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FOCUS ENERGY TRUST

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2006

ANNUAL REPORT

CONTENTS

NOTICE OF ANNUAL GENERAL AND SPECIAL MEETING

The Annual General and Special Meeting of unitholders will be held at 3:00 p.m. on Wednesday, May 17, 2007 at the Bow Valley Conference Centre, 3rd Floor, 205 – 5th Avenue S.W., Calgary, Alberta.

All unitholders are invited to attend.

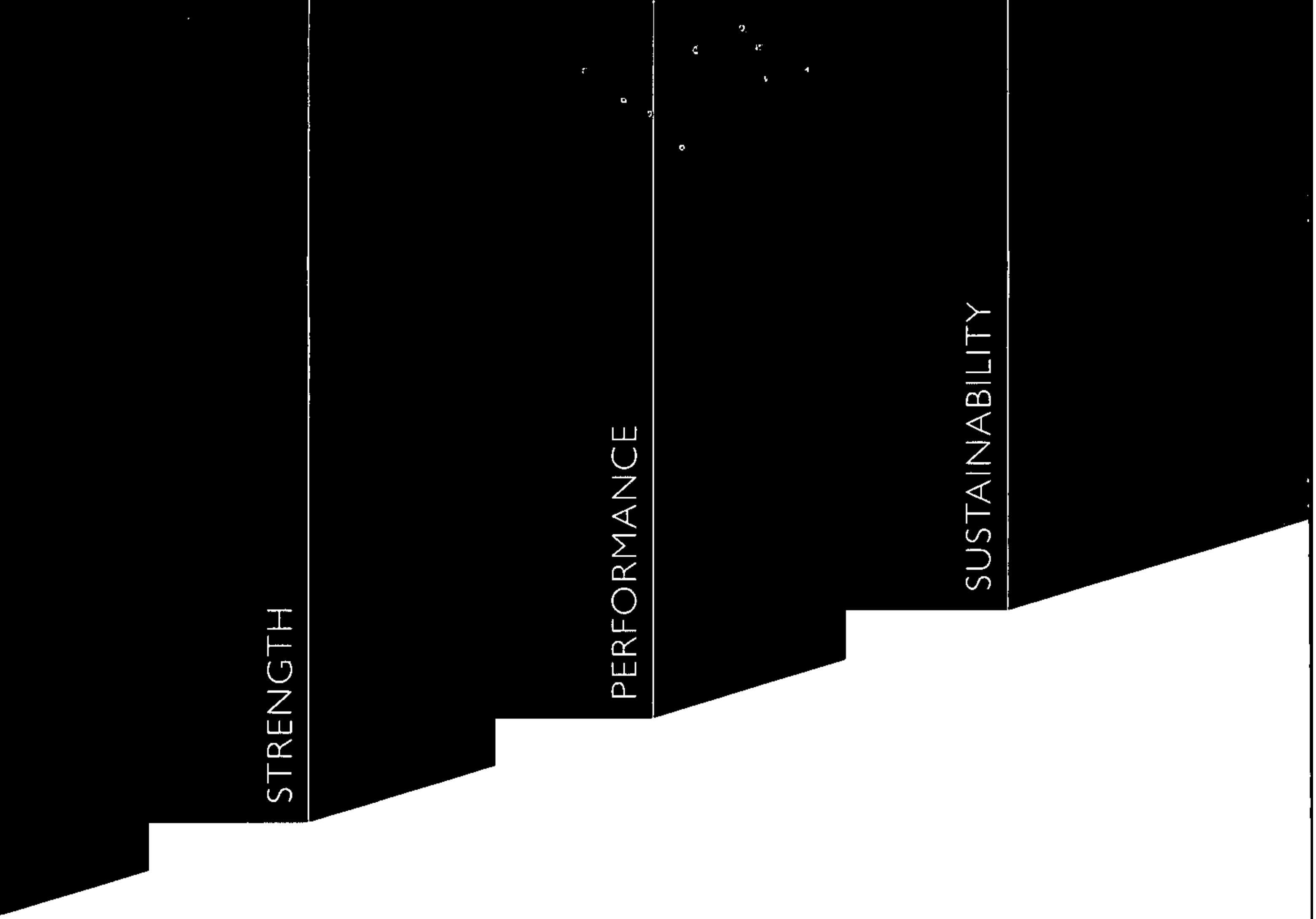
FORWARD-LOOKING INFORMATION

Certain information set forth in this document, including management's assessment of Focus' future plans and operations, contains forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond Focus' control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Focus' actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do, what benefits Focus will derive therefrom. Focus disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. Readers are cautioned that net present value of reserves does not represent fair market value of reserves.

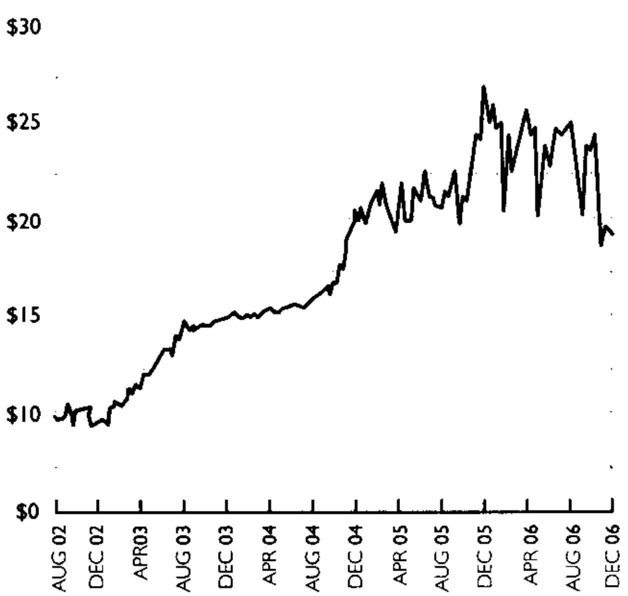
IS A NATURAL GAS WEIGHTED ENERGY TRUST. FOCUS IS COMMITTED TO MAINTAINING ITS EMPHASIS ON OPERATING HIGH-QUALITY OIL AND GAS PROPERTIES, DELIVERING CONSISTENT DISTRIBUTIONS TO UNITHOLDERS AND ENSURING FINANCIAL STRENGTH AND SUSTAINABILITY.

FOCUS ENERGY TRUST UNITS TRADE ON THE TSX UNDER THE SYMBOL **FET.UN.**

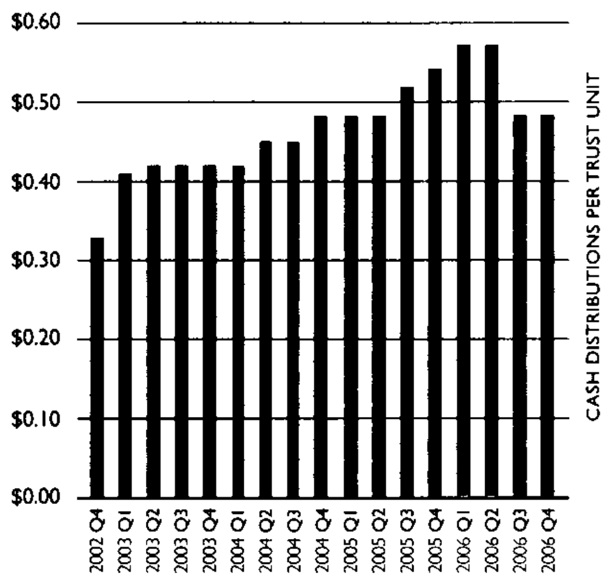
PRODUCTION OF NATURAL GAS AND LIGHT OIL IS APPROXIMATELY 22,000 BOE/D AND IS PRODUCED FROM EIGHT AREAS IN SASKATCHEWAN, BRITISH COLUMBIA AND ALBERTA. PRODUCTION IS WEIGHTED 84% TO NATURAL GAS AND FOCUS OPERATES APPROXIMATELY 93% OF ITS PRODUCTION.



FET.UN EQUITY



FET.UN DISTRIBUTIONS PER QUARTER



2006 Highlights

(thousands of dollars except where indicated)	Three Months Ended December 31, 2006	2005	Years Ended December 31, 2006	2005	Year Over Year Change
FINANCIAL					
Oil and gas revenues, before transportation system charges and royalties	**98,434**	52,315	**285,639**	191,669	49%
Funds flow from operations (1)	**64,412**	32,350	**181,223**	116,368	56%
Per unit (2) (3)	**$ 0.82**	$ 0.86	**$ 3.09**	$ 3.12	(1%)
Cash distributions per trust unit					
Per unit	**$ 0.48**	$ 0.54	**$ 2.10**	$ 2.02	4%
Payout ratio (per-unit basis)	**59%**	63%	**68%**	65%	3%
Net income	**21,646**	17,858	**72,967**	63,464	15%
Per unit	**$ 0.28**	$ 0.49	**$ 1.26**	$ 1.74	(28%)
Capital expenditures (4)	**26,986**	10,865	**90,406**	43,035	101%
Acquisitions (4)	**45**	(33)	**1,091,339**	10,363	
Long-term debt less working capital	**308,122**	92,518	**308,122**	92,518	233%
Total Trust Units – outstanding (000's) (3)	**78,504**	37,456	**78,504**	37,456	109%
Weighted average Total Trust Units (000's) (5)	**78,453**	37,442	**58,583**	37,344	57%
OPERATIONS					
Average daily production					
Crude oil (bbls/d)	**1,965**	1,714	**1,747**	1,765	(1%)
NGLs (bbls/d)	**706**	762	**728**	777	(6%)
Natural gas (mcf/d)	**113,539**	42,629	**80,544**	44,526	81%
Barrels of oil equivalent (@ 6:1)	**21,594**	9,532	**15,899**	9,963	60%
Average product prices realized, net of transportation system charges (6)					
Crude oil (CDN$/bbl)	**$ 57.51**	$ 59.20	**$ 65.61**	$ 56.61	16%
NGLs (CDN$/bbl)	**$ 53.85**	$ 60.64	**$ 61.52**	$ 57.50	7%
Natural gas (CDN$/mcf)	**$ 7.80**	$ 9.24	**$ 7.37**	$ 7.92	(7%)
Field netback per BOE					
Revenue (6)	**$ 48.09**	$ 56.61	**$ 47.45**	$ 49.97	(5%)
Royalties, net of ARTC	**$ (8.94)**	$ (13.41)	**$ (9.32)**	$ (11.98)	(22%)
Production expenses	**$ (4.04)**	$ (4.61)	**$ (4.17)**	$ (4.11)	1%
Field netback	**$ 35.11**	$ 38.58	**$ 33.96**	$ 33.88	0%
Wells drilled					
Gross	**56**	6	**227**	37	514%
Net	**46.3**	4.8	**190.3**	29.4	547%
Success rate	**100%**	100%	**100%**	100%	–
TRUST UNIT TRADING STATISTICS					
Unit prices					
High	**$ 24.30**	$ 26.74	**$ 25.89**	$ 26.74	
Low	**$ 17.09**	$ 19.72	**$ 17.09**	$ 18.60	
Close	**$ 18.18**	$ 25.72	**$ 18.18**	$ 25.72	(29%)
Daily average trading volume	**288,131**	103,540	**220,668**	100,967	119%
RESERVES					
Proved plus probable (7)					
Crude oil (mbbls)			**5,239**	5,608	(7%)
NGLs (mbbls)			**3,267**	3,420	(4%)
Natural gas (Mmcf)			**450,938**	187,506	140%
Barrels of oil equivalent (@ 6:1)			**83,662**	40,279	108%
Reserve life index of proved plus probable reserves (8)			**9.9**	10.5	(6%)
Gas weighting of proved plus probable reserves			**90%**	78%	12%
Proved reserves/proved plus probable reserves			**74%**	77%	(3%)

(1) Funds flow from operations ("funds flow" before changes in non-cash working capital and reclamation costs) is used by management to analyze operating performance and leverage. Funds flow as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures of other entities. Funds flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to funds flow throughout this report are based on funds flow from operations before changes in non-cash working capital and reclamation costs.
(2) Based on the weighted average Total Trust Units outstanding for the period
(3) Total Trust Units being trust units, exchangeable partnership units, and exchangeable shares converted at the exchange ratio prevailing at the time. Total Trust Units as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures of other entities. The exchange ratio for exchangeable shares was 1.46445 at December 31, 2006 and 1.37265 at December 31, 2005. These shares were redeemed for trust units on January 16, 2007. Each exchangeable partnership unit is exchangeable into one trust unit.
(4) Cost of capital expenditures and acquisitions excluding any asset retirement obligation or future income tax
(5) Weighted average Total Trust Units including trust units, exchangeable partnership units, and exchangeable shares converted at the average exchange ratio
(6) Net of settlements for financial hedging instruments and net of transportation system charges
(7) Reserve numbers are total proved plus probable company gross reserves (before deduction of royalties payable, not including royalties receivable) as defined in National Instrument 51-101.
(8) Reserve life index is calculated by dividing year-end reserves by the forward year production estimate from the reserve reports.

Message to Unitholders

2006 was a very successful year for Focus. In addition to successfully continuing to develop and expand our existing assets, we undertook a major strategic transaction with the mid-year acquisition of Profico Energy Management Ltd. ("PEML"). Since our inception five years ago, we have maintained that we would be patient, picky and prudent with respect to acquiring strategic assets, and the PEML transaction follows through on this philosophy. The strategic rationale for this acquisition is founded on our conviction that large accumulations of long-life natural gas, such as the PEML assets, are ideally suited to Focus' sustainable business model. The addition of these assets to our already strong portfolio, makes the Trust stronger and more sustainable going forward and will ultimately result in increased value for unitholders.

Highlights

- The acquisition of PEML created a new core area and more than doubled Focus' production and reserves. The transaction also significantly expanded our undeveloped land holdings and drilling inventory in one of the lowest cost operating environments in the Western Canadian Sedimentary Basin.
- We completed our most extensive drilling program to date with 227 wells drilled with 100 percent success.
- Drilling inventory has expanded materially with over three years of drill-ready inventory at Shackleton and Tommy Lakes.
- Undeveloped land, the majority of which exists around our Shackleton and Tommy Lakes pools, increased six fold to 390,000 acres.
- December 31, 2006 proved plus probable reserves increased 108 percent to 83.7 MMBOE.
- Our internal exploration and development programs added 4.0 MMBOE of reserves at finding and development costs of $17.89 per BOE, representing a recycle ratio of 1.9 times.
- Revenue of $38.6 million from our hedging program helped stabilize funds flow (increased realized natural gas price by $1.31 per mcf).

Sustainability

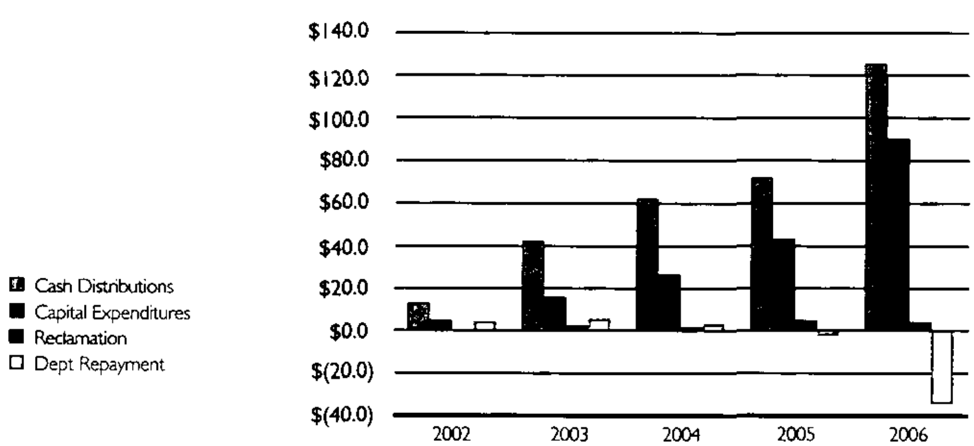
Five years ago, we set out to create a trust with a strong operational focus that utilized the drill bit to create value and focused on sustainability. The four main elements that we believe define sustainability are production per unit, reserves per unit, capital use versus funds flow, and drilling inventory.

Production per unit is a proxy for funds flow. Stable funds flow is important in that it allows for stable capital and distribution programs. Production per unit has remained essentially flat over the last five years. On a debt-adjusted basis, production per unit has dropped approximately 1.6 percent per year. Debt-adjusted assumes year-end debt is eliminated by the issuance of additional trust units. We believe this is an important measure as it eliminates the impact of the amount of debt in the capital structure.

Reserves per unit is a proxy for whether value is being created. Reserves per unit has increased 11.5 percent since the Trust inception. On a debt-adjusted basis, reserves per unit is up 2.3 percent over the same period.

In 2006 the sum of capital expenditures, distributions and reclamation obligations exceeded funds flow by approximately $36.6 million, largely as a result of a large land purchase, acceleration of our winter capital programs, and various payments associated with the PEML transaction.

USE OF FUNDS FLOW FROM OPERATIONS



Our drilling inventory has grown substantially with the PEML transaction, with over 1,000 drilling locations and over three years of drill-ready inventory at Tommy Lakes and Shackleton. The Trust's inventory has grown in both quantity and quality. The expansion of the inventory has been driven by our technical team's continued ability to generate new drilling ideas on our existing asset base.

As our history details, we are selective acquirers of assets. We continue to evaluate potential property and corporate acquisition opportunities, looking for large accumulations of long-life natural gas.

Acquisitions typically provide opportunities to expand or add to new core areas. It appears that this year the acquisition market may provide greater opportunities to acquire assets that fit our strategic requirements at a reasonable price.

Although acquisitions are important, we continue to focus the majority of our attention on generating drilling ideas on our existing land base as this is the most cost effective way for us to create value for our unitholders.

Outlook

In 2007, our drilling and development activity will focus on the Tommy Lakes and Shackleton areas with the bulk of our \$95-\$115 million capital program being spent in those two areas. By focusing our capital dollars in these two core areas, we hope to be able to achieve operational and execution cost efficiencies in addition to greater service cost reductions associated with increased volume.

We anticipate that our capital program will result in average production of 21,500 to 23,500 BOE/d in 2007 with associated operating costs in the range of \$3.75 to \$4.25 per BOE.

After the 25 percent drop experienced in natural gas prices in 2006, we remain cautious with respect to our outlook for natural gas prices in 2007 and resulting funds flow. To that end, we have broadened the range of our production and capital guidance to be more reflective of potential gas price volatility. Our hedging program, with approximately 60 percent of our 2007 gas price protected at \$8.26 per mcf, provides excellent protection in a volatile natural gas market. As we have no crystal ball to provide clarity on future commodity prices, we will continue to focus our attention on the parts of the business in which we can have an impact, primarily the control of our operating costs and our capital reinvestment efficiencies.

Industry activity levels have been dropping since late 2006 and, as a result, the sourcing of equipment and qualified people is becoming easier. In addition, prices for services are slowly decreasing reflecting the lower activity levels.

The Trust is in an excellent financial position with a low debt-to-funds-flow ratio of 1.2 times, and a sustainable business model that will not lead to a substantial increase in net debt on a year-over-year basis.

On October 31, 2006 the Federal Government announced tax proposals pertaining to distributions of publicly traded trusts. The tax announcement had a negative impact on the Canadian equity market and resulted in a significant decrease in trust unit prices. Irrespective of this taxation announcement, our core business of creating value for our unitholders remains intact. We have a high-quality asset base that allows us the luxury of time to assess any and all alternatives with respect to the future structure of the Trust.

We would like to thank our unitholders for investing in Focus and for their continued support.

We would also like to thank our Board of Directors for their continued guidance and the Focus team for their incredible efforts and enthusiasm.

On behalf of the Board,

Derek W. Evans

President and Chief Executive Officer

Operations Review

Focus' production is concentrated in two main core areas at Shackleton and Tommy Lakes. These two properties comprise approximately 80 percent of the Trust's production, 84 percent of reserves and the majority of our future development inventory. The remaining 20 percent of the Trust's production comes from six minor areas – Red Earth, Southwest Saskatchewan, Pouce Coupe, Sylvan Lake, Medicine Hat and Kotcho-Cabin.

In 2006, production of the Trust was weighted 84 percent to natural gas, with the remaining 16 percent consisting of crude oil and natural gas liquids. Our average working interest is approximately 80 percent and we operate approximately 93 percent of our production.

Shackleton, Saskatchewan

The Trust's Shackleton area, located in southwestern Saskatchewan, was the primary asset acquired in the PEML transaction. Production at Shackleton is from the Cretaceous Milk River formation, which produces sweet dry gas from relatively shallow depths ranging from 400 to 550 meters. This long-life natural gas property is characterized by operated high working interest production, a large inventory of low risk drilling locations, low production expenses, attractive Crown royalty rates and a dominant land position.

During 2006, Focus' gross production from Shackleton averaged 36.9 Mmcf per day of natural gas. This annual average only represents the impact of production from the June 27, 2006 effective date of the PEML acquisition. For the period from June 27 to December 31, 2006, production from the area averaged 71.7 Mmcf per day. Production at Shackleton is compressed and dehydrated at 13 Focus-operated facilities and delivered into the Transgas system for delivery to markets. At December 31, 2006, Shackleton represented approximately 51 percent of the Trust's reserves.

Since the acquisition, the Trust has been very active in developing the Shackleton asset, drilling 179 (150.3 net) wells in the second half of 2006, and commissioning two new compression facilities. This activity level has continued into the first quarter of 2007, which will see the drilling of approximately 90 gross wells, the installation of two new compressors, and selective recompletions. These development activities have focused on five main themes:

- development drilling at eight wells per section on lands in the western and northern portions of the field, offsetting successful pilot programs drilled in 2005;
- infill drilling to 4 wells per section in the central portions of the field;
- selective pilots in the central portions of the field to test the economics of eight wells per section in specific areas;
- step-out drilling to continue the evaluation of lands not currently developed, mainly along the northern boundary of the field;
- recompletion of additional Milk River intervals in currently producing wells.

These programs have been successful both in terms of additional production and reserves and in terms of increasing our understanding of the resource potential of this asset. Based on these results, we continue to believe that Shackleton will provide the Trust with a minimum of three more years of low-risk drilling and recompletion inventory.

Tommy Lakes, NE British Columbia

The Trust's Tommy Lakes property is located in northeastern British Columbia. The main producing zone at Tommy Lakes is the areally extensive blanket sand of the Triassic Halfway formation. Total original gas in place in the main Tommy Lakes Halfway A Pool is in excess of 600 Bcf, of which approximately 34 percent has been produced to date. Although the reservoir is thick (more than 10 meters) and continuous, permeability is low, requiring all wells to be fracture stimulated to achieve stabilized rates of 500 to 700 mcf per day, with natural gas liquids recovered at 20 barrels per million cubic feet.

During 2006, Focus' gross production from the Tommy Lakes property averaged 32.4 Mmcf per day of natural gas and 639 bbls per day of natural gas liquids. Production at the property is compressed at four Focus-operated facilities and delivered into the Duke system for further processing and delivery to markets. At December 31, 2006, Tommy Lakes represented approximately 33 percent of the Trust's reserves.

Subsequent to year end, the Trust successfully completed its 14-well (13.0 net) winter drilling program at Tommy Lakes. Twelve of these wells (12.0 net) were development wells drilled within the existing Tommy Lakes Halfway pool. All of these wells were cased and have been placed on production. Two wells (1.0 net) were follow-up exploratory tests drilled to the northwest of the existing Halfway pool. Both of these wells were successful, and were tied in to the Trust's Tommy Lakes gathering system via a 14-kilometer pipeline, along with one well from the previous year's winter program. The production performance of these wells over the remainder of the year will allow us to define the most appropriate development strategy for these lands.

This year's 14-well drilling program set out to achieve five main objectives:

- the continued efficient infill development of the Halfway pool;
- selective Halfway step-out drilling to continue to extend the economic boundaries of the main pool;
- development of secondary zone potential in the Doig and Bluesky formations;
- the continued implementation of well design and program execution initiatives designed to maximize per-well recoveries and minimize costs;
- further delineation of the Halfway potential on the exploratory lands to the northwest of the main pool.

The program was successful in achieving all of these objectives and the overall winter program at Tommy Lakes came in as per our expectations. Based upon this continued success, Focus anticipates several more years of similar sized development programs at Tommy Lakes.

Drilling

During 2006, the Trust participated in the drilling of 227 wells (190.3 net) with excellent drilling results and a success rate of 100 percent. The 2006 development program was strongly weighted towards natural gas with 98 percent of net wells and 91 percent of capital expenditures in the field directed towards gas targets. Focus was the operator of 222 of the 227 wells drilled in 2006.

Approximately 35 percent of Focus' capital expenditures for 2006 were invested at Shackleton for the drilling of 179 (151.3 net) Milk River natural gas wells. A further 32 percent of capital expenditures was invested at Tommy Lakes for the drilling of 15 (13.5 net) Halfway natural gas wells.

Additional activity in 2006 took place at Pouce Coupe with the drilling of two (2.0 net) natural gas wells for the Montney zone. At Medicine Hat and Southwest Saskatchewan, Focus drilled a total of 22 (17.8 net) wells targeting Milk River, Medicine Hat and Second White Specks gas. At Sylvan Lake, the Trust drilled three (2.0 net) Edmonton Sand gas wells. Finally, six oil wells (3.7 net) were drilled in the Red Earth area.

	2006				2005			
Drilling (Gross Wells)	Oil	Gas	Abandoned	Total	Oil	Gas	Abandoned	Total
Shackleton	–	179	–	179	–	–	–	–
Tommy Lakes	–	15	–	15	–	11	–	11
Red Earth	6	–	–	6	6	–	–	6
Southwest Saskatchewan	–	5	–	5	–	–	–	-
Pouce Coupe	–	2	–	2	–	2	–	2
Sylvan Lake	–	3	–	3	–	4	–	4
Medicine Hat	–	17	–	17	–	13	–	13
Kotcho	–	–	–	–	–	1	–	1
	6	221	–	227	6	31	–	37

	2006				2005			
Drilling (Net Wells)	Oil	Gas	Abandoned	Total	Oil	Gas	Abandoned	Total
Shackleton	–	151.3	–	151.3	–	–	–	–
Tommy Lakes	–	13.5	–	13.5	–	10.3	–	10.3
Red Earth	3.7	–	–	3.7	2.7	–	–	2.7
Southwest Saskatchewan	–	4.6	–	4.6	–	–	–	–
Pouce Coupe	–	2.0	–	2.0	–	2.0	–	2.0
Sylvan Lake	–	2.0	–	2.0	–	2.0	–	2.0
Medicine Hat	–	13.2	–	13.2	–	12.0	–	12.0
Kotcho	–	–	–	–	–	0.4	–	0.4
	3.7	186.6	–	190.3	2.7	26.7	–	29.4

Undeveloped Land

At December 31, 2006 Focus had undeveloped land of 389,546 net acres, a significant increase from 57,051 net acres at December 31, 2005. The majority of this increase is due to undeveloped lands acquired in the PEML transaction. The average working interest of the Trust's undeveloped land is 74 percent. Net undeveloped land is concentrated in Shackleton (64 percent) and Tommy Lakes (11 percent).

	December 31, 2006		December 31, 2005	
Undeveloped Acres	Gross	Net	Gross	Net
Saskatchewan	459,749	334,101	–	–
Alberta	15,366	10,978	16,807	11,573
British Columbia	53,559	44,467	50,207	45,478
Total	528,674	389,546	67,014	57,051

Production

Focus had average production in 2006 of 15,899 BOE per day, weighted 84 percent towards natural gas. These average annual production levels only reflect the impact of the acquired PEML assets for the second half of the year. For 2007, Focus expects average production of between 21,500 and 23,500 BOE per day.

	2006				2005			
	Oil	Natural Gas	NGLs		Oil	Natural Gas	NGLs	
Average Production by Area	bbls/d	mcf/d	bbls/d	BOE/d	bbls/d	mcf/d	bbls/d	BOE/d
Shackleton (1)	–	36,936	–	6,156	–	–	–	–
Tommy Lakes (2)	–	32,382	639	6,036	–	33,123	681	6,201
Red Earth	1,524	–	15	1,539	1,688	–	12	1,700
Southwest Saskatchewan (1)	158	1,729	–	446	–	–	–	–
Pouce Coupe	11	3,232	25	575	11	3,352	27	597
Sylvan Lake	54	1,845	49	410	66	2,111	57	475
Medicine Hat	–	2,255	–	376	–	1,822	–	304
Kotcho-Cabin	–	2,165	–	361	–	4,118	–	686
	1,747	80,544	728	15,899	1,765	44,526	777	9,963

(1) Includes production from June 27, 2006 PEML acquisition date
(2) Includes August 12, 2005 acquisition of additional interests at Tommy Lakes

	2006				2005			
Production by Quarter	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Crude oil (bbls/d)	1,965	1,844	1,563	1,610	1,714	1,718	1,779	1,850
Natural gas (mcf/d)	113,539	115,612	46,753	45,137	42,629	44,910	46,997	43,575
NGLs (bbls/d)	706	740	682	784	762	833	770	743
BOE/d	21,594	21,853	10,038	9,917	9,582	10,036	10,382	9,856

Year-End Reserves Review

Year-End Reserves

Based on independent engineering evaluations conducted by Paddock Lindstrom and Associates Ltd. ("Paddock") and GLJ Petroleum Consultants Ltd. ("GLJ") effective December 31, 2006, Focus had proved plus probable reserves of 83.7 MMBOE, an increase of 108 percent from the 40.3 MMBOE recorded at December 31, 2005. Reserve additions from exploration and development activities (including revisions) were 4.0 MMBOE, while 45.2 MMBOE were added through acquisition (net of minor dispositions), resulting in total additions of 49.2 MMBOE. Year-end reserves were evaluated in accordance with National Instrument 51-101 ("NI 51-101").

GLJ and Paddock evaluated 100 percent of the Trust's reserves. The portion of the evaluation conducted by GLJ represented 54 percent of the proved plus probable reserves and 51 percent of the associated future net revenue discounted at 10 percent. The remaining 46 percent of the proved plus probable reserves and 49 percent of the associated future net revenue were evaluated by Paddock. The GLJ December 31, 2006 price forecast was used in the future net revenue determinations for both evaluations. The Trust's Reserves Committee, made up of independent and qualified directors of the Trust, has reviewed the reports prepared by GLJ and Paddock and other pertinent reserves data. The Board of Directors, on the recommendation of the Reserves Committee, has approved the content of the GLJ and Paddock reports and other pertinent reserves data.

Proved developed producing reserves represent 47 percent of proved plus probable reserves, while total proved reserves represent 74 percent of total proved plus probable reserves. On a BOE basis, total proved plus probable reserves consist of 90 percent natural gas, six percent crude oil and four percent natural gas liquids.

On a proved basis, additions from exploration and development activities (discoveries and extensions including infill drilling) were 5.7 MMBOE and technical revisions were negative 1.4 MMBOE, resulting in total additions of 4.3 MMBOE. On a proved plus probable basis, additions from exploration and development activities were 7.3 MMBOE and technical revisions were negative 3.3 MMBOE, resulting in total additions of 4.0 MMBOE. The proved plus probable additions including revisions replaced 69 percent of the 5.8 MMBOE produced during 2006.

Net Present Value of Future Net Revenue

The estimated net present value of Focus' crude oil, natural gas and natural gas liquids reserves was evaluated using GLJ's December 31, 2006 price forecast prior to provision for income taxes, interest, debt service charges and general and administrative expenses. At a 10 percent discount rate, the net present value of the Trust's proved plus probable reserves was $1,276 million. Proved producing and total proved reserves make up respectively 63 percent and 79 percent of the total proved plus probable value.

On October 31, 2006, the Federal Government announced proposals pertaining to the taxation of distributions from publicly traded Canadian income trusts, royalty trusts and partnerships. The proposals include a 31.5 percent tax imposed on income before distributions at the trust level and taxed to the taxable Canadian investor, effectively as a dividend. If enacted, the proposals would apply to the Trust effective January 1, 2011. On December 21, 2006, the Department of Finance issued draft legislation consistent with the proposals described above. As at December 31, 2006, the legislative proposals are not substantively enacted. Any changes to income tax legislation that may result from these proposals may adversely affect the net present value of future net revenue of Focus' oil and gas reserves.

Reserve Life Index

Focus' proved plus probable RLI at year-end 2006 is 9.9 years, down slightly from the year-end 2005 RLI of 10.5 years. The lower RLI reflects the shorter reserve life index of the properties acquired in the PEML transaction. Similarly, the Trust's proved year-end 2006 RLI is 7.7 years as compared to 8.3 years at year-end 2005, again reflecting the impact of the acquired properties. These RLIs are calculated using period-end reserves and forward-year forecast production from the reserves report.

Reserve Addition Costs

Under NI 51-101, the methodology to be used to calculate FD&A costs includes incorporating changes in future development capital ("FDC") required to bring the proved undeveloped and probable reserves to production. Excluding acquisitions and divestitures, Focus' 2006 reserve addition costs were $16.09 per BOE on a proved basis and $17.89 per BOE on a proved plus probable basis. Including acquisitions and divestitures, 2006 reserve addition costs were $37.00 per BOE on a proved basis and $28.77 per BOE on a proved plus probable basis. At year end, total estimated FDC was $259 million for proved reserves and $337 million for proved plus probable reserves.

Three-year average reserve addition costs, excluding acquisitions and divestitures, are $18.30 per BOE on a proved basis and $21.44 per BOE on a proved plus probable basis. Three-year average reserve addition costs, including acquisitions and divestitures, are $30.58 per BOE on a proved basis and $24.80 per BOE on a proved plus probable basis. The Trust believes that these three-year average costs are the most accurate reflection of our ongoing reserve addition costs. Using a three-year average mitigates the impact of year-to-year variability in factors such as acquisition activity, the timing of the development of proved undeveloped reserves, reserve revisions, and changes to capital costs and estimates for future development capital.

Reserves Information

The following cautionary statements are specifically required by NI 51-101.

1. It should not be assumed that the estimates of future net revenues presented in the tables represent the fair market value of the reserves. There is no assurance that the constant price and cost assumptions and forecast prices and costs assumptions will be attained and variances could be material.
2. Disclosure provided herein in respect of BOE may be misleading, particularly if used in isolation. In accordance with NI 51-101, a BOE conversion ratio of 6 mcf:1 bbl has been used in all cases in this disclosure. This BOE conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
3. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during the year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.
4. Estimates of reserves and future net revenues for individual properties may not reflect the same confidence level as estimates of reserves and future net revenues for all properties due to the effects of aggregation.
5. In all cases, the F&D or FD&A cost is calculated by dividing the identified capital expenditures by the applicable reserves additions.

2006 Reserves Summary

Company Gross Reserves at December 31, 2006

(before deduction of royalties payable, not including royalties receivable) (based on Forecast Prices and Costs)	Light & Medium Crude Oil (mbbl)	Natural Gas (Mmcf)	NGLs (mbbl)	Oil Equivalent (MBOE)
Proved producing	3,971	199,538	1,709	38,936
Proved non-producing	57	14,467	147	2,615
Total proved developed	**4,028**	**214,005**	**1,856**	**41,552**
Proved undeveloped	188	116,936	693	20,370
Total proved	**4,216**	**330,941**	**2,549**	**61,922**
Probable additional	1,023	119,997	718	21,740
Total proved + probable	**5,239**	**450,938**	**3,267**	**83,662**

Company Net Reserves at December 31, 2006

(after deduction of royalties payable, not including royalties receivable) (based on Forecast Prices and Costs)	Light & Medium Crude Oil	Natural Gas	NGLs	Oil Equivalent
	(mbbl)	(Mmcf)	(mbbl)	(MBOE)
Proved producing	3,438	172,322	1,313	33,471
Proved non-producing	45	10,785	113	1,956
Total proved developed	**3,483**	**183,107**	**1,426**	**35,427**
Proved undeveloped	166	100,708	548	17,499
Total proved	**3,649**	**283,815**	**1,974**	**52,926**
Probable additional	892	103,168	560	18,646
Total proved + probable	**4,541**	**386,983**	**2,534**	**71,572**

(1) Numbers may not add due to rounding.

Net Asset Value (before tax)

The following net asset value ("NAV") table shows what is commonly referred to as a "produce out" NAV calculation before tax. The value is a snapshot in time and is based on various assumptions including commodity prices and foreign exchange rates that vary over time.

NAV at December 31, 2006 (before tax)

	Discounted at 10%		Discounted at 5%	
($ millions except per-unit amounts)	GLJ Price Forecast	Constant Price Forecast	GLJ Price Forecast	Constant Price Forecast
Value of proved plus probable reserves	1,276	923	1,669	1,181
Undeveloped lands	37	37	37	37
Net debt including working capital	(308)	(308)	(308)	(308)
Reclamation fund	6	6	6	6
Abandonment and reclamation liability (1)	(5)	(3)	(4)	(1)
Net asset value	1,006	655	1,400	915
Total Trust Units outstanding (millions)	78.5	78.5	78.5	78.5
Per Total Unit (before tax)	$ 12.81	$ 8.34	$ 17.83	$ 11.65

(1) In addition to abandonment and reclamation liability already included in reserve reports

Net asset value per unit of $12.81, based on the GLJ Price Forecast and a 10 percent discount rate, decreased 22 percent on a year-over-year basis from $16.50 at December 31, 2005, driven primarily by a lower commodity price forecast. Note that the value of reserves does not include the effect of our price protection program. Including the value of physical and financial hedging contracts in place at December 31, 2006 would increase our net asset value per unit from $12.81 to $13.11.

2006 Reserve Reconciliation

Company Gross Reserves

(before deduction of royalties payable, not including royalties receivable)	Light & Medium Crude Oil (mbbl)	Natural Gas (Mmcf)	NGLs (mbbl)	Oil Equivalent (MBOE)
TOTAL PROVED				
December 31, 2005	4,087	145,828	2,631	31,022
Discoveries	0	377	0	63
Extensions	135	30,322	404	5,593
Improved recovery	0	0	0	0
Technical revisions	(120)	(6,284)	(216)	(1,384)
Economic factors	0	0	0	0
Acquisitions	749	191,567	0	32,677
Dispositions	0	(1,470)	0	(245)
Production	(634)	(29,399)	(270)	(5,804)
December 31, 2006	**4,216**	**330,941**	**2,549**	**61,922**
PROBABLE				
December 31, 2005	1,521	41,678	789	9,257
Discoveries	0	75	0	13
Extensions	45	8,881	79	1,604
Improved recovery	0	0	0	0
Technical revisions	(731)	(6,077)	(149)	(1,893)
Economic factors	0	0	0	0
Acquisitions	187	75,552	0	12,779
Dispositions	0	(113)	0	(19)
Production	0	0	0	0
December 31, 2006	**1,023**	**119,997**	**718**	**21,740**
PROVED PLUS PROBABLE				
December 31, 2005	5,608	187,506	3,420	40,279
Discoveries	0	452	0	75
Extensions	180	39,203	483	7,196
Improved recovery	0	0	0	0
Technical revisions	(851)	(12,361)	(366)	(3,277)
Economic factors	0	0	0	0
Acquisitions	936	267,119	0	45,456
Dispositions	0	(1,583)	0	(264)
Production	(634)	(29,399)	(270)	(5,804)
December 31, 2006	**5,239**	**450,938**	**3,267**	**83,662**

(1) All reserves are based on Forecast Prices and Costs.
(2) Numbers may not add due to rounding.

Net Present Value Summary

Net Present Value of Future Net Revenue Before Income Taxes – Forecast Prices and Costs

($ thousands)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved producing	1,217,303	961,714	802,245	693,059	613,455
Proved non-producing	73,094	53,491	42,806	35,835	30,849
Total proved developed	**1,290,397**	**1,015,205**	**845,051**	**728,894**	**644,304**
Proved undeveloped	416,016	257,184	168,295	113,351	76,974
Total proved	**1,706,413**	**1,272,389**	**1,013,346**	**842,245**	**721,278**
Probable additional	676,660	397,089	262,405	187,039	140,339
Total proved + probable	**2,383,073**	**1,669,478**	**1,275,751**	**1,029,284**	**861,617**

(1) Numbers may not add due to rounding.

December 31, 2006 Price Forecast – GLJ Petroleum Consultants Ltd.

	WTI Crude Oil	Edmonton Light Crude Oil	Henry Hub Natural Gas	AECO C Natural Gas	Westcoast Station 2 Natural Gas	Exchange Rate
	$US/bbl	$CDN/bbl	$US/Mmbtu	$CDN/Mmbtu	$CDN/Mmbtu	$US/$CDN
2007	62.00	70.25	7.25	7.20	7.20	0.87
2008	60.00	68.00	7.50	7.45	7.45	0.87
2009	58.00	65.75	7.50	7.75	7.75	0.87
2010	57.00	64.50	7.50	7.80	7.80	0.87
2011	57.00	64.50	7.50	7.85	7.85	0.87
2012	57.50	65.00	7.75	8.15	8.15	0.87
2013	58.50	66.25	7.90	8.30	8.30	0.87
2014	59.75	67.75	8.05	8.50	8.50	0.87
2015	61.00	69.00	8.20	8.70	8.70	0.87
2016	62.25	70.50	8.40	8.90	8.90	0.87
2017	63.50	71.75	8.55	9.10	9.10	0.87
Escalate thereafter at	2%/yr	2%/yr	2%/yr	2%/yr	2%/yr	0%/yr

Net Present Value of Future Net Revenue Before Income Taxes – Constant Prices and Costs

($ thousands)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved producing	925,108	751,029	637,173	556,728	496,768
Proved non-producing	52,374	39,843	32,397	27,330	23,623
Total proved developed	**977,482**	**790,872**	**669,570**	**584,058**	**520,391**
Proved undeveloped	222,035	129,795	76,307	42,662	20,290
Total proved	**1,199,517**	**920,667**	**745,877**	**626,720**	**540,681**
Probable additional	421,439	260,694	176,952	127,643	96,083
Total proved + probable	**1,620,956**	**1,181,361**	**922,829**	**754,363**	**636,764**

(1) Numbers may not add due to rounding.

Constant Prices at December 31, 2006

	Edmonton Light Crude Oil	AECO C Natural Gas	Westcoast Station 2 Natural Gas
	$CDN/bbl	$CDN/Mmbtu	$CDN/Mmbtu
2007 and thereafter	67.58	6.07	6.22

Finding and Development Costs

Company Gross Reserves Excluding the Effect of Acquisitions and Dispositions (1)

	2006	2005	2004	Three-Year Total
Capital expenditures – $MM	**57.2**	43.0	25.2	125.4
Net change in future development capital – $MM				
Proved	**11.5**	13.9	9.5	35.0
Proved plus probable	**14.3**	15.9	3.6	33.8
Total capital including change in future development capital – $MM				
Proved	**68.7**	57.0	34.6	160.3
Proved plus probable	**71.5**	58.9	28.8	159.1
Reserve additions – MMBOE				
Proved	**4.27**	2.61	1.88	8.76
Proved plus probable	**4.00**	1.63	1.80	7.42
Finding and development cost – $/BOE				
Proved	**$ 16.09**	$ 21.86	$ 18.40	$ 18.30
Proved plus probable	**$ 17.89**	$ 36.15	$ 15.99	$ 21.44

(1) Reserves are based on Forecast Prices and Costs.
(2) Numbers may not add due to rounding.

Finding, Development and Acquisition Costs

Company Gross Reserves Including the Effect of Acquisitions and Dispositions (1)

	2006	2005	2004	Three-Year Total
Capital expenditures – $MM	**1,161.0**	53.4	154.8	1,369.2
Net change in future development capital – $MM				
Proved	**197.1**	14.1	18.6	229.8
Proved plus probable	**254.2**	18.9	21.4	294.4
Total capital including change in future development capital – $MM				
Proved	**1,358.1**	67.5	173.4	1,599.0
Proved plus probable	**1,415.2**	72.3	176.2	1,663.6
Reserve additions – MMBOE				
Proved	**36.70**	3.09	12.50	52.30
Proved plus probable	**49.19**	2.42	15.48	67.09
Finding and development cost – $/BOE				
Proved	**$ 37.00**	$ 21.84	$ 13.87	$ 30.58
Proved plus probable	**$ 28.77**	$ 29.87	$ 11.38	$ 24.80

(1) Reserves are based on Forecast Prices and Costs.
(2) Numbers may not add due to rounding.

Sustainability

Five years ago we set out to create a Trust with a strong operational focus, that utilized the drill bit to create value and focused on a sustainable business plan. The objective was to provide superior and sustainable long-term returns to our unitholders. The four elements that we believe define sustainability are production per unit, reserves per unit, capital use versus funds flow and drilling inventory.

Production and Reserves per Unit

Production per Unit	**2006**	2005	2004	2003	2002
Unadjusted (1)	**0.27**	0.27	0.27	0.28	0.28
Debt adjusted (3)	**0.23**	0.24	0.24	0.25	0.25

Reserves per Unit	**2006**	2005	2004	2003	2002
Unadjusted (2)	**1.07**	1.08	1.11	0.93	0.96
Debt adjusted (4)	**0.88**	0.98	1.01	0.88	0.86

(1) Average daily production per thousand units divided by weighted average Total Trust Units
(2) Proved plus probable reserves divided by period-end Total Trust Units
(3) Debt adjusted assumes year-end debt eliminated by adding units equal to the average net debt for the period divided by the average monthly closing unit prices for the period.
(4) Debt adjusted assumes year-end debt eliminated by adding units equal to the end of period debt divided by the closing unit price.

Production per unit is a proxy for funds flow. Stable funds flow is important in that it allows for stable capital and distribution programs. On an unadjusted basis, production per unit has remained essentially flat since inception of the Trust. On a debt-adjusted basis, production per unit decreased by 2.9 percent to 0.23 from 0.24 in 2005. This decrease is the result of lower than anticipated production levels and the seasonality of production additions. Production per unit on a debt-adjusted basis has decreased by approximately eight percent over the last five years.

Reserves per unit is an important metric, as it points to whether value is being created on a year-over-year basis. On an unadjusted basis the Trust's per-unit reserves have increased by 11.5 percent since the Trust's inception, with a corresponding 2.3 percent increase on a debt-adjusted basis.

On a debt-adjusted basis, 2006 reserves per unit decreased by 10 percent as compared to 2005. The decrease is impacted by the 29 percent drop in our year-end unit prices on a year-over-year basis as well as the relative immaturity of the Shackleton asset base which will see reserve appreciation as it matures. We anticipate seeing reserve appreciation on the existing producing wells as well as through identification of additional infill and step-out locations.

Financial Sustainability

($ millions)	**2006**	2005	2004	2003	2002	Cumulative
Capital expenditures	**90.4**	43.0	25.2	16.8	4.1	179.6
Distributions	**124.2**	73.7	61.4	41.0	11.1	311.4
Reclamation fund & expenditures	**3.2**	1.4	1.0	1.3	–	6.9
Total	**217.8**	118.1	87.6	59.1	15.2	497.9
Available funds flow	**181.2**	116.4	89.6	65.8	19.0	472.0
Difference	**(36.6)**	(1.8)	2.0	6.7	3.8	(25.9)

We adhere to a business strategy of sustainability where the sum of capital expenditures, distributions and reclamation obligations is equal to or less than funds flow. The above table demonstrates our performance in this regard since Trust inception and points to 2006 where we had a significant difference between available funds flow and total expenditures of $36.6 million. This difference resulted from the rapid decline in natural gas prices throughout 2006 resulting in a shortfall of approximately $20 million. The other major components of the $36.6 million were Focus' decision to invest $9.8 million at the Saskatchewan land sale in August and $5.0 million related to acceleration of the Tommy Lakes and Shackleton 2006/2007 winter drilling programs into the fourth quarter.

The Trust continually monitors the forward strip for natural gas and takes action in a prudent and proactive manner to ensure sustainability through price protection activities and by adjusting capital programs and distributions levels.

Inventory

	2006	2005	2004	2003	2002
Reserve life index	**9.9**	10.5	10.6	9.8	9.1
Undeveloped land (000's of net acres)	**389.5**	57.1	26.9	14.4	14.4

Our drilling inventory and undeveloped land have expanded materially with the PEML acquisition. At the end of 2006 we have in excess of three years of drill-ready inventory at Shackleton and Tommy Lakes. In addition, we have concrete plans at both properties to expand that drill-ready inventory by extending pool boundaries onto the surrounding undeveloped land.

We continue to add to our land position in and around Shackleton and Tommy Lakes. In August we increased our Shackleton land position with the acquisition of 12,320 acres of additional land in the centre of the Shackleton pool with over 100 Milk River drilling locations.

The expansion of our drilling inventory in both breadth and depth has been driven by the PEML acquisition, the August Saskatchewan land sale and our technical team's efforts and ability to generate new ideas on our existing asset base. Key strengths within Focus are the concentration and quality of its long-life natural gas assets, combined with an extensive undeveloped land position surrounding the large natural gas pools, low operating costs and low royalty rates resulting in attractive netbacks through all parts of the commodity price cycle.

Management's Discussion and Analysis

The following is a discussion and analysis of the operating and financial results of Focus for the three months and year ended December 31, 2006 compared with the prior year, as well as information and opinions concerning the Trust's future outlook based on currently available information. This discussion is dated March 5, 2007 and should be read in conjunction with the Trust's audited consolidated financial statements for the years ended December 31, 2006 and 2005, together with accompanying notes.

Throughout this Management's Discussion and Analysis, we use the term funds flow from operations ("funds flow" before changes in non-cash working capital and reclamation costs). Funds flow is used by management to analyze operating performance and leverage. Funds flow, as presented, does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures of other entities. Funds flow, as presented, is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to funds flow throughout this report are based on funds flow from operations before changes in non-cash working capital and reclamation costs.

Per barrel of oil equivalent ("BOE") amounts have been calculated using a conversion of six thousand cubic feet of natural gas to one barrel of oil (6 mcf = 1 bbl).

Overall 2006 Performance

2006 was a year of significant growth and solid results for Focus in a business environment which experienced a 25 percent decline in the average reference price for natural gas and continued cost pressures for the industry. Focus continued to adhere to its strategy of surfacing value on our existing assets, maintaining cost efficiencies, maintaining financial strength and acquiring quality assets. During the year, Focus undertook a large acquisition of quality assets which will enhance our sustainability, value creation through drilling and financial strength going forward.

The most significant event for Focus during the year was the acquisition of PEML effective June 27, 2006 which added a new core area and more than doubled production, reserves, undeveloped land and drilling inventory. The assets acquired are long-life gas plays in the early stage of development, 98 percent weighted to natural gas, and characterized by high working interest, low production expenses and operated production with a dominant land position. The results for the last half of 2006 reflect the expanded asset and unitholder base following the acquisition through substantially increased production, funds flow from operations, development drilling activity and the overall strength of the organization.

Focus utilized $181.2 million of funds flow from operations plus $36.6 million of debt to fund distributions of $124.2 million, $90.4 million of capital expenditures and $3.2 million of reclamation fund contributions and expenditures in 2006. Distributions for the year include the payment of $7.8 million on July 17, 2006 to the former shareholders of PEML in connection with the acquisition on June 27, 2006. Capital expenditures include $9.8 million spent by Focus at the Saskatchewan land sale in August to acquire 19.5 sections of undeveloped land in the centre of the Shackleton Milk River gas play.

Focus' production is 85 percent to 90 percent weighted to natural gas, and fluctuations in natural gas prices have a significant impact on our funds flow from operations and field netback. Natural gas prices were volatile in 2006 based on high natural gas storage levels and uncertainty with respect to weather, hurricanes and the supply response to lower prices and higher capital costs. The volatility of natural gas prices per mcf is demonstrated by a high of $11.43 in the fourth quarter of 2005, $7.50 in the first quarter of 2006, $6.04 for the second quarter of 2006, $5.66 in the third quarter of 2006 and a rebound to $6.99 in the fourth quarter of 2006. Focus continues to actively utilize a price protection program to reduce the volatility of commodity prices and the corresponding funds flow from operations. For 2006, the longer term physical delivery sales contracts and financial hedging contracts for natural gas strongly supported our financial results with approximately $38.6 million of additional natural gas revenue and a realized natural gas price higher by $1.31 per mcf. For the fourth quarter of 2006, price protection for natural gas added approximately $14.8 million of additional revenue and increased the realized natural gas price by $1.42 per mcf.

Funds flow from operations for the fourth quarter of 2006 was a record $64.4 million and brought the total for 2006 to $181.2 million. This represents $0.82 per unit for the fourth quarter of 2006 and $3.09 per unit for 2006, compared with $0.86 in the fourth quarter of 2005 and $3.12 for 2005. The results for 2006 reflect the decline in the average natural gas reference price being largely offset by the positive impact of the price protection programs, a lower effective rate for royalties (due to financial hedging settlements) and lower production expenses per BOE.

Net income for 2006 was $72.9 million compared with $63.4 million in 2005. On a per unit basis, net income declined to $1.26 in 2006 compared with $1.74 in 2005. With funds flow from operations per unit remaining relatively constant for both years, this decline in net income per unit is primarily due to the significantly higher charges recorded for depletion and depreciation in the second half of 2006 resulting from the acquisition effective June 27, 2006, and a two percent decrease in funds flow from operations per BOE.

Focus had active development programs in 2006 with reinvestment in our core areas and a 100 percent drilling success rate. Focus invested $90.4 million in capital programs for the year and drilled a record 190.3 net wells, with 98 percent of net wells drilled targeting natural gas. There was a significant increase in development activity in the second half of 2006 following the acquisition, with capital expenditures of $63.5 million and 174.9 net wells drilled. The 2006 Tommy Lakes winter drilling program resulted in 11 new producing wells and two exploration wells. On the PEML assets (primarily Shackleton), Focus invested $43.0 million and successfully drilled 155.9 net wells during the second half of 2006.

Operations Summary

	Three Months Ended Dec. 31, 2006	2005	Years Ended Dec. 31, 2006	2005	Year Over Year Change
Average daily production					
Barrels of oil equivalent (@ 6:1)	**21,594**	9,582	**15,899**	9,963	60%
% Natural gas	**88%**	74%	**84%**	74%	
Average product prices realized(1)					
Crude oil sales (CDN$/bbl)	**$ 58.27**	$ 68.95	**$ 68.31**	$ 66.81	2%
Financial hedging settlements (CDN$/bbl)	**$ (0.76)**	$ (9.75)	**$ (2.70)**	$ (10.20)	(74%)
Realized price (CDN$/bbl)	**$ 57.51**	$ 59.20	**$ 65.61**	$ 56.61	16%
NGLs (CDN$/bbl)	**$ 53.85**	$ 60.64	**$ 61.52**	$ 57.50	7%
NGL price/crude oil price	**92%**	88%	**90%**	86%	4%
Natural gas sales (CDN$/mcf)	**$ 6.97**	$ 10.20	**$ 6.84**	$ 8.64	(21%)
Transportation system charges (CDN$/mcf)	**$ (0.33)**	$ (0.62)	**$ (0.41)**	$ (0.61)	(32%)
Financial hedging settlements (CDN$/mcf)	**$ 1.16**	$ (0.34)	**$ 0.94**	$ (0.11)	958%
Realized price (CDN$/mcf)	**$ 7.80**	$ 9.24	**$ 7.37**	$ 7.92	(7%)
Reference prices & differential to Focus sales price, after transportation and before price protection					
Crude oil (Edm. Light Price CDN$/bbl)	**$ 64.55**	$ 71.17	**$ 72.85**	$ 68.50	6%
Differential (CDN$/bbl)	**$ (6.29)**	$ (2.22)	**$ (4.54)**	$ (1.69)	168%
Natural gas (AECO daily CDN$/mcf)	**$ 6.99**	$ 11.43	**$ 6.55**	$ 8.77	(25%)
Differential (CDN$/mcf)	**$ (0.61)**	$ 0.17	**$ (0.48)**	$ (0.17)	(184%)
Funds flow from operations per BOE					
Production revenue	**$ 43.79**	$ 62.62	**$ 45.06**	$ 55.00	(18%)
Financial hedging settlements	**6.03**	(3.27)	**4.48**	(2.30)	
Transportation system charges	**(1.74)**	(2.74)	**(2.09)**	(2.73)	(24%)
Realized price (1)	**48.09**	56.61	**47.45**	49.97	(5%)
Royalties, net of ARTC	**(8.94)**	(13.41)	**(9.32)**	(11.98)	(22%)
Production expenses	**(4.04)**	(4.61)	**(4.17)**	(4.11)	1%
Field netback	**35.11**	38.58	**33.96**	33.88	0%
Facility income	**0.38**	0.44	**0.47**	0.54	(13%)
Business interruption insurance	**–**	–	**0.07**	–	100%
Interest income	**0.01**	0.01	**0.01**	0.01	0%
General and administrative, cash portion	**(0.99)**	(1.27)	**(0.97)**	(1.22)	(20%)
Elimination of the Executive Bonus Plan	**–**	–	**(0.49)**	–	100%
Interest and financing and other	**(2.09)**	(1.07)	**(1.77)**	(0.97)	82%
Current and large corporations tax	**–**	0.01	**(0.04)**	(0.24)	(84%)
Funds flow from operations per BOE	**$ 32.42**	$ 36.70	**$ 31.23**	$ 32.00	(2%)
Funds flow from operations/field netback	**92%**	95%	**92%**	94%	(2%)
Royalty rate (before hedging settlements and net of transportation system charges)	**21%**	22%	**22%**	23%	(1%)
Production revenue, before transportation system charges ($ thousands)					
Crude oil, before hedging settlements	**10,563**	10,925	**43,720**	43,182	1%
Financial hedging settlements	**(137)**	(1,538)	**(1,722)**	(6,573)	(74%)
NGLs	**3,497**	4,255	**16,346**	16,321	0%
Natural gas, before transportation system charges	**72,939**	40,017	**201,393**	140,516	43%
Financial hedging settlements	**12,114**	(1,345)	**27,746**	(1,777)	
Non-cash amortization of hedging contracts (2)	**(542)**	–	**(1,843)**	–	(100%)
Production revenue	**98,435**	52,315	**285,639**	191,669	49%
Funds flow from operations ($ thousands)					
Cash flow from operating activities	**60,008**	36,818	**150,323**	114,744	31%
Reclamation costs	**(8)**	34	**277**	632	(56%)
Net change in non-cash working capital items	**4,412**	(4,502)	**30,623**	992	
Funds flow from operations	**64,412**	32,350	**181,223**	116,368	56%

(1) Net of settlements for financial hedging instruments and transportation system charges
(2) See Note 14 of the notes to consolidated financial statements

Business Acquisition

Effective June 27, 2006 Focus acquired PEML pursuant to a Plan of Arrangement which was approved by both the unitholders of Focus and the shareholders of PEML.

Acquisition impacts:

- Production more than doubled and the resulting production is weighted 88 percent towards natural gas.
- A much larger capital expenditure program going forward will be centered on development drilling opportunities at Shackleton in Saskatchewan and Tommy Lakes in British Columbia, conducted on a year-round basis.
- Total acquisition costs of approximately $1.1 billion, before asset retirement obligations and future tax, was financed through the issuance of equity of 30.8 million trust units and 10 million exchangeable partnership units and the remaining $200 million was financed through debt and cash.
- The acquisition financing included $179 million of additional net debt. In connection with the acquisition, Focus increased its syndicated bank credit facility to $350 million, in addition to a $15 million demand operating line of credit.
- Reflecting the new production base and level of capital programs of the Trust, Focus strengthened the organization with the addition of personnel in all areas of the Trust. General and administrative expenses increased accordingly; however, general and administrative expenses on a per BOE basis are lower due to increases in production and overhead recoveries.

Focus remains committed to long-term sustainability, value creation through development drilling and maintaining a strong financial position.

Seasonality of Operations

Prior to the acquisition in June 2006, most of the natural gas properties of Focus were in areas of British Columbia which were only accessible by road in the winter. This included Tommy Lakes and Kotcho-Cabin. These areas represented approximately 70 percent of our production and the majority of the Trust's capital program. Seasonality resulted in capital expenditures, overhead recoveries and utilization of bank credit facilities being highest in the first and fourth quarters of the year. In addition, higher production volumes, revenue and royalties were reported in Q1 and production expenses were higher in the first and fourth quarters when the properties were accessible.

With the acquisition in June 2006, only 30 percent of production is from northeast British Columbia and seasonality will be less of a factor than it has been historically. Winter access issues, especially for the Tommy Lakes winter development program and some environmentally sensitive areas within Shackleton, will continue to impact the operating results of Focus.

Production

2006 Q4:

- Production was essentially flat on a BOE basis during the fourth quarter to 21,594 BOE per day from 21,853 BOE per day in the third quarter. Production for the fourth quarter was weighted 88 percent towards natural gas and three percent towards natural gas liquids.
- Oil and NGL production increased three percent to 2,671 BOE per day largely due to increases from three new wells in the Red Earth area which came on production in September. Natural gas production declined two percent from 115.6 mcf per day to 113.5 mcf per day.
- The Saskatchewan properties contributed 74.6 mcf per day to natural gas production in the fourth quarter compared to 75.4 mcf per day in the third quarter. Production from Tommy Lakes of 29.4 Mmcf per day in the fourth quarter is consistent with the pattern of fourth quarter production levels being the lowest of the year. Fourth quarter natural gas production increased at Sylvan Lake, with three new gas wells brought on stream in mid October, and Cabin where a well was brought back on production in late November.

2006 compared with 2005:

- Production averaged 15,899 BOE per day in 2006 compared to 9,963 BOE per day in 2005. The most significant factor impacting production was the PEML acquisition in late June 2006 which contributed 6,602 BOE per day to average 2006 production.
- Oil and NGL production decreased three percent to 2,475 BOE per day in 2006 from 2,542 BOE per day in 2005. Heavy oil acquired with the PEML acquisition contributed 158 BOE per day to the average. Overall crude oil production going forward will reflect the natural decline of the properties and limited capital investment in oil properties.
- Average 2006 natural gas production increased 81 percent to 80.5 Mmcf per day from 44.5 Mmcf per day in 2005. Production from the PEML properties increased annual average production by 38.7 Mmcf per day, based on average production of 75.0 Mmcf per day in the last half of 2006. Tommy Lakes natural gas production declined two percent on a year-over-year basis. Production at Medicine Hat increased 24 percent from 1.8 Mmcf per day to 2.3 Mmcf per day. Natural gas production declines at Kotcho-Cabin were approximately 2.0 Mmcf per day.

Pricing and Price Risk Management

Natural Gas Pricing to June 30, 2006 (prior to the PEML acquisition)

- Focus had a differential between the realized price compared to the AECO average daily reference price resulting from:
  a) a higher than standard heat content of our natural gas at 1.16 GJ's per mcf;
  b) approximately 83 percent of our natural gas being delivered to British Columbia markets which received a lower price;
  c) approximately 83 percent of our natural gas incurring transportation system charges in British Columbia which have a higher charge per mcf;
  d) the timing differences between how physical gas is sold during the period versus the AECO daily average.

Natural Gas Pricing after June 30, 2006 (after the PEML acquisition)

- Focus has a differential between the realized price compared to the AECO average daily reference price resulting from:
  a) an average heat content of our natural gas of 1.06 GJ's per mcf;
  b) approximately 30 percent of natural gas being delivered to British Columbia markets which receives a lower price than the AECO reference price;
  c) approximately 30 percent of natural gas incurring transportation system charges in British Columbia which have a higher charge per mcf;
  d) the timing differences between how physical gas is sold during the period versus the AECO daily average.
- Realized natural gas price compared to AECO daily reference price to December 31, 2006:

Realized Price Per Mcf	Three Months Ended December 31, 2006	Three Months Ended December 31, 2005	Years Ended December 31, 2006	Years Ended December 31, 2005
AECO daily average (CDN$/mcf) (1)	$ 6.99	$ 11.43	$ 6.55	$ 8.77
Plus: heat content adjustment (1) (2)	–	1.29	0.17	0.83
Less: differential to B.C. markets (1) (2)	(0.03)	(0.02)	(0.20)	(0.16)
Less: transportation system charges (2)	(0.33)	(0.62)	(0.41)	(0.61)
Adjust: timing of actual gas sales (1) (2)	(0.24)	(0.48)	(0.04)	(0.23)
Price before price protection (physical & financial)	6.38	11.60	6.06	8.60
Impact of longer term physical sales contracts (1)	0.26	(2.02)	0.37	(0.57)
Financial hedging settlements	1.16	(0.34)	0.94	(0.11)
Focus' realized price per mcf	$ 7.80	$ 9.24	$ 7.37	$ 7.92
(1) Focus natural gas sales price per mcf (before transportation system charges and financial hedging settlements)	$ 6.97	$ 10.20	$ 6.84	$ 8.64
(2) Differential of Focus sales price to AECO daily reference price after transportation and before price protection per mcf	$ (0.61)	$ 0.17	$ (0.48)	$ (0.17)

Natural Gas Pricing

- Natural gas reference prices recovered somewhat in the fourth quarter of 2006; however, the average natural gas reference price for 2006 was 25 percent below the average reference price for 2005. The average AECO daily reference price per mcf for natural gas was $6.99 during the fourth quarter of 2006 compared with $5.66 for the third quarter of 2006, $6.04 for the second quarter of 2006 and $7.50 in the first quarter of 2006.
- Focus' realized natural gas price in the fourth quarter of 2006 was 16 percent higher than the third quarter of 2006 due to a higher price protected (with physical and financial contracts) and through a 23 percent increase in the reference price. The realized price in the fourth quarter of 2006 was 16 percent lower than the fourth quarter of 2005 due to significant decrease in the reference price of natural gas.
- During the fourth quarter of 2006, the price protection program of Focus reduced some of the volatility in natural gas prices and increased the realized price received by $1.42 per mcf. During the quarter, 25 percent of natural gas was sold under forward physical sales contracts which resulted in natural gas sales being $2.7 million higher than if the natural gas had been sold based on the AECO daily reference price. A further 47 percent of natural gas production was hedged with financial instruments. The impact of the financial instrument settlements was positive $12.1 million for the fourth quarter of 2006.
- For 2006, price protection through physical delivery contracts and financial instruments increased revenue by approximately $38.6 million and increased the realized price for natural gas by $1.31 per mcf. This compares with a cost of $10.9 million, or $0.57 per mcf in 2005. At December 31, 2006, the mark-to-market value for natural gas of financial instruments was $25.8 million and $7.8 million for physical contracts.
- Accounting for financial contracts will change in 2007 to mark-to-market accounting from hedge accounting. This is further discussed in Note 14 of the notes to consolidated financial statements.

Crude Oil

- The price realized by Focus for crude oil, after settlement of financial hedges, was $57.51 per barrel for the fourth quarter of 2006 versus $59.20 for the comparable period in 2005, and $70.09 per barrel in the third quarter of 2006.
- The differential between the sales price of our crude oil compared with the Edmonton par reference price for light oil in the fourth quarter of 2006 was $6.29 per barrel. Heavy oil production, representing 16 percent of oil production for the quarter, had a differential of $25.53 per barrel compared with the light oil production which had a differential of $2.54 per barrel. Apportionment on the Rainbow pipeline resulted in additional trucking charges in the fourth quarter of 2006.
- Focus has utilized price protection for a portion of its crude oil production. For 2006, 700 barrels per day were hedged financially with a cost of $1.7 million, or $2.70 per barrel. This compares with a cost of $6.6 million in 2005 on the 1,100 barrels per day hedged, or $10.20 per barrel. For the fourth quarter of 2006, 700 barrels per day were hedged, representing approximately 36 percent of crude oil production, with a cost of $0.1 million or $0.76 per barrel. At December 31, 2006, the mark-to-market cost for crude oil financial instruments was $0.1 million.

Price Protection

- Focus uses price protection through longer term physical delivery contracts and financial contracts to reduce the volatility in commodity prices and assist in maintaining sustainable distributions.
- Our current price protection program is outlined below. A full description of the outstanding financial instruments and the physical sales contracts and their estimated mark-to-market values as at December 31, 2006 is contained in Notes 14 and 15 of the notes to consolidated financial statements.

Price Protection at March 6, 2007

(volume and reference price)	2007				2008
	Q1	Q2	Q3	Q4	Q1
Natural gas (1)					
Mmcf/d	81.9	77.5	77.5	51.2	37.7
CDN$/mcf	$ 8.68	$ 8.01	$ 8.01	$ 8.36 - $ 8.51	$ 8.76 - $ 9.06
Crude oil					
bbls/d	400	800	800	400	–
CDN$/bbl	$ 70.00 - $ 79.00	$ 70.47 - $ 79.00	$ 70.47 - $ 79.00	$ 70.00 - $ 79.00	–

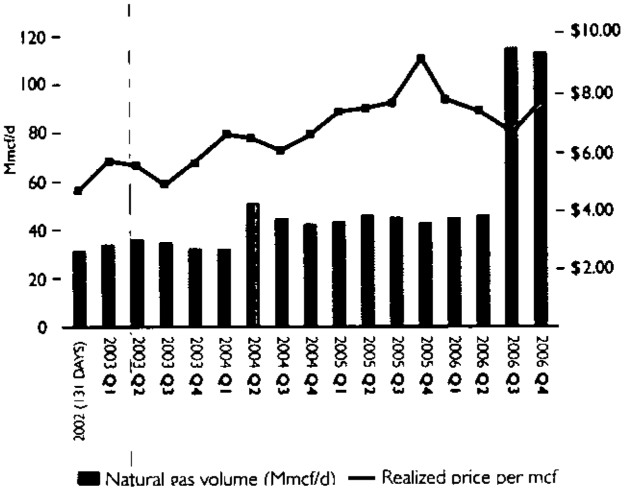
(1) These amounts reflect our average natural gas heat content of 1.06 GJ per mcf.

New CICA Handbook Standards sections, Financial Instruments – Recognition and Measurement, Hedges, and Comprehensive Income are applicable beginning in 2007 (refer to Note 14 of the notes to consolidated financial statements).

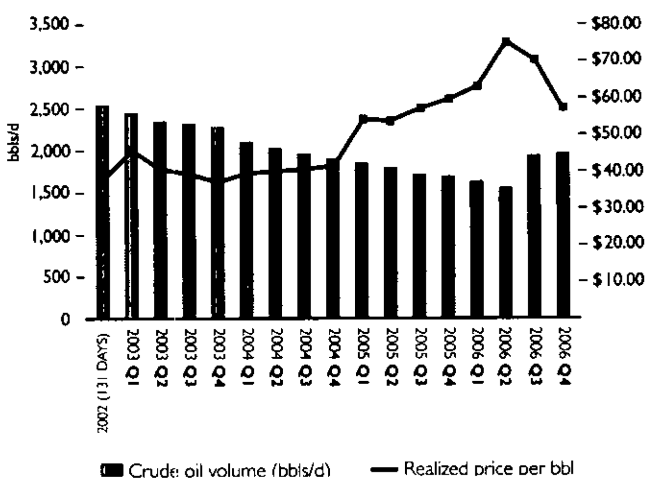
Production Revenue

- Production revenue for the fourth quarter of 2006 was $98.4 million compared to $90.4 million for the third quarter of 2006. The nine percent increase is mostly due to the increase in realized natural gas prices which were partially offset by a reduction in crude oil and NGL realizations and lower natural gas production. Production revenue for the fourth quarter of 2006 was 86 percent from natural gas compared to 88 percent in the third quarter of 2006 and 74 percent for the fourth quarter of 2005.
- Production revenue for 2006 increased 49 percent to $285.6 million from $191.7 million in 2005. The most significant contributor to the increase was the 81 percent increase in average natural gas production, mainly from the Saskatchewan properties acquired in mid 2006. Higher realizations for crude oil and NGL's were offset by the lower realizations for natural gas. Natural gas revenue made up 80 percent of production revenue in 2006 compared to 72 percent in 2005.

NATURAL GAS VOLUMES & REALIZED PRICE PER MCF



CRUDE OIL VOLUMES & REALIZED PRICE PER BARREL



Production Expenses

	2006	2005	2004	2003	2002 (1)
Production expenses per BOE	$ 4.17	$ 4.11	$ 3.29	$ 3.39	$ 3.09

(1) The Trust was created in August 2002 and the results for 2002 include the 131-day period from August 23 to December 31.

- Production expenses for 2006 were $4.17 per BOE compared to $4.11 per BOE in 2005. Production expenses increased slightly as the addition of the lower production expense Saskatchewan properties acquired in late June offset general upward expense pressures due to high activity levels in the sector, competition for services and higher energy costs.

	2006				2005			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Production expenses per BOE	$ 4.04	$ 3.50	$ 4.62	$ 5.50	$ 4.61	$ 3.56	$ 4.10	$ 4.19

- For the fourth quarter of 2006, production expenses increased 15 percent from the third quarter 2006 to $4.04 per BOE. Production expenses in the fourth quarter were impacted by seasonal costs at properties which are only accessible in the winter, increased utility costs and facility turnarounds completed in the quarter.

General and Administrative Expenses

	Three Months Ended December 31,		Years Ended December 31,	
(thousands)	2006	2005	2006	2005
Cash G&A expenses	$ 4,126	$ 1,941	$ 11,103	$ 6,899
Overhead recoveries	(2,163)	(822)	(5,453)	(2,470)
Total cash G&A expenses	1,963	1,119	5,650	4,429
Non-cash G&A expense (1)	-	348	804	1,455
Trust Unit Rights Plan expense (2)	809	266	2,120	884
Net G& A reported	$ 2,772	$ 1,733	$ 8,574	$ 6,768
Cash based G&A per BOE	$ 0.99	$ 1.27	$ 0.97	$ 1.22
Net reported G&A per BOE	$ 1.40	$ 1.97	$ 1.48	$ 1.86

(1) Gross general and administrative expenses for 2006 included $1.6 million related to the Executive Bonus Plan (2005 - $2.9 million). Half of this amount was non-cash and settled through the issuance of units from treasury at a price equal to the average of the last five trading days of the month for which the bonus relates. The Executive Bonus Plan was terminated June 30, 2006.

(2) Trust Unit Rights Plan compensation expense is calculated using the fair value method adopted in 2003 and represents a non-cash charge. Details of this compensation expense are contained in Note 11 of the notes to consolidated financial statements.

Cash-based general and administrative expenses were $0.99 per BOE for the fourth quarter of 2006 compared with $0.63 per BOE for the third quarter of 2006 and $1.27 per BOE in the fourth quarter of 2005. Fourth quarter 2006 expenses included annual cash bonus expenses and expenses associated with compliance with the new regulations regarding internal controls over financial reporting.

With the acquisition of PEML in late June, Focus increased its organizational strength with the addition of personnel in all areas of the Trust as required by the expanded production base, capital programs and corporate requirements. This growth increased general and administrative costs associated with personnel, rent and corporate activities. Notwithstanding that Focus has grown in size, general and administrative expenses per BOE have declined due to increased production of the Trust after the acquisition and additional overhead recoveries from the acquired operated properties.

Elimination of the Executive Bonus Plan

Late in the second quarter of 2006, the Board of Directors approved a new compensation plan that would better suit the expanded employee base of the Trust and be more comparable with the standard industry compensation framework for a trust of this size. As part of the change to compensation arrangements, the Executive Bonus Plan was eliminated. In eliminating the Executive Bonus Plan, $3.0 million was to be paid to the participants in the Plan. Half was paid on July 4, 2006 and the remainder will be paid on July 3, 2007. In addition, participants received, in aggregate, an additional 495,600 trust unit appreciation rights during the third quarter of 2006. The financial statements for the second quarter of 2006 recognized the full $3.0 million amount, of which $2,871,856 was allocated to general and administrative expenses and $128,144 was allocated to production expenses.

Interest and Financing Expenses

Interest and financing expenses increased from $3.7 million in the third quarter of 2006 to $4.1 million in the fourth quarter of 2006 due to an increase in average debt outstanding.

Interest and financing expenses for 2006 were $10.3 million, an increase from $3.5 million in 2005. The increase is largely due to the additional debt associated with the business acquisition of $179 million, which was incurred at the end of June 2006. The increase is also due to a slight increase in interest rates. Outstanding long-term debt at December 31, 2006 was $297.0 million compared to $87.5 million at December 31, 2005.

Depletion and Depreciation

The depletion and depreciation rate, excluding the impact of exchangeable share conversions, for the three months ended December 31, 2006, increased to $22.95 per BOE ($24.61 per BOE, including the exchangeable share impact) compared to $11.47 per BOE ($15.08 per BOE, including the exchangeable share impact) in the fourth quarter of 2005.

The depletion and depreciation rate incorporates the results of independent reserve reports dated December 31, 2006 and actual capital expenditures. The increase in the rate is largely due to the significant business acquisition in June 2006 for which the Trust recorded a higher proportionate cost per BOE of proved reserves compared to the historic Focus properties.

Asset Retirement Obligation

The asset retirement obligation increased $21.0 million to $36.1 million at December 31, 2006 from $15.1 million at December 31, 2005. The obligation includes $14.6 million associated with the business acquisition in June 2006. The remainder of the increase is due to drilling activity, new construction activity and higher accretion expense. The asset retirement obligation recorded represents the net present value of cash flows required to settle asset retirement obligations, and a full description is contained in Note 5 of the notes to consolidated financial statements.

The higher asset retirement obligation has resulted in a higher accretion expense beginning in the second half of 2006.

Income and Other Taxes

Income and other taxes include a future income tax recovery of $30.2 million in 2006 compared to a recovery of $5.7 million in 2005. The recovery of future income tax results from a reduction in corporate income tax rates in 2006, distributions to unitholders which transfers taxable income from the Trust to individual unitholders and from the depletion associated with accounting for exchangeable shares.

Large corporations tax, predominantly based on year-end debt and equity levels, in 2006 was nil compared to $0.8 million in 2005 due to the elimination of the large corporations tax effective January 1, 2006.

Certain of the Trust's assets are held by entities which transfer taxable income to unitholders. The excess of the carrying value of these assets over the tax value is approximately $77.2 million. Total available tax pools of the Trust and subsidiary entities is approximately $322 million at December 31, 2006 before adjusting for deferred income amounts ($184 million after adjusting for deferred income amounts).

On October 31, 2006, the Federal Government announced proposals pertaining to the taxation of distributions from publicly traded Canadian income trusts, royalty trusts and partnerships. The proposals include a 31.5 percent tax imposed on income before distributions at the trust level and taxed to the taxable Canadian investor, effectively as a dividend. If enacted, the proposals would apply to the Trust effective January 1, 2011. On December 21, 2006, the Department of Finance issued draft legislation consistent with the proposals described above.

As at December 31, 2006, the legislative proposals are not substantively enacted and thus there is no impact on the recognition of future income taxes in 2006. If the legislation is enacted, the Trust's taxable status will change resulting in recognition of future tax liabilities at substantively enacted tax rates in respect of temporary differences described above, which were $77.2 million at December 31, 2006. This temporary difference amount is reduced each year by depletion and increased through the use of tax claims and therefore the temporary difference amount in 2011 is not necessarily $77.2 million. Also, as the Trust would become a taxable entity in 2011, under the proposals future income tax recoveries would likely not be recognized for income transfers from the Trust to unitholders for 2011 onward.

The Trust is currently assessing various structural alternatives in light of the Government's proposals. However, the legislation is not yet enacted and the Trust cannot conclude on a form of structure nor the total implication to the Trust. Despite the structural implication of the proposals, the core business of the Trust remains the same.

On December 15, 2006, the Government announced guidance regarding "normal growth" for equity capital during the transitional period from October 31, 2006 to 2011. This amount will be measured with reference to the Trust's market capitalization on October 31, 2006. The "normal growth" will permit new equity of 40 percent to the end of December 31, 2007 with an additional 20 percent per year 2008 through 2010, for a total of 100 percent. In addition, Trusts will be permitted to repay existing debt outstanding on October 31, 2006 without impacting the normal growth limits.

Capital Expenditures

Capital expenditures for field operations were $27.0 million in the fourth quarter of 2006. The majority of the capital was concentrated at Shackleton, Tommy Lakes and Medicine Hat. At Shackleton the Trust finished drilling its 159-well summer program, completed and tied in these wells and commissioned two new compressor stations. Additionally, due to favorable weather conditions and rig availability we were able to get an early start on our 2007 Shackleton winter program, drilling 18 wells prior to year end. At Tommy Lakes we were also able to get an early start, and as a result we drilled a total of eight wells prior to the end of the year, including two successful 50 percent working interest wells on the Trutch exploratory Halfway play to the west of our main Tommy Lakes field. Due to the early commencement of these winter projects we spent approximately $5.0 million more in the quarter than we had anticipated. This will be offset by lower expenditures on these projects in the first quarter of 2007. At Medicine Hat, we completed our 17-well program and tied 15 of these wells into our existing infrastructure. In total Focus drilled 56 wells during the quarter, including 31 wells (26.1 net) at Shackleton, eight wells (7.0 net) at Tommy Lakes and 17 wells (13.2 net) at Medicine Hat.

For 2006, total capital expenditures for field operations were $90.4 million, excluding the amount recorded for asset retirement obligations. Our expectation for 2006 was that we would spend approximately $84.0 million, and our budgeted 2006 projects came in essentially in line with this expectation. The $6.4 million difference between expectation and actual is largely due to the $5.0 million of 2007 spending accelerated into December 2006, as described above. The remaining difference is due to an increase in inventory at year end due to the timing of bulk purchases of items such as line pipe and coiled tubing.

The majority of the 2006 capital expenditures were directed towards development of our two core properties, with 35 percent of total capital spent at Shackleton and 32 percent at Tommy Lakes. In addition, 13 percent of total capital was spent on other gas properties including Pouce Coupe, Sylvan Lake and Medicine Hat, and nine percent was spent on our Red Earth oil properties. The remaining 11 percent, or $10.2 million, was spent to acquire undeveloped land at Crown land sales, primarily at Shackleton. During 2006 Focus continued to maximize the value of our existing asset base and acquired properties through the drill bit.

In June 2006 Focus invested approximately $1.1 billion, before asset retirement obligations and future tax, to acquire PEML. On a proved plus probable basis, acquired reserves were 45.5 MMBOE, consisting of 267 Bcf of natural gas and 0.9 Mmbls of heavy oil. More detail with respect to the PEML acquisition is contained in the Business Acquisition section of this Management's Discussion and Analysis.

Focus will continue to actively develop and expand its core properties in 2007 with a capital budget for field operations of approximately $95.0 million to $115.0 million. Significant development activities will continue at Shackleton, Tommy Lakes, Loon Lake and Medicine Hat; however, the ultimate overall size of our development program will be guided by our sustainable business strategy, realized commodity prices and service costs. There will be a continued emphasis on natural gas development and on those projects that we operate and control.

Liquidity and Capital Resources

As at December 31, 2006 Focus had a working capital deficit of $11.1 million compared with a working capital deficit of $5.0 million at December 31, 2005. The increase in the working capital deficit of $6.1 million from December 31, 2005 is mainly due to an increase in activity level resulting from the acquisition of PEML. The increase in receivable accounts due to the increase in production levels is more than offset by the increase in payables from drilling programs at Shackleton and an increase in distributions payable resulting from the issuance of trust units and exchangeable partnership units in connection with the acquisition.

The working capital deficit at December 31, 2006 has decreased from $19.8 million at September 30, 2006, largely due to an increase in accrued natural gas revenue commensurate with the increase in natural gas prices. The September realized natural gas price was $7.32 per mcf compared to a December realized natural gas price of $7.90 per mcf. In addition, the estimated net working capital deficiency assumed with the acquisition of PEML decreased by $5.1 million. On a monthly basis, there are fluctuations in accounts receivable and accounts payable reflecting the extent of capital programs, distributions to unitholders after month end and accrued revenue and royalties for the current month.

Long-term debt at December 31, 2006 was $297.0 million compared with $87.5 million at December 31, 2005 and $293.5 million at September 30, 2006. The increase in long-term debt of $209.5 million is largely due to $142.5 million incurred with the acquisition in June 2006 and debt incurred to settle net obligations related to the acquisition. The remainder of the increase in long-term debt is a result of payments for distributions, capital expenditures and reclamation activities being greater than funds flow received for the period.

Focus had a $350 million revolving syndicated credit facility among four financial institutions and a $15 million operating facility at December 31, 2006. The credit facility revolves until June 25, 2007, whereupon it may be renewed for a further 364-day term subject to a review by the lenders. If not extended, principal payments will commence after expiry of the revolving period and will consist of three quarterly payments of eight and one-third percent commencing 15 months after the term date and the remaining 75 percent at the end of the term. Management intends to request the extension. The credit facilities are secured by a floating charge debenture covering all of the assets of the Trust and a general security agreement.

Long-term debt plus the working capital deficiency increased $215.6 million during 2006 from $92.5 million at December 31, 2005 to $308.1 million at December 31, 2006. This increase of $215.6 million during the year primarily resulted from the following factors.

- Funds flow from operations of $181.2 million plus $36.6 million of debt and working capital were used to fund $124.2 million in distributions declared to unitholders, $90.4 million invested in capital expenditures for field operations, and $3.2 million of contributions to the reclamation fund and reclamation costs. Capital of $90.4 million includes $9.8 million spent at a Saskatchewan land sale in August 2006.
- With respect to the PEML acquisition, Focus paid $199.8 million and obtained net working capital of $20.8 million for a net change in debt and working capital deficiency of $179 million.
- Proceeds were $1.8 million from the issuance of equity pursuant to the exercise of trust unit appreciation rights and from the Distribution Reinvestment and Optional Trust Unit Purchase Plan ("DRIP Plan").
- Working capital includes a $1.8 million charge for non-cash mark-to-market losses.

Central to Focus' business strategy is the concept of sustainability where the sum of capital expenditures to maintain production and distributions is equal to funds flow from operations. Focus plans to finance its program for production replacement primarily through investing approximately 35 to 45 percent of funds flow from operations. Capital expenditures, including acquisitions and significant purchases of undeveloped land, above this level will be financed through a combination of funds flow, debt and equity and by issuing units from treasury.

On October 11, 2006 Focus announced the introduction of the DRIP Plan which provides eligible unitholders of Focus trust units the advantage of accumulating additional trust units by reinvesting their cash distributions paid by Focus and by making optional payment for additional trust units. Under the distribution reinvestment portion of the DRIP Plan, participants can potentially buy additional units from treasury at 95 percent of the average market price. This DRIP Plan provides a service to unitholders and increases the financial flexibility of Focus. Focus wants to maintain financial flexibility at a time of shifting commodity prices. Consistent with the experience of other trusts for this basic type of plan, we expect the DRIP Plan will generate between $5.0 million and $10.0 million through the issuance of equity on an annual basis. From inception of the plan to December 31, 2006, the plan generated $1.0 million and 58,793 trust units were issued from treasury. Focus will generally use funds generated by this plan to reduce debt and invest in additional capital projects (including land purchases and expanded development operations).

Capitalization Table

(thousands except per-unit amounts)		**December 31, 2006**		December 31, 2005
Long-term debt	**$**	**297,000**	$	87,500
Plus: working capital deficiency		**11,122**		5,018
Total debt	**$**	**308,122**	$	92,518
Total units outstanding and issuable for exchangeable shares and exchangeable partnership units		**78,504**		37,456
Market price	**$**	**18.18**	$	25.72
Market capitalization	**$**	**1,427,203**	$	963,368
Total capitalization	**$**	**1,736,507**	$	1,055,886
Total debt as a percentage of total capitalization		**17.8%**		8.8%
Funds flow from operations	**$**	**181,223**	$	116,368
Total debt to funds flow (1)		**1.2**		0.8

(1) The calculation of debt to annualized funds flow at December 31, 2006 is based on the funds flow of the Trust for the period of July 1 to December 31, 2006 to more appropriately match the asset base after the acquisition with the debt level after the acquisition late in June 2006.

2006 Cash Distributions

We announce our distribution policy on a quarterly basis. The actual amount of the cash distribution is determined by the Board of Directors and is dependent upon the commodity price environment, production levels and the amount of capital expenditures to be funded from funds flow. Our distribution policy incorporates the withholding of approximately 35 to 45 percent of funds flow for the financing of capital expenditures to provide more sustainable distributions.

Focus declared distributions of $2.10 per unit in respect of 2006 production. On January 11, 2007 the Trust announced that distributions in respect of January to March production would be at a rate of $0.14 per month. The distribution rate reflects Focus' commitment to a business strategy of sustainability where the sum of capital expenditures and distributions is approximately equal to cash flow. The Trust continually monitors the forward strip for natural gas and takes action in a prudent and proactive manner to ensure sustainability through price protection activities and by adjusting capital programs and distribution levels.

Exchangeable partnership units receive a cash distribution equal to the cash distribution declared for each Focus unit.

The cash distributions are taxed as ordinary income to the investor.

Cash distributions were not paid on the exchangeable shares and the cash flow related to the exchangeable shares was retained by the Trust for reduction of debt or for additional capital expenditures. The exchangeable shares of FET Resources Ltd. were convertible into trust units of Focus based on the exchange ratio, which was adjusted monthly to reflect the distribution paid on the trust units. All outstanding exchangeable shares were redeemed for trust units on January 16, 2007.

Taxation of Cash Distributions

Focus Energy Trust, for purposes of the Canadian Income Tax Act, is treated as a mutual fund trust and each year the Trust files an income tax return with the taxable income allocated to the unitholders. Distributions paid to the unitholders may be both a return on capital (income) and a return of capital. The allocation between these two streams is dependent upon the income tax deductions that the Trust is able to claim against the income it earns. The return of capital portion reduces the adjusted cost base of the trust units held. The Trust has net income for each year that is required to be calculated on an accrual basis of accounting. Net income includes all interest income from FET and other income that accrues to the Trust to the end of the year. Under the Trust Indenture, net income of the Trust for each year will be paid or payable by way of cash distributions to the unitholders. Taxable income of the Trust includes a deduction for the allocation of taxable income to unitholders, which is paid or becomes payable in the year and a deduction relating to income tax pools residing at the Trust level. The Trust Indenture provides that an amount at least equal to the taxable income of the Trust must be paid or payable each year to unitholders in order to reduce the Trust's taxable income to zero. Such taxable income is allocated to unitholders. Any taxable income relating to a payable amount is allocated to unitholders of record at December 31, 2006, and each unitholder receives a pro rata share of that payable amount on January 15, 2007.

For 2006, cash distributions will be 100 percent taxable income (return on capital).

2006 Canadian Tax Information

The following information is intended to assist Canadian holders of trust units of Focus Energy Trust (FET.UN – TSX) in the preparation of their 2006 T1 Income Tax Return. This summary is directed to a unitholder who, for purposes of the Income Tax Act (Canada), is a resident of Canada and holds the units as capital property. Other unitholders are advised to consult with their tax advisor concerning their circumstances.

- Trust units held within an RRSP, RRIF or DPSP - NO AMOUNTS are to be reported on the 2006 income tax return where trust units are held within a Registered Retirement Savings Plan (RRSP), Registered Retirement Income Fund (RRIF), Deferred Profit Savings Plan (DPSP), or any other such registered plans.
- Trust units held outside of an RRSP, RRIF or DPSP - If the trust unit is held through a broker or other intermediary then the unitholder will receive a T3 Supplementary slip directly from the broker or intermediary, not from the transfer agent (Valiant Trust Company) or from Focus, no later than March 31, 2007. If the unitholder is a registered holder then the unitholder will receive a T3 Supplementary slip directly from Valiant Trust Company no later than March 31, 2007.
- The amount reported in Box (26) on the T3 Supplementary slip, "Other Income", should be reported on the 2006 T1 Income Tax Return.

Taxable Income Allocated to Unitholders for 2006 and Taxation Treatment

- Focus Energy Trust, for purposes of the Canadian Income Tax Act, is treated as a mutual fund trust and each year the Trust files an income tax return with the taxable income allocated to the unitholders. Distributions paid to the unitholders may be both a return on capital (income) and a return of capital. The allocation between these two streams is dependent upon the income tax deductions that the Trust is able to claim against the income it earns.
- For those unitholders who held their Focus Energy Trust units outside of a registered plan, the income portion is reported in Box (26) of the T3 Supplementary slip, "Other Income", and should be reported on the 2006 T1 Income Tax Return.
- The following table outlines the breakdown of cash distributions per unit paid by Focus Energy Trust with respect to record dates for the period January 31 to December 31, 2006.

Record Date	Payment Date	Distribution Paid	Taxable Income (Box 26 Other Income)	Tax Deferred Amount (Box 42 Return of Capital)
January 31, 2006	February 15, 2006	$ 0.19	$ 0.19	$ 0.00
February 28, 2006	March 15, 2006	$ 0.19	$ 0.19	$ 0.00
March 31, 2006	April 17, 2006	$ 0.19	$ 0.19	$ 0.00
April 30, 2006	May 15, 2006	$ 0.19	$ 0.19	$ 0.00
May 31, 2006	June 15, 2006	$ 0.19	$ 0.19	$ 0.00
June 30, 2006	July 17, 2006	$ 0.19	$ 0.19	$ 0.00
July 31, 2006	August 15, 2006	$ 0.16	$ 0.16	$ 0.00
August 31, 200	September 15, 2006	$ 0.16	$ 0.16	$ 0.00
September 30, 2006	October 16, 2006	$ 0.16	$ 0.16	$ 0.00
October 31, 2006	November 15, 2006	$ 0.16	$ 0.16	$ 0.00
November 30, 2006	December 15, 2006	$ 0.16	$ 0.16	$ 0.00
December 31, 2006	January 15, 2007	$ 0.16	$ 0.16	$ 0.00
Total		$ 2.10	$ 2.10	$ 0.00

Adjusted Cost Base

In most circumstances, the return of capital portion will reduce the unitholder's adjusted cost base of their Focus Energy Trust units. Since the return of capital for 2006 is nil, there should be no effect on the adjusted cost base.

2006 United States Tax Information

The following information is provided to assist U.S. individual unitholders of Focus Energy Trust in reporting distributions received from Focus during 2006 on their Internal Revenue Service ("IRS") Form 1040 – U.S. Individual Income Tax Return ("Form 1040") for 2006.

Focus has not obtained a legal or tax opinion, nor has it requested a ruling from the IRS on these matters.

Trust Units held outside of a Qualified Retirement Plan

- For distributions relating to 2006, 100 percent of the distributions should be considered taxable as dividends to the unitholder for U.S. federal income tax purposes. After consulting with its tax advisors, Focus believes that its distributions should be considered "Qualified Dividends" under the Jobs and Growth Tax Relief Reconciliation Act of 2003 and should be eligible for the reduced U.S. dividend tax rate. However, the individual taxpayer's situation must be considered before making this determination. "Qualified Dividends" should be reported on Line 9(b) of the IRS Form 1040, unless the facts of the U.S. individual unitholder determine otherwise. Page 23 of the IRS 2006 Form 1040 instruction booklet provides examples of individual situations where the distributions would not be "Qualified Dividends". Where the distributions are not considered "Qualified Dividends" due to an individual's situation, the amount should be reported on Schedule B, Part II – Ordinary Dividends and Line 9 (a) of your IRS Form 1040.
- U.S. unitholders are encouraged to utilize the Qualified Dividends and Capital Gain Tax Worksheet provided by the IRS to determine the amount of tax applicable.
- Canadian withholding taxes that have been withheld from the taxable portion of your distributions (as computed under Canadian tax principles) should be reported on Form 1116 "Foreign Tax Credit (Individual, Estate or Trust)". Amounts over-withheld should be claimed as a refund from the Canada Revenue Agency and should not be claimed as a credit against your U.S. federal income tax liability. Information regarding the amount of Canadian tax withheld relating to 2006 distributions should be available through your investment advisor or other intermediary and is not available from Focus.

Trust Units held within a Qualified Retirement Plan

- There should be no amount that is required to be reported as income on an IRS Form 1040 where the Focus trust units are held in a Qualified Retirement Plan.

The information in this release is not meant to be an exhaustive discussion of all possible income tax considerations, but a general guideline and is not intended to be legal or tax advice to any particular holder or potential holder of Focus Energy Trust units. Holders or potential holders of trust units should consult their tax advisors as to their particular tax consequences of holding Focus trust units.

Contractual Obligations and Commitments

The Trust has contractual obligations in the normal course of operations including purchase of assets and services, operating agreements, transportation commitments and sales commitments. These obligations are of a recurring and consistent nature and impact cash flow in an ongoing manner. See Note 18 of the notes to consolidated financial statements for further details.

Off Balance Sheet Arrangements

The Trust has certain lease agreements that are entered into in the normal course of operations. All leases are treated as operating leases whereby the lease payments are included in operating expenses or general and administrative expenses depending on the nature of the lease. No asset or liability value has been assigned to these leases in the balance sheet as at December 31, 2006.

Focus has not entered into any guarantee or off balance sheet arrangements other than in the normal course of operations.

Critical Accounting Estimates

Focus' financial and operating results incorporate certain estimates including:

- estimated revenues, royalties and operating expenses on production as at a specific reporting date but for which actual revenues and expenses have not yet been received;
- estimated capital expenditures on projects that are in progress;
- estimated depletion, depreciation and accretion that are based on estimates of oil and gas reserves that the Trust expects to recover in the future, estimated future salvage values, and estimated future capital costs;
- estimated fair values of derivative contracts and physical sales contracts that are subject to fluctuation depending upon the underlying commodity prices and foreign exchange rates;
- estimated value of asset retirement obligations that are dependent upon estimates of future costs and timing of expenditures.

The Trust has hired individuals and consultants who have the skill sets to make such estimates and ensures that the individuals and departments with the most knowledge of an activity are responsible for the estimates. Past estimates are reviewed and compared to actual results in order to make more informed decisions on future estimates. The management team's mandate includes ongoing development of procedures, standards and systems to allow the Trust to make the best estimates possible.

Assessment of Business Risks

Following are the primary risks associated with the business of the Trust. These risks are similar to those affecting others in the conventional oil and gas income trust sector. The Trust's financial position, results of operations and distributions to unitholders are directly impacted by these factors:

1. operational risk associated with the production of oil and natural gas;
2. reserve risk in respect to the quantity and quality of recoverable reserves;
3. market risk relating to the availability of transportation systems to move the product to market;
4. commodity risk as crude oil and natural gas prices fluctuate due to market forces;
5. financial risk such as the Canadian/U.S. dollar exchange rate, interest rates and debt service obligations;
6. environmental and safety risk associated with well operations and production facilities;
7. change in laws, regulation and administrative practice of governmental authorities relating to the oil and natural gas industry and the trust sector, particularly with respect to operations, environmental controls, royalties and income taxes, including changes in foreign ownership rules and changes to the taxation of trusts.

Focus seeks to mitigate these risks by:

1. acquiring properties with large contiguous accumulations of hydrocarbon in place to reduce technical uncertainty;
2. acquiring long-life reserves to ensure more stable production and to reduce the economic risks associated with commodity price cycles;
3. maintaining a low-cost structure to maximize product netbacks and reduce impact of commodity price cycles;
4. diversifying properties to mitigate individual property and well risk;
5. conducting rigorous reviews of all property acquisitions;
6. monitoring pricing trends and developing a mix of contractual arrangements for the marketing of products with creditworthy counterparties;
7. maintaining a hedging program to hedge commodity prices and foreign exchange currency rates with creditworthy counterparties;
8. ensuring strong third-party operators for non-operated properties;
9. adhering to the Trust's safety program and keeping abreast of current operating best practices;
10. keeping informed of proposed change in regulations and laws to properly respond to and plan for the effects that these changes may have on our operations;
11. carrying insurance to cover losses and business interruption;
12. establishing and building cash resources to fund future site reclamation costs.

Please refer to the Income and Other Taxes section of this report which provides additional information on the business risks associated with the October 31, 2006 announcement by the Canada Department of Finance regarding proposed changes to the taxation of income trusts.

Disclosure Controls and Internal Controls Over Financial Reporting

The Trust maintains a Disclosure Committee (the "Committee") that is responsible for ensuring that all public and regulatory disclosures are sufficient, timely and appropriate, and that disclosure controls and procedures are operating effectively. The Committee consists of the Chief Executive Officer and each of the Vice Presidents. As at the end of the period covered by this report, the design and operating effectiveness of the Trust's disclosure controls were evaluated by the Chief Executive Officer and the Chief Financial Officer. According to this evaluation, the Trust's disclosure controls and procedures are effective to ensure that any material, or potentially material, information is made known to the Committee and is properly included in this report. This evaluation took into consideration Focus' Disclosure, Confidentiality & Trading Policy and the functioning of its senior management, Board of Directors and board committees.

Management has designed internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements for external purposes in accordance with GAAP and has concluded, as of December 31, 2006, that the design of internal controls over financial reporting was effective.

There were no changes in internal control over financial reporting that have materially affected or are reasonably likely to materially affect the Trust's internal control over financial reporting. Subsequent to the PEML acquisition, which significantly increased activity and staff levels, and during the review of the design of internal controls over financial reporting, management made some changes to the Trust's internal controls. These changes related mainly to changes in formalization and documentation of reviews, as well as further segregation of duties.

The Trust's management, including the Chief Executive Officer and the Chief Financial Officer, do not expect that our disclosure controls or our internal controls over financial reporting will prevent or detect all error or fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the control system's objectives will be met. The design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Further, because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that misstatements due to error or fraud will not occur or that all control issues and instances of fraud, if any, within the Trust have been detected.

Update on Financial Reporting and Regulatory Matters

The following new accounting policies will impact the Trust in 2007:

- Comprehensive Income – Section 1530

  These standards require presentation of comprehensive income and its components and may require a separate financial statement that is displayed with the same prominence as other financial statements. Other comprehensive income refers to items that are recognized in comprehensive income but are excluded from net income calculated in accordance with GAAP.

  These standards are applicable for interim and annual financial statements for fiscal years beginning on or after October 1, 2006.

- Financial Instruments – Recognition and Measurement – Section 3855

  These standards address the recognition and measurement of financial instruments. They require all financial instruments which includes derivatives, with certain exceptions, be recognized on the balance sheet at fair value or in certain circumstances, cost or amortized cost. The standards also address when gains and losses as a result of changes in fair value are to be recognized in the income statement.

  The standards regarding Financial Instruments – Disclosure and Presentation have been revised with regards to the presentation and disclosure of financial instruments and non-financial derivatives.

  These standards are applicable for interim and annual financial statements for fiscal years beginning on or after October 1, 2006.

  Please see Note 14 of the notes to consolidated financial statements for further discussion.

- Hedges – Section 3865

  These standards address in what circumstances hedge accounting may apply and how hedge accounting is performed.

  These standards are applicable for interim and annual financial statements for fiscal years beginning on or after October 1, 2006.

  As a result of adoption of the above-described standards, the Trust will no longer use hedge accounting for its financial contracts. Please see Note 14 of the notes to consolidated financial statements for further discussion.

Other future possible impacts:

- In February, the Canadian Securities Administrators issued CSA Notice 52-317 – Timing of Proposed National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings. This notice disclosed the intention of the Canadian Securities Administrators to propose the requirements for issuers to evaluate and certify the effectiveness of internal controls over financial reporting to apply in respect of financial years ending on or after June 30, 2008.
- In November 2006, the Canadian Institute of Chartered Accountants released draft interpretive release, Distributable Cash in Income Trusts and Other Flow-Through Entities, Guidance on Preparation and Disclosure in Management's Discussion and Analysis. This release is a draft for comment until March 31, 2007.

  This guidance is a first statement of general recommended practices and has been prepared to provide guidance to flow-through entities, including income trusts, on the measurement and presentation of distributable cash. Distributable cash is a non-GAAP measure that is frequently published by flow-through entities as supplementary financial information often with varying calculation methodology.

Summary of Quarterly Results

The following table provides a summary of results for each of the last eight quarters. Please refer to the Quarterly Information Table on page 52 for additional information. Significant factors and trends which have impacted these results include:

- Revenue and royalties are directly related to fluctuations in the underlying commodity prices and the extent to which price protection has been achieved through financial hedges and forward physical sales contracts.
- Prior to the PEML acquisition in late June 2006, many of Focus' natural gas areas were only accessible by road in the winter. This includes the Tommy Lakes area, which is very significant from a production and development program perspective. Please refer to the "Seasonality of Operations" section for additional information.
- Focus completed a major acquisition in June 2006, for approximately $1.1 billion where production more than doubled, weighted 88 percent towards natural gas. Properties acquired allow for year-round access. The acquisition was financed with the issuance of 40.8 million trust units or exchangeable partnership units and an increase in long-term debt plus working capital deficiency of $179 million. See the Business Acquisition section for additional information.

	2006				2005			
($ thousands, except as indicated)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Oil and gas revenues, before royalties	**98,434**	**90,395**	**48,663**	**48,146**	52,315	48,790	46,583	43,981
Net income	**21,646**	**12,671**	**21,873**	**16,778**	17,858	17,573	14,682	13,351
Per unit – basic	**$ 0.28**	**$ 0.19**	**$ 0.57**	**$ 0.46**	$ 0.49	$ 0.48	$ 0.40	$ 0.37
– diluted	**$ 0.28**	**$ 0.16**	**$ 0.55**	**$ 0.45**	$ 0.48	$ 0.47	$ 0.40	$ 0.36

Outlook – 2007

The Trust's operational results and financial condition will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by demand and supply factors, including weather and general economic conditions as well as conditions in other oil and natural gas producing regions.

The following chart summarizes Focus' 2007 outlook. No acquisitions are assumed for the purposes of these forecasts.

In 2007, Focus will continue its active development drilling programs on its major natural gas properties. It is anticipated that these development activities will maintain production by offsetting production declines.

We do not attempt to forecast commodity prices, and as a result, we do not forecast funds flow from operations or future cash distributions to unitholders.

Summary Of 2007 Expectations

(full year average)	
Production	21,500 - 23,500 BOE/d
Weighting to natural gas	89%
Production expenses per BOE	$ 3.75 - $ 4.25
Cash G&A expenses per BOE	$ 0.90 - $ 1.10
Capital expenditures – field	$ 95 - $ 115 million
Payout ratio	55% - 65%
Approximate taxable portion of distributions	100%
Funds from operations/net debt	1.1x – 1.3x

The table below shows the potential impact on the Trust's funds flow (before price protection) resulting from changes to the business environment or operations.

Business Environment	Change	Change to Funds Flow $000's	$/Unit
Price per barrel of crude oil (US$ WTI)	$ 1.00	825	0.01
Price per mcf of natural gas (CDN$ AECO)	$ 0.25	8,500	0.11
US/CDN exchange rate	$ 0.01	3,400	0.04
Interest rate on debt	1%	3,300	0.04
Operations			
Oil production – bbls/d	100	1,825	0.02
Gas production – mcf/d	1,000	1,850	0.02
Operating expenses ($ per BOE)	$ 0.25	2,050	0.03
Cash G&A expenses ($ per BOE)	$ 0.25	2,050	0.03

Focus is committed to increasing the long-term value of the Trust to unitholders. The following goals are the foundation of our commitment to value creation:

- Maximize the value of existing assets;
- Attract and retain the best value creation team in the business;
- Pursue quality acquisitions that are strategic and accretive;
- Protect margins and improve profitability;
- Surface value through operational expertise and control; and
- Maintain financial flexibility and strength.

Management's Responsibility

Management is responsible for the preparation of the accompanying consolidated financial statements and for the consistency therewith of all other financial and operating data. The consolidated financial statements have been prepared in accordance with the accounting policies detailed in the notes thereto. In management's opinion, the consolidated financial statements are in accordance with Canadian generally accepted accounting principles and have been prepared within acceptable limits of materiality.

Management maintains a system of internal controls to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable and timely information. Where estimates are used in the preparation of these financial statements, management has ensured that careful judgment has been made and that these estimates are reasonable, based on all information known at the time the estimates are made.

Independent auditors appointed by the Trustee have examined and expressed their opinion on the consolidated financial statements of the Trust. The Audit Committee, consisting of independent directors of FET Resources Ltd., has reviewed these consolidated financial statements with management and the auditors, and has recommended them to the Board of Directors for approval. The Board has approved the consolidated financial statements of the Trust.

Derek W. Evans
President and Chief Executive Officer

William D. Ostlund
Senior Vice President and Chief Financial Officer

March 6, 2007

Auditor's Report

We have audited the consolidated balance sheets of Focus Energy Trust as at December 31, 2006 and 2005 and the consolidated statements of income and accumulated income and cash flows for the years ended December 31, 2006 and 2005. These consolidated financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years ended December 31, 2006 and 2005 in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada

March 5, 2007

Consolidated Balance Sheets

(thousands)	December 31, 2006	December 31, 2005
ASSETS		
Current assets		
Cash and cash equivalents	$ –	$ 4,696
Accounts receivable	51,392	21,065
Prepaid expenses and deposits	5,467	1,952
Commodity contracts [note 14]	2,959	–
	59,818	27,713
Petroleum and natural gas properties and equipment [notes 3 & 4]	1,301,056	430,865
Goodwill [note 3]	453,241	5,100
Reclamation fund [note 6]	5,649	2,711
	$ 1,819,764	$ 466,389
LIABILITIES		
Current		
Accounts payable and accrued liabilities	$ 50,426	$ 26,127
Cash distributions payable	12,443	6,604
Current bank debt	4,948	–
Commodity contracts [note 14]	3,123	–
	70,940	32,731
Long-term debt [note 7]	297,000	87,500
Asset retirement obligation [note 5]	36,131	15,090
Future income taxes [note 17]	318,800	81,634
	722,871	216,955
NON-CONTROLLING INTEREST		
Exchangeable shares [note 8]	4,550	4,131
UNITHOLDERS' EQUITY		
Unitholders' capital [note 9]	922,426	244,426
Exchangeable partnership units [note 10]	218,500	–
Contributed surplus [note 11]	2,945	1,135
Accumulated income [note 13]	(51,528)	(258)
	1,092,343	245,303
Commitments and contingencies [note 18]		
Subsequent event [note 19]		
	$ 1,819,764	$ 466,389

SEE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Approval on behalf of the Board:

Stuart G. Clark
Director

James H. McKelvie
Director

Consolidated Statements of Income and Accumulated Income

(thousands except per-unit amounts)	December 31, 2006	December 31, 2005
Revenue		
Production revenue	$ 285,639	$ 191,669
Royalties	(54,563)	(44,067)
Alberta Royalty Tax Credit	470	490
Facility income	3,115	1,950
Interest income	35	40
	234,696	150,082
Expenses		
Transportation system charges	12,117	9,931
Production	24,192	14,948
General and administrative	8,574	6,768
Elimination of the executive bonus plan [note 12]	2,872	-
Interest and financing	10,265	3,531
Depletion and depreciation [note 4]	130,379	53,916
Accretion on asset retirement obligation [note 5]	2,445	889
	190,844	89,983
Income before income and other taxes	43,852	60,099
Income and other taxes [note 17]		
Future income tax reduction	(30,219)	(5,678)
Current and large corporations tax	220	876
	(29,999)	(4,802)
Non-controlling interest – exchangeable shares	884	1,437
Net income for the period	72,967	63,464
Accumulated income (deficit), beginning of period	(258)	9,955
Cash distributions	(124,237)	(73,677)
Accumulated income (deficit), end of period	(51,528)	(258)
Net income per unit [note 16]		
Basic	$ 1.26	$ 1.74
Diluted	$ 1.25	$ 1.71

SEE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Statements of Cash Flows

(thousands)	December 31, 2006	December 31, 2005
Operating activities		
Net income for the period	$ 72,967	$ 63,464
Add non-cash items:		
Non-controlling interest – exchangeable shares	884	1,437
Non-cash general and administrative expenses [notes 11& 12]	2,924	2,340
Depletion and depreciation	130,379	53,916
Accretion on asset retirement obligation	2,445	889
Non-cash amortization of hedging contracts	1,843	–
Future income tax recovery	(30,219)	(5,678)
Reclamation costs	(277)	(632)
Net change in non-cash working capital items	(30,623)	(992)
	150,323	114,744
Financing activities		
Proceeds from issue of trust units (net of costs)	889	–
Proceeds from exercise of unit appreciation rights	806	813
Increase (decrease) in long-term debt	209,500	13,000
Cash distributions paid	(118,399)	(72,829)
	92,796	(59,016)
Investing activities		
Capital asset additions	(90,406)	(43,035)
Acquisition expenditures [note 3]	(143,998)	(10,363)
Reclamation fund contributions, net of costs	(2,938)	(788)
Net change in non-cash working capital items	(10,473)	3,110
	(247,815)	(51,076)
Increase (decrease) in cash and cash equivalents during the period	(4,696)	4,652
Cash and cash equivalents, beginning	4,696	44
Cash and cash equivalents, ending	$ –	$ 4,696

SEE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Notes to Consolidated Financial Statements

DECEMBER 31, 2006 AND 2005

1. Structure of the Trust

Focus Energy Trust (the "Trust") was established on August 23, 2002 under a Plan of Arrangement involving the Trust, Storm Energy Inc., FET Resources Ltd., and Storm Energy Ltd. The Trust is an open-end unincorporated investment trust governed by the laws of the Province of Alberta and created pursuant to a trust indenture (the "Trust Indenture"). Valiant Trust Company has been appointed Trustee under the Trust Indenture. The beneficiaries of the Trust are the holders of the trust units (the "unitholders").

Under the Trust Indenture, the Trust may declare payable to unitholders all or any part of the income of the Trust. The income of the Trust consists primarily of interest earned on promissory notes issued to FET Resources Ltd., Focus BC Trust, and FET Energy Ltd., entities that are wholly owned by the Trust, distributions paid on subordinated units from Focus BC Trust units owned by the Trust, as well as amounts attributed to a net profits interest agreement (the "NPI Agreement").

Pursuant to the terms of the NPI Agreement, the Trust is entitled, through a subsidiary, to a payment from FET Resources Ltd. each month essentially equal to the amount by which the gross proceeds from the sale of production exceed certain deductible expenditures (as defined). Under the terms of the NPI Agreement, deductible expenditures may include amounts, determined on a discretionary basis, to fund capital expenditures, to repay third party debt and to provide for working capital required to carry out the operations of FET Resources Ltd.

The taxable income of the Trust includes a deduction for the allocation of taxable income to unitholders, which is paid or becomes payable in the year. The Trust Indenture provides that an amount at least equal to the taxable income of the Trust must be paid or payable each year to unitholders in order to reduce the Trust's taxable income to zero. Such taxable income relating to the payable amount is allocated to unitholders of record at the end of the year, and each unitholder at the distribution record date receives a pro rata share of the payable amount.

FET Resources Ltd. (the "Company") is a subsidiary of the Trust. Under the Plan of Arrangement, the Company became the successor company to Storm Energy Inc. through amalgamation on August 23, 2002. The Company is actively engaged in the business of oil and natural gas exploitation, development, acquisition and production.

FET Energy Ltd. is a subsidiary of the Trust. Under a Plan of Arrangement with Profico Energy Management Ltd. ("PEML") dated June 26, 2006, FET Energy Ltd. became the successor company to PEML through amalgamation on June 27, 2006. FET Energy Ltd., through its interest in a partnership, is engaged in the business of oil and natural gas exploitation, development, acquisition and production.

2. Summary of Accounting Policies

The consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP"). The preparation of these consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingencies at the date of the financial statements, and revenues and expenses during the reporting period. Correspondingly, actual results could differ from estimated amounts. These consolidated financial statements have, in management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the accounting policies summarized below.

In particular, the amounts recorded for depletion and depreciation of the petroleum and natural gas properties and equipment and for asset retirement obligations are based on estimates of reserves and future costs. The cost impairment test is based on estimates of proved reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the consolidated financial statements of future periods could be material.

a) Principles of Consolidation

The consolidated financial statements of the Trust include the accounts of Focus Energy Trust, its subsidiaries FET Resources Ltd., FET Gas Production Ltd., Focus B.C. Trust and FET Energy Ltd., and its share of three partnerships. All inter-entity transactions and balances have been eliminated.

b) Petroleum and Natural Gas Properties and Equipment

The Trust follows the full cost method of accounting for petroleum and natural gas properties, whereby all costs of acquiring petroleum and natural gas properties and related development costs, whether productive or unproductive, are capitalized and accumulated in one Canadian cost centre, including asset retirement costs. Such costs include acquisition, drilling, geological, geophysical, and equipment costs and overhead expenses related to the properties and development activities. Costs of acquiring and evaluating unproved properties are excluded from depletion calculations until it is determined in the period that proved reserves are attributable to the properties or impairment has occurred. Maintenance and repairs are charged against income, and renewals and enhancements which extend the economic life of the properties and equipment are capitalized. Gains or losses are not recognized upon disposition of petroleum and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the rate of depletion by 20 percent or more.

Depletion of petroleum and natural gas properties and depreciation of equipment are provided for using the unit-of-production method based on estimated proved petroleum and natural gas reserves, before royalties, as determined by independent engineers calculated in accordance with National Instrument 51-101. Production and reserves of natural gas are converted to equivalent barrels of crude oil based on the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of oil. The depletion and depreciation cost base includes total capitalized costs, less prior depletion and depreciation charges, less costs of unproved properties, less the estimated future net realizable value of production equipment and facilities, plus provision for future development costs and future asset retirement costs of proved undeveloped reserves.

c) Cost Impairment Test

The Trust places a limit on the aggregate carrying value of petroleum and natural gas properties and equipment, which may be amortized against revenues of future periods (the "cost impairment test"). The cost impairment test requires an evaluation of petroleum and natural gas assets in each reporting period to determine that the carrying amount in a cost centre is recoverable and does not exceed the fair value of the properties in the cost centre.

Cost impairment is recognized if the carrying amount of the petroleum and natural gas properties exceeds the sum of the undiscounted cash flows expected to result from the Trust's proved reserves. Cash flows are calculated based on third party quoted forward prices, adjusted for the Trust's contract prices and quality differentials.

Upon recognition of impairment, the Trust would then measure the amount of impairment by comparing the carrying amounts of the petroleum and natural gas properties to an amount equal to the estimated net present value of future cash flows from proved plus risked probable reserves. The Trust's risk-free interest rate is used to arrive at the net present value of the future cash flows. Any excess carrying amount above the net present value of the Trust's future cash flows would be recognized as a permanent impairment.

The cost of unproved properties is excluded from the cost impairment test calculation and is subject to a separate impairment test.

d) Asset Retirement Obligation

The Trust uses the asset retirement obligation method of recording the future cost associated with removal, site restoration and asset retirement costs. The fair value of the liability for the Trust's asset retirement obligation is recorded in the period in which it is incurred, discounted to its present value using the credit adjusted risk-free interest rate and the corresponding amount recognized by increasing the carrying amount of property, plant and equipment. The asset recorded is depleted on a unit-of-production basis over the life of the reserves. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost could also result in an increase or decrease to the obligation. Actual costs incurred upon settlement of the retirement obligation are charged against the obligation to the extent of the liability recorded.

e) Goodwill

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the fair value for accounting purposes of the net identifiable assets and liabilities of the acquired business. Net identifiable liabilities of the acquired business include an estimate of future income taxes. The goodwill balance is assessed for impairment annually at year end or more frequently if events change and circumstances indicate that the asset might be impaired. The test for impairment is the comparison of the carrying amount to the fair value of the reporting entity. If the fair value of the consolidated Trust is less than the book value, impairment is measured by allocating the fair value of the consolidated Trust to the identifiable assets and liabilities at their fair values. The excess of this allocation is the fair value of goodwill. Any excess of the book value of goodwill over this implied value is the impairment amount. Impairment is charged to income in the period in which it occurs.

Goodwill is stated at cost less impairment and is not amortized.

An impairment test of goodwill was completed at December 31, 2006 resulting in no impairment amount.

f) Financial Instruments

The Trust uses financial instruments to reduce its exposure to fluctuations in commodity prices and foreign exchange rates. The Trust's policy is not to use financial instruments for speculative or trading purposes. Gains and losses on contracts which constitute effective hedges are recognized in production income at the time of sale of the related production. Financial instruments which do not qualify as hedges are recorded on a mark-to-market basis at the balance sheet date with the resulting gains or losses being taken into income in the period.

g) Income Taxes

Income taxes are calculated using 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 differences between the amounts reported in the consolidated financial statements of the Trust and their respective tax base, using substantively enacted income tax rates. The effect of a change in income tax rates on future tax liabilities and assets is recognized in income in the period in which the change occurs. Temporary differences arising on acquisitions result in future income tax assets and liabilities.

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the unitholders.

As the Trust allocates all of its taxable income to the unitholders in accordance with the Trust Indenture, and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no provision for income tax expense or liability has been made in the Trust. See Note 17 for further discussion.

In the Trust structure, payments are made between the Company and the Trust which result in the transferring of taxable income from the Company to individual unitholders. These payments may reduce future income tax liabilities previously recorded by the Company which would be recognized as a recovery of income tax in the period incurred.

h) Non-Controlling Interest

The exchangeable shares issued by a subsidiary, FET Resources Ltd., are reflected as non-controlling interest on the consolidated balance sheet and in turn, net income is reduced by the amount of net income attributed to the non-controlling interest. See Note 8 for further information.

The non-controlling interest on the consolidated balance sheet consists of the book value of exchangeable shares at the time of the Plan of Arrangement with Storm Energy Inc. in August 2002, plus net income attributable to the exchangeable shareholders, less exchangeable shares converted. The net income attributable to the non-controlling interest on the consolidated statement of income and accumulated income represents the cumulative share of net income attributable to the non-controlling interest based on the trust units issuable for exchangeable shares in proportion to Total Trust Units issued and issuable each period end.

i) Unit-Based Compensation Plan

The Trust has a unit-based compensation plan (the "Plan") for employees, directors and consultants of the Trust and its subsidiaries which are described in Note 11. Compensation expense associated with rights granted under the Plan is deferred and recognized in earnings over the vesting period of the Plan, with a corresponding increase or decrease in contributed surplus. Compensation expense is based on the fair value of the unit-based compensation at the date of grant using a modified Black Scholes option pricing model. The fair value method has been adopted prospectively with rights granted in 2003.

Consideration paid upon the exercise of the rights together with the amount previously recognized in contributed surplus is recorded as an increase in unitholders' capital.

The Trust has not incorporated an estimated forfeiture rate for rights that will not vest, rather the Trust accounts for actual forfeitures as they occur.

j) Per-Unit Amounts

Net income per unit is calculated using the weighted average number of trust units and exchangeable partnership units outstanding during the year. Diluted net income per unit includes additional trust units for the dilutive impact of the Rights Plan and exchangeable shares converted at the average exchange rate. The treasury stock method is used to determine the dilutive effect of unit-based compensation. The treasury stock method assumes that the proceeds received from the exercise of in-the-money trust unit rights are used to repurchase units at the average market rate during the period. The weighted average number of units outstanding is then adjusted by the net change. Net income is also increased for the net income attributable to the exchangeable shareholders in calculating dilutive per-unit amounts.

k) Revenue Recognition

Revenue associated with sales of crude oil, natural gas, and natural gas liquids is recognized when title passes to the purchaser, normally at the pipeline delivery point for natural gas and at the wellhead for crude oil.

l) Joint Operations

Certain of the Trust's exploration and production activities are conducted jointly with others. The accounts of the Trust reflect its proportionate interest in such activities.

m) Cash and Cash Equivalents

The Trust considers all highly liquid investments with a maturity of three months or less at the time of purchase to be cash equivalents. These cash equivalents consist primarily of funds on deposit for various terms. Cash and cash equivalents are stated at cost which approximates fair value.

n) Foreign Currency Translation

Monetary assets and liabilities denominated in a foreign currency are translated at the rate of exchange in effect at the balance sheet date. Revenues and expenses are translated at the monthly average rates of exchange. Translation gains and losses are included in income in the period in which they arise.

o) Transportation System Charges

The Trust records revenue gross of transportation system charges and a transportation system charge on the income statement.

p) Comparative Figures

Certain of the comparative figures have been reclassified to conform to the current year's presentation.

3. Business Acquisition

Effective June 27, 2006 Focus acquired PEML pursuant to a Plan of Arrangement with PEML. On June 26, 2006, the unitholders of the Trust and the shareholders of PEML voted to approve resolutions to effect the Plan of Arrangement by which security holders of PEML received a total of 5.17 Focus Energy Trust units and/or Focus Limited Partnership exchangeable units and $25.12 cash for each PEML common share and the Trust received the assets and assumed the liabilities of PEML for total consideration of $1,091.3 million. Of this amount, $1,070.5 million was for the acquisition of oil and gas assets, and the remaining $20.8 million was for the acquisition of working capital.

This amount consisted of the issuance of 30,802,817 Focus Energy Trust units, 9,999,992 Focus Limited Partnership exchangeable units and $199.8 million in cash and transaction costs. Both the Trust and Partnership units had a fair value of $21.85 per unit. The Board of Directors approved the Information Circular dated May 25, 2006 with respect to the Plan of Arrangement on May 24, 2006.

The Trust's aggregate consideration for the acquisition of PEML consists of the following:

Consideration for the acquisition:

($ thousands)	
Trust units issued	673,041
Exchangeable partnership units issued	218,500
Cash	198,253
Transaction costs	1,500
	1,091,294

This transaction has been accounted for using the purchase method whereby the assets acquired and the liabilities assumed are recorded at their fair values with the excess consideration over the fair value of the identifiable net assets allocated to goodwill. The following summarizes the allocation of the aggregate consideration of the PEML acquisition.

Allocation of purchase price:

($ thousands)	
Cash acquired	55,800
Net working capital	(36,717)
Petroleum and natural gas properties and equipment	903,645
Fair value of commodity contracts	1,679
Goodwill	448,141
Asset retirement obligation	(14,570)
Future income taxes	(266,684)
	1,091,294

Effective June 27, 2006, the results from operations from the assets purchased from PEML have been included in the consolidated financial statements of the Trust.

4. Petroleum and Natural Gas Properties and Equipment

(thousands)		2006		2005
Petroleum and natural gas properties and equipment, at cost	$	1,619,627	$	655,693
Accumulated depletion and depreciation		(318,571)		(224,828)
Petroleum and natural gas properties and equipment, at cost, net	$	1,301,056	$	430,865

The calculation of depletion and depreciation in 2006 included an estimate of $258.6 million (2005 – $61.6 million) for future development costs and $27.3 million (2005 – $3.4 million) for future asset retirement costs associated with proved undeveloped reserves. Unproved property costs of $26.7 million (2005 – $4.7 million) and estimated net realizable value of production equipment and facilities of $45.4 million (2005 – $25.0 million) were excluded from the depletion calculation.

The Trust performed a cost impairment test at December 31, 2006 to assess the recoverable amount of the net carrying value of petroleum and natural gas properties and equipment. Future prices for crude oil and natural gas were obtained for the period 2007 to 2011 inclusive from the Trust's year-end independent reserve evaluations and then escalated based on escalation factors in the same evaluations. Based on these assumptions, the recoverable value was in excess of the carrying value of the Trust's net carrying value of the petroleum and natural gas properties and equipment.

The future prices used for the cost impairment test for December 31, 2006 are as follows:

Consultant's Price Forecasts	2007	2008	2009	2010	2011
Crude Oil – WTI ($US/bbl)	$ 62.00	$ 60.00	$ 58.00	$ 57.00	$ 57.00
Natural Gas – AECO ($CDN/Mmbtu)	$ 7.20	$ 7.45	$ 7.75	$ 7.80	$ 7.85

5. Asset Retirement Obligation

The Trust's asset retirement obligations result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Trust estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations is approximately $84.6 million which will be incurred between 2007 and 2040. The majority of the costs will be incurred after 2021. A credit-adjusted risk-free rate of 7.5 percent and an inflation rate of 2.1 percent were used to calculate the fair value of the asset retirement obligation.

A reconciliation of the asset retirement obligation is provided below:

(thousands)	2006	2005
Balance, as at January 1	**$ 15,090**	$ 11,461
Accretion expense	**2,445**	889
Liabilities incurred		
Acquisitions	**14,570**	366
Development activity and change in estimates	**4,303**	3,006
Settlement of liabilities	**(277)**	(632)
Balance, as at December 31	**$ 36,131**	$ 15,090

6. Reclamation Fund

(thousands)	2006	2005
Balance as at January 1	**$ 2,711**	$ 1,923
Contributions	**3,215**	1,420
Reclamation costs	**(277)**	(632)
Balance, as at December 31	**$ 5,649**	$ 2,711

At the inception of the Trust in 2002, a reclamation fund was established to fund the payment of environmental and site reclamation costs. Annual contributions will be made to the reclamation fund such that the currently estimated future environmental and site reclamation costs will be funded after 20 years. The Company may use the reclamation fund for purposes of funding its environmental and site reclamation costs. The reclamation fund is held on deposit at a Canadian financial institution.

7. Long-Term Debt

The Trust has a $350 million revolving syndicated credit facility among four Canadian financial institutions with an extendible 364-day revolving period and a two-year amortization period. In addition, the Trust has a $15 million demand operating line of credit. At December 31, 2006, the available borrowings under these facilities were reduced by $3.0 million of letters of credit. The credit facilities are secured by a floating charge debenture covering all of the assets of the Trust and a general security agreement.

Advances bear interest at the bank's prime rate, bankers' acceptance rates plus stamping fees, or U.S. LIBOR rates plus applicable margins depending on the form of borrowing by the Trust. Stamping fees and margins vary from zero percent to 1.5 percent dependent upon financial statement ratios and type of borrowing. The effective rate on debt outstanding at December 31, 2006 is approximately 5.2 percent.

The credit facility will revolve until June 25, 2007, whereupon it may be renewed for a further 364-day term subject to review by the lenders. If not extended, principal payments will commence after expiry of the revolving period and will consist of three quarterly payments of eight and one-third percent commencing 15 months after the term date and the remaining 75 percent at the end of the term.

8. Non-Controlling Interest – Exchangeable Shares

The exchangeable shares of FET Resources Ltd. are convertible at any time into trust units (at the option of the holder) based on the exchange ratio. The exchange ratio is increased monthly based on the cash distribution paid on the trust units divided by the ten-day weighted average unit price preceding the record date. During the period of January 1 to December 31, 2006, a total of 57,631 exchangeable shares were converted into 81,818 trust units at exchange ratios prevailing at the time. At December 31, 2006, the exchange ratio was 1.46445 trust units for each exchangeable share. Cash distributions are not paid on the exchangeable shares. The exchangeable shares of FET Resources Ltd. are listed for trading on the Toronto Stock Exchange under the symbol FTX.

The Trust announced that as a result of minimal number of exchangeable shares outstanding, FET Resources Ltd. has elected to redeem all of its exchangeable shares outstanding on January 16, 2007. In connection with this redemption, FET Resources Ltd. has exercised its overriding "redemption call right" to purchase such exchangeable shares from holders of record. Each redeemed exchangeable share will be purchased for trust units of the Trust in accordance with the exchange ratio in effect at January 15, 2007, rounded to the nearest whole trust unit. A Notice of Redemption has been mailed to all exchangeable shareholders outlining the terms of this redemption.

Exchangeable Shares of FET Resources Ltd.	Number of Shares		Consideration (thousands)	
	2006	2005	**2006**	2005
Balance as at January 1	**560,218**	977,346	**$ 4,131**	$ 4,934
Net income attributable to non-controlling interest			**884**	1,437
Exchanged for trust units	**(57,631)**	(417,128)	**(465)**	(2,240)
Balance as at December 31	**502,587**	560,218	**$ 4,550**	$ 4,131

9. Unitholders' Capital

An unlimited number of trust units may be issued pursuant to the Trust Indenture. Each trust unit entitles the holder to one vote at any meeting of the unitholders and represents an equal fractional undivided beneficial interest in any distribution from the Trust and in any net assets in the event of termination or winding up of the Trust. The trust units are redeemable at the option of unitholders up to a maximum of $250,000 per annum. This limitation may be waived at the discretion of the Trust.

In October 2006, the Trust put in place the Distribution Reinvestment and Optional Trust Unit Purchase ("DRIP Plan") which provides the option for unitholders to reinvest cash distributions into additional units, either issued from treasury at 95 percent of the prevailing market price or through the facilities of the Toronto Stock Exchange at prevailing market rates with no additional commissions or fees. The Trust expects to issue units from treasury at a discount to satisfy the distribution reinvestment component of the DRIP Plan. As at December 31, 2006, the Trust has listed and reserved 941,207 trust units for the DRIP Plan.

Trust Units of Focus Energy Trust	Number of Units		Consideration (thousands)	
	2006	2005	**2006**	2005
Balance as at January 1	**36,687,167**	35,973,651	**$ 244,426**	$ 230,478
Issued pursuant to Plan of Arrangement with PEML (i)	**30,802,817**	–	**673,041**	–
Issued on conversion of exchangeable shares (ii)	**81,818**	546,473	**1,922**	11,479
Issued pursuant to the Executive Bonus Plan (iii)	**42,530**	67,293	**1,032**	1,408
Issued pursuant to the Distribution Reinvestment Plan (iv)	**58,793**	–	**1,029**	–
Exercise of Unit Appreciation Rights (v)	**95,000**	99,750	**1,116**	1,061
Trust unit issue expense	**–**	–	**(140)**	–
Balance as at December 31	**67,768,125**	36,687,167	**$ 922,426**	$ 244,426

(i) Issued pursuant to the Plan of Arrangement with PEML at a fair value of $21.85 per trust unit.

(ii) Issued on conversion of exchangeable shares to trust units with the consideration recorded being equal to the market value of the trust units received on the date of conversion.

(iii) Pursuant to the Executive Bonus Plan, 50 percent of all amounts due under such plan are payable through the issuance of trust units priced at the five day weighted average trading price for the last five trading days of the month for which the bonus relates.

(iv) Issued pursuant to the DRIP Plan, units are either issued from treasury at 95 percent of the average market price for the 10 days immediately preceding the distribution date or through facilities of the TSX, at prevailing market prices.

(v) Exercise of Unit Appreciation Rights includes cash consideration of $805,743 (2005 – $813,123) and contributed surplus credit of $310,639 (2005 – $247,446).

10. Exchangeable Partnership Units

The exchangeable partnership units of Focus Limited Partnership are convertible after January 1, 2007 into trust units, at the option of the holder, on a one-for-one basis. Cash distributions equal to the distribution paid to Trust unitholders are paid to the holders of the exchangeable partnership units.

The Board of Directors may redeem the exchangeable partnership units after January 8, 2017, unless certain conditions are met to permit an earlier redemption date.

The exchangeable partnership units are entitled to vote on Focus matters with Trust unitholders through the Special Voting Unit. The exchangeable partnership units are not listed on any stock exchange and are not transferable.

Exchangeable Partnership Units of Focus Energy Trust	Number of Units		Consideration (thousands)	
	2006	2005	**2006**	2005
Balance as at January 1	**–**	–	–	–
Issued pursuant to Plan of Arrangement with PEML	**9,999,992**	–	**$ 218,500**	–
Balance as at December 31	**9,999,992**	–	**$ 218,500**	–

The exchangeable partnership units were issued at a fair value of $21.85 per unit.

11. Trust Unit Rights Plan

The Trust Unit Rights Plan (the "Plan") was established August 23, 2002 as part of the Plan of Arrangement. The Trust may grant rights to employees, directors, consultants and other service providers of the Trust and any of its subsidiaries. The Trust is authorized to grant up to five percent of the outstanding trust units, including units issuable upon exchange of exchangeable shares and exchangeable partnership units. As at December 31, 2006, the Trust has listed and reserved 3,848,321 trust units and there are rights outstanding to purchase 2,438,063 trust units pursuant to the terms of the Plan.

The initial exercise price of rights granted under the Plan is equal to the weighted average of the closing price of the trust units on the immediately preceding five trading days. At the option of the unitholder, the exercise price per right is calculated by deducting from the grant price the aggregate of all distributions, on a per-unit basis, made by the Trust after the grant date which represents a return of more than 0.833 percent of the Trust's recorded cost of capital assets less depletion, depreciation and amortization charges and any future income tax liability associated with such capital assets at the end of each month. Provided this test is met, then the entire amount of the distribution is deducted from the grant price. Rights granted prior to June 2006 have a life of five years and vest equally over a four-year period commencing on the first anniversary of the grant. Rights granted under the Plan subsequent to May 2006 have a life of four years and vest equally over a three-year period commencing on the first anniversary of the grant.

	2006		2005	
	Number of Rights	**Weighted Average Exercise Price**	Number of Rights	Weighted Average Exercise Price
Balance as at January 1	**1,311,100**	**$ 12.52**	1,113,100	$ 11.78
Granted	**1,338,447**	**$ 22.82**	337,750	$ 21.68
Exercised	**(95,000)**	**$ 8.48**	(99,750)	$ 8.15
Cancelled	**(116,484)**	**$ 19.74**	(40,000)	$ 15.10
Before reduction of exercise price	**2,438,063**	**$ 17.99**	1,311,100	$ 14.51
Reduction of exercise price	**–**	**$ (1.47)**	–	$ (1.99)
Balance as at December 31	**2,438,063**	**$ 16.52**	1,311,100	$ 12.52

- The average exercise price at the grant date is $19.49 ($15.89 for 2005).
- The average contractual life of the rights outstanding is 2.96 years (3.21 years for 2005).
- The number of rights exercisable at December 31, 2006 is 434,500 (273,500 for 2005).
- The average value at the grant date for the year ended December 31, 2006 is $5.05 ($4.77 for 2005).

The fair value of rights is estimated using a modified Black Scholes option pricing model.

The Trust has recorded non-cash compensation expense of $2,120,550 for the year ended December 31, 2006. The Trust recorded non-cash compensation expense of $884,362 for the year ended December 31, 2005.

The fair value of rights granted in 2006 was estimated using a modified Black Scholes option pricing model with the following weighted average assumptions: risk-free interest rate of 4.29 percent, volatility of 27 percent, life of 2.8 years and a dividend yield rate of 11 percent. Users are cautioned that the assumptions made are estimates of future events and actual results could differ materially from those estimated.

12. Elimination of the Executive Bonus Plan

Late in the second quarter of 2006, the Board of Directors approved a new compensation plan that would better suit the expanded employee base of the Trust and be more comparable with the standard compensation framework within the sector.

In eliminating the Executive Bonus Plan, $3.0 million is being paid to the participants in the Executive Bonus Plan. Half was paid at the end of June 2006 and the remainder will be paid on July 1, 2007. In addition participants received, in aggregate, an additional 495,600 trust unit appreciation rights.

13. Accumulated Income

(thousands)		2006		2005
Accumulated income, before cash distributions	$	259,925	$	186,958
Accumulated cash distributions		(311,453)		(187,216)
Balance as at December 31	$	(51,528)	$	(258)

14. Financial Instruments

The Company's financial instruments included in the balance sheet consist of accounts receivable, other receivables, accounts payable and accrued liabilities and bank debt.

Credit risk:

The Company's accounts receivable are due from a diverse group of customers and as such are subject to normal credit risks.

Interest rate risk:

The Company is also exposed to interest rate risk to the extent that long-term debt is at a floating rate of interest.

Fair values:

The fair values of short-term financial instruments, being accounts receivable, accounts payable and accrued liabilities and cash distributions payable approximate their carrying values due to their short term to maturity. The fair value of long-term debt approximates its carrying value due to the floating interest rate and the revolving nature of the obligation.

The following financial contracts were outstanding at the date of writing. The fair market value of the contracts outstanding at December 31, 2006, which have no book value, would have resulted in a net payment to the Trust of $25.7 million.

Financial Contracts	Daily Quantity		Contract Price	Price Index	Term
Crude oil	400 bbls	$	70.00 – 79.00 Cdn	WTI	January 2007 – December 2007
	400 bbls	$	70.93 Cdn	WTI	April 2007 – September 2007*
Natural gas	6,000 GJ	$	8.01 Cdn	AECO	August 2006 – March 2007
	7,000 GJ	$	9.00 Cdn	AECO	August 2006 – March 2007
	20,000 GJ	$	7.66 Cdn	AECO	August 2006 – March 2007
	11,000 GJ	$	8.73 Cdn	AECO	November 2006 – March 2007
	13,000 GJ	$	9.32 Cdn	AECO	November 2006 – March 2007
	7,300 GJ	$	7.70 Cdn	AECO	March 2007 – October 2007
	15,000 GJ	$	7.77 Cdn	AECO	April 2007 – October 2007
	10,000 GJ	$	7.90 Cdn	AECO	April 2007 – October 2007
	5,000 GJ	$	8.00 Cdn	AECO	April 2007 – October 2007
	5,000 GJ	$	7.52 Cdn	AECO	April 2007 – October 2007
	5,000 GJ	$	7.50 Cdn	AECO	April 2007 – October 2007
	5,000 GJ	$	7.53 Cdn	AECO	April 2007 – October 2007
	5,000 GJ	$	7.50 Cdn	AECO	April 2007 – October 2007
	15,000 GJ	$	8.25 – 9.00 Cdn	AECO	November 2007 – March 2008
	15,000 GJ	$	8.02 Cdn	AECO	November 2007 – March 2008*
	10,000 GJ	$	8.60 Cdn	AECO	November 2007 – March 2008*

* contract entered into subsequent to December 31, 2006

Focus has designated their commodity contracts as effective accounting hedges on their respective contract dates.

New CICA Handbook Standards, Financial Instruments – Recognition and Measurement – Section 3855, Hedges – Section 3865, and Comprehensive Income – Section 1530 are applicable for the Trust beginning in 2007.

As a result, hedge accounting for financial contracts will not be continued in future periods beyond 2006. All derivative contracts will be recorded at fair value on the balance sheet. Derivatives will be adjusted to fair value each period with the change recognized in the determination of income. Settlement of derivatives will be included in the Statement of Cash Flows as an operating activity. Unrealized gains and losses will be subtracted or added back as a non-cash item.

Adoption of these new standards is applied retrospectively which means the opening balance of retained earning is restated in 2007. Prior periods are not restated.

Focus has recognized an asset for commodity contracts of $1.7 million as part of the business acquisition with PEML. This amount will be amortized over the term of those contracts, November 2006 to March 2007. In 2006, $0.7 million has been recognized in the income statement leaving an asset balance of $1.0 million at December 31, 2006.

In July 2006, Focus amended certain commodity contracts effectively canceling a number of contracts with terms of November 2006 to March 2007 and writing new contracts with the same volume over the term of August 2006 to March 2007. The result of these amendments was recognition of the fair value of the original commodity contracts as an asset and liability in the balance sheet. The asset is being amortized over the original contracts and has a balance of $2.0 million at December 31, 2006. The liability is being amortized over the original contracts and has a balance of $3.1 million at December 31, 2006. The difference of $1.1 million has been recognized in the income statement. Total amortization of hedging contracts was $1.8 million in 2006.

15. Physical Sales Contracts

In addition to the financial contracts described above, the following physical contracts were outstanding at the date of writing. The fair market value of these contracts at December 31, 2006, which have no book value, would have resulted in a net payment to the Trust of $7.8 million.

Physical Sales Contracts	Daily Quantity		Contract Price	Term
Natural gas – fixed price	5,000 GJ	$	10.32 Cdn	November 2006 – March 2007
	12,500 GJ	$	7.31 Cdn	August 2006 – March 2007
	10,000 GJ	$	6.77 Cdn	August 2006 – March 2007
	15,000 GJ	$	7.15 Cdn	April 2007 – October 2007
	10,000 GJ	$	7.18 Cdn	April 2007 – October 2007

16. Per-Unit Amounts and Supplementary Cash Flow Information

Basic per-unit calculations are based on the weighted average number of trust units and exchangeable partnership units outstanding during the period. Diluted per-unit calculations include additional trust units for the dilutive impact of rights outstanding pursuant to the Rights Plan and include exchangeable shares converted at the average exchange ratio and include exchangeable partnership units.

Basic per-unit calculations for the year ended December 31 are based on the weighted average number of trust units and exchangeable partnership units outstanding in 2006 of 57,828,890 (2005 of 36,432,905).

Diluted calculations for the year ended December 31 include additional trust units for the dilutive impact of the Rights Plan in 2006 of 529,664 (2005 of 564,620) and 753,769 exchangeable shares (2005 of 910,887) converted at the average exchange rate. Net income has been increased for the net income attributable to the exchangeable shareholders in calculating dilutive per-unit amounts.

Supplementary cash flow information for the year ended December 31:

(thousands)		2006		2005
Interest paid	**$**	**13,490**	$	3,345
Interest received	**$**	**33**	$	40
Taxes paid	**$**	**30,993**	$	791
Cash distributions paid	**$**	**118,399**	$	72,829

17. Income Taxes

Effective July 1, 2006, the Saskatchewan general corporate income tax rate decreased from 17 percent to 14 percent with a further reduction to 13 percent expected on July 1, 2007 and to 12 percent on July 1, 2008. Effective April 1, 2006, the Alberta general corporate income tax rate decreased from 11.5 percent to 10 percent. In 2003, Royal Assent was received legislating the reduction of the federal general corporate income tax rate on income from resource activities from 28 percent to 21 percent and for the elimination of the existing 25 percent resource allowance deduction and introduced the deductibility of actual provincial and other Crown royalties paid, to be phased in over a five-year period. The phase in will be complete in 2007. In addition, the Federal Government further announced in 2006 a reduction in the general corporate tax rate from 21 percent to 19 percent from 2008 to 2010 and the elimination of the corporate surtax in 2008 and the large corporations tax in 2006.

The Trust's expected future income tax rate is approximately 30.8 percent at December 31, 2006 compared to 34 percent at December 31, 2005. The Trust recorded a future income tax recovery of $30.2 million in 2006. This amount includes a recovery of $8.2 million relating to accounting for non-controlling interest – exchangeable shares ($5.7 million in 2005).

The Trust recognized future income tax liabilities of $266.7 million in 2006 related to the acquisition of PEML, a private company.

Certain of the Trust's assets are held by entities which transfer taxable income to unitholders. The excess of the carrying value of these assets over the tax value is $77.2 million at December 31, 2006.

On October 31, 2006, the Federal Government announced proposals pertaining to the taxation of distributions from publicly traded Canadian income trusts, royalty trusts and partnerships. The proposals include a 31.5 percent tax imposed on income before distributions at the trust level and taxed to the taxable Canadian investor, effectively as a dividend. If enacted, the proposals would apply to the Trust effective January 1, 2011. On December 21, 2006, the Department of Finance issued draft legislation consistent with the proposals described above.

As at December 31, 2006, the legislative proposals are not substantively enacted and thus there is no impact on the recognition of future income taxes in 2006. If the legislation is enacted, the Trust's taxable status will change resulting in recognition of future tax liabilities at substantively enacted tax rates in respect of temporary differences described above.

The provision for future income taxes is different from the amount computed by applying the combined statutory Canadian Federal and Provincial income tax rate to income for the period before income taxes. The differences are as follows:

(thousands)		2006		2005
Income before income and other taxes and non-controlling interest – exchangeable shares	**$**	**43,852**	$	60,099
Statutory combined federal and provincial income tax rate		**35.5%**		38.08%
Expected income tax expense at statutory rates	**$**	**15,567**	$	22,885
Add (deduct) the income tax effect of:				
Income attributable to the Trust, not subject to income tax		**(39,726)**		(28,779)
Non-deductible Crown charges		**3,294**		9,969
Resource allowance		**(3,718)**		(8,781)
Alberta Royalty Tax Credit		**(58)**		(121)
Reduction in corporate tax rate		**(10,094)**		(1,832)
Capital tax		**–**		836
Other		**4,736**		1,021
Income and other taxes	**$**	**(29,999)**	$	(4,802)

The components of the future tax liability at December 31 are as follows:

(thousands)		2006		2005
Capital assets in excess of tax value	**$**	**331,150**	$	87,973
Provision for asset retirement obligation		**(11,143)**		(5,170)
Other		**(1,207)**		(1,169)
Future income taxes	**$**	**318,800**	$	81,634

18. Commitments and Contingencies

The Trust is involved in claims arising in the normal course of operations. Management is of the opinion that any resulting settlements would not materially affect the Trust's financial position or reported results in operations.

The following table is a summary of all contractual obligations and commitments for the next five years.

($ thousands)	Total	2007	2008 – 2009	2010 – 2011	2012 and thereafter
Office premises	2,436	626	1,315	495	–
Operating leases	342	342	–	–	–
Mineral and surface leases(2)	26,434	4,406	8,811	8,811	4,406
Transportation and processing	20,138	11,250	5,276	1,038	2,574
Asset retirement obligations(3)	36,131	193	490	950	34,498
Total contractual obligations	85,481	16,817	15,892	11,294	41,478

(1) The table does not include the Trust's obligations for financial instruments and physical sales contracts which are fully disclosed in Notes 14 and 15.

(2) The Trust makes payments for mineral and surface leases. The table includes payments for each of the years 2007 to 2011 under these leases, assuming continuation of the leases. The continuation of leases is based on decisions by the Trust relating to each of the underlying properties. Payments for the period after 2012 have not been included in the table but would continue at the same yearly rate if there were no change to the underlying properties.

(3) Based on the estimated timing of expenditures to be made in future periods.

In addition, the Trust has income and capital tax filings that are subject to audit and potential reassessment. The findings from such audit may impact the tax liability of the Trust. The final results are not reasonably determinable at this time and management believes it has adequately provided for income and capital taxes.

19. Subsequent Event

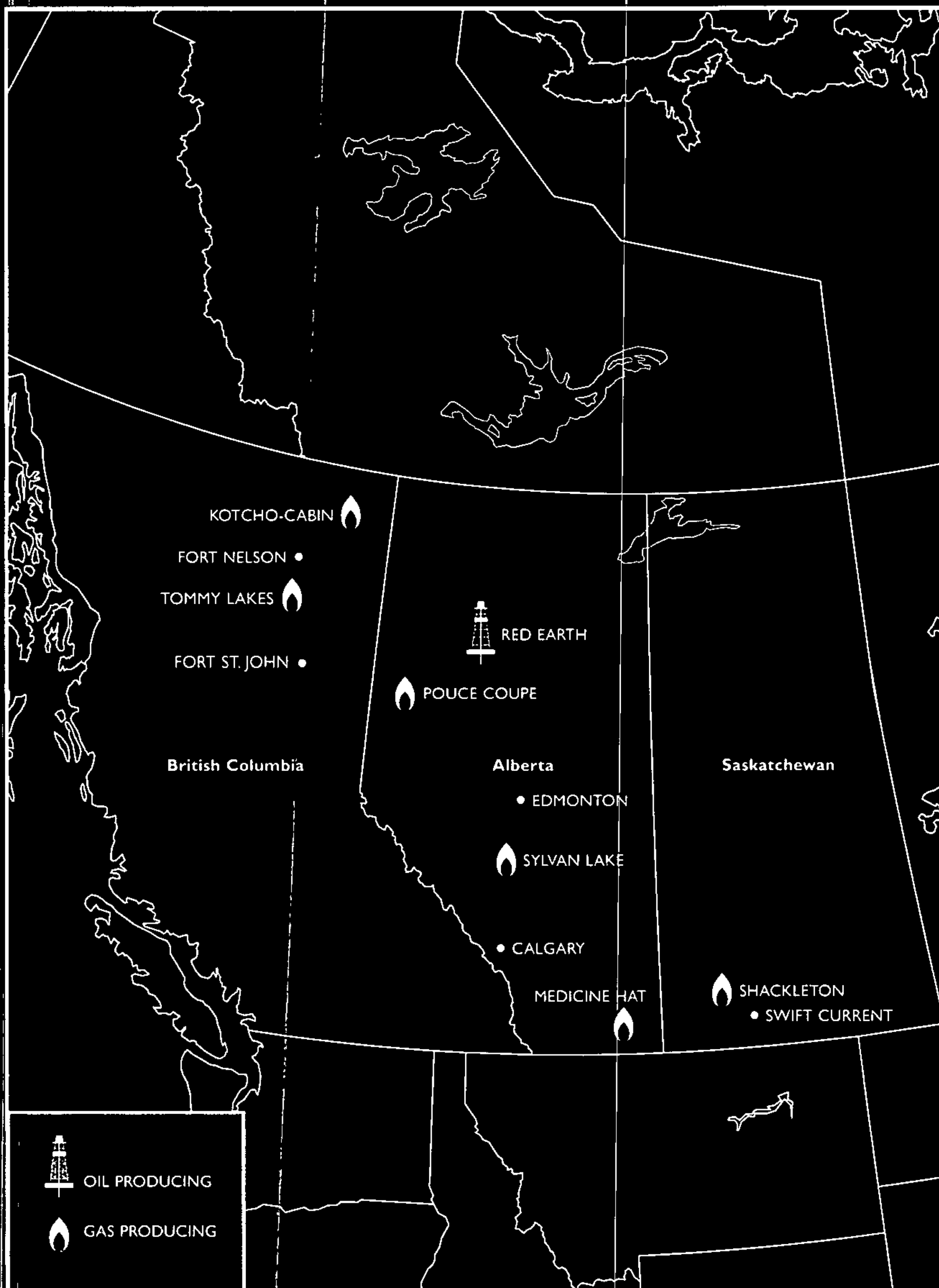
On January 16, 2007 FET Resources Ltd. redeemed all of its outstanding exchangeable shares. Each redeemed exchangeable share was exchanged for trust units in accordance with the exchange rate in effect at January 15, 2007 of 1.47300.

Quarterly Information

Summary of Quarterly Results

	2006				2005			
(thousands of dollars, except as indicated)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
FINANCIAL								
Oil and gas revenues, before royalties	98,434	90,395	48,663	48,146	52,315	48,790	46,583	43,981
Funds flow from operations	64,412	60,134	27,988	28,688	32,350	29,773	27,436	26,809
Per Total Unit – basic	$ 0.82	$ 0.77	$ 0.70	$ 0.77	$ 0.86	$ 0.80	$ 0.73	$ 0.72
Cash distributions per trust unit	$ 0.48	$ 0.48	$ 0.57	$ 0.57	$ 0.54	$ 0.52	$ 0.48	$ 0.48
Payout ratio – per-unit basis	58%	63%	82%	74%	63%	65%	65%	67%
Net income (1)	21,646	12,671	21,873	16,778	17,858	17,573	14,682	13,351
Per unit – basic (1)	$ 0.28	$ 0.19	$ 0.57	$ 0.46	$ 0.49	$ 0.48	$ 0.40	$ 0.37
Capital expenditures (2)	26,986	36,457	2,674	24,289	10,865	5,658	3,962	22,475
Acquisition expenditures, net (2)	45	–	1,091,294	–	(33)	10,394	0	77
Long-term debt plus working capital	308,122	313,013	297,450	109,094	92,518	94,252	88,965	94,548
Per Total Unit – basic	$ 3.92	$ 3.99	$ 3.80	$ 2.91	$ 2.47	$ 2.52	$ 2.38	$ 2.54
Times funds flow from operations (3)	1.2	1.3	2.7	1.0	0.7	0.8	0.8	0.9
Total Trust Units – outstanding (000's)	78,504	78,425	78,359	37,521	37,456	37,418	37,339	37,290
Wtgd average Total Trust Units (000's)	78,453	78,399	40,223	37,489	37,442	37,381	37,317	37,254
OPERATIONS								
Average daily production								
Crude oil (bbls/d)	1,965	1,844	1,563	1,610	1,714	1,718	1,779	1,850
NGLs (bbls/d)	706	740	682	784	762	833	770	743
Natural gas (mcf/d)	113,539	115,612	46,753	45,137	42,629	44,910	46,997	43,575
BOE (@ 6:1)	21,594	21,853	10,038	9,917	9,582	10,036	10,382	9,856
Natural gas weighting	88%	88%	78%	76%	74%	75%	75%	74%
Product prices realized (4)								
Crude oil (CDN$/bbl)	$ 57.51	$ 70.09	$ 75.06	$ 63.13	$ 59.20	$ 57.78	$ 54.66	$ 54.94
NGLs (CDN$/bbl)	$ 53.85	$ 66.56	$ 66.37	$ 59.45	$ 60.64	$ 62.41	$ 55.13	$ 51.08
Natural gas (CDN$/mcf)	$ 7.80	$ 6.75	$ 7.36	$ 7.92	$ 9.24	$ 7.77	$ 7.40	$ 7.36
Netback per BOE								
Revenue, net of transportation (4)	$ 48.09	$ 43.92	$ 50.27	$ 51.11	$ 56.61	$ 49.87	$ 46.91	$ 46.75
Royalties, net of ARTC	(8.94)	(8.37)	(9.71)	(11.92)	(13.41)	(12.16)	(11.90)	(10.46)
Production expenses	(4.04)	(3.50)	(4.62)	(5.50)	(4.61)	(3.56)	(4.10)	(4.19)
Netback per BOE	$ 35.11	$ 32.04	$ 35.95	$ 33.69	$ 38.58	$ 34.15	$ 30.91	$ 32.09
Funds flow from operations per BOE	$ 32.42	$ 29.91	$ 30.64	$ 32.14	$ 36.70	$ 32.25	$ 29.04	$ 30.22
Wells drilled (gross)	56	154	8	9	6	16	3	12
TRUST UNIT TRADING STATISTICS								
Unit prices (based on daily closing price)								
High	$ 24.30	$ 25.09	$ 25.89	$ 25.65	$ 26.74	$ 24.05	$ 22.40	$ 22.60
Low	$ 17.09	$ 20.85	$ 20.31	$ 20.65	$ 19.72	$ 20.99	$ 18.99	$ 18.60
Close	$ 18.18	$ 21.25	$ 23.65	$ 23.71	$ 25.72	$ 24.04	$ 21.60	$ 20.80
Daily average trading volume	288,131	282,942	243,598	116,940	103,540	117,859	73,020	115,824

(1) Restated at June 30, 2005 with new Accounting Policy EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts"
(2) Cost of capital expenditures and acquisitions excluding any asset retirement obligation or future income tax
(3) Long-term debt plus working capital divided by funds flow from operations for the quarter annualized
(4) Realized prices are net of hedging settlements and transportation system charges which are reported separately.


KOTCHO-CABIN
FORT NELSON
TOMMY LAKES
FORT ST. JOHN
RED EARTH
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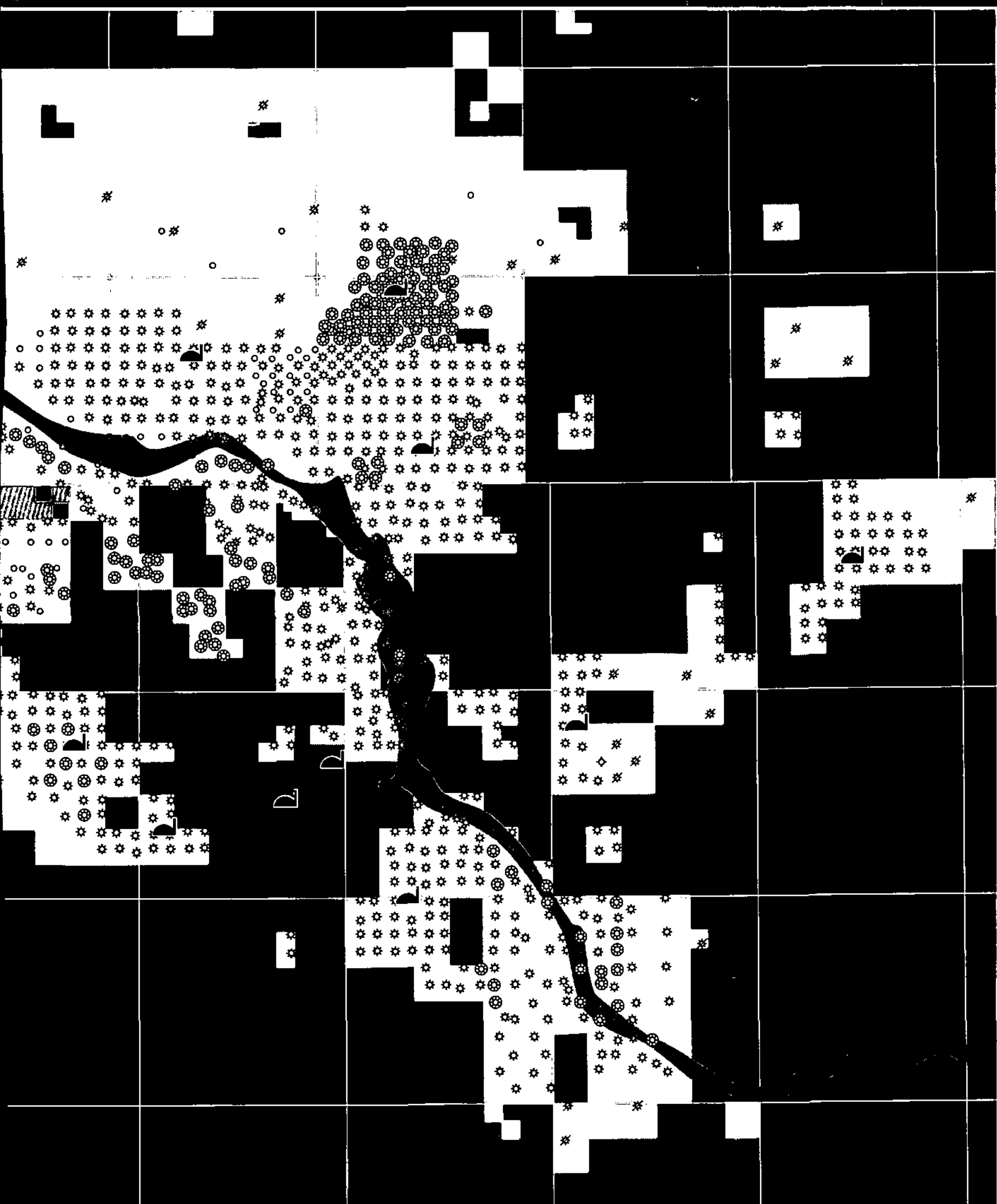

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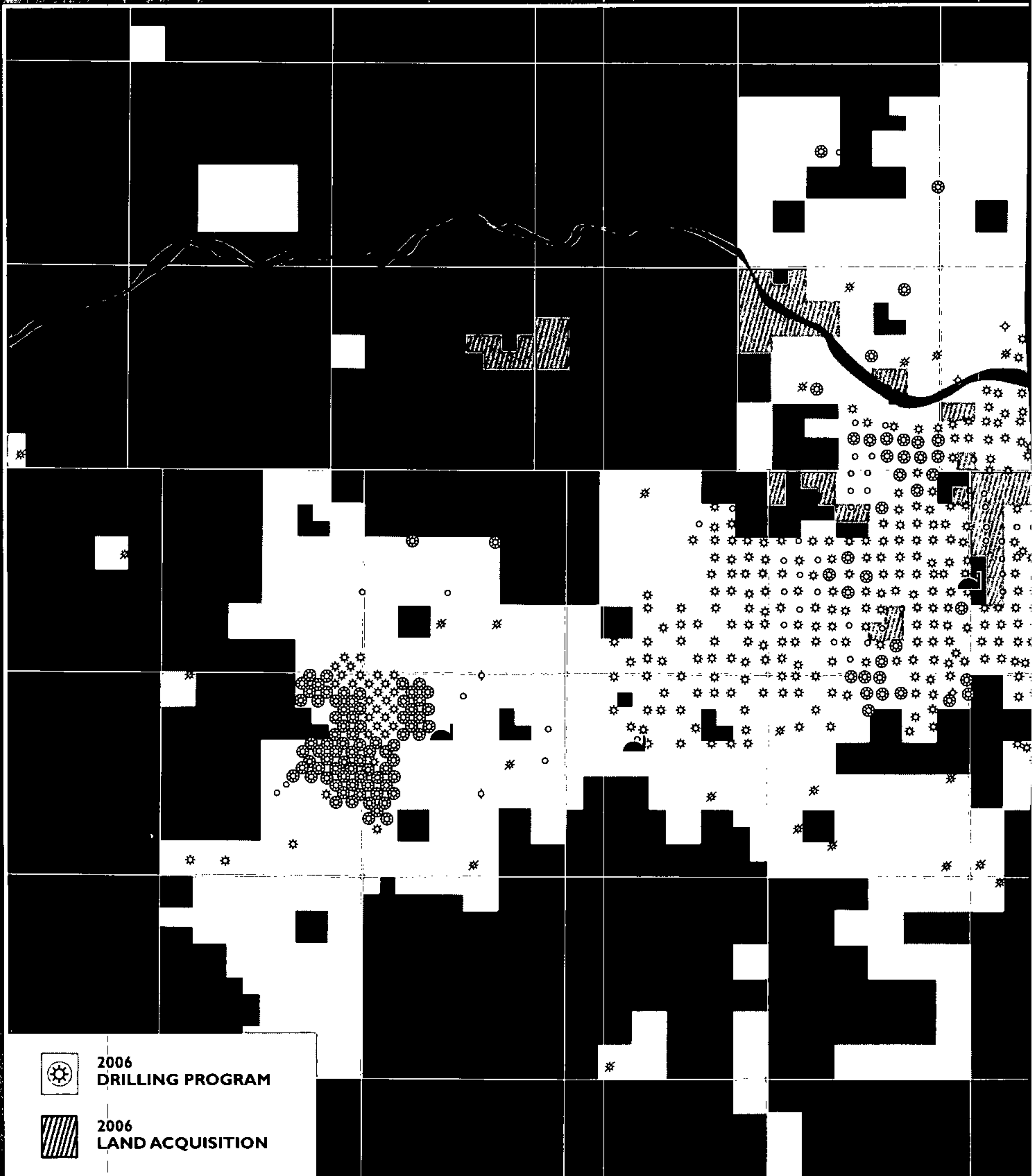
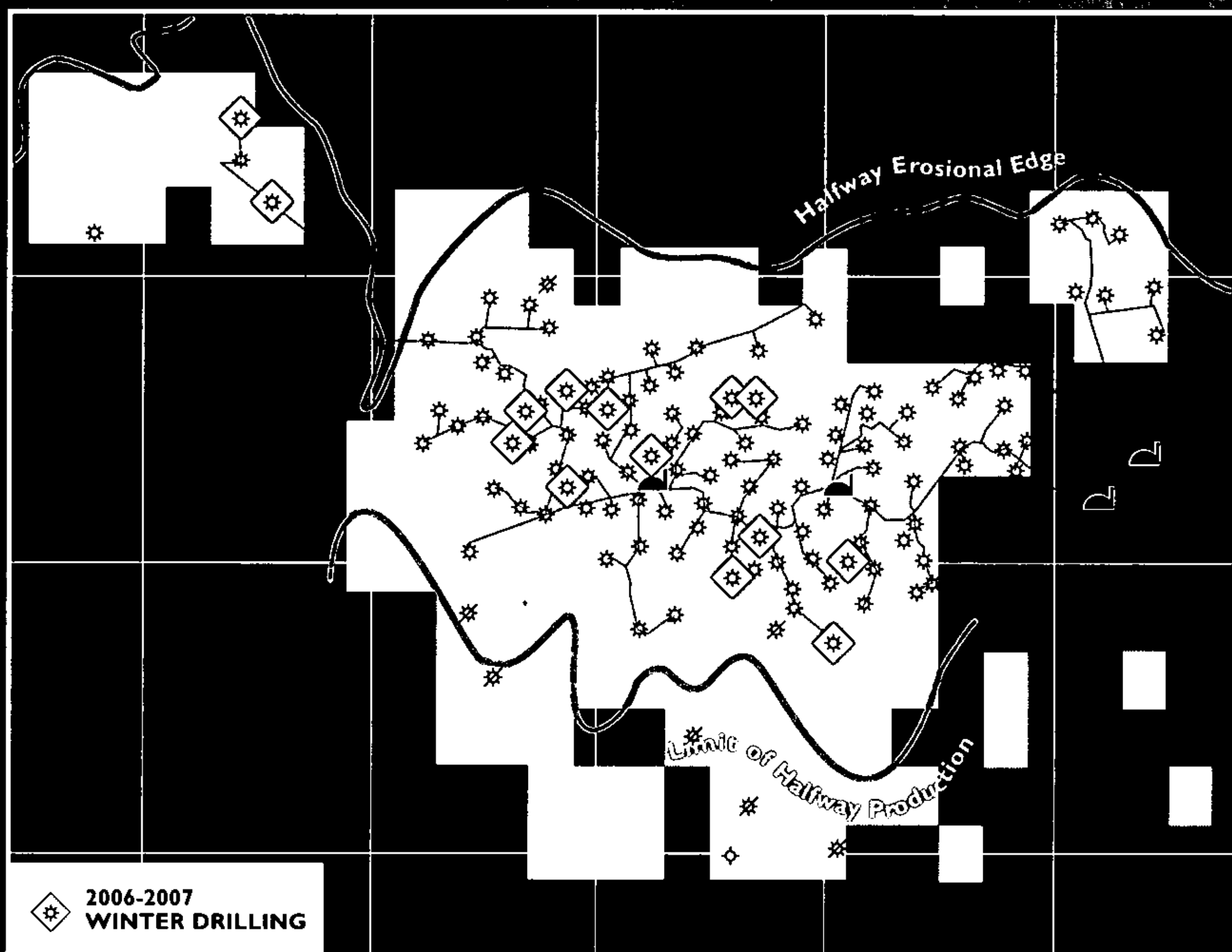


Tommy Lakes



Halfway Erosional Edge
Limit of Halfway Production
2006-2007
WINTER DRILLING

SENIOR MANAGEMENT

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President and C.E.O.

William D. Ostlund
Senior Vice President and C.F.O.

Dennis M. Lawrence
Senior Vice President and C.O.O.

Bryce H. Murdoch
Vice President, Geology

Al S. Pickering
Vice President, Land

David W. Sakal
Vice President, Operations

Hugh C. McCaskill
Vice President, Development

A. Kim Schoenroth
Vice President, Finance

Grant A. Zawalsky
Corporate Secretary

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Jeff S. Lebbert[3]
James H. McKelvie[2][3]
David P. O'Brien[5]
Gerald A. Romanzin[2][4][5]
Clayton H. Woitas[4]

(1) CHAIRMAN OF THE BOARD
(2) MEMBER OF THE AUDIT COMMITTEE
(3) MEMBER OF THE COMPENSATION COMMITTEE
(4) MEMBER OF THE RESERVES COMMITTEE
(5) MEMBER OF THE CORPORATE GOVERNANCE COMMITTEE

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KPMG LLP
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BANKERS

Bank Syndicate
Lead Agent: Royal Bank of Canada
Calgary, Alberta

ENGINEERING CONSULTANTS

Paddock Lindstrom & Associates Ltd.
Calgary, Alberta

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

REGISTRAR & TRANSFER AGENT

Valiant Trust Company
Calgary, Alberta

ABBREVIATIONS

api	American Petroleum Institute
ARTC	Alberta Royalty Tax Credit
Bcf	Billions of cubic feet
Bcfe	Billions of cubic feet equivalent
BOE	Barrels of oil equivalent @ 6:1
BOE/d	Barrels of oil equivalent per day
bbl	Barrel of oil or natural gas liquids
bbls	Barrels of oil or natural gas liquids
bbls/d	Barrels per day
$CDN	Canadian Dollar
GJ	Gigajoules
GJ/d	Gigajoules per day
Mmbtu	Millions of British Thermal Units
Mmbtu/d	Millions of British Thermal Units per day
mbbl	Thousand barrels
mbbls	Thousands of barrels
Mmbbls	Millions of barrels
Mmcfe/d	Millions of cubic feet equivalent per day
MBOE	Thousands of barrels of oil equivalent
MBOE/d	Thousands of barrels of oil equivalent per day
MMBOE	Millions of barrels of oil equivalent
mcf	Thousands of cubic feet
mcf/d	Thousands of cubic feet per day
Mmcf	Millions of cubic feet
Mmcf/d	Millions of cubic feet per day
Mw	Megawatt
Mw/hr	Megawatt per hour
NGL	Natural gas liquid
OPEC	Organization of Petroleum Exporting Countries
RLI	Reserve Life Index
TSX	Toronto Stock Exchange
WTI	West Texas Intermediate
$US	United States Dollar

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