producing			
Canada	11,434	727,596	230,569
United States	-	13,626	24,204
Total	11,434	741,222	254,773
Proved developed non-producing			
Canada	621	17,317	4,044
United States	-	724	992
Total	621	18,041	5,036
Proved undeveloped			
Canada	635	160,348	39,341
United States	-	450	662
Total	635	160,798	40,003
Total Proved			
Canada	12,690	905,261	273,954
United States	-	14,800	25,858
Total	12,690	920,061	299,812

Probable			
Canada	3,777	306,804	128,693
United States	-	37,221	14,840
Total	3,777	344,025	143,533
Proved plus Probable			
Canada	16,467	1,212,065	402,647
United States	-	52,021	40,698
Total	16,467	1,264,086	443,345

Proved Reserve Reconciliation

Proved Reserves - Company Interest Volumes (Forecast Prices)

CANADA	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Oil Sands) (Mbbls)	Total Oil (Mbbls)
Proved Reserves at Dec. 31, 2005	73,249	32,901	9,453	115,603
Acquisitions	984	-	-	984
Divestments	(30)	-	(591)	(621)
Discoveries	-	48	-	48
Extensions	1,648	11	-	1,659
Technical Revisions	(2,191)	1,058	(132)	(1,265)
Economic Factors	226	58	-	284
Improved Recovery	2,806	327	-	3,133
Production	(6,188)	(3,250)	-	(9,438)
Proved Reserves at Dec. 31, 2006	70,504	31,153	8,730	110,387

CANADA	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)
Proved Reserves at Dec. 31, 2005	13,084	952,624	287,458
Acquisitions	160	5,518	2,063
Divestments	(1)	(145)	(647)
Discoveries	27	4,095	757
Extensions	671	26,180	6,693
Technical Revisions	372	(4,956)	(1,717)
Economic Factors	(17)	(5,304)	(616)
Improved Recovery	30	23,981	7,159
Production	(1,636)	(96,732)	(27,196)

Proved Reserves at Dec. 31, 2006	12,690	905,261	273,954

UNITED STATES	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Oil Sands) (Mbbls)	Total Oil (Mbbls)
Proved Reserves at Dec. 31, 2005	23,595	-	-	23,595
Acquisitions	401	-	-	401
Divestments	-	-	-	-
Discoveries	-	-	-	-
Extensions	440	-	-	440
Technical Revisions	584	-	-	584
Economic Factors	-	-	-	-
Improved Recovery	2,122	-	-	2,122
Production	(3,751)	-	-	(3,751)
Proved Reserves at Dec. 31, 2006	23,391	-	-	23,391

UNITED STATES	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)
Proved Reserves at Dec. 31, 2005	-	13,152	25,787
Acquisitions	-	341	458
Divestments	-	-	-
Discoveries	-	-	-
Extensions	-	384	504
Technical Revisions	-	1,732	872
Economic Factors	-	-	-
Improved Recovery	-	1,364	2,350
Production	-	(2,173)	(4,113)
Proved Reserves at Dec. 31, 2006	-	14,800	25,858

TOTAL ENERPLUS	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Oil Sands) (Mbbls)	Total Oil (Mbbls)
Proved Reserves at Dec. 31, 2005	96,844	32,901	9,453	139,198

Acquisitions	1,385	-	-	1,385
Divestments	(30)	-	(591)	(621)
Discoveries	-	48	-	48
Extensions	2,088	11	-	2,099
Technical Revisions	(1,607)	1,058	(132)	(681)
Economic Factors	226	58	-	284
Improved Recovery	4,928	327	-	5,255
Production	(9,939)	(3,250)	-	(13,189)
Proved Reserves at Dec. 31, 2006	93,895	31,153	8,730	133,778

TOTAL ENERPLUS	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)
Proved Reserves at Dec. 31, 2005	13,084	965,776	313,245
Acquisitions	160	5,859	2,521
Divestments	(1)	(145)	(647)
Discoveries	27	4,095	757
Extensions	671	26,564	7,197
Technical Revisions	372	(3,224)	(845)
Economic Factors	(17)	(5,304)	(616)
Improved Recovery	30	25,345	9,509
Production	(1,636)	(98,905)	(31,309)
Proved Reserves at Dec. 31, 2006	12,690	920,061	299,812

Probable Reserve Reconciliation

Probable Reserves - Company Interest Volumes (Forecast Prices)

CANADA	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Oil Sands) (Mbbls)	Total Oil (Mbbls)
Probable Reserves at Dec. 31, 2005	17,498	8,495	43,700	69,693
Acquisitions	451	-	-	451
Divestments	(5)	-	(2,738)	(2,743)
Discoveries	1	18	-	19
Extensions	407	9	6,935	7,351
Technical Revisions	(2,414)	337	101	(1,976)
Economic Factors	47	10	-	57
Improved Recovery	887	43	-	930
Production	-	-	-	-
Probable Reserves at Dec. 31, 2006	16,872	8,912	47,998	73,782

CANADA	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)
Probable Reserves at Dec. 31, 2005	3,539	309,572	124,827
Acquisitions	72	2,219	893
Divestments	(1)	(13)	(2,745)
Discoveries	8	845	168
Extensions	217	9,593	9,167
Technical Revisions	(62)	(22,147)	(5,730)
Economic Factors	(5)	(1,642)	(223)
Improved Recovery	9	8,377	2,336
Production	-	-	-
Probable Reserves at Dec. 31, 2006	3,777	306,804	128,693

UNITED STATES	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Oil Sands) (Mbbls)	Total Oil (Mbbls)
Probable Reserves at Dec. 31, 2005	5,574	-	-	5,574
Acquisitions	202	-	-	202
Divestments	-	-	-	-
Discoveries	-	-	-	-
Extensions	982	-	-	982
Technical Revisions	37	-	-	37
Economic Factors	-	-	-	-
Improved Recovery	1,842	-	-	1,842
Production	-	-	-	-
Probable Reserves at Dec. 31, 2006	8,637	-	-	8,637

UNITED STATES	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)
Probable Reserves at Dec. 31, 2005	-	32,946	11,065
Acquisitions	-	230	240
Divestments	-	-	-

Discoveries	-	-	-
Extensions	-	1,095	1,164
Technical Revisions	-	(1,002)	(129)
Economic Factors	-	-	-
Improved Recovery	-	3,952	2,500
Production	-	-	-
Probable Reserves at Dec. 31, 2006	-	37,221	14,840

TOTAL ENERPLUS	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Oil Sands) (Mbbls)	Total Oil (Mbbls)
Probable Reserves at Dec. 31, 2005	23,072	8,495	43,700	75,267
Acquisitions	653	-	-	653
Divestments	(5)	-	(2,738)	(2,743)
Discoveries	1	18	-	19
Extensions	1,389	9	6,935	8,333
Technical Revisions	(2,377)	337	101	(1,939)
Economic Factors	47	10	-	57
Improved Recovery	2,729	43	-	2,772
Production	-	-	-	-
Probable Reserves at Dec. 31, 2006	25,509	8,912	47,998	82,419

TOTAL ENERPLUS	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)
Probable Reserves at Dec. 31, 2005	3,539	342,518	135,892
Acquisitions	72	2,449	1,133
Divestments	(1)	(13)	(2,745)
Discoveries	8	845	168
Extensions	217	10,688	10,331
Technical Revisions	(62)	(23,149)	(5,859)
Economic Factors	(5)	(1,642)	(223)
Improved Recovery	9	12,329	4,836
Production	-	-	-
Probable Reserves at Dec. 31, 2006	3,777	344,025	143,533

Proved Plus Probable Reserve Reconciliation

Proved Plus Probable Reserves - Company Interest Volumes (Forecast Prices)

CANADA	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Oil Sands) (Mbbls)	Total Oil (Mbbls)
Proved Plus Probable Reserves at Dec. 31, 2005	90,747	41,396	53,153	185,296
Acquisitions	1,435	-	-	1,435
Divestments	(35)	-	(3,329)	(3,364)
Discoveries	1	66	-	67
Extensions	2,055	20	6,935	9,010
Technical Revisions	(4,605)	1,395	(31)	(3,241)
Economic Factors	273	68	-	341
Improved Recovery	3,693	370	-	4,063
Production	(6,188)	(3,250)	-	(9,438)
Proved Plus Probable Reserves at Dec. 31, 2006	87,376	40,065	56,728	184,169

CANADA	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at Dec. 31, 2005	16,623	1,262,196	412,285
Acquisitions	232	7,737	2,956
Divestments	(2)	(158)	(3,392)
Discoveries	35	4,940	925
Extensions	888	35,773	15,860
Technical Revisions	310	(27,103)	(7,447)
Economic Factors	(22)	(6,946)	(839)
Improved Recovery	39	32,358	9,495
Production	(1,636)	(96,732)	(27,196)
Proved Plus Probable Reserves at Dec. 31, 2006	16,467	1,212,065	402,647

UNITED STATES	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Oil Sands) (Mbbls)	Total Oil (Mbbls)
Proved Plus Probable Reserves				

at Dec. 31, 2005	29,169	-	-	29,169
Acquisitions	603	-	-	603
Divestments	-	-	-	-
Discoveries	-	-	-	-
Extensions	1,422	-	-	1,422
Technical Revisions	621	-	-	621
Economic Factors	-	-	-	-
Improved Recovery	3,964	-	-	3,964
Production	(3,751)	-	-	(3,751)
Proved Plus Probable Reserves at Dec. 31, 2006	32,028	-	-	32,028

UNITED STATES	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at Dec. 31, 2005	-	46,098	36,852
Acquisitions	-	571	698
Divestments	-	-	-
Discoveries	-	-	-
Extensions	-	1,479	1,668
Technical Revisions	-	730	743
Economic Factors	-	-	-
Improved Recovery	-	5,316	4,850
Production	-	(2,173)	(4,113)
Proved Plus Probable Reserves at Dec. 31, 2006	-	52,021	40,698

TOTAL ENERPLUS	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Oil Sands) (Mbbls)	Total Oil (Mbbls)
Proved Plus Probable Reserves at Dec. 31, 2005	119,916	41,396	53,153	214,465
Acquisitions	2,038	-	-	2,038
Divestments	(35)	-	(3,329)	(3,364)
Discoveries	1	66	-	67
Extensions	3,477	20	6,935	10,432
Technical Revisions	(3,984)	1,395	(31)	(2,620)
Economic Factors	273	68	-	341
Improved Recovery	7,657	370	-	8,027
Production	(9,939)	(3,250)	-	(13,189)

Proved Plus Probable Reserves at Dec. 31, 2006	119,404	40,065	56,728	216,197

TOTAL ENERPLUS	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at Dec. 31, 2005	16,623	1,308,294	449,137
Acquisitions	232	8,308	3,654
Divestments	(2)	(158)	(3,392)
Discoveries	35	4,940	925
Extensions	888	37,252	17,528
Technical Revisions	310	(26,373)	(6,704)
Economic Factors	(22)	(6,946)	(839)
Improved Recovery	39	37,674	14,345
Production	(1,636)	(98,905)	(31,309)
Proved Plus Probable Reserves at Dec. 31, 2006	16,467	1,264,086	443,345

Net Present Value of Future Production Revenue - Forecast Prices and Costs (after U.S. taxes) at December 31, 2006

Conventional Reserves ($ millions, discounted at)	0%	5%	10%	15%
Proved developed producing				
Canada	6,705	4,479	3,464	2,877
United States	804	624	509	431
Total	7,509	5,103	3,973	3,308
Proved developed non-producing				
Canada	120	75	56	45
United States	25	19	16	13
Total	145	94	72	58
Proved undeveloped				
Canada	556	385	272	196
United States	26	16	10	7
Total	582	401	282	203

Total Proved				
Canada	7,381	4,939	3,792	3,118
United States	855	659	535	451
Total	8,236	5,598	4,327	3,569
Probable				
Canada	2,721	1,242	745	516
United States	419	217	126	78
Total	3,140	1,459	871	594
Total Proved Plus Probable Conventional Reserves	11,376	7,057	5,198	4,163
Bitumen (Oil Sands) Reserves				
Proved developed producing	20	16	13	11
Proved undeveloped	39	20	10	4
Total Proved	59	36	23	15
Probable	453	104	25	2
Total Proved plus Probable Bitumen (Oil Sands)Reserves	512	140	48	17
Total Conventional and Bitumen (Oil Sands) Reserves	11,888	7,197	5,246	4,180

Net Asset Value

Enerplus' net asset value is measured with reference to the present value of all future net revenue from our reserves, assuming current income tax laws, as estimated by our independent reserve engineers, Sproule, GLJ and D&M, plus land values, adjusted for working capital and long-term debt at year-end. This calculation can vary significantly depending on the oil and natural gas price assumptions used by the independent reserve engineers. In addition, this calculation ignores "going concern" value and assumes only the reserves identified in the reserve reports with no further acquisitions, despite our 20 year history of replacing production through acquisitions and development.

Net Asset Value - Forecast Prices and Costs (After U.S. Tax) at December 31, 2006

($ millions except trust unit amounts, discounted at)	0%	5%	10%	15%
Present value of proved				

plus probable reserves				
Canadian Conventional	10,102	6,181	4,537	3,634
United States (after tax)	1,274	876	661	529
Bitumen (Oil Sands)	512	140	48	17
Total, present value of proved plus probable reserves	11,888	7,197	5,246	4,180
Undeveloped acreage				
Canada	53	53	53	53
United States	16	16	16	16
Long-term debt (net of cash)	(680)	(680)	(680)	(680)
Asset retirement obligations(1)	(194)	(95)	(24)	(11)
Net Working Capital excluding deferred financial assets and distributions payable to unitholders.	(102)	(102)	(102)	(102)
Net Asset Value	10,981	6,389	4,509	3,456
Net Asset Value per Trust Unit at December 31, 2006(2)	$ 89.17	$ 51.88	$ 36.61	$ 28.06

(1) Asset retirement obligations do not equal the amount on the balance sheet ($124 million) as the balance sheet amount uses a 6% discount rate and a portion of the ARO costs are already reflected in the present value of reserves computed by the independent engineers

(2) Based on 123,151,000 Trust Units outstanding as at December 31, 2006

FINDING DEVELOPMENT AND ACQUISITION COSTS

FD&A costs can be calculated either including or excluding future development capital ("FDC"). FD&A costs under NI 51-101 include FDC as this provides a more representative view of the full cost of reserve additions as it accounts for future costs to bring the reserves to market. Under the historic method, FD&A costs are understated as reserves are included without taking into account the future capital expenditures required to fully develop the reserve base. We have included both the NI 51-101 method which includes FDC and the historic method for comparison purposes.

FD&A Costs (including Future Development Capital)

($ millions, except per BOE amounts)	2006	2005	2004
Proved Reserves Excluding Oil Sands:			
Capital expenditures and net acquisitions	$ 502.0	$ 973.0	$ 803.2
Net change in future development capital	8.0	184.7	99.0
Company reserve additions (MMBOE)	18.6	53.7	57.5

Oil Sands:			
Capital expenditures and net acquisitions	19.4	33.2	8.3
Net change in future development capital	(13.6)	44.6	-
Company reserve additions (MMBOE)	(0.7)	9.5	-
FD&A costs ($/BOE)	$ 28.82	$ 19.55	$ 15.83
Three-year average FD&A costs ($/BOE)(1)	$ 19.20	$ 22.73	$ 18.85
Proved plus Probable Reserves			
Excluding Oil Sands:			
Capital expenditures and net acquisitions	$ 502.0	$ 973.0	$ 803.2
Net change in future development capital	54.4	197.7	120.7
Company reserve additions (MMBOE)	21.9	66.6	58.0
Oil Sands:			
Capital expenditures and net acquisitions	19.4	33.2	8.3
Net change in future development capital	15.6	33.4	266.1
Company reserve additions (MMBOE)	3.6	5.4	47.7
FD&A costs ($/BOE)	$ 23.19	$ 17.18	$ 11.34
Three-year average FD&A costs ($/BOE)(1)	$ 14.90	$ 13.46	$ 11.02

(1) FD&A calculated over a three-year period.

FD&A Costs (excluding Future Development Capital)

($ millions, except per BOE amounts)	2006	2005	2004
Proved Reserves			
Excluding Oil Sands:			
Capital expenditures and net acquisitions	$ 502.0	$ 973.0	$ 803.2
Company reserve additions (MMBOE)	18.6	53.7	57.5
Oil Sands:			
Capital expenditures and net acquisitions	19.4	33.2	8.3
Company reserve additions (MMBOE)	(0.7)	9.5	-
FD&A costs ($/BOE)	$ 29.13	$ 15.92	$ 14.11
Three-year average FD&A costs ($/BOE)(1)	$ 16.88	$ 14.30	$ 11.62
Proved plus Probable Reserves			
Excluding Oil Sands:			
Capital expenditures and net acquisitions	$ 502.0	$ 973.0	$ 803.2
Company reserve additions (MMBOE)	21.9	66.6	58.0
Oil Sands:			
Capital expenditures and net acquisitions	19.4	33.2	8.3
Company reserve additions (MMBOE)	3.6	5.4	47.7
FD&A costs ($/BOE)	$ 20.45	$ 13.98	$ 7.68
Three-year average FD&A costs ($/BOE)(1)	$ 11.51	$ 10.09	$ 8.22

(1) Calculated as FD&A over a three-year period.

RECYCLE RATIO

Recycle ratio is calculated as operating income divided by FD&A including FDC. It is indicative of the value created for each dollar invested and accounts for the quality of reserves, operating costs and attractiveness of acquisitions and internal development capital.

(Proved plus probable reserves)	2006	2005	2004
Operating income ($/BOE)	31.75	29.80	21.86
Finding, development and acquisition costs including FDC ($/BOE)	23.19	17.18	11.34
Recycle ratio	1.4x	1.7x	1.9x
Three-year average recycle ratio	1.6x	1.8x	1.8x

FINANCIAL OVERVIEW

Update on Canadian Government Announcement on Intention to Tax Trusts

On October 31, 2006, the Canadian federal government (the "Government") announced plans to introduce a tax on publicly traded income trusts. For existing income trusts, such as Enerplus, the new tax measures would be effective for 2011, provided we comply with the "normal growth" parameters regarding equity growth until that time. A "Notice of Ways and Means Motion" was passed in Parliament shortly after the Government announcement. This notice was a one-page summary of the Government's proposal and it did not identify any specific amendments to the Income Tax Act.

On December 15, 2006 the Government announced safe harbour guidance regarding "normal growth" for equity capital. The safe harbour amount will be measured by reference to the individual trust's market capitalization as of the end of trading on October 31, 2006 (which was approximately $7.5 billion for Enerplus). For the period from November 1, 2006 to December 31, 2007 a trust's safe harbour amount will be 40 percent of the October 31, 2006 market capitalization benchmark and for each of the years 2008 through and including 2010 will be 20 percent of the benchmark, cumulatively allowing growth of up to 100 percent until 2011. In addition, we understand that trusts will be able to issue equity to retire debt existing on October 31, 2006 without eroding their safe harbour limits.

On December 21, 2006, the Government released more detailed draft legislation with respect to the proposed amendments to the Income Tax Act and requested comments from stakeholders. In late January 2007, the House of Commons Standing Committee on Finance held special hearings on the proposed tax and the draft legislation. At this time we are unable to determine the impact, if any, these hearings may have on the proposed legislation or the timing of when the proposed legislation could be passed in Parliament.

Should the tax legislation become substantially enacted, future income taxes may be adjusted to include temporary differences between the accounting and tax bases of the trust's assets and liabilities. In addition, reserves reported under NI 51-101 may be adjusted to include an estimate of the tax effect on our estimated future revenues from our reserves. We will assess alternative organizational structures during the four-year transition period. We are confident we have the team, the assets, and the opportunities to prosper regardless of our organizational structure.

RESULTS OF OPERATIONS

Production

Daily production during 2006 averaged 85,779 BOE/day, slightly above our guidance of 85,500 BOE/day and 8% higher than 79,727 BOE/day in 2005. The increase was primarily due to our U.S. acquisitions in the second half of 2005 which added an incremental 8,121 BOE/day of production in 2006 along with our development capital program which added an additional 5,633 BOE/day of production in 2006. These increases were offset in part by natural reservoir declines experienced throughout the year.

Average production during the year was weighted 53% to natural gas and 47% to liquids on a BOE basis. Average production volumes for the years ended December 31, 2006 and 2005 are outlined below:

Daily Production Volumes	2006	2005	% Change
Natural gas (Mcf/day)	270,972	274,336	(1%)
Crude oil (bbls/day)	36,134	29,315	23%
Natural gas liquids (bbls/day)	4,483	4,689	(4%)
Total daily sales (BOE/day)	85,779	79,727	8%

We exited the year with production of approximately 87,500 BOE/day based on December's production, in line with our target of 88,000 BOE/day.

We expect 2007 annual production volumes to remain essentially flat year-over-year, averaging 85,000 BOE/day, weighted 54% to natural gas and 46% to liquids. As a result of the timing of our planned development capital program, we expect to exit 2007 with production of approximately 86,000 BOE/day. This does not contemplate any potential acquisitions or dispositions.

Pricing

The prices received for our natural gas and crude oil production directly impact our earnings, cash flow and financial condition. The following table compares our average selling prices for 2006 with those of 2005. It also compares the benchmark price indices for the same periods.

Average Selling Price(1)	2006	2005	% Change
Natural gas (per Mcf)	$ 6.81	$ 8.41	(19%)
Crude oil (per bbl)	61.80	55.93	10%
Natural gas liquids (per bbl)	50.90	47.33	8%
Per BOE	$ 50.23	$ 52.36	(4%)

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

Average Benchmark Pricing	2006	2005	% Change
AECO natural gas - monthly index (CDN$/Mcf)	$ 6.99	$ 8.48	(18%)
AECO natural gas - daily index (CDN$/Mcf)	6.53	8.71	(25%)
NYMEX natural gas - monthly NX3 index (US$/Mcf)	7.26	8.55	(15%)
NYMEX natural gas - monthly NX3 index: CDN$ equivalent (CDN$/Mcf)	8.25	10.30	(20%)
WTI crude oil (US$/bbl)	66.22	56.56	17%
WTI crude oil: CDN$ equivalent (CDN$/bbl)	75.25	68.14	10%
CDN$/US$ exchange rate	$ 0.88	$ 0.83	6%

Natural Gas

Natural gas prices were in a downward trend during 2006, influenced initially by demand loss, the residual high storage inventories after a warm winter, and strong drilling. In July 2006, prices received some support due to above normal temperatures in key consuming regions of the United States, and forecasts for a strong hurricane season. Year-over-year the natural gas storage surplus continued to build and those hurricanes that did develop were moderate. This ultimately drove the AECO monthly index price to a low for the year of $4.45/Mcf in October, with the daily spot price dropping to $3.25/Mcf in the same month. Spot and forward prices recovered significantly as winter approached, with spot prices rising briefly above $8.00/Mcf before the warmer than normal November and December, caused by an El Nino weather pattern, pushed the daily spot price back to $6.07/Mcf on December 31, 2006.

Our natural gas portfolio is comprised of aggregator, AECO, and downstream direct sales. In 2006 we sold 42% of our natural gas on the daily AECO market and 42% on the monthly AECO market, as well as 16% against the day and month NYMEX indices. During 2006 we realized an average price for our natural gas sales of $6.81/Mcf (net of transportation costs), a decrease of 19% from the $8.41/Mcf realized in 2005. This reduction is comparable to the price decreases realized in each of: the AECO daily index which decreased by 25% year over year; the AECO monthly index which decreased by 18%; and the NYMEX monthly index (converted to CDN$/Mcf) which decreased by 20%.

Crude Oil

World crude prices continued to be influenced by a tight supply-demand balance through the first half of 2006, continuing the upward trend in prices experienced during 2005. WTI spot prices peaked in July during the Israel-Hezbollah conflict at US$77.03/bbl. With strong inventories, forecasts for warmer than normal conditions for the winter, and a strengthening supply picture, prices fell thereafter through the second half of 2006. The WTI spot price hit a low of US$55.81/bbl in November, representing a 28% reduction from the July high.

Our crude oil portfolio in 2006 was approximately 70% light/medium and 30% heavy. The average price received for our crude oil (net of transportation costs) was $61.80/bbl during 2006, a 10% increase over 2005. Similarly, the West Texas Intermediate ("WTI") crude oil benchmark price, after adjusting for the change in the US$ exchange rate, also increased by 10% year over year. Although we added more light sweet crude oil to our portfolio in 2006 compared to 2005, this benefit was offset by widening heavy crude oil differentials during the year.

Canadian/US Exchange Rate

The Canadian dollar strengthened 6% against the U.S. dollar during 2006 compared to 2005 based on the annual average exchange rate. As most of our crude oil and a portion of our natural gas are 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.

Price Risk Management

While the overall energy outlook remains generally bullish long term, there remains uncertainty as to the direction prices might move in 2007. Both natural gas and crude oil prices have the potential to fall further in 2007 given current levels of inventory, aggressive drilling in the U.S. for gas and across the globe for crude oil and some uncertainty with respect to the world

economy.

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 acquisitions and capital development program. 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 have entered into additional commodity contracts during the fourth quarter and subsequent to year end. These contracts are designed to protect a portion of our natural gas revenue for the period January 2007 through March 2008 and to protect a portion of our crude oil revenue for the period January 2007 through December 2007. We have also hedged electricity volumes for the period January 2007 through September 2008 to protect against rising electricity costs in the Alberta power market. 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 February 13, 2007 as a percentage of our forecasted net production volumes:

	Natural Gas (CDN$/Mcf)			Crude Oil (US$/bbl)
	January 1, 2007 - March 31, 2007	April 1, 2007 - October 31, 2007	November 1, 2007 - March 31, 2008	January 1, 2007 - December 31, 2007
Floor Protection				
Price	$ 7.53	$ 7.32	$ 8.13	$ 68.93
% (net of royalties)	21%	32%	3%	34%
Upside Capped Price	$ 10.64	$ 9.07	$ 10.31	$ -
% (net of royalties)	14%	28%	3%	-%
Fixed Price	$ -	$ 7.58	$ 8.70	$ 66.24
% (net of royalties)	-%	12%	2%	8%

Based on weighted average price, before premiums, and average production of 85,000 BOE/day.

Assumes production mix of 54% gas, 42% oil and 4% NGL.

Accounting for Price Risk Management

During 2006, our commodity price risk management positions incurred cash costs of $27.2 million on crude oil contracts and $7.1 million on natural gas contracts compared to cash costs of $91.0 million and $51.6 million respectively during 2005. The decrease in crude oil cash costs is due to the expiration of contracts on June 30, 2006 that had ceiling prices between US$35.35/bbl and US$45.80/bbl on 4,500 bbls/day. The decrease in natural gas cash costs is the result of lower natural gas prices experienced during 2006 and the expiration of old contracts.

The unrealized gain on our financial contracts of $81.0 million for the year ended December 31, 2006 represents the change in the fair value of financial contracts since December 31, 2005. 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 are reflected as a non-cash charge or increase to earnings. At December 31, 2006 the fair value of our financial contracts net of premiums is $23.6 million and is recorded on

the balance sheet as a deferred financial asset. See Note 2 for details.

Effective December 31, 2005, we elected to stop designating our commodity financial contracts as hedges. As a result we recorded a deferred credit representing the fair value of these contracts on that day, with an offset recorded as a deferred financial asset that is amortized to income over the life of the underlying contracts. These costs of $49.9 million are fully amortized at December 31, 2006. See Note 2 for details.

The following table summarizes the effects of our financial contracts on income for the years ended December 31, 2006 and 2005.

Risk Management (Gains) /Losses ($ millions, except per unit amounts)	2006		2005	
Cash (gains)/losses:				
Crude oil	$ 27.2	$ 2.06/bbl	$ 91.0	$ 8.51/bbl
Natural Gas	7.1	$ 0.07/Mcf	51.6	$ 0.52/Mcf
Total Cash losses	$ 34.3	$ 1.10/BOE	$ 142.6	$ 4.90/BOE
Non-cash (gains)/losses:				
Change in fair value - financial contracts	$ (81.0)	$(2.59)/BOE	$ (35.8)	$(1.23)/BOE
Amortization of deferred financial assets	49.9	$ 1.59/BOE	3.1	$ 0.11/BOE
Total Non-cash gains	$ (31.1)	$(0.99)/BOE	$ (32.7)	$(1.12)/BOE
Total losses	$ 3.2	$ 0.11/BOE	$ 109.9	$ 3.78/BOE

Cash Flow Sensitivity

The sensitivities below reflect all commodity contracts as described in Note 10 and are based on current forward markets for 2007 at February 13, 2007. To the extent the market price of crude oil and natural gas change significantly from current levels, the sensitivities will no longer be relevant as the effect of our commodity contracts will change.

Sensitivity Table	Estimated Effect on 2007 Cash Flow per Trust Unit(1)
Change of $0.15 per Mcf in the price of AECO natural gas	$ 0.08
Change of US$1.00 per barrel in the price of WTI crude oil	$ 0.05
Change of 1,000 BOE/day in production	$ 0.13
Change of $0.01 in the US$/CDN$ exchange rate	$ 0.12
Change of 1% in interest rate	$ 0.06

(1) Assumes constant working capital and 123,151,000 units outstanding.

The impact of a change in one factor may be compounded or offset by changes in other factors. This table does not consider the impact of any

inter-relationship among the factors.

Revenues

Crude oil and natural gas revenues for the year ended December 31, 2006 were $1,572.7 million ($1,595.3 million, net of $22.6 million of transportation costs) compared to $1,523.7 million ($1,550.6 million, net of $26.9 million of transportation costs) during 2005. Increased crude oil volumes from our 2005 acquisitions along with higher realized oil prices were offset primarily by the decrease in natural gas prices. The result was an increase of 3% or $49.0 million in revenue net of transportation costs.

Analysis of Sales Revenue(1)

($ millions)	Crude oil	NGLs	Natural Gas	Total
2005 Sales Revenue	$ 598.4	$ 81.0	$ 844.3	$ 1,523.7
Price variance(1)	77.4	5.9	(159.6)	(76.3)
Volume variance	139.2	(3.6)	(10.3)	125.3
2006 Sales Revenue	$ 815.0	$ 83.3	$ 674.4	$ 1,572.7

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

Royalties

Royalties are paid to various government entities and other land and mineral rights owners. Royalties in 2006 and 2005 were approximately 19% of oil and gas sales, net of transportation costs. Overall, royalties decreased marginally in 2006 to $293.2 million compared to $297.0 million during 2005 primarily as a result of the decrease in natural gas prices experienced over the period.

For 2007 we expect royalties to remain at approximately 19% of oil and gas sales, net of transportation costs, however this may change as a result of the Alberta government's stated intention to review the oil and gas royalty regime. Alberta royalties represented approximately 70% of our total royalties incurred during 2006 (2005 - 87%).

Operating Expenses

Operating expenses for the year ended December 31, 2006 were $8.02/BOE or $251.2 million. This represents a 3% increase over our guidance of $7.80/BOE and an 8% increase from $7.45/BOE in 2005. Cost pressures associated with the high level of industry activity have increased operating costs during 2006. The areas that were most impacted by these activity levels included scheduled facility maintenance and well servicing.

During the fourth quarter we experienced increases as a result of the timing of certain well servicing and facility maintenance programs. As well, we experienced higher natural gas processing fees at certain facilities.

We anticipate continued increases in operating costs in 2007 due to general cost escalation. As a result, we expect costs to average $8.45/BOE, representing an increase of 5% per BOE compared to 2006. Although we are seeing evidence that the cost inflation in our industry has moderated, it is too soon to tell if this trend is sustainable.

General and Administrative Expenses

G&A expenses were $1.91/BOE or $59.9 million for the year ended

December 31, 2006. On a BOE basis G&A was 3% higher than our guidance of $1.85/BOE and 37% higher than $1.39/BOE 2005.

The highly competitive marketplace resulted in challenges to recruit and retain skilled professionals. For the year ended December 31, 2006 compensation and long-term incentives increased approximately $14.0 million or $0.45/BOE compared to the same period in 2005. Other increases included additional technology and information systems, our commitment to education funding for SAIT Polytechnic, along with ongoing regulatory compliance requirements.

For the year ended December 31, 2006, our G&A expenses included non-cash charges for our trust unit rights incentive plan of $6.3 million or $0.20/BOE compared to $3.0 million or $0.11/BOE for 2005. These amounts are determined using a binomial lattice option-pricing model. The increased volatility of our trust unit price combined with the increased number of rights outstanding, as a result of an increase in the number of employees, have impacted 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)	2006	2005
Cash	$ 53.6	$ 37.4
Trust unit rights incentive plan (non-cash)	6.3	3.0
Total G&A	$ 59.9	$ 40.4

(Per BOE)	2006	2005
Cash	$ 1.71	$ 1.28
Trust unit rights incentive plan (non-cash)	0.20	0.11
Total G&A	$ 1.91	$ 1.39

In 2007 we expect total G&A costs to be approximately $2.40/BOE, including non-cash G&A costs of approximately $0.30/BOE. The forecasted increase reflects cost pressures to recruit and retain a technically skilled labour force. It also includes increased costs associated with ongoing regulatory compliance and costs associated with planning and responding to the proposed tax on trusts.

Interest Expense

Annual interest expense increased by $6.4 million to $32.2 million compared to $25.8 million in 2005. This increase is due to higher average debt outstanding and rising interest rates during 2006. Our average borrowing rate, before the effects of hedging, for 2006 was 4.8% compared to 3.4% for 2005. At December 31, 2006, 20% of our debt was based on fixed interest rates while 80% was floating. These instruments are more fully described in Note 10.

Capital Expenditures

During the year ended December 31, 2006 we spent $491.2 million on development capital and facilities, our largest capital program to date. This was $6.2 million higher than our guidance of $485.0 million and $122.5 million or 33% higher than the $368.7 million spent in 2005. We achieved a 99% success

rate with our drilling program as 361 net wells were drilled during 2006. Development in 2006 focused primarily on Bakken oil, shallow gas, coalbed methane, waterfloods, and our Joslyn oil sands property.

Property acquisitions were $51.3 million for the year ended December 31, 2006 compared to $119.9 million in 2005. Acquisitions during 2006 included $16.0 million for assets in the U.S., as well as $11.9 million and $11.7 million for properties at Copton and Gleneath respectively. There were no corporate acquisitions during 2006 whereas in 2005 we spent $584.1 million for the acquisitions of Lyco Energy Corporation and TriLoch Resources Inc. Property dispositions were $21.1 million for the year ended December 31, 2006 compared to $66.5 million for 2005. The majority of our 2006 divestments related to the sale of a 1% working interest in the Joslyn property in the amount of $19.7 million compared to the 2005 non-core divestment program which raised $66.5 million.

Capital Expenditures ($ millions)	2006	2005
Development expenditures	$ 380.5	$ 272.2
Plant and facilities	110.7	96.5
Development Capital	491.2	368.7
Office	5.0	4.3
Sub-total	496.2	373.0
Acquisitions of oil and gas properties(1)	51.3	119.9
Corporate acquisitions	-	584.1
Dispositions of oil and gas properties(1)	(21.1)	(66.5)
Total Net Capital Expenditures	$ 526.4	$ 1,010.5
Total Capital Expenditures financed with cash flow	$ 249.4	$ 276.4
Total Capital Expenditures financed with debt and equity	296.5	734.1
Total non-cash consideration for 1% sale of Joslyn project	(19.5)	-
Total Net Capital Expenditures	$ 526.4	$ 1,010.5

(1) Net of post-closing adjustments.

The following is a summary by major property of our largest development capital expenditures during 2006 and 2005.

($ millions) Property	Development Type	2006	2005
Sleeping Giant	Bakken oil	$ 116.7	$ 29.1
Joslyn and oil sands	Oil sands	39.1	33.2
Bantry	Conventional oil and shallow gas	21.7	42.0
Joarcam	Oil waterflood	20.2	16.9
Pembina 5-Way	Oil waterflood	15.7	19.8
Medicine Hat	Oil waterflood and shallow gas	14.9	11.0
Shackleton	Shallow gas	12.7	5.6
Hanna/Garden Plains	Shallow gas	12.5	18.5

Joffre	Coalbed methane	12.5	15.9
Deep Basin	Natural gas	12.4	11.6
Other	Oil and gas	212.8	165.1
Total		$ 491.2	$ 368.7

We expect total development capital expenditures in 2007 to be approximately $410 million. We plan to spend approximately $70 million on Bakken oil development, $65 million on waterflood development, $43 million on shallow natural gas and coalbed methane development and $40 million on oil sands development. We expect other conventional development costs to be approximately $192 million during 2007.

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

DDA&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. For the year ended December 31, 2006 DDA&A increased to $15.38/BOE compared to $13.27/BOE during the year ended December 31, 2005. The increase was due to the inclusion of a full year of operations from our U.S. properties which were acquired in the latter half of 2005.

No impairment existed at December 31, 2006 using year-end reserves and management's estimates of future prices. Our future price estimates are more fully discussed in Note 3.

Asset Retirement Obligations

We have estimated our total future asset retirement obligations based on our net ownership interest in wells and facilities, estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. Our asset retirement obligation was $123.6 million at December 31, 2006 compared to $110.6 million at December 31, 2005. The increase of $13.0 million was due to our acquisition and development activity during the year combined with changes in estimated future liabilities. The remainder of the change was due to retirement costs incurred offset by accretion expense for the year. See Note 4.

The following chart compares the amortization of the asset retirement cost, accretion of the asset retirement obligation, and asset retirement obligations settled.

($ millions)	2006	2005
Amortization of the asset retirement cost	$ 12.6	$ 10.6
Accretion of the asset retirement obligation	6.2	6.3
Total Amortization and Accretion	$ 18.8	$ 16.9
Asset Retirement Obligations Settled	$ 11.5	$ 7.8

Actual asset retirement costs will be incurred at different times compared to the recording 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 the operating companies' assets and liabilities. Net income of the operating companies and the tax recovery fluctuate based on the royalty and interest payments to the Fund. Therefore, the future income tax that is recorded on the balance sheet is expected to be recovered through earnings over time.

For the year ended December 31, 2006, a future income tax recovery of $112.0 million was recorded in income compared to a future income tax expense of $15.3 million in 2005. The change year-over-year was mainly due to a lower effective tax rate for 2006, a change in discretionary tax deductions in prior years resulting in a $21.4 million recovery and recognition of a tax rate reduction for future years resulting in a $35.5 million recovery. See Note 9 for more details.

On October 31, 2006, the Government announced plans to introduce a tax on publicly traded income trusts, effective for 2011. A "Notice of Ways and Means Motion" was passed in parliament shortly after the government announcement. This notice was a one-page summary of the government's proposal and it did not identify any specific amendments to the Income Tax Act. On December 21, 2006, draft legislative proposals to implement the tax were released for comment. If the tax legislation becomes substantively enacted as proposed, future income taxes may be adjusted to include temporary differences between the accounting and tax bases of the trust's assets and liabilities.

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.

For the year ended December 31, 2006 our U.S. operations incurred income related taxes in the amount of $18.2 million compared to $2.8 million for the year ended December 31, 2005. The increase is primarily a result of a full year of U.S. operations in 2006.

The amount of current taxes recorded throughout the year is dependent upon the level of U.S. cash flow as well as the timing of both capital expenditures and repatriation of the funds to Canada. Our U.S. taxes as a percentage of cash flow, assuming constant working capital, were 9% for the year ended December 31, 2006 as compared to our guidance of 15%. The reduction is mainly due to funds being retained in the U.S. for the 2007 development capital program and acquisitions (see Note 13 describing the acquisition of gross overriding royalty interests in the Jonah natural gas field in Wyoming). We expect the current income and withholding taxes to average approximately 15% of cash flow from U.S. operations in 2007 assuming all funds are repatriated to Canada after U.S. development capital spending.

Tax Pools

We estimate our tax pools at December 31, 2006 to be as follows:

Pool Type ($ millions)	Trust	Operating entities	Total
COGPE	$ 450	$ 100	$ 550
CDE	-	300	300

UCC	-	500	500
Tax losses and other	50	400	450
Foreign tax pools	-	100	100
Total	$ 500	$ 1,400	$ 1,900

Net Income

Net income for the year ended December 31, 2006 was $544.8 million or $4.48 per trust unit compared to $432.0 million or $3.96 per trust unit for the year ended December 31, 2005. The $112.8 million increase in net income was primarily due to a $49.0 million increase in oil and gas sales (net of transportation costs), reduced risk management costs of $106.7 million and an increased future income tax recovery of $127.4 million, partially offset by increased DDA&A charges of $95.1 million, operating costs of $34.4 million and G&A costs of $19.6 million.

Cash Flow from Operating Activities

Cash flow from operating activities for the year ended December 31, 2006 was $863.7 million or $7.10 per trust unit compared to $774.6 million or $7.10 per trust unit for 2005. Cash flow increased during the year as a result of higher oil and gas sales and reduced cash risk management costs, offset in part by increases in operating costs and G&A expenses.

Selected Financial Results

Per BOE of production (6:1)	2006	2005
Production per day	85,779	79,727
Weighted average sales price(1)	$ 50.23	$ 52.36
Royalties	(9.36)	(10.21)
Financial contracts	(0.11)	(3.78)
Deduct: Non-cash financial contract gain	(0.99)	(1.12)
Operating costs	(8.02)	(7.45)
General and administrative	(1.91)	(1.39)
Add back: Non-cash G&A expense (trust unit rights)	0.20	0.11
Interest expense, net of interest and other income	(0.95)	(0.51)
Foreign exchange gain (loss)	0.02	(0.06)
Deduct: Non-cash foreign exchange gain	-	(0.07)
Capital taxes	(0.11)	(0.22)
Current income tax	(0.59)	(0.09)
Asset retirement obligations settled	(0.37)	(0.27)
Cash flow before changes in non-cash working capital	28.04	27.30
Asset retirement obligations settled	0.37	0.27
Non-cash items:		
Depletion, depreciation, amortization and accretion	(15.38)	(13.27)
Financial contracts	0.99	1.12
G&A expense (trust unit rights)	(0.20)	(0.11)
Foreign exchange gain	-	0.07
Future income tax recovery/(expense)	3.58	(0.53)

Total net income per BOE	$ 17.40	$ 14.85

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

Selected Canadian and U.S. Financial Results

The following table provides a geographical analysis of key financial results for 2006.

($ millions, except per unit amounts)	Canada	U.S.	Total
Daily Production Volumes			
Natural gas (Mcf/day)	265,019	5,953	270,972
Crude oil (bbls/day)	25,858	10,276	36,134
Natural gas liquids (bbls/day)	4,483	-	4,483
Total daily sales (BOE/day)	74,511	11,268	85,779
Pricing(1)			
Natural gas (per Mcf)	$ 6.79	$ 7.78	$ 6.81
Crude oil (per bbl)	59.36	67.93	61.80
Natural gas liquids (per bbl)	50.90	-	50.90
Capital			
Development capital and office	$ 378.5	$ 117.7	$ 496.2
Acquisitions of oil and gas properties	35.3	16.0	51.3
Dispositions of oil and gas properties	(21.1)	-	(21.1)
Revenues			
Oil and gas sales(1)	$ 1,301.0	$ 271.7	$ 1,572.7
Royalties	(241.0)	(52.2)(2)	(293.2)
Other financial contracts	(3.2)	-	(3.2)
Expenses			
Operating	$ 243.8	$ 7.4	$ 251.2
General and administrative	51.4	8.5	59.9
Depletion, depreciation, amortization and accretion	369.6	112.0	481.6
Current income taxes	-	18.2	18.2

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

Quarterly Financial Information

Overall oil and gas sales increased during 2005 due to higher crude oil production and higher crude oil and natural gas prices, and decreased during 2006 due to lower gas prices. Net income has been affected by fluctuating oil and gas prices and risk management costs, the fluctuating Canadian dollar, higher operating and G&A costs, changes in future tax provisions as well as changes to accounting policies adopted during 2005. Furthermore, changes in the fair value of our financial contracts, which are impacted by future prices, continue to cause net income to fluctuate between quarters.

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
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

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

Summary Fourth Quarter Information

In comparing the fourth quarter of 2006 with the same period in 2005:

- Net income decreased 27% to $110.2 million due to decreased natural gas prices and increased operating and G&A costs, partially offset by reduced risk management costs.

- Cash flow decreased 28% to $207.1 million in 2006 compared to $288.5 million in 2005.

- Average daily production increased 2% due to our development capital program.

- The average selling price per BOE decreased 28% due to weaker natural gas prices.

- Operating expenses increased 17% on a BOE basis to $8.52/BOE. Due to the timing of well servicing and facility maintenance programs additional costs were recorded in the fourth quarter of 2006.

- G&A expenses increased 29% on a BOE basis to $2.13/BOE due to compensation costs.

- Development capital spending decreased 12% compared to the fourth quarter of 2005 as a result of 2005 capital spending being weighted towards the fourth quarter while 2006 capital spending was evenly weighted between all four quarters.

Summary Fourth Quarter Information ($ millions, except per unit amounts)	Three Months Ended December 31, 2006	Three Months Ended December 31, 2005	% Change
Daily Production Volumes			
Natural gas (Mcf/day)	277,715	269,443	3%
Crude oil (bbls/day)	36,339	35,167	3%
Natural gas liquids (bbls/day)	4,467	5,045	(11%)
Total daily sales (BOE/day)	87,092	85,119	2%
Average Selling Price(1)			
Natural gas (per Mcf)	$ 6.58	$ 11.65	(44%)
Crude oil (per bbl)	54.53	58.41	(7%)
Natural gas liquids (per bbl)	46.15	50.56	(9%)
Per BOE	46.11	64.26	(28%)
Revenue(1)	369.5	503.2	(27%)
Per BOE	46.11	64.26	(28%)
Operating Expenses	68.3	57.1	20%
Per BOE	8.52	7.29	17%
General and Administrative Expenses	17.1	12.9(2)	33%
Per BOE	2.13	1.65(2)	29%
Net Income	110.2	150.9	(27%)
Per BOE	13.75	19.27	(29%)
Cash flow	207.1	277.9	(25%)
Per BOE	25.85	35.49	(27%)
Development Capital Spending	123.1	139.1	(12%)
Acquisitions	4.8	112.5	(96%)
Divestments	0.1	0.4	(75%)

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(2) Certain prior year amounts have been restated to conform with current year presentation.

Three Year Summary of Key Measures

Overall, increased production volumes have resulted in higher oil and gas sales, net income and cash flow from operating activities over the last three years. The rise in crude oil and natural gas prices during 2004 and 2005 contributed to higher oil and gas sales and cash flow, however the growth of these measures moderated in 2006 as a result of lower natural gas prices. The following table provides a summary of net income, cash flow and other key measures.

($ millions, except per unit amounts)	2006	2005	2004
Oil and gas sales(1)	$ 1,572.7	$ 1,523.7	$ 1,124.6
Net income	544.8	432.0	258.3
Per unit (Basic)(2)	4.48	3.96	2.60
Per unit (Diluted)	4.47	3.95	2.60

Cash flow from operating activities	863.7	774.6	555.1
Per unit (Basic)(2)	7.10	7.10	5.59
Cash distributions	614.3	498.2	423.3
Per unit (Basic)(2)	5.05	4.57	4.26
Payout ratio	71%	64%	76%
Total assets	4,203.8	4,130.6	3,180.7
Long-term debt, net of cash	679.7	649.8	585.0

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(2) Based on weighted average trust units outstanding. Cash distributions to unitholders per unit will not correspond to the actual monthly distributions of $5.04 as a result of using the annual weighted average trust units outstanding.

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 acquisitions and ongoing development activities 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.

Acquisitions and development activities 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 will be reduced. Should external sources of capital become limited or unavailable, our ability to make the necessary acquisitions and development expenditures to maintain or expand our asset base may be impaired and the amount of cash distributions may be reduced.

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. Although we intend to continue to make cash distributions to our unitholders, these distributions are not guaranteed.

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 2006 cash distributions of $614.3 million were funded entirely through cash flow of $863.7 million. Our payout ratio, which is calculated as cash distributions divided by cash flow, was 71% for 2006 compared to 64% in 2005.

After consideration of cash distributions, the balance of our 2006 cash

flow of $249.4 million was used to fund approximately 47% of our net capital expenditures. Our remaining net capital expenditures of $296.5 million were financed from the proceeds of our March 2006 equity issue and through additional debt. For more information, refer to the Capital Expenditures section of the MD&A.

In aggregate, our 2006 cash distributions of $614.3 million and our net capital expenditures of $526.4 million totaled $1,140.7 million, or approximately 132% of our cash flow of $863.7 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 oil sands project) 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 difficult 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 year ended December 31, 2006 our cash distributions exceeded our net income by $69.5 million (2005 - $66.2 million). Net income includes $318.9 million of non-cash items (2005 - $342.6 million) such as DDA&A and future income taxes that do not reduce our cash flow from operations. 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. Future income taxes can fluctuate from period to period as a result of changes in tax rates, or based on the royalty, interest and dividends from our operating subsidiaries to the Fund, all of which are not indicative of the productive capacity of our entity. 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 would represent a return of the unitholders' capital.

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

($ millions, except per unit amounts)		2006		2005
Cash flow from operating activities:	$	863.7	$	774.6
Use of cash flow:				
Cash distributions	$	614.3	$	498.2
Capital expenditures		249.4		276.4
	$	863.7	$	774.6
Excess of cash flow over cash distributions	$	249.4	$	276.4
Net income	$	544.8	$	432.0
Shortfall of net income over cash distributions	$	(69.5)	$	(66.2)
Cash distributions per weighted average trust unit	$	5.05	$	4.57
Payout ratio(1)		71%		64%

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

activities.

Asset Retirement Costs

Actual asset retirement costs incurred in the period are deducted for purposes of calculating cash flow. Differences between actual site restoration costs incurred and the amortization of the capitalized asset retirement cost and accretion of the asset retirement obligation are discussed in the Asset Retirement Obligations section of the MD&A and Note 4.

Long-Term Debt

Long-term debt, net of cash, at December 31, 2006 was $679.7 million, an increase of $29.8 million from December 31, 2005. Long-term debt at December 31, 2006 is comprised of $348.5 million of bank indebtedness and $331.3 million of senior unsecured notes.

Our working capital, excluding cash, at December 31, 2006 increased $46.1 million compared to December 31, 2005. Current liabilities were higher in 2005 primarily due to the recording of our commodity financial instruments at fair value.

We continue to maintain a conservative balance sheet as demonstrated below:

Financial Leverage and Coverage	Year ended Dec. 31, 2006	Year ended Dec. 31, 2005
Long-term debt to trailing cash flow	0.8 x	0.8 x
Cash flow to interest expense	26.8 x	30.0 x
Long-term debt to long-term debt plus equity	20%	21%

Long-term debt is measured net of cash.

Cash flow and interest expense are 12-months trailing.

Enerplus has an $850 million bank credit facility (the "Bank Credit Facility") through its wholly-owned subsidiary EnerMark Inc. The Bank Credit Facility is an unsecured, covenant-based, three-year committed credit agreement with nine North American banks. We have the ability to extend the facility each year or repay the entire balance at the end of the three-year term. At December 31, 2006 we had $501.5 million of available borrowing capacity under this facility, which currently extends to November, 2009. This bank debt 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.

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 operating companies to make payments to the Fund and consequently the Fund's ability to make distributions to the unitholders may be restricted. As at December 31, 2006 we are in compliance with our debt covenants. Refer to 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 $410.0 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.

Commitments

We have contracted to transport natural gas with various pipelines totaling 35.3 MMcf/day until 2008; of this amount 5 MMcf/day extends until 2015. We also have a contract to transport a minimum of 2,480 bbls/day of crude oil until 2010. These transportation contracts will cost approximately $6.4 million in 2007.

Approximately 35% of our current gas production is dedicated to aggregator sales arrangements. Under these arrangements, we receive a price based on the average netback price of the pool, net of transportation costs incurred by the aggregator for the life of the reserves.

Our office lease commitments expire between November 2009 and January 2011. Annual costs of these lease commitments, which include rent and operating fees, amount to approximately $6.7 million in 2007. The Fund's commitments, contingencies, and guarantees are more fully described in Note 11.

Enerplus has the following minimum annual commitments including long-term debt:

	Minimum Annual Commitment Each Year						Total Committed after
($ millions)	Total	2007	2008	2009	2010	2011	2011
Bank credit facility	$348.5(1)	$ -	$ -	$348.5	$ -	$ -	$ -
Senior unsecured notes	331.3(1)	-	-	-	53.7	66.3	211.3
Pipeline commitments	28.5	6.4	5.8	3.0	2.4	2.2	8.7
Office lease	20.9	6.7	6.8	6.7	0.6	0.1	-
Total commitments(2)	$ 729.2	$ 13.1	$ 12.6	$358.2	$ 56.7	$ 68.6	$ 220.0

(1) Interest payments have not been included since future debt levels and interest rates are not known at this time.

(2) Crown and surface royalties, lease rentals, mineral taxes, and abandonment and reclamation costs (hydrocarbon production rights) have not been included as amounts paid depend on future ownership, production, prices and the legislative environment.

Accumulated Deficit

We have historically paid cash distributions in excess of accumulated earnings as cash distributions are based on cash flow generated in the period whereas accumulated earnings are based on net income which includes non-cash items such as DDA&A charges, financial contract gains and losses, unit based compensation charges and future income tax provisions.

Trust Unit Information

We had 123,151,000 trust units outstanding at December 31, 2006 compared to 117,539,000 trust units at December 31, 2005. The weighted average number of trust units outstanding during 2006 was 121,588,000 (2005 - 109,083,000). At February 10, 2007 we had 123,253,000 trust units outstanding.

On March 20, 2006 we closed an equity offering of 4,370,000 units at a price of $58.00 per unit for gross proceeds of $253,460,000 ($240,287,000 net of issuance costs).

On August 9, 2005 we announced the closing of a subscription receipt financing related to the Lyco acquisition. A total of 10,637,500 subscription receipts were issued at a price of CDN$46.25 per receipt for gross proceeds of approximately $492.0 million. With the closing of the Lyco acquisition on August 30, 2005, subscription receipt holders received one trust unit for each subscription receipt held along with the August 2005 cash distribution of $0.37 per trust unit. The distribution paid to subscription receipt holders has been included in cash distributions.

On July 1, 2005 we acquired all of the issued and outstanding shares of TriLoch in exchange for 1,633,000 trust units, a value of approximately $69.1 million after issuance costs.

In addition 1,242,000 trust units (2005 - 1,144,000) were issued pursuant to the Trust Unit Monthly Distribution Reinvestment and Unit Purchase Plan ("DRIP") and the trust unit rights plans, net of redemptions. This resulted in $55.9 million (2005 - $40.4 million) of additional equity to the Fund.

SUMMARY 2007 OUTLOOK

Enerplus offers investors the benefits of owning a large, diversified portfolio of producing oil and natural gas properties within Canada and the United States. As such, our business prospects are closely linked to the opportunities and challenges associated with oil and natural gas production. In particular, we are strongly influenced by the price of crude oil and natural gas, both of which have been volatile in recent years. Our comments with respect to our 2007 outlook should be taken within the context of the current commodity price environment.

The following summarizes Enerplus' 2007 guidance as provided throughout this news release. We do not attempt to forecast commodity prices and, as a result, we do not forecast future cash flow or cash distributions. Readers are encouraged to apply their own price expectations to the following factors to arrive at an expected cash distribution.

Summary of 2007 Expectations	Target	Comments
Average annual production	85,000 BOE/day	Assumes no new acquisitions or dispositions
Exit rate December 2007 production	86,000 BOE/day	Assumes $410 million development capital spending
2007 production mix	54% gas, 42% oil, 4% NGL	
Average royalty rate	19%	Percentage of gross unhedged sales
Operating costs	$8.45/BOE	
G&A costs	$2.40/BOE	Includes non-cash charges of $0.30/BOE (unit rights plan)
U.S. income and withholding tax - cash costs	15%	Applied to net cash flow generated by U.S. operations and assumes repatriation of the funds

		to Canada after U.S. development capital spending
Average interest cost	5.0%	Based on current fixed rates and forward market
Payout ratio	60% -90%	
Development capital spending	$410 million	Based on current plans and price environment

Over time we have reduced our reliance on acquisitions to supplement production declines by focusing our efforts on development capital opportunities within our existing asset base. We expect to be able to essentially maintain production in 2007 through internally generated development efforts without relying on new acquisitions.

We expect our 2007 development capital spending to be $410 million, which is 17% lower than our 2006 spending. We plan to continue to withhold a portion of our cash flow to finance this capital program and we expect the payout ratio to be within our 60-90% guidance range. We believe it is important to maintain a conservative balance sheet as a defense against commodity price changes and to be positioned to capture acquisition opportunities.

We will continue to focus on low-risk development opportunities and review our risk management strategies in response to changing prices and the economics of our acquisition and development projects.

For 2007, we estimate that 95% of cash distributions will be taxable and 5% will be a tax-deferred return of capital for our Canadian unitholders. For our U.S. unitholders, we estimate that 90% of cash distribution will be taxable and 10% will be a tax-deferred return of capital.

We are encouraged by the results from our 2005 acquisitions which have been fully integrated with our existing staff and systems. The establishment of an office in Denver continues to enhance our growing presence in the U.S. oil and gas market.

ADDITIONAL INFORMATION

Additional information relating to Enerplus Resources Fund is available under our profile on the SEDAR website at www.sedar.com, on the EDGAR website at www.sec.gov and at www.enerplus.com. Readers should review the risk factors regarding our business and operations contained in our publicly filed documents including our Annual Information Form.

UNAUDITED CONSOLIDATED BALANCE SHEETS

As at December 31 (CDN$ thousands)	2006	2005
Assets		
Current assets		
Cash	$ 124	$ 10,093
Accounts receivable	175,454	170,623
Deferred financial assets (Note 2)	23,612	49,874
Other current (Note 10)	6,715	26,751
	205,905	257,341
Property, plant and equipment (Note 3)	3,726,097	3,650,327
Goodwill (Note 6)	221,578	221,234
Other assets (Notes 7 and 10)	50,224	1,721

	$ 4,203,804	$ 4,130,623
Liabilities		
Current liabilities		
Accounts payable	$ 284,286	$ 316,875
Distributions payable to unitholders	51,723	49,367
Deferred credits (Note 2)	-	57,368
	336,009	423,610
Long-term debt (Note 7)	679,774	659,918
Future income taxes (Note 9)	331,340	442,970
Asset retirement obligations (Note 4)	123,619	110,606
	1,134,733	1,213,494
Equity		
Unitholders' capital (Note 8)		
Trust Units		
Authorized: Unlimited		
Issued and Outstanding: 2006 - 123,150,820		
2005 - 117,539,331	3,713,126	3,410,614
Accumulated deficit	(971,085)	(901,527)
Cumulative translation adjustment (Note 1(j))	(8,979)	(15,568)
	2,733,062	2,493,519
	$ 4,203,804	$ 4,130,623

UNAUDITED CONSOLIDATED STATEMENTS OF ACCUMULATED DEFICIT

For the year ended December 31 (CDN$ thousands)	2006	2005
Accumulated income, beginning of year	$ 1,408,178	$ 976,137
Net income	544,782	432,041
Accumulated income, end of year	$ 1,952,960	$ 1,408,178
Accumulated cash distributions, beginning of year	$(2,309,705)	$(1,811,500)
Cash distributions	(614,340)	(498,205)
Accumulated cash distributions, end of year	$(2,924,045)	$(2,309,705)
Accumulated deficit, end of year	$ (971,085)	$ (901,527)

UNAUDITED CONSOLIDATED STATEMENTS OF INCOME

For the year ended December 31 (CDN$ thousands except per trust unit amounts)	2006	2005

Revenues		
Oil and gas sales	$ 1,595,324	$ 1,550,569
Royalties	(293,161)	(296,983)
Derivative instruments (Notes 2 and 10)		
Financial contracts - qualified hedges	-	(27,256)
Other financial contracts	(3,226)	(82,664)
Other income	2,465	11,064
	1,301,402	1,154,730
Expenses		
Operating	251,239	216,808
General and administrative (Note 8(b))	59,937	40,375
Transportation	22,611	26,915
Interest on long-term debt (Note 7)	32,168	25,791
Foreign exchange (gain)/loss	(528)	1,677
Depletion, depreciation, amortization and accretion	481,598	386,545
	847,025	698,111
Income before taxes	454,377	456,619
Capital taxes	3,393	6,486
Current taxes	18,236	2,764
Future income tax (recovery)/expense (Note 9)	(112,034)	15,328
Net Income	$ 544,782	$ 432,041
Net income per trust unit		
Basic	$ 4.48	$ 3.96
Diluted	$ 4.47	$ 3.95
Weighted average number of trust units outstanding (thousands)		
Basic	121,588	109,083
Diluted	121,858	109,371

UNAUDITED CONSOLIDATED STATEMENTS OF CASH FLOWS

For the year ended December 31 (CDN$ thousands)	2006	2005
Operating Activities		
Net income	$ 544,782	$ 432,041
Non-cash items add/(deduct):		
Depletion, depreciation, amortization and accretion	481,598	386,545
Non-cash financial contracts (Note 2)	(31,106)	(32,679)
Non-cash foreign exchange	(32)	(2,036)
Unit based compensation (Note 8)	6,323	3,040
Future income tax (Note 9)	(112,034)	15,328
Asset retirement obligations settled (Note 4)	(11,514)	(7,829)
	878,017	794,410
Increase in non-cash operating working capital	(14,321)	(19,777)

Cash flow from operating activities	863,696	774,633
Financing Activities		
Issue of trust units, net of issue costs (Note 8)	296,189	507,209
Cash distributions to unitholders	(614,340)	(498,205)
Increase in bank credit facilities (Note 7)	19,888	76,963
Decrease in non-cash financing working capital	2,356	12,924
Cash flow from financing activities	(295,907)	98,891
Investing Activities		
Capital expenditures	(496,201)	(373,032)
Property acquisitions (Note 5)	(51,313)	(123,896)
Property dispositions	1,599	66,511
Corporate acquisitions, net of cash acquired (Note 6)	-	(483,014)
Purchase of investments	(29,172)	-
(Increase)/Decrease in non-cash investing working capital	(3,535)	51,045
Cash flow from investing activities	(578,622)	(862,386)
Effect of exchange rate changes on cash	864	(1,045)
Change in cash	(9,969)	10,093
Cash, beginning of year	10,093	-
Cash, end of year	$ 124	$ 10,093
Supplementary Cash Flow Information		
Cash income taxes paid	$ 14,060	$ 2,669
Cash interest paid	$ 34,924	$ 24,220

NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The management of Enerplus Resources Fund ("Enerplus" or the "Fund") prepares the financial statements in accordance with Canadian generally accepted accounting principles ("GAAP"). A reconciliation between Canadian GAAP and United States of America GAAP is disclosed in Note 14. The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The following significant accounting policies are presented to assist the reader in evaluating these consolidated financial statements and, together with the following notes, should be considered an integral part of the consolidated financial statements.

(a) Organization and Basis of Accounting

The Fund is an open-end investment trust created under the laws of the Province of Alberta operating pursuant to the Amended and Restated Trust Indenture between EnerMark Inc. (the Fund's wholly-owned subsidiary), Enerplus Resources Corporation ("ERC") and CIBC Mellon Trust Company as Trustee. The beneficiaries of the Fund (the "unitholders") are holders of the trust units issued by the Fund. As a trust under the Income Tax Act (Canada), Enerplus is limited to holding and administering permitted investments and making distributions to the unitholders.

The Fund's financial statements include the accounts of the Fund and its subsidiaries on a consolidated basis. All inter-entity transactions have been eliminated. Many of the Fund's production activities are conducted through joint ventures and the financial statements reflect only the Fund's proportionate interest in such activities.

(b) Revenue Recognition

Revenue associated with the sale of crude oil, natural gas and natural gas liquids is recognized when title passes from the Fund to its customers based on volumes delivered and contractual delivery points and price. A portion of the properties acquired through the March 5, 2003 acquisition of PCC Energy Inc. and PCC Energy Corp. are subject to a royalty arrangement with a private company that is structured as a net profits interest. The results from operations included in the Fund's consolidated financial statements for these properties are reduced for this net profits interest.

(c) Property, Plant and Equipment ("PP&E")

The Fund follows the full cost method of accounting for petroleum and natural gas properties under which all acquisition and development costs are capitalized on a country by country cost centre basis. Such costs include land acquisition, geological, geophysical, drilling costs for productive and non- productive wells, facilities and directly related overhead charges. Repairs, maintenance and operational costs that do not extend or enhance the recoverable reserves are charged to earnings. Proceeds from the sale of petroleum and natural gas properties are applied against the capitalized costs. Gains and losses are not recognized upon disposition of oil and natural gas properties unless such a disposition would alter the rate of depletion by 20% or more. Net costs related to operating and administrative activities during the development of large capital projects are capitalized until commercial production has commenced.

(d) Impairment Test

A limit is placed on the aggregate carrying value of PP&E (the "impairment test"). The Fund performs an impairment test on a country by country basis. An impairment loss exists when the carrying amount of the country's PP&E exceeds the estimated undiscounted future net cash flows associated with the country's proved reserves. If an impairment loss is determined to exist, the costs carried on the balance sheet in excess of the discounted future net cash flows associated with the country's proved and probable reserves are charged to income.

(e) Depletion and Depreciation

The provision for depletion and depreciation of oil and natural gas assets is calculated on a country by country basis using the unit-of-production method, based on the country's share of estimated proved

reserves before royalties. Reserves and production are converted to equivalent units on the basis of 6 Mcf = 1 bbl, reflecting the approximate relative energy content.

(f) Goodwill

The Fund, when appropriate, recognizes goodwill relating to corporate acquisitions when the total purchase price exceeds the fair value of the net identifiable assets and liabilities of the acquired companies. The goodwill balance is assessed for impairment annually at year-end or as events occur that could result in an impairment. To assess impairment, the fair values of the Canadian and U.S. reporting units are compared to their respective book values. If the fair value is less than the book value, a second test is performed to determine the amount of impairment. The amount of impairment is measured by allocating the fair value of the reporting unit to its identifiable assets and liabilities as if they had been acquired in a business combination for a purchase price equal to their fair value. If goodwill determined in this manner is less than the carrying value of goodwill, an impairment loss is recognized in the period in which it occurs. Goodwill is stated at cost less impairment and is not amortized. Goodwill is not deductible for income tax purposes.

(g) Asset Retirement Obligations

The Fund recognizes as a liability the estimated fair value of the future retirement obligations associated with PP&E. The fair value is capitalized and amortized over the same period as the underlying asset. The Fund estimates the liability based on the estimated costs to abandon and reclaim its net ownership interest in all wells and facilities and the estimated timing of the costs to be incurred in future periods. This estimate is evaluated on a periodic basis and any adjustment to the estimate is prospectively applied. As time passes, the change in net present value of the future retirement obligation is expensed through accretion. Retirement obligations settled during the period reduce the future retirement liability. No gains or losses on retirement activities were realized, due to settlements approximating the estimates.

(h) Income Taxes

The Fund is a taxable entity under the Income Tax Act (Canada) and is taxable only on Canadian income that is not distributed or distributable to the Fund's unitholders. In the Trust structure, payments made between the Canadian operating entities and the Fund, ultimately transfers both income and future income tax liability to the unitholders. The future income tax liability associated with Canadian assets recorded on the balance sheet is recovered over time through these payments. As the Canadian operating entities transfer all of their Canadian taxable income to the Fund, no provision for current Canadian income tax has been made by any Canadian operating entity.

The U.S. operating entity is subject to U.S. income taxes on its taxable income determined under U.S. income tax rules and regulations. Repatriation of funds from U.S. operations will also be subject to applicable withholding taxes as required under U.S. tax law. A provision has been setup to reflect these current U.S. income taxes.

The Fund follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to temporary differences between the amounts reported in the financial statements of the Fund's

corporate subsidiaries and their respective tax bases, using substantively enacted income tax rates. The effect of a change in these income tax rates on future income tax liabilities and assets is recognized in income during the period that the change occurs.

(i) Financial Instruments

The Fund is exposed to market risks resulting from fluctuations in commodity prices and interest rates in the normal course of operations. The Fund uses various types of financial instruments to manage these market risks. Prior to December 31, 2005, the Fund designated certain commodity contracts and interest rate swaps as qualified hedges. Effective December 31, 2005, the Fund elected to stop designating commodity contracts as qualified hedges. The fair value of the former commodity hedges has been recorded as a financial liability with an offset to deferred financial assets. The deferred financial asset will be amortized over the remaining lives of the associated financial contracts. The fair value of the financial liability will be determined at each period end with any resulting change in fair value being taken into income in that period.

The gain or loss in fair value of all financial contracts that had not previously qualified for hedge accounting are taken into income during the period of change and charged to deferred credits or deferred financial assets on the balance sheet.

Proceeds or costs realized from holding interest rate swaps are recognized at the time each transaction under a contract is settled and is recorded in interest expense. The Fund has designated the interest rate swaps as qualified hedges and these swaps are evaluated quarterly to ensure they effectively hedge the underlying interest rate.

(j) Foreign Currency Translation

The Fund's U.S. operations are self-sustaining. Assets and liabilities of these operations are translated into Canadian dollars at period end exchange rates, while revenues and expenses are converted using average rates for the period. Gains and losses from the translation into Canadian dollars are deferred and included in the cumulative translation adjustment as part of unitholders' equity.

Other monetary assets and liabilities, not related to the Fund's U.S. operations, are translated into Canadian dollars at rates of exchange in effect at the balance sheet date. The other assets and related depreciation, depletion and amortization, other liabilities, revenue and other expenses are translated into Canadian dollars at rates of exchange in effect at the respective transaction dates. The resulting exchange gains or losses are included in earnings.

(k) Unit Based Compensation

The Fund uses the fair value method of accounting for the trust unit rights incentive plan. Under this method, the fair value of the rights is determined on the date in which fair value can reasonably be determined, generally being the grant date. This amount is charged to earnings over the vesting period of the rights, with a corresponding increase in contributed surplus. When rights are exercised, the proceeds, together with the amount recorded in contributed surplus, are recorded to unitholders' capital.

2. DEFERRED FINANCIAL ASSETS AND DEFERRED CREDITS

The deferred financial assets of $23,612,000 at December 31, 2006 consist of the fair value of the financial instruments of $49,268,000 less the related deferred premiums of $25,656,000.

Deferred Financial Assets ($ thousands)	
Fair value of financial instruments	
Deferred financial assets as at December 31, 2005	$ 49,874
Deferred financial credits as at December 31, 2005	(57,368)
Change in fair value - other financial contracts(1)	80,980
Amortization of deferred financial assets(2)	(49,874)
	$ 23,612

(1) Changes in the fair value of financial contracts that do not qualify for hedge accounting are taken into income during the period as other financial contracts and reflected as an increase or decrease in the deferred financial asset or liability.

(2) Represents the amortization of the fair value of financial contracts on December 31, 2005 for which hedge accounting is no longer applied. These deferred financial assets are fully amortized at December 31, 2006.

The following table summarizes the income statement effects of other financial contracts:

Other Financial Contracts ($ thousands)	2006	2005
Change in fair value	$ (80,980)	$ (35,823)
Amortization of deferred financial assets	49,874	3,144
Realized cash costs, net	34,332	115,343
Other financial contracts	$ 3,226	$,664 82

During the year ended December 31, 2006, the Fund realized cash costs of $nil from commodity financial contracts that qualified as hedges compared to cash costs of $27,256,000 (net gains and losses) during 2005.

3. PROPERTY, PLANT AND EQUIPMENT

($ thousands)	2006	2005
Property, plant and equipment	$ 5,855,511	$ 5,306,137
Accumulated depletion, depreciation and accretion	(2,129,414)	(1,655,810)
Net property, plant and equipment	$ 3,726,097	$ 3,650,327

Capitalized development G&A of $14,111,000 (2005 - $11,571,000) is included in PP&E and the depletion and depreciation calculation includes future capital costs of $472,567,000 (2005 - $464,423,000) included in our reserve reports. Excluded from PP&E for the depletion and depreciation calculation is $81,183,000 (2005 - $61,795,000) related to the Joslyn development project that has not commenced commercial production.

An impairment test calculation was performed on a country by country basis on the PP&E values at December 31, 2006 in which the estimated undiscounted future net cash flows associated with the proved reserves exceeded the carrying amount of the Fund's PP&E.

The following table outlines benchmark prices and the exchange rate used in the impairment tests for both Canadian and U.S. cost centres at December 31, 2006:

Year	WTI Crude Oil(1) US$/bbl	Exchange Rate US$/CDN$	Edm Light Crude(1) CDN$/bbl	Natural Gas 30 day spot @ AECO(1) CDN$/Mcf
2007	$ 65.73	$ 0.87	$ 74.10	$ 7.72
2008	68.82	0.87	77.62	8.59
2009	62.42	0.87	70.25	7.74
2010	58.37	0.87	65.56	7.55
2011	55.20	0.87	61.90	7.72
Thereafter	+ 2.0%	0.87	+ 2.0%	+ 2.0%

(1) Actual prices used in the impairment test were adjusted for commodity price differentials specific to the Fund

4. ASSET RETIREMENT OBLIGATIONS

Total future asset retirement obligations were estimated by management based on the Fund's net ownership interest in wells and facilities, estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. The Fund has estimated the net present value of its total asset retirement obligations to be $123,619,000 at December 31, 2006 compared to $110,606,000 at December 31, 2005 based on a total liability of $436,663,000 and $422,045,000 respectively. These payments are expected to be made over the next 66 years with the majority of costs incurred between 2036 and 2045. To calculate the present value of the asset retirement obligations for 2006 the Fund used a weighted credit-adjusted rate of approximately 6.3% and an inflation rate of 2.0%, the same as for 2005. Settlements during the year approximated our estimates and as a result, no gains or losses were recognized.

Following is a reconciliation of the asset retirement obligations:

($ thousands)	2006	2005
Asset retirement obligations, beginning of year	$ 110,606	$ 105,978
Changes in estimates	12,757	8,764
Acquisition and development activity	5,574	6,791
Dispositions	(45)	(9,413)

Asset retirement obligations settled	(11,514)	(7,829)
Accretion expense	6,241	6,315
Asset retirement obligations, end of year	$ 123,619	$ 110,606

5. PROPERTY ACQUISITIONS

Assets of Sleeping Giant LLC ("Sleeping Giant")

On October 4, 2005 the Fund acquired all ownership interests and retired the debt of Sleeping Giant, a private U.S. company holding additional working interests in certain properties of Lyco Energy Corporation for total cash consideration of $111,914,000 which was financed through existing credit facilities. The fair value of this consideration was allocated to cash and positive working capital assumed of $5,754,000 and PP&E of $106,160,000. This acquisition has been accounted for as an asset acquisition. The operating results of Sleeping Giant subsequent to October 4, 2005 are included in the Fund's consolidated financial statements.

6. CORPORATE ACQUISITIONS

The allocation to the fair value of the assets acquired and liabilities assumed plus the future income tax cost are summarized as follows:

($ thousands)	2005 Lyco	2005 TriLoch
Property, plant and equipment	$ 506,379	$ 77,786
Goodwill (with no tax base)	179,019	18,450
Future income taxes	(179,019)	(18,450)
	506,379	77,786
Cash	27,231	-
Non-cash working capital deficiency	(31,664)	(399)
Net assets acquired	$ 501,946	$ 77,387

Goodwill is comprised of the following:

Goodwill ($ thousands)	2006	2005
Balance, beginning of year	$ 221,234	$ 29,082
Lyco acquisition	-	179,019
TriLoch acquisition	-	18,450
Foreign exchange(1)	344	(5,317)
Balance, end of year	$ 221,578	$ 221,234

(1) The foreign exchange results from the translation of Lyco goodwill at the period end rate.

Lyco Energy Corporation ("Lyco")

On August 30, 2005 the Fund acquired all the outstanding common shares and retired the debt including all outstanding mandatorily redeemable preferred shares of Lyco, a private U.S. company operating in the states of Montana and North Dakota. Total consideration was approximately $501,946,000, and the Fund assumed a net working capital deficiency of $4,433,000. Goodwill of $179,019,000 was recorded based on the excess of the consideration paid over the value assigned to the identifiable assets and liabilities including the future income tax liability. The acquisition, which was financed through an equity offering and available credit facilities, has been accounted for using the purchase method of accounting for business combinations. Results from the operations of Lyco subsequent to August 30, 2005 are included in the Fund's consolidated financial statements.

TriLoch Resources Inc. ("TriLoch")

On July 1, 2005 the Fund acquired all the outstanding common shares of TriLoch, a public Alberta corporation operating in southern Alberta, in exchange for 1,632,516 trust units of the Fund with a recorded value of $69,088,000. The trust unit value was based on the weighted average price of the Fund's trust units on the Toronto Stock Exchange during the five day trading period surrounding the announcement of the TriLoch transaction. Total consideration was $77,387,000 consisting of units, deal costs and the retirement of TriLoch's bank indebtedness. The Fund also assumed a working capital deficiency of $399,000. Goodwill of $18,450,000 has been recorded as a result of the excess of the consideration paid over the value allocated to the identifiable assets and liabilities including the future income tax liability. This acquisition has been accounted for using the purchase method of accounting for business combinations. Results from the operations of TriLoch subsequent to July 1, 2005 are included in the Fund's consolidated financial statements.

7. LONG-TERM DEBT

($ thousands)	2006	2005
Bank credit facilities(a)	$ 348,520	$ 328,632
Senior notes(b)		
US$175 million (issued June 19, 2002)	268,328	268,328
US$54 million (issued October 1, 2003)	62,926	62,958
Total long-term debt	$ 679,774	$ 659,918

(a) Unsecured Bank Credit Facility

Enerplus has an $850,000,000 unsecured covenant based three year term facility and has the ability to extend the facility each year or repay the entire balance at the end of the three year term. During 2006, the facility was extended until November 2009. At December 31, 2006, Enerplus had available credit of $501,480,000 under this 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 year ended December 31, 2006 was 4.8% (2005 - 3.4%).

(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. Costs incurred in connection with issuing the notes in the amount of $475,000 are classified as deferred charges on the balance sheet and are being amortized as a part of depletion, depreciation, amortization and accretion ("DDA&A") over the term of the notes. At December 31, 2006, the amount remaining to be amortized associated with these costs was $346,000 (2005 - $386,000). The notes are subject to fluctuations in foreign exchange rates.

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. Costs incurred in connection with issuing the notes in the amount of $1,892,000 are classified as deferred charges on the balance sheet and are being amortized to DDA&A over the term of the notes. At December 31, 2006, the amount remaining to be amortized was $1,177,000 (2005 - $1,335,000). Concurrent with the issuance of the notes on June 19, 2002, the Fund entered into a cross currency swap 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 bank credit facility and the senior notes (the "Combined Facilities") are the legal obligation of EnerMark Inc. and are guaranteed by its subsidiaries. Payments with respect to the Combined Facilities have priority over payments to the Fund and over claims of and future distributions to the unitholders. However, unitholders have no direct liability beyond their equity investment should cash flow be insufficient to repay the Combined Facilities.

8. FUND CAPITAL

(a) Unitholders' Capital

Trust Units

Authorized: Unlimited number of trust units

(thousands)	2006		2005	
Issued:	Units	Amount	Units	Amount
Balance before				

Contributed Surplus, beginning of year	117,539	$ 3,407,567	104,124	$ 2,826,641
Issued for cash:				
Pursuant to public offerings	4,370	240,287	10,638	466,885
Pursuant to rights plans	640	22,974	805	24,737
Trust unit rights incentive plan (non-cash) - exercised	-	3,065	-	4,629
DRIP(*), net of redemptions	602	32,928	339	15,613
Issued for acquisition of corporate and property interests (non-cash)	-	-	1,633	69,062
	123,151	3,706,821	117,539	3,407,567
Contributed Surplus (Trust Unit Rights Plan)	-	6,305	-	3,047
Balance, end of year	123,151	$ 3,713,126	117,539	$ 3,410,614

(*) Distribution Reinvestment and Unit Purchase Plan

Contributed surplus ($ thousands)	2006	2005
Balance, beginning of year	$ 3,047	$ 4,636
Trust unit rights incentive plan (non-cash) - exercised	(3,065)	(4,629)
Trust unit rights incentive plan (non-cash) - expensed	6,323	3,040
Balance, end of year	$ 6,305	$ 3,047

On March 20, 2006 the Fund closed an equity offering of 4,370,000 units at a price of $58.00 per unit for gross proceeds of $253,460,000 ($240,287,000 net of issuance costs).

On August 9, 2005 the Fund completed a Canadian equity offering of 10,637,500 subscription receipts at a price of $46.25 per subscription receipt for gross proceeds of $491,984,000 ($466,885,000 net of issuance costs). The subscription receipts were exchanged for an equal number of trust units on August 30, 2005 upon the closing of the Lyco transaction.

On July 1, 2005 the Fund issued 1,632,516 trust units pursuant to the acquisition of TriLoch valued at $42.32 per trust unit, being the weighted average trading price of the Fund's trust units on the Toronto Stock Exchange during the five day trading period surrounding the announcement of the TriLoch transaction, for a recorded value of $69,088,000 ($69,062,000 net of issuance costs).

Pursuant to the monthly Distribution Reinvestment and Unit Purchase Plan

("DRIP"), Canadian unitholders are entitled to reinvest cash distributions in additional trust units of the Fund. Trust units are issued at 95% of the weighted average market price on the Toronto Stock Exchange for the 20 trading days preceding a distribution payment date without service charges or brokerage fees. Eligible unitholders are also entitled to make optional cash payments to acquire additional trust units; however, the 5% discount does not apply.

Trust units are redeemable by unitholders at approximately 85% of the current market price. Redemptions are limited to $500,000 during any rolling two calendar months. Redemption requests in excess of $500,000 can be paid using investments of the Fund or a non-interest bearing instrument.

(b) Trust Unit Rights Incentive Plan

As at December 31, 2006 a total of 3,079,000 rights issued pursuant to the Trust Unit Rights Incentive Plan ("Rights Plan") were outstanding at an average exercise price of $48.53. This represents 2.5% of the total trust units outstanding of which 809,000 rights, with an average exercise price of $39.81, 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 year ended December 31, 2006 reduced the exercise price of the outstanding rights by $2.02 per trust unit of which a $0.51 reduction is effective January 2007 and a $0.50 reduction is effective April 2007. Plan members have the choice to exercise rights using the original exercise price or a reduced strike price. In certain circumstances, it may be more advantageous to use the original exercise price as it could effectively lower the plan member's tax rate on the transaction.

The Fund uses a binomial lattice option-pricing model to calculate the estimated fair value of rights granted under the plan. The following assumptions were used to arrive at the estimate of fair value:

	2006	2005
Dividend yield	9.26%	8.97%
Right's exercise price reduction	$ 1.61	$ 1.43
Volatility	25.61%	21.46%
Risk-free interest rate	4.13%	3.70%
Forfeiture rate	2.80%	4.60%

The fair value of the rights granted under the plan during 2006 ranged between 12% and 14% (2005 - 9% and 10%) of the underlying market price of a trust unit on the grant date.

During the year the Fund expensed $6,323,000 or $0.05 per unit (2005 - $3,040,000 or $0.03 per unit) of unit based compensation expense using the fair value method. The remaining future fair value of the rights of $10,113,000 at December 31, 2006 (2005 - $6,380,000) will be recognized in earnings over the remaining vesting period of the rights. Activity for the rights issued pursuant to the Rights Plan is as follows:

	2006		2005	
	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 year	2,621	$ 42.80	2,401	$ 34.33
Granted	1,473	54.49	1,125	53.07
Exercised	(640)	35.94	(805)	30.72
Cancelled	(375)	46.35	(100)	37.15
End of year	3,079	48.53	2,621	42.80
Rights exercisable at the end of the year	809	$ 39.81	643	$ 32.46

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

The following table summarizes information with respect to outstanding rights as at December 31, 2006. Rights vest between one and three years and expire between four and six years.

Rights Outstanding at December 31, 2006 (000's)	Original Exercise Price	Exercise Price after Price Reductions	Expiry Date December 31	Rights Exercisable at December 31, 2006 (000's)
10	$ 24.50	$ 18.41	2007	10
1	26.40	20.43	2008	1
38	26.09	20.33	2008	38
6	27.70	22.14	2009	6
23	33.00	27.75	2009	23
19	36.00	31.13	2009	19
192	37.62	33.14	2009	192
14	40.70	36.61	2010	1
30	37.25	33.53	2010	8
58	38.83	35.51	2010	40
387	40.80	37.83	2010	208
80	45.55	42.90	2011	9
92	44.86	42.56	2011	16
143	49.75	47.85	2011	46
566	56.93	55.44	2011	192
178	56.55	55.54	2012	-
436	54.21	53.70	2012	-
320	56.00	56.00	2012	-
486	52.90	52.90	2012	-
3,079	$ 50.10	$ 48.53		809

(b) Basic and Diluted per Trust Unit Calculations

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

(thousands)	2006	2005
Weighted average units	121,588	109,083
Dilutive impact of rights	270	288
Diluted trust units	121,858	109,371

No rights were excluded in calculating the weighted average number of diluted units for the year ended December 31, 2006. In 2005 we excluded 132,511 rights because their exercise price was greater than the annual average unit market price of $48.08. During the last two years, outstanding rights were the only potential dilutive instrument.

9. INCOME TAXES

(a) Enerplus Resources Fund

The Fund is an inter-vivos trust for income tax purposes. As such, the Fund's income that is not allocated to the Fund's unitholders is taxable. The Fund intends to allocate all income to unitholders.

For 2006, the Fund had taxable income of $588,000,000 (2005 - $451,000,000) or $4.81 per trust unit (2005 - $4.05 per trust unit). Taxable income of the Fund is comprised of dividend, royalty, interest and partnership income, less deductions for Canadian oil and gas property expense ("COGPE") and trust unit issue costs.

The amounts of COGPE and issue costs remaining in the Fund at December 31, 2006 are $466,700,000 and $35,543,000 respectively (2005 - $466,700,000 and $40,109,000).

Proposed Tax on Income Trusts

On October 31, 2006, the Federal Government announced a new tax on publicly traded flow through entities including Enerplus. The tax would be applicable beginning in 2011 at the rate of 31.5% provided that Enerplus does not exceed the guidance provided on normal growth. Enerplus can issue up to $7.5 billion of new equity before 2011 without exceeding the guidance on normal growth. In addition, we understand that a trust will be able to issue equity to retire debt existing on October 31, 2006 without eroding their safe harbour equity limits.

At the present time, the proposed changes to tax legislation are not substantively enacted. Further, the timing of the enactment or the exact content of the proposed changes is difficult to predict. Therefore, no amounts in respect of this matter are reflected in the future tax liability presented on the balance sheet.

If substantively enacted, the Fund would be treated as a taxable entity resulting in the recording of future income tax assets and liabilities. Enerplus' future tax liability would be adjusted to include differences between the accounting and tax bases of the trust's assets and liabilities at the substantively enacted tax rates.

(b) Corporate Subsidiaries

The future income tax liability on the balance sheet arises as a result of the following temporary differences:

($ thousands)	Canadian	Foreign	2006 Total
Excess of net book value of property, plant and equipment over the underlying tax bases	$ 179,770	$ 183,081	$ 362,851
Asset retirement obligations	(37,667)	-	(37,667)
Deferred hedging and other	6,963	(807)	6,156
Future income tax liability	$ 149,066	$ 182,274	$ 331,340

($ thousands)	Canadian	Foreign	2005 Total
Excess of net book value of property, plant and equipment over the underlying tax bases	$ 302,610	$ 183,355	$ 485,965
Asset retirement obligations	(37,976)	-	(37,976)
Deferred hedging and other	(1,925)	(3,094)	(5,019)
Future income tax liability	$ 262,709	$ 180,261	$ 442,970

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

($ thousands)	2006	2005
Income before taxes	$ 454,377	$ 456,619
Computed income tax expense at the enacted rate of 34.88% (38.01% for 2005)	$ 158,487	$ 173,564
Increase (decrease) resulting from:		
Net income attributed to the Fund	(197,694)	(172,463)
Non-deductible crown royalties	11,878	30,652
Resource allowance	(11,998)	(37,047)
Amended returns and pool balances	(21,446)	16,544
Change in tax rate	(35,500)	-
Other	2,475	6,842
	$ (93,798)	$ 18,092
Future income tax (recovery)/expense	$ (112,034)	$ 15,328
Current tax	$ 18,236	$ 2,764

The breakdown of our current and future income tax balances between our

Canadian and Foreign operations is as follows:

For the year ended December 31, 2006 ($ thousands)	Canadian	Foreign	Total
Future income (recovery)/expense	$ (113,643)	$ 1,609	$ (112,034)
Current income tax	-	18,236	18,236

For the year ended December 31, 2005 ($ thousands)	Canadian	Foreign	Total
Future income expense	$ 8,708	$ 6,620	$ 15,328
Current income tax	-	2,764	2,764

10. FINANCIAL INSTRUMENTS

The Fund's financial instruments presented on the balance sheet consist of cash, accounts receivable, deferred financial assets, other current assets, other assets, accounts payable, distributions payable to unitholders, deferred credits and long-term debt.

The carrying value of cash, accounts receivable, deferred financial assets, other assets, current liabilities and the outstanding bank credit facility balances approximate their fair value. Other current assets are comprised of prepaid expenses and marketable securities and other assets are comprised of long-term investments. Marketable securities and long-term investments are carried on the balance sheet at the lower of cost and fair value. The fair value of the marketable securities at December 31, 2006 exceeded the cost of these securities by $14,493,000. The book value of other assets at December 31, 2006 of $48,700,000 was lower than the fair value of these assets by $3,231,000.

The Fund carried US$54,000,000 of fixed rate debt. In addition, it carried US$175,000,000 of fixed rate debt that was converted to CDN$268,328,000 floating rate debt through a cross-currency swap with a syndicate of financial institutions. At December 31, 2006 the fair value of the senior unsecured notes was $62,990,000 (for the US$54,000,000 notes) and $208,217,000 (for the US$175,000,000 notes), see Note 7.

The estimated fair values have been determined based on available market information and appropriate valuation methods. The actual amounts realized may differ from these estimates.

(a) Credit Risk

Most of the Fund's accounts receivable relate to oil and natural gas sales and are exposed to typical industry credit risks. The Fund manages this credit risk by entering into sales contracts with only credit-worthy counterparties and reviewing its exposure to individual entities on a regular basis. The Fund is also exposed to certain losses in the event of non-performance by counterparties to derivative financial instruments. This credit risk is managed by the Fund by selecting financially sound counterparties.

In 2006, approximately 15% of the Fund's oil and gas sales were made to a AA+ rated counterparty.

(b) Interest Rate Risk

The Fund is exposed to movements in interest rates. Long-term debt is comprised of both variable rate bank facilities and fixed rate senior notes. The Fund monitors the interest rate forward market and through the use of interest rate swaps along with the fixed-rate notes has fixed the interest rate on approximately 20% of its debt. See part (d) below.

(c) Currency Risk

The Fund is exposed to fluctuations in foreign currency as a result of its U.S. operations and the issuance of senior unsecured notes denominated in U.S. dollars. Through the use of a financial swap, the exposure on our US$175,000,000 senior unsecured notes has been converted to Canadian dollar debt. As well, the Fund has indirect exposure to fluctuations in foreign currency as crude oil sales and a portion of natural gas sales are based on U.S. dollar indices. We have not entered into any foreign currency derivatives with respect to oil and natural gas sales.

(d) Derivative Financial Instruments

The Fund uses certain derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. The fair values of these instruments are based on an approximation of the amounts that would have been paid to or received from counterparties to settle the instruments outstanding as at December 31, 2006 with reference to forward prices and market valuations provided by third party sources.

The fair values of derivative financial instruments are as follows:

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 January 2007 and January 2012. The fair value of the $75,000,000 interest rate swaps as at December 31, 2006 represents an unrealized cost of $673,000. These swaps have been designated as a cash flow hedge for accounting purposes.

Cross Currency Interest Rate Swap

The fair value of the cross currency interest rate swap related to the US$175,000,000 senior unsecured notes as at December 31, 2006 represents an unrealized cost of $65,002,000 whereas the fair value of the underlying debt instrument as at December 31, 2006 represents an unrealized gain of $60,111,000. The cross currency swap has been designated as a fair value hedge for accounting purposes.

Crude Oil Instruments

Enerplus has entered into the following financial option contracts to reduce the impact of a downward movement in crude oil prices. The net premium cost of the crude oil instruments entered into as of December 31, 2006 is $20,108,000.

The following table summarizes the Fund's crude oil risk management positions at February 13, 2007:

	Daily Volumes bbls/day	WTI US$/bbl Purchased Put	Fixed Price and Swaps
Term			
January 1, 2007 - December 31, 2007			
Put	5,000	$ 71.00	-
Put	2,500	$ 68.00	-
Put(1)	2,500	$ 65.70	-
Swap(1)	2,500	-	$ 66.24

(1) Financial contracts entered into during the fourth quarter of 2006.

Natural Gas Instruments

Enerplus has physical and financial contracts in place on its natural gas production as described below. The net premium cost of the natural gas instruments entered into as of December 31, 2006 is $5,548,000.

The following table summarizes the Fund's natural gas risk management positions at February 13, 2007:

	Daily Volumes MMcf/day	AECO CDN$/Mcf Sold Call	Purchased Put	Sold Put	Fixed Price and Swaps
Term					
January 1, 2007 - March 31, 2007					
Collar	6.6	$ 11.45	$ 9.00	-	-
Collar(1)	9.5	$ 9.50	$ 7.00	-	-
Collar(1)	9.5	$ 10.66	$ 7.00	-	-
Costless Collar	6.6	$ 11.45	$ 7.70	-	-
Put(1)	6.6	-	$ 7.50	-	-
Put(1)	4.7	-	$ 7.39	-	-
January 1, 2007 - June 30, 2007					
Put(1)	4.7	-	$ 7.50	-	-
April 1, 2007 - October 31, 2007					
Collar	6.6	$ 10.02	$ 7.50	-	-
Collar	6.6	$ 9.00	$ 7.50	-	-
Collar(1)	9.5	$ 9.10	$ 7.10	-	-
Collar(1)	9.5	$ 9.15	$ 7.14	-	-
Collar(1)	9.5	$ 9.50	$ 7.20	-	-
Costless Collar(2)	4.7	$ 8.02	$ 7.17	-	-
Costless Collar(2)	4.7	$ 8.23	$ 7.28	-	-
Costless Collar(2)	4.7	$ 8.20	$ 7.50		
3-Way option(1)	4.7	$ 9.50	$ 7.75	$ 5.49	-
Put(1)	4.7	-	$ 7.28	-	-
Swap(1)	6.6	-	-	-	$ 7.60
Swap(1)	4.7	-	-	-	$ 7.33

Swap(1)	2.4	-	-	-	$ 7.84
Swap(1)	2.4	-	-	-	$ 7.96
Swap(2)	7.1	-	-	-	$ 7.17
Swap(2)	2.4	-	-	-	$ 7.70
Swap(2)	2.4	-	-	-	$ 7.53
Swap(2)	2.4	-	-	-	$ 8.35
November 1, 2007 - March 31, 2008					
Collar(1)	2.4	$ 9.95	$ 8.00	-	-
3-Way option(1)	4.7	$ 10.50	$ 8.20	$ 5.70	-
Swap(1)	4.7	-	-	-	$ 8.70
2007 - 2010					
Physical (escalated pricing)	2.0	-	-	-	$ 2.52

(1) Financial contracts entered into during the fourth quarter of 2006.
(2) Financial contracts entered into during the first quarter of 2007.

Electricity Instrument

The Fund has entered into electricity swap contracts that fix the price of electricity. These contracts have been designated as cash flow hedges and the fair value of these instruments as at December 31, 2006 represents an unrealized gain of $1,494,000. Proceeds or costs realized from the electricity contracts are recognized as operating costs.

The following table summarizes the Fund's electricity management positions at February 13, 2007:

Term	Volumes MWh	Price CDN$/MWh
January 1, 2007 - December 31, 2007	5.0	$ 61.50
January 1, 2007 - December 31, 2007	4.0	$ 62.90
January 1, 2008 - September 30, 2008	4.0	$ 63.00

The Fund did not enter into any new electricity contracts in the fourth quarter of 2006.

11. COMMITMENTS AND CONTINGENCIES

(a) Pipeline Transportation

Enerplus has contracted to transport natural gas with various pipelines totaling 35.3 MMcf/day until 2008; of this amount 5 MMcf/day extends until 2015. Enerplus also has a contract to transport a minimum of 2,480 bbls/day of crude oil from the field to suitable marketing sales points until 2010.

(b) Oil Sands Lease No. 24

The Fund's acquisition of a working interest in the Joslyn project included the assumption of a proportionate share of certain contingent project debt. Effectively, this debt is comprised of principal of $3,150,000 plus accrued interest to December 31, 2006 of $1,379,000. Interest is accrued at the Bank of Canada prime business rate and is not

compounded. The debt is contingent on attaining certain production hurdles with respect to development of the project. As it is still too early to determine if these hurdles will be satisfied, no portion of the contingent debt has been accrued for in the consolidated financial statements.

(c) Office Lease

Enerplus has office lease commitments for both its Canadian and U.S. operations that expire between November 2009 and January 2011. Annual costs of these lease commitments, which include rent and operating fees, amount to approximately $6,700,000.

(d) Guarantees

(i) Corporate indemnities have been provided by the Fund to all directors and certain officers of its subsidiaries and affiliates for various items including, but not limited to, all costs to settle suits or actions due to their association with the Fund and its subsidiaries and/or affiliates, subject to certain restrictions. The Fund has purchased directors' and officers' liability insurance to mitigate the cost of any potential future suits or actions. Each indemnity, subject to certain exceptions, applies for so long as the indemnified person is a director or officer of one of the Fund's subsidiaries and/or affiliates. The maximum amount of any potential future payment cannot be reasonably estimated.

(ii) The Fund may provide indemnifications in the normal course of business that are often standard contractual terms to counterparties in certain transactions such as purchase and sale agreements. The terms of these indemnifications will vary based upon the contract, the nature of which prevents the Fund from making a reasonable estimate of the maximum potential amounts that may be required to be paid. Management believes the resolution of these matters would not have a material adverse impact on the Fund's liquidity, consolidated financial position or results of operations.

Enerplus has the following minimum annual commitments including long-term debt:

		Minimum Annual Commitment Each Year					Total Committed after
($thousands)	Total	2007	2008	2009	2010	2011	2011
Bank credit facility	$348,520	$ -	$ -	$348,520	$ -	$ -	$ -
Senior unsecured notes	331,254	-	-	-	53,666	66,251	211,337
Pipeline commitments	28,543	6,364	5,788	2,952	2,444	2,275	8,720
Office lease	20,917	6,745	6,828	6,702	592	50	-
Total commitments	$729,234	$ 13,109	$ 12,616	$358,174	$ 56,702	$ 68,576	$220,057

In addition, the Fund is involved in claims and litigation arising in the normal course of business. The resolution of these claims is uncertain and there can be no assurance they will be resolved in favour of the Fund; however, management believes the resolution of these matters would not have a material adverse impact on the Fund's liquidity, consolidated financial position or results of operations.

12. GEOGRAPHICAL INFORMATION

As at December 31, 2006

($ thousands)	Canada	U.S.	Total
Oil and gas revenue	$ 1,323,631	$ 271,693	$ 1,595,324
Capital assets	3,101,277	624,820	3,726,097
Goodwill	47,532	174,046	221,578

As at December 31, 2005

($ thousands)	Canada	U.S.	Total
Oil and gas revenue	$ 1,471,473	$ 79,096	$ 1,550,569
Capital assets	3,054,078	596,249	3,650,327
Goodwill	47,532	173,702	221,234

13. EVENTS SUBSEQUENT TO DECEMBER 31, 2006

On January 31, 2007, Enerplus closed the acquisition of gross overriding royalty ("GORR") interests in the Jonah natural gas field in Wyoming for total consideration of US$52,000,000 (CDN$60,000,000). The full amount of the purchase price will be recorded to PP&E in 2007. This represents a GORR of approximately 0.5% on about 650 producing natural gas wells in the Jonah field.

5 YEAR DETAILED STATISTICAL REVIEW

($ thousands, except per unit amounts)	2006	2005	2004	2003	2002
Financial					
Oil and gas sales(1)	$1,569,487	$1,413,734	$ 989,266	$ 890,011	$ 621,450
Cash distributions to unitholders	614,340	498,205	423,311	372,576	237,621
Per unit	5.04	4.47	4.20	4.29	3.25
Net income	544,782	432,041	258,316	248,046	116,621
Per unit	4.48	3.96	2.60	2.88	1.62
Total net capital					

expenditures	526,387	1,010,549	813,636	312,073	361,702
Total assets	4,203,804	4,130,623	3,180,748	2,661,765	2,517,976
Long-term debt, net of cash	679,650	649,825	584,991	257,701	361,011
Net debt/cash flow ratio	0.8x	0.8x	1.1x	0.6x	1.2x
Average Benchmark Pricing					
AECO natural gas (per Mcf)	$ 6.99	$ 8.48	$ 6.79	$ 6.70	$ 4.07
NYMEX natural gas (US$ per Mcf)	7.26	8.55	6.09	5.54	3.25
WTI crude oil (US$ per bbl)	66.22	56.56	41.40	31.04	26.08
CDN$/US$ exchange rate	0.88	0.83	0.77	0.72	0.64
($ per BOE except percentage data)					
Oil and Gas Economics					
Net royalty rate	19%	19%	21%	20%	21%
Weighted average price(2)	$ 50.23	$ 52.36	$ 40.90	$ 36.94	$ 27.49
Hedging(3)	(1.10)	(4.90)	(3.50)	(1.81)	(0.38)
Weighted average price(1)	49.13	47.46	37.40	35.13	27.11
Net royalty expense	9.36	10.21	8.40	7.51	5.75
Operating expense	8.02	7.45	7.14	6.73	5.86
Operating netback	31.75	29.80	21.86	20.89	15.50
General and adminis-trative expense(3)	1.71	1.28	1.06	0.95	0.70
Management fee	-	-	-	2.29	0.94
Interest expense, net of interest and other income	0.95	0.51	0.68	0.74	0.78
Foreign					

exchange(3)	(0.02)	0.13	(0.01)	0.08	-
Taxes	0.70	0.31	0.24	0.26	0.23
Restoration and abandonment cash costs	0.37	0.27	0.25	0.26	0.20
Cash flow before changes in non-cash working capital	$ 28.04	$ 27.30	$ 19.64	$ 16.31	$ 12.65

(1) Net of commodity derivative instruments and transportation.
(2) Net of transportation and before commodity derivative instruments.
(3) Does not include non-cash portion of expense.

OPERATIONAL STATISTICS

The following information outlines Enerplus' gross average daily production volumes for the years indicated and our Company interest reserves based upon forecast prices and costs at December 31 each year.

	2006(1)	2005(1)	2004(1)	2003(1)	2002
Daily Production					
Oil Sands	n/a	n/a	n/a	n/a	n/a
Crude Oil (bbls/day)	36,134	29,315	25,550	24,597	23,288
NGLs (bbls/day)	4,483	4,689	4,398	4,666	4,410
Natural Gas (Mcf/day)	270,972	274,336	271,091	240,907	210,517
BOE per day	85,779	79,727	75,130	69,414	62,784
Proved Reserves					
Oil Sands	8,730	9,453	n/a	n/a	n/a
Crude Oil (Mbls)	125,048	129,745	104,408	91,063	105,247
NGLs (Mbbls)	12,690	13,084	12,776	13,571	16,035
Natural Gas (MMcf)	920,061	965,776	971,598	867,204	1,001,913
MBOE	299,812	313,245	279,117	249,168	288,267
Probable Reserves(2)					
Oil Sands	47,998	43,700	47,747	n/a	n/a
Crude Oil					

(Mbls)	34,421	31,567	26,783	27,807	16,725
NGLs (Mbbls)	3,777	3,539	3,292	3,742	2,319
Natural Gas (MMcf)	344,025	342,518	295,698	284,096	138,789
MBOE	143,533	135,892	127,105	78,898	42,175
Proved Plus Probable Reserves					
Oil Sands	56,728	53,153	47,747	n/a	n/a
Crude Oil (Mbls)	159,469	161,312	131,191	118,870	121,972
NGLs (Mbbls)	16,467	16,623	16,068	17,313	18,354
Natural Gas (MMcf)	1,264,086	1,308,294	1,267,296	1,151,300	1,140,702
MBOE	443,345	449,137	406,222	328,066	330,442
Reserve Life Index(3) Without Oil Sands:					
Proved (years)	9.8	9.6	10.1	10.6	12.0
Proved Plus Probable (years)	12.2	12.0	12.4	13.3	13.8
With Oil Sands:					
Proved (years)	10.1	9.9	10.1	10.6	12.0
Proved Plus Probable (years)	14.0	13.5	14.0	13.3	13.8

(1) 2003 - 2006 reserve information reflects NI 51-101 reporting methodology. Year 2002 information has not been restated for NI 51-101.
(2) Probable reserves for year 2002 have been risked by 50%.
(3) The Reserve Life Indices (RLI) are based upon year-end proved plus probable reserves (established reserves for the year 2002) divided by the following year's proved and proved plus probable production volumes as determined in the independent reserve engineering reports for 2003 forward and management's estimate for 2002.

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

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