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82- SUBMISSIONS FACING SHEET

Follow-Up Materials

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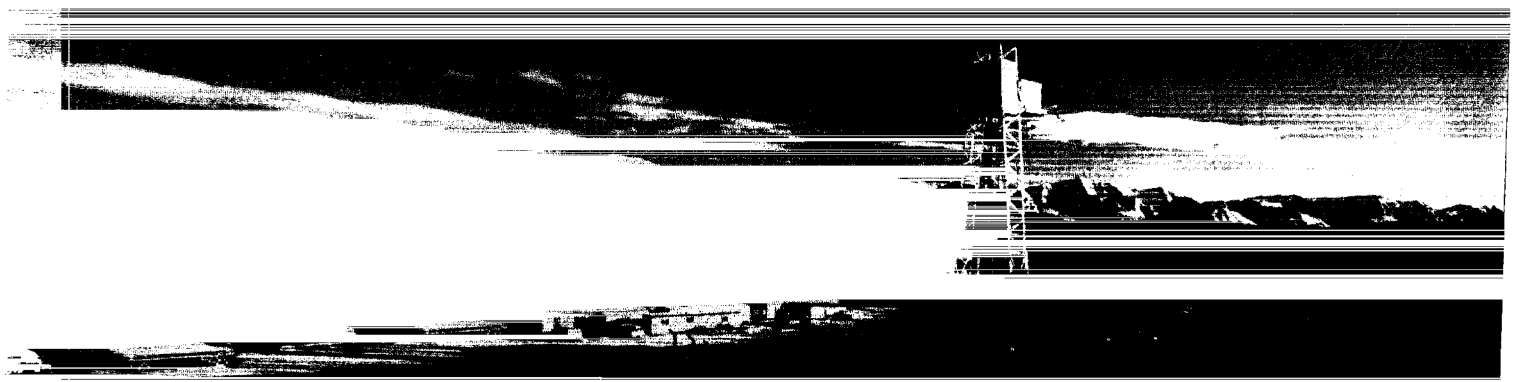
FOCUS ENERGY TRUST



STRENGTH. PERFORMANCE. SUSTAINABILITY.

2004 ANNUAL REPORT

NOTICE OF ANNUAL GENERAL MEETING

The Annual General and Special Meeting of Unitholders will be held at 3:00 p.m. on Tuesday, May 17, 2005 in the Nakiska Room at the Westin Hotel, 320 – 4th Avenue S.W., Calgary, Alberta.

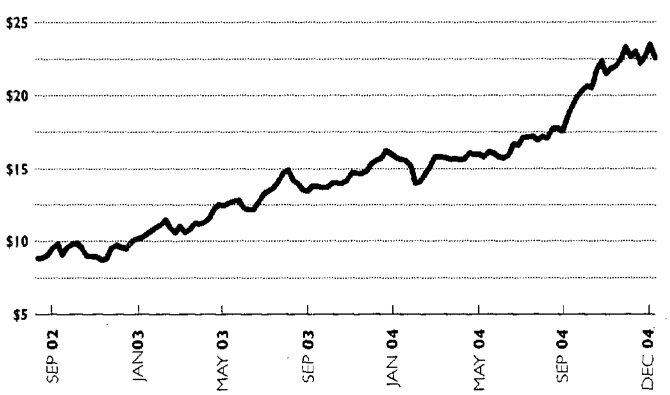
All Unitholders are invited to attend.

FOCUS ENERGY TRUST 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.

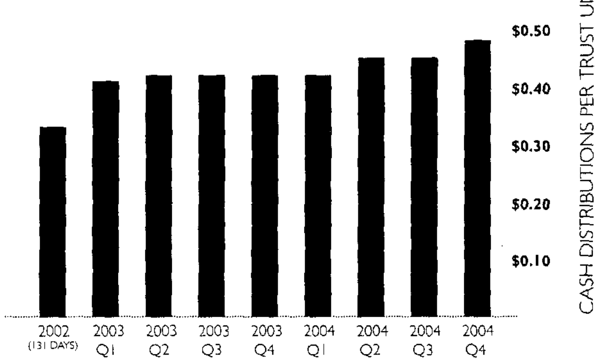
Focus Energy Trust Units trade on the TSX under the symbol **FET.UN**, and the Exchangeable Shares of FET Resources Ltd. trade on the TSX under the symbol **FTX**.

Production of natural gas and light oil is approximately 10,000 BOE/d and is produced from six main areas in British Columbia and Alberta. Production is weighted 73% to natural gas, and Focus operates approximately 87% of its production.

FET-UN EQUITY



FET-UN DISTRIBUTIONS PER QUARTER



CONTENTS

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.

2004 HIGHLIGHTS

(000s OF DOLLARS, EXCEPT WHERE INDICATED)		Years Ended, December 31, 2004[1]		2003[2]	Change
FINANCIAL					
Oil and gas revenues, before transportation system charges and royalties	$	**150,173**	$	119,367	26%
Funds flow from operations[3]	$	**89,567**	$	65,808	36%
Per Total Unit[4]	$	**2.49**	$	2.16	16%
Cash distributions per Trust Unit					
Per Total Unit[5]	$	**1.80**	$	1.665	8%
Payout ratio (per-Unit basis)		**72%**		77%	(5)%
Net income[1]	$	**59,628**	$	41,446	44%
Per Unit[1]	$	**1.66**	$	1.36	22%
Capital expenditures and acquisitions	$	**154,855**	$	37,026	318%
Long-term debt plus working capital	$	**81,158**	$	24,641	229%
Total Trust Units - outstanding (000s)[6]		**37,223**		31,822	17%
Weighted average Total Trust Units (000s)[7]		**35,903**		30,493	18%
OPERATIONS					
Average daily production					
Crude oil (bbls/d)		**1,996**		2,354	(15)%
NGLs (bbls/d)		**669**		485	38%
Natural gas (mcf/d)		**42,706**		34,254	25%
Barrels of oil equivalent (@ 6:1)		**9,782**		8,548	14%
Average net product prices realized[8]					
Crude oil (CDN$/bbl)	$	**40.43**	$	40.74	(1)%
NGLs (CDN$/bbl)	$	**43.73**	$	34.24	28%
Natural gas (CDN$/mcf)	$	**6.41**	$	5.55	16%
Netback per BOE					
Revenue[8]	$	**39.27**	$	35.41	11%
Royalties, net of ARTC	$	**(9.52)**	$	(9.78)	(3)%
Production expenses	$	**(3.29)**	$	(3.39)	(3)%
Netback	$	**26.46**	$	22.24	19%
Wells drilled					
Gross		**24**		23	4%
Net		**14.6**		9.3	57%
Success rate		**96%**		96%	–
TRUST UNIT TRADING STATISTICS					
Unit prices					
High	$	**21.39**	$	15.30	
Low	$	**12.90**	$	10.05	
Close	$	**19.97**	$	15.00	33%
Daily average trading volume		**112,677**		87,848	28%
RESERVES					
Proved plus probable[9]					
Crude oil (mbbls)		**5,697**		6,498	(12)%
NGLs (mbbls)		**3,387**		2,037	66%
Natural gas (Mmcf)		**194,462**		126,360	54%
Barrels of oil equivalent (MBOE/d @ 6:1)		**41,495**		29,595	40%
Reserve life index of proved plus probable[10]		**10.6**		9.8	8%
Gas weighting of proved plus probable reserves		**78%**		71%	7%
Proved reserves/proved plus probable reserves		**76%**		77%	(1)%

(1) FINANCIAL RESULTS PREVIOUSLY REPORTED FOR THE FIRST THREE QUARTERS OF 2004 HAVE BEEN RESTATED FOR CHANGES IN ACCOUNTING POLICIES RELATED TO TRANSPORTATION SYSTEM CHARGES AS DESCRIBED IN NOTE 2 OF THE FINANCIAL STATEMENTS.

(2) FINANCIAL RESULTS FOR 2003 HAVE BEEN RESTATED FOR CHANGES IN ACCOUNTING POLICIES RELATED TO ASSET RETIREMENT OBLIGATIONS AND TRANSPORTATION SYSTEM CHARGES AS DESCRIBED IN NOTE 2 OF THE FINANCIAL STATEMENTS.

(3) FUNDS FLOW FROM OPERATIONS ("FUNDS FLOW" BEFORE CHANGES IN NON-CASH WORKING CAPITAL) 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.

(4) BASED ON THE WEIGHTED AVERAGE TOTAL UNITS OUTSTANDING FOR THE PERIOD (SEE NOTES 9 AND 10)

(5) BASED ON THE NUMBER OF TOTAL UNITS OUTSTANDING AT EACH CASH DISTRIBUTION DATE (SEE NOTE 9)

(6) TOTAL UNITS BEING TRUST 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 WAS 1.27833 AT DECEMBER 31, 2004 AND 1.16718 AT DECEMBER 31, 2003.

(7) WEIGHTED AVERAGE TOTAL UNITS INCLUDING TRUST UNITS AND EXCHANGEABLE SHARES CONVERTED AT THE AVERAGE EXCHANGE RATIO (SEE NOTE 9)

(8) SETTLEMENTS FOR FINANCIAL HEDGING INSTRUMENTS NET OF TRANSPORTATION SYSTEM CHARGES

(9) RESERVE NUMBERS ARE TOTAL PROVED PLUS PROBABLE COMPANY WORKING INTEREST RESERVES BEFORE DEDUCTION OF ROYALTIES AND WITHOUT INCLUDING ANY ROYALTY INTERESTS AS DEFINED IN NATIONAL INSTRUMENT 51-101.

(10) RESERVE LIFE INDEX IS CALCULATED BY DIVIDING YEAR-END RESERVES BY THE FORWARD YEAR PRODUCTION ESTIMATE FROM THE RESERVE REPORTS.

MESSAGE TO THE UNITHOLDERS

2004 was a very successful year for Focus. We continued to execute our sustainable business model, add to our inventory of internal development opportunities and acquire strategic assets that are reflective of our tight gas initiatives. A l the while, we enjoyed a strong commodity price environment that allowed us to increase distributions twice during the year.

HIGHLIGHTS

- Focus Units realized a 45 percent total annualized return in 2004. This makes Focus one of the top performing oil and gas trusts.
- Monthly distributions increased from $0.14 per Unit at the start of the year to $0.16 per Unit in the final quarter.
- Funds flow from operations per Unit increased 16 percent on a year-over-year basis.
- We successfully completed two strategic gas acquisitions. One of these acquisitions increased our presence at Tommy Lakes and the other provided us with a unique opportunity to grow a new tight gas core area with year-round access.
- Our capital program, including acquisitions, resulted in a 432 percent replacement of our annual production based on proved plus probable reserves.
- Year-over-year proved plus probable company gross reserves increased 40 percent. On a per-Unit basis, proved plus probable reserves increased by 20 percent .
- Net asset value per Unit increased 41 percent on a year-over-year basis, driven by significant increases in reserves per Unit and stronger commodity price forecasts.
- Our reserve life index on a proved plus probable basis increased from 9.8 years to 10.6 years.
- Proved plus probable, finding, development and acquisition costs of $11.38 per BOE (including future capital) represent a recycle ratio of 2.3.
- Operating costs of $3.29 per BOE decreased slightly from last year but have fundamentally held constant since the inception of the Trust two and a half years ago.
- Our sustainable business model allowed us to retire $2 million of debt after funding the Trust's distributions, capital and reclamation fund expenditures from cash flow.

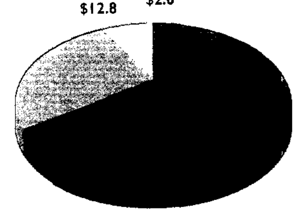
SUSTAINABILITY

When Focus was created in 2002, we set out to create a trust with a strong operational focus that utilized the drill bit to create value and that focused on sustainability.

We have accomplished what we set out to do. Our production has remained essentially constant on a per-Unit basis since inception as we have put retained cash flow to work on the Trust's asset base. In addition to fully funding our capital program, we have contributed $2 million to our reclamation fund and reduced debt by almost $13 million through this period.

Our ability to put cash flow to work on our lands is a function of our asset base and our technical team's talent in finding organic development opportunities. Over the last year we have strengthened our technical team with the further addition of geologists and engineers. The greater the replacement of production through organic drill bit activity, the greater the value creation for the Unitholder. Ultimately this leads to less reliance on the acquisition market and a greater control of our destiny.

FUNDS FLOW FROM OPERATIONS Q3 2002 – Q4 2004 (MILLIONS)



TIGHT GAS ACQUISITIONS

As our history details, we are a selective acquirer of assets, focusing on large tight gas and oil accumulations where hydrocarbons are known to exist but where we either have not had the right price or technology, or a combination of both, to warrant economic development. Our two acquisitions in 2004 were both tight gas acquisitions, the first being the acquisition of a partner's interest at Tommy Lakes and the second being a private company active in southern Alberta on the edge of the 20 TCF Milk River, Medicine Hat and Second White Specks shallow gas fairway. Both of these assets exhibit typical tight gas characteristics of low decline rates and long reserve life index, as well as reserves that continue to grow over time as innovative technology and higher gas prices make it possible to coax more gas from these reservoirs. Approximately 75 percent of the Trust's reserves are in tight gas, low decline reservoirs. We believe these assets are key foundation elements to the Trust and we are committed to continuing to add this type of asset to our portfolio.

OUTLOOK

In 2005, our drilling and development activity will occur in all core areas with the majority of our $27 to $30 million capital program being spent at Tommy Lakes, Pouce Coupe, Medicine Hat and Loon Lake. Oilfield services have been at a premium for the last two quarters as industry activity levels reach new highs. We have adjusted our expectations accordingly, altered our execution parameters and continue to exercise prudence and caution. We are not going to spend more capital to do less. We anticipate that our capital program will result in average production of 10,000 to 10,500 BOE per day in 2005, and that our operating cost structure will remain essentially flat in the range of $3.40 to $3.50 per BOE.

Although we continue to evaluate both property and corporate acquisition opportunities, we have found little by way of public offering that fits our strategic requirements of large accumulations of tight gas or oil involving opportunities to put the drill bit to work. Accordingly, we have focused our attention on generating drilling ideas in and around our existing land base.

We anticipate that commodity prices and the Canadian/U.S. dollar exchange rate will continue to be volatile in 2005 as they were in 2004. 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. We remain committed to managing our distribution profile through our price protection program and conservative distribution policy in order that, ultimately, long-term returns to Unitholders are enhanced.

As we continue to enjoy an exceptional commodity price environment, be assured that your management team remains disciplined, focused and committed to increasing Unitholder value.

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 our Focus team for their tireless efforts and continued enthusiasm.

On behalf of the Board,

Derek W. Evans
President and Chief Executive Officer

OPERATIONS REVIEW

All of Focus' producing properties are located in six main areas in Alberta and British Columbia. These include the natural gas dominated areas of Tommy Lakes, Kotcho-Cabin, Pouce Coupe, Sylvan Lake and Medicine Hat, and the oil dominated area of Red Earth.

In 2004, production of the Trust was weighted 73 percent to natural gas, with the remaining 27 percent consisting of light sweet crude and natural gas liquids. Our average working interest is approximately 71 percent, and we operate approximately 87 percent of our production.

TOMMY LAKES, NE BRITISH COLUMBIA

The Trust's largest single asset and main natural gas producing property is the Tommy Lakes area in northeastern British Columbia. The main producing zone at Tommy Lakes is the areally extensive blanket sand of the Triassic Halfway formation. Total pool original gas in place is in excess of 600 Bcf, of which approximately 27 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 600 to 800 mcf per day, with liquids recovered at 20 barrels per million cubic feet.

During 2004, Focus' gross production from the Tommy Lakes property averaged 29.4 Mmcf per day of natural gas and 569 bbls per day of natural gas liquids from 82 (78 net) wells. The base decline rate on the existing production is approximately 12 percent per year. Production at the property is compressed at four Focus-operated facilities and delivered into the Duke (Westcoast) system for further processing and delivery to markets.

On April 1, 2004 Focus acquired additional working interests at Tommy Lakes for $110 million. The acquisition increased our working interest in the western portion of the property to 100 percent and brought our overall average working interest up to approximately 95 percent. At December 31, 2004, Tommy Lakes represented approximately 65 percent of the Trust's reserves.

Subsequent to year-end, the Trust has successfully completed its 11-well (9.7 net) winter drilling program at Tommy Lakes. All 11 wells were cased and have been placed on production. This year's winter program set out to achieve four main objectives:

- further efficient infill development of the Halfway A Pool;
- selective Halfway step-out drilling to continue to extend the economic boundaries of the pool;
- testing of secondary zones such as the Bluesky and Doig;
- the implementation of well design and program execution initiatives designed to maximize our cost efficiencies.

The program was successful in achieving all of these objectives and the overall winter program at Tommy Lakes came in as per our expectations in terms of production rates and reserves. Based upon this continued success, Focus anticipates that the Tommy Lakes property will continue to be the main development area for the Trust, with at least two more years of similar sized development programs.

RED EARTH, ALBERTA

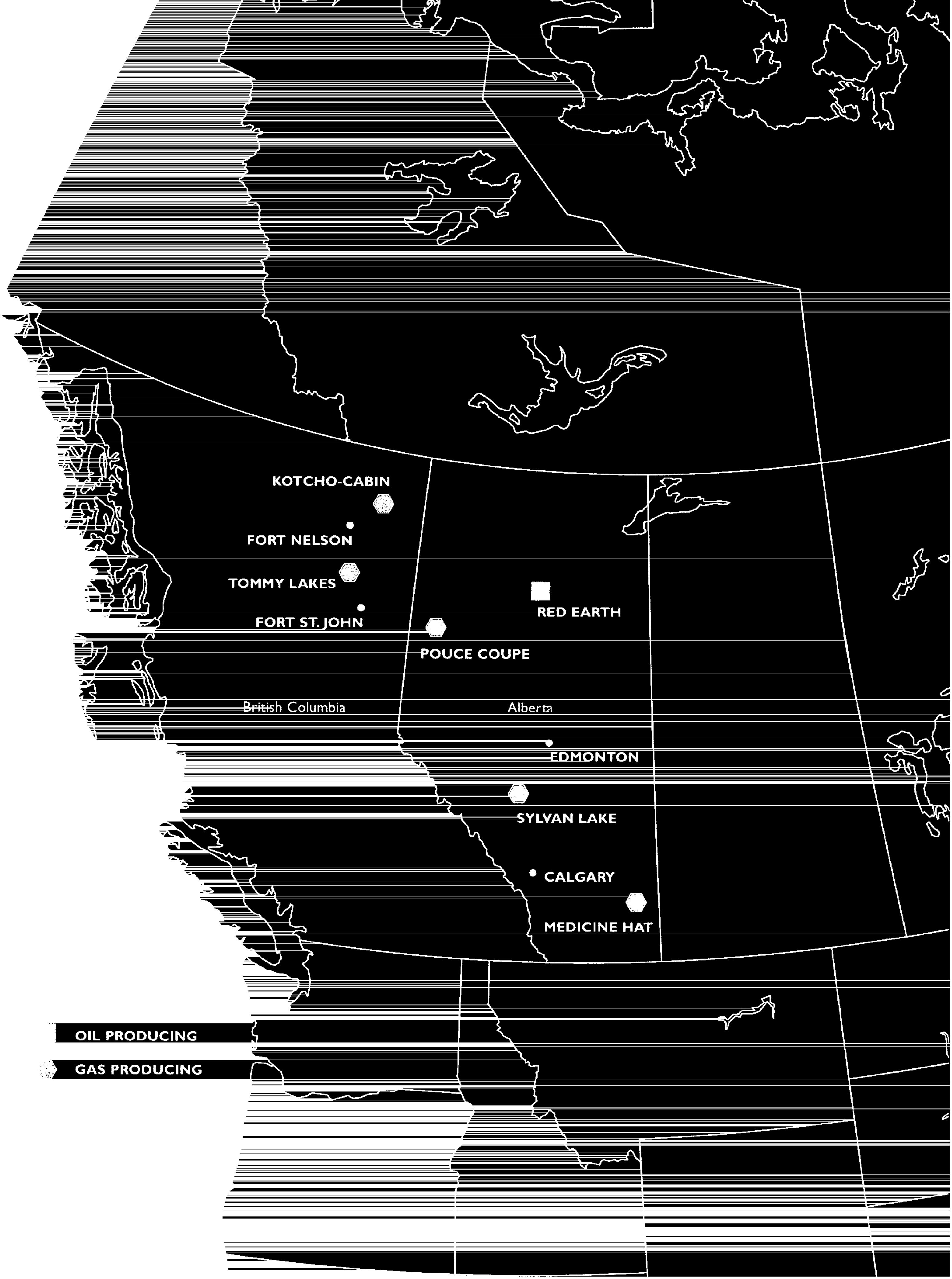
The Trust's light oil production is concentrated in the Red Earth area, within which the main producing properties are Golden, Loon Lake, Loon Lake North, Evi, and Kitty. In 2004 Focus' gross production from the Red Earth area averaged 1,913 bbls per day of 38° API light sweet crude. Approximately 44 percent of the Red Earth production is operated by Focus.

The majority of the Trust's development activity within the Red Earth area is concentrated at Loon Lake, which was acquired in June 2003. The main productive horizon at Loon Lake is the Slave Point G pool, which is a light oil reservoir under active waterflood. During 2004, the Trust drilled one well and recompleted two others into the Slave Point G pool, with encouraging results. Activities in 2005 will include further infill and step-out drilling as well as waterflood optimization.

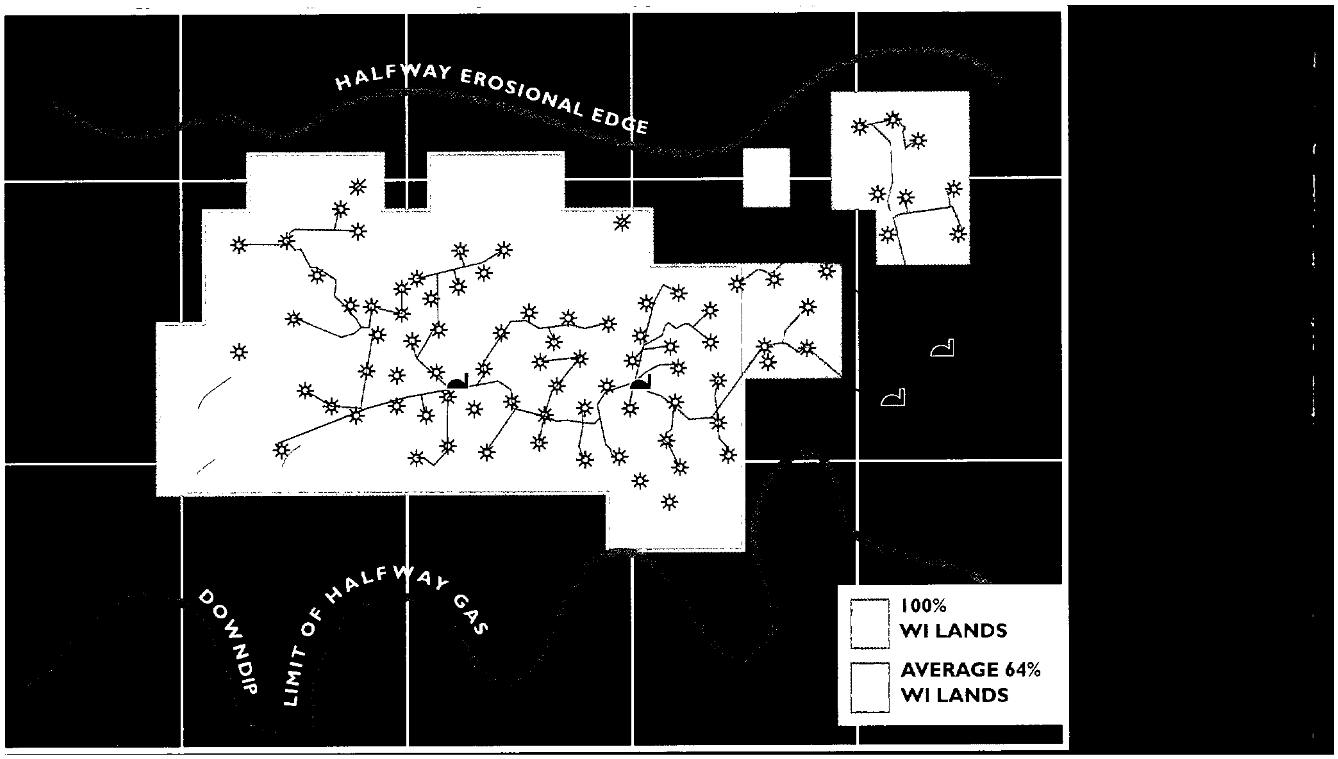
KOTCHO-CABIN, NE BRITISH COLUMBIA

At Kotcho and Cabin the Trust is producing from two sour high-pressure gas pools along a dolomitized reef edge in the Devonian Slave Point formation. Production from both properties is processed through 100 percent Focus-owned dehydration and water disposal facilities and delivered to the Duke (Westcoast) system.

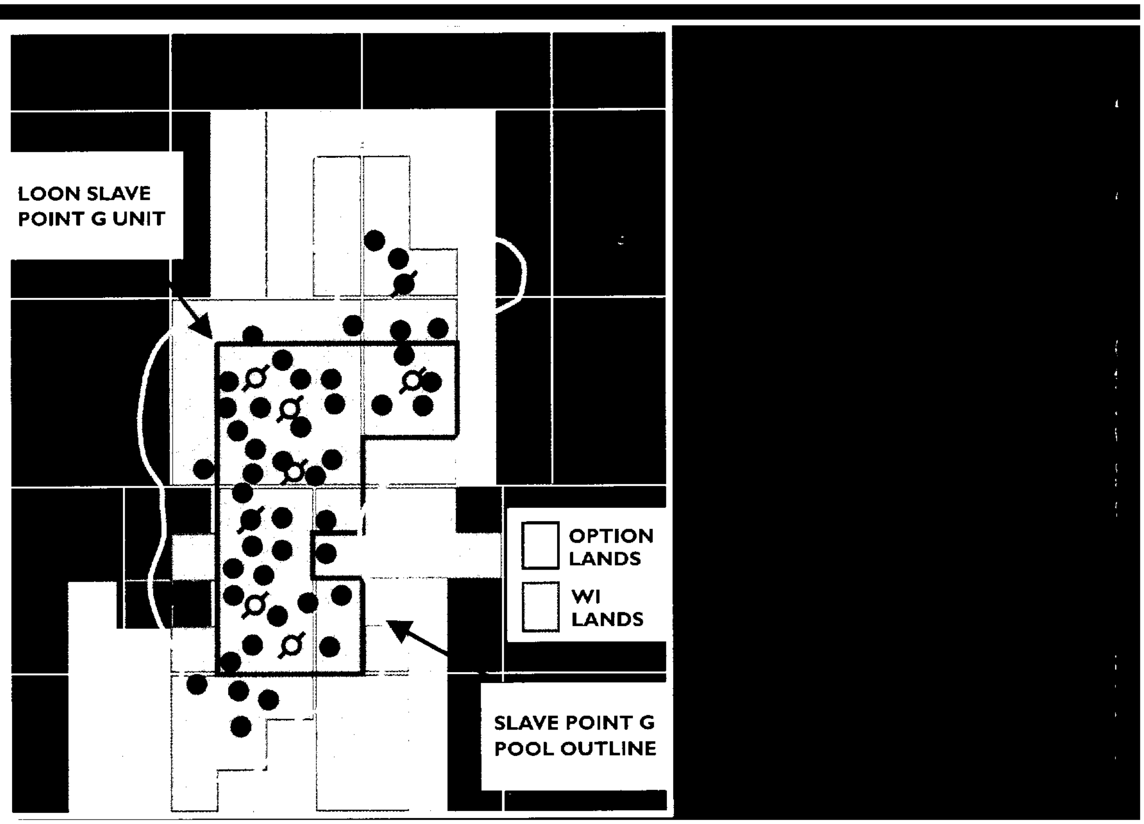
During 2004, Focus' gross production from this area averaged 8.1 Mmcf per day of natural gas. At Kotcho, volumes have decreased over the course of the year due to the onset of water production from the pool. Recently, volumes appear to be stabilizing, which is typical of offsetting Slave Point production. We continue to monitor production closely and


KOTCHO-CABIN
FORT NELSON
TOMMY LAKES
FORT ST. JOHN
RED EARTH
POUCE COUPE
British Columbia
Alberta
EDMONTON
SYLVAN LAKE
CALGARY
MEDICINE HAT
OIL PRODUCING
GAS PRODUCING

TOMMY LAKES



LOON LAKE



pursue the appropriate strategies to ensure that recovery from the pool is maximized. To this end, in the first quarter of 2005 the Trust will participate in the drilling of one well at Kotcho targeting the Slave Point.

POUCE COUPE, ALBERTA

At Pouce Coupe the Trust produces natural gas and associated NGLs from the Triassic Montney and Doig formations. Focus' gross production from this property in 2004 averaged 2.9 Mmcf per day of natural gas and 29 bbls per day of natural gas liquids. The majority of production is compressed at a 100 percent Focus-owned facility and then delivered to a third-party plant for further processing and delivery onto the TransCanada pipeline system.

Activity at Pouce Coupe has been concentrated on down-spacing within the Montney reservoir. Offsetting operators have commonly downspaced the Montney to four wells per section and in specific cases appear to be testing the economics of eight-well per section spacing. Focus drilled two wells into the Montney in late 2004 with good success, and anticipates drilling two more wells in 2005, which would bring the spacing on our lands to four wells per section.

SYLVAN LAKE, ALBERTA

Sylvan Lake is a multi-zone area which produces both gas and light oil from a number of formations ranging in depth from 400 to 2,200 meters. The primary producing zones are the Shunda, Pekisko, Lower Mannville, and Edmonton. In 2004, Focus' gross production from the area averaged 1.7 Mmcf per day of natural gas, and 154 bbls per day of oil and natural gas liquids. Production at Sylvan Lake is processed through the Focus-operated Sylvan Lake gas plant, in which the Trust holds an average working interest of 60 percent. The Trust owns excess capacity in this plant which generates material third party processing income.

In 2004 the Trust participated in the drilling of five (2.2 net) wells at Sylvan Lake, all targeting the Edmonton sand. All of these wells were successfully completed for gas, and the Trust anticipates a similar sized drilling program for 2005.

MEDICINE HAT, ALBERTA

Effective September 1, 2004, Focus acquired producing assets at Medicine Hat in southeastern Alberta for total consideration of $18.6 million. Effective October 1, 2004 the Trust acquired additional minor interests in the property for total consideration of $1.1 million. The property produces sweet natural gas from the Milk River, Medicine Hat and Second White Specks formations. Average working interest in the production is 90 percent, and the gas is compressed at two Focus-operated facilities. Focus' gross production from the Medicine Hat property averaged 1.9 Mmcf per day during the fourth quarter of 2004.

The Trust anticipates the first round of infill drilling on the Medicine Hat property will occur in early Q2 2005, depending on weather conditions and equipment availability. Pending the success of this program further development drilling is targeted for Q3 2005.

DRILLING

During 2004, the Trust participated in the drilling of 24 wells (14.6 net) with excellent drilling results and a success rate of 96 percent. The 2004 development program was strongly weighted towards natural gas with 96 percent of net wells and 84 percent of capital expenditures in the field directed towards gas targets. Focus was the operator of 20 of the 24 wells drilled in 2004.

Approximately two thirds of the Trust's capital expenditures for 2004 were invested at Tommy Lakes for the drilling of 16 (9.9 net) natural gas wells. Of the 16 wells, 11 were drilled and 10 of those tied in during the first quarter of 2004, and five were drilled in the fourth quarter of 2004 and tied in during the first quarter of 2005.

Additional activity in 2004 took place at Pouce Coupe with the drilling of two (2.0 net) natural gas wells in the Montney zone. At Sylvan Lake, the Trust participated in the drilling of five (2.2 net) Edmonton Sand gas wells. One Slave Point oil well (0.5 net) was drilled at Loon Lake, which is part of the Red Earth project area.

	2004				2003			
Drilling (Gross Wells)	**Oil**	**Gas**	**Abandoned**	**Total**	Oil	Gas	Abandoned	Total
Tommy Lakes	**–**	**15**	**1**	**16**	–	8	1	9
Red Earth	**1**	**–**	**–**	**1**	10	–	–	10
Pouce Coupe	**–**	**2**	**–**	**2**	–	2	–	2
Sylvan Lake	**–**	**5**	**–**	**5**	–	2	–	2
	1	**22**	**1**	**24**	10	12	1	23

	2004				2003			
Drilling (Net Wells)	**Oil**	**Gas**	**Abandoned**	**Total**	Oil	Gas	Abandoned	Total
Tommy Lakes	**–**	**9.1**	**0.8**	**9.9**	–	4.3	0.5	4.8
Red Earth	**0.5**	**–**	**–**	**0.5**	3.0	–	–	3.0
Pouce Coupe	**–**	**2.0**	**–**	**2.0**	–	1.3	–	1.3
Sylvan Lake	**–**	**2.2**	**–**	**2.2**	–	0.2	–	0.2
	0.5	**13.3**	**0.8**	**14.6**	3.0	5.8	0.5	9.3

UNDEVELOPED LAND

At December 31, 2004 Focus had undeveloped land of 26,876 net acres with an average working interest of 77 percent. Net undeveloped land is concentrated in Tommy Lakes (51 percent), Medicine Hat (21 percent), and Red Earth (16 percent).

	December 31, 2004	
Undeveloped Acres	Gross	Net
Alberta	16,729	11,645
British Columbia	18,027	15,231
	34,756	26,876

PRODUCTION

Focus had average production in 2004 of 9,782 BOE per day, with a weighting of 73 percent towards natural gas. Focus has had a very active drilling program at Tommy Lakes this past winter and 11 natural gas wells have been brought on stream in the first quarter of 2005. With the significance of winter drilling operations, Focus will continue to have its highest production volumes in the second quarter of the year as a result of flush production. For 2005, Focus is expecting to average between 10,000 and 10,500 BOE per day.

	2004				2003			
Production by Area	**Oil bbls/d**	**Natural Gas mcf/d**	**NGLs bbls/d**	**BOE/d**	Oil bbls/d	Natural Gas mcf/d	NGLs bbls/d	BOE/d
Tommy Lakes[1]	**–**	**29,391**	**569**	**5,468**	–	17,251	370	3,246
Red Earth	**1,913**	**–**	**–**	**1,913**	2,274	–	–	2,274
Kotcho-Cabin	**–**	**8,156**	**–**	**1,359**	–	11,978	–	1,996
Pouce Coupe	**9**	**2,865**	**20**	**507**	10	3,255	22	574
Sylvan Lake[2]	**74**	**1,679**	**80**	**433**	70	1,770	93	458
Medicine Hat[3]	**–**	**615**	**–**	**102**	–	–	–	–
	1,996	**42,706**	**669**	**9,782**	2,354	34,254	485	8,548

(1) INCLUDES APRIL 1, 2004 ACQUISITION OF ADDITIONAL INTERESTS AT TOMMY LAKES
(2) INCLUDES LANAWAY
(3) MEDICINE HAT PROPERTY WAS ACQUIRED EFFECTIVE SEPTEMBER 1, 2004.

	2004				2003			
Production by Quarter	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Oil (bbls/d)	**1,903**	**1,932**	**2,027**	**2,122**	2,278	2,336	2,361	2,444
Natural gas (mcf/d)	**43,080**	**44,903**	**50,913**	**31,902**	32,475	33,593	36,815	34,158
NGL (bbls/d)	**724**	**776**	**703**	**472**	460	508	501	471
BOE/d	**9,807**	**10,191**	**11,215**	**7,911**	8,151	8,443	8,997	8,608

YEAR-END RESERVES REVIEW

YEAR-END RESERVES

Based on independent engineering evaluations conducted by Paddock Lindstrom and Associates Ltd. ("Paddock") and McDaniel and Associates Consultants Ltd. ("McDaniel") effective December 31, 2004, Focus had proved plus probable reserves of 41.5 MMBOE, an increase of 40 percent from the 29.6 MMBOE recorded at December 31, 2003. Year-end reserves were evaluated in accordance with National Instrument 51-101 ("NI 51-101").

Paddock and McDaniel evaluated 100 percent of the Trust's reserves. The portion of the evaluation conducted by Paddock represented 87 percent of the proved plus probable reserves and 84 percent of the associated future net revenue discounted at 10 percent. The remaining reserves and associated future net revenue were evaluated by McDaniel. The Paddock December 31, 2004 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 and approved the reports prepared by Paddock and McDaniel and other pertinent reserves data.

Proved developed producing reserves represent 54 percent of proved plus probable reserves, while total proved reserves represent 76 percent of total proved plus probable reserves. On a BOE basis, total proved plus probable reserves consist of 78 percent natural gas, 14 percent light crude oil and eight percent natural gas liquids. On a proved basis, technical revisions were positive 1.1 MMBOE, or approximately five percent of the opening balance. On a proved plus probable basis, technical revisions were positive 0.8 MMBOE, or three percent of the opening balance. In both cases, the revisions were due to performance changes on producing properties.

NET PRESENT VALUE OF FUTURE NET REVENUE

The estimated net present value of Focus' crude oil, natural gas and natural gas liquids reserves before tax was evaluated using Paddock's December 31, 2004 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 $488 million. Proved producing and total proved reserves make up respectively 66 percent and 83 percent of the total proved plus probable value.

RESERVE LIFE INDEX

Focus' proved plus probable RLI at year-end 2004 increased to 10.6 years from 9.8 years at year-end 2003. The Trust's proved year-end 2004 RLI increased to 8.4 years from 7.7 years at year-end 2003. 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. On a proved plus probable basis, Focus' 2004 reserve addition costs were $11.38 per BOE including acquisitions and divestitures or $15.99 per BOE excluding acquisitions and divestitures. On a total proved basis, 2004 reserve addition costs were $13.87 per BOE including acquisitions and divestitures or $18.40 per BOE excluding acquisitions and divestitures. At year-end, total estimated FDC was $47.5 million for proved reserves and $63.8 million for proved plus probable reserves.

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 price and cost 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.

2004 RESERVES SUMMARY

Company Gross Reserves at December 31, 2004 (before deduction of royalties payable, not including royalties receivable) (based on Forecast Prices and Costs)	Light Crude Oil (mbbl)	Natural Gas (Mmcf)	NGLs (mbbl)	Oil Equivalent (MBOE)
Proved producing	3,306	102,229	1,909	22,253
Proved non-producing	195	10,883	114	2,123
Total proved developed	**3,501**	**113,112**	**2,023**	**24,376**
Proved undeveloped	736	35,258	578	7,191
Total proved	**4,237**	**148,370**	**2,601**	**31,567**
Probable additional	1,460	46,092	786	9,928
Total proved + probable	**5,697**	**194,462**	**3,387**	**41,495**

Company Net Reserves at December 31, 2004 (after deduction of royalties payable, including royalties receivable) (based on Forecast Prices and Costs)	Light Crude Oil (mbbl)	Natural Gas (Mmcf)	NGLs (mbbl)	Oil Equivalent (MBOE)
Proved producing	2,903	77,995	1,505	17,407
Proved non-producing	184	8,267	92	1,654
Total proved developed	**3,087**	**86,262**	**1,597**	**19,061**
Proved undeveloped	681	27,311	463	5,696
Total proved	**3,768**	**113,573**	**2,060**	**24,757**
Probable additional	1,288	35,002	626	7,748
Total proved + probable	**5,056**	**148,575**	**2,686**	**32,505**

NET ASSET VALUE

Net Asset Value (before tax) December 31, 2004

The following net asset value ("NAV") table shows what is commonly referred to as a "produce out" NAV calculation. 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, 2004

($thousands except per-Unit amounts)	Paddock Price Forecast	Constant Price Forecast
Value of proved plus probable reserves discounted at 10%	487,795	520,608
Undeveloped lands	3,490	3,490
Net debt including working capital	(81,158)	(81,158)
Reclamation fund	1,923	1,923
Net abandonment, reclamation and salvage[1]	(300)	(179)
Net asset value	411,750	444,684
Total Units outstanding (thousands)	37,223	37,223
Per Total Unit	$11.06	$11.95

(1) IN ADDITION TO ABANDONMENT AND RECLAMATION LIABILITY ALREADY INCLUDED IN RESERVE REPORTS

Net asset value per Unit increased 41 percent on a year-over-year basis, driven by significant increases in reserves per Unit and stronger commodity price forecasts.

2004 RESERVE RECONCILIATION

Company Gross Reserves (before deduction of royalties payable, not including royalties receivable)	Light Crude Oil (mbbl)	Natural Gas (Mmcf)	NGLs (mbbl)	Oil Equivalent (MBOE)
TOTAL PROVED				
December 31, 2003	4,962	96,488	1,603	22,646
Discoveries	0	1,912	25	343
Extensions	29	0	0	29
Improved recovery	0	2,294	48	431
Technical revisions	(51)	5,752	171	1,078
Economic factors	0	0	0	0
Acquisitions	24	57,554	1,003	10,619
Dispositions	0	0	0	0
Production	(727)	(15,630)	(248)	(3,580)
December 31, 2004	**4,237**	**148,370**	**2,601**	**31,567**
PROBABLE				
December 31, 2003	1,536	29,872	434	6,949
Discoveries	0	455	4	80
Extensions	15	0	0	15
Improved recovery	0	307	6	58
Technical revisions	(92)	(1,070)	35	(235)
Economic factors	0	0	0	0
Acquisitions	1	16,527	307	3,063
Dispositions	0	0	0	0
Production	0	0	0	0
December 31, 2004	**1,460**	**46,092**	**786**	**9,928**
PROVED PLUS PROBABLE				
December 31, 2003	6,498	126,360	2,037	29,595
Discoveries	0	2,367	28	423
Extensions	44	0	0	44
Improved recovery	0	2,602	55	488
Technical revisions	(143)	4,682	206	843
Economic factors	0	0	0	0
Acquisitions	25	74,081	1,310	13,682
Dispositions	0	0	0	0
Production	(727)	(15,630)	(248)	(3,580)
December 31, 2004	**5,697**	**194,462**	**3,387**	**41,495**

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

(including ARTC) ($ thousands)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved producing	498,370	385,354	319,752	276,508	245,609
Proved non-producing	40,163	30,075	24,212	20,295	17,470
Total proved developed	**538,532**	**415,429**	**343,963**	**296,803**	**263,078**
Proved undeveloped	147,308	89,167	61,750	45,548	34,785
Total proved	**685,840**	**504,596**	**405,713**	**342,351**	**297,863**
Probable additional	226,249	125,062	82,082	59,331	45,559
Total proved + probable	**912,089**	**629,658**	**487,795**	**401,682**	**343,422**

NUMBERS MAY NOT ADD DUE TO ROUNDING.

December 31, 2004 Price Forecast – Paddock Lindstrom and Associates Ltd.

	WTI Crude Oil $US/bbl	Edmonton Light Crude Oil $CDN/bbl	Henry Hub Natural Gas $US/Mmbtu	AECO C Natural Gas $CDN/Mmbtu	Westcoast Station 2 Natural Gas $CDN/Mmbtu	Exchange Rate $US/$CDN
2005	42.00	50.22	6.30	6.78	6.76	0.82
2006	40.00	47.76	6.10	6.52	6.50	0.82
2007	37.50	44.69	5.90	6.26	6.24	0.82
2008	35.00	41.62	5.70	6.00	5.98	0.82
2009	33.00	39.16	5.50	5.73	5.71	0.82
2010	33.50	39.75	5.61	5.85	5.83	0.82
2011	34.00	40.34	5.72	5.96	5.94	0.82
2012	34.50	40.92	5.84	6.08	6.06	0.82
2013	35.00	41.51	5.95	6.21	6.19	0.82
2014	35.50	42.10	6.07	6.33	6.31	0.82
2015	36.00	42.68	6.19	6.46	6.44	0.82
2016	36.50	43.27	6.32	6.59	6.57	0.82
2017	37.00	43.85	6.44	6.72	6.70	0.82
2018	37.50	44.44	6.57	6.85	6.83	0.82
2019	38.00	45.02	6.70	6.99	6.97	0.82
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

(including ARTC) ($ thousands)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved producing	536,481	410,893	336,987	288,192	253,460
Proved non-producing	43,618	32,431	25,834	21,429	18,273
Total proved developed	**580,098**	**443,324**	**362,821**	**309,621**	**271,733**
Proved undeveloped	153,665	97,337	68,588	50,993	39,125
Total proved	**733,764**	**540,661**	**431,409**	**360,614**	**310,857**
Probable additional	231,875	133,550	89,199	64,933	49,965
Total proved + probable	**965,638**	**674,210**	**520,608**	**425,547**	**360,822**

NUMBERS MAY NOT ADD DUE TO ROUNDING.

Constant Prices at December 31, 2004	Edmonton Light Crude Oil $CDN/bbl	AECO C Natural Gas $CDN/Mmbtu	Westcoast Station 2 Natural Gas $CDN/Mmbtu
2005 and thereafter	47.25	6.78	6.27

FINDING AND DEVELOPMENT COSTS

Company Gross Reserves Excluding the Effect of Acquisitions and Dispositions[1]

		2004		2003		2002[2][3]		Three-Year Total
Capital expenditures – $M		**25,156**		16,589		39,535		81,280
Net change in future development capital – $M								
Proved		**9,469**		(2,506)		14,140		21,103
Proved plus probable		**3,599**		(921)		17,703		20,381
Total capital including change in future development capital – $M								
Proved		**34,625**		14,083		53,675		102,383
Proved plus probable		**28,755**		15,668		57,238		101,661
Reserve additions – MBOE								
Proved		**1,882**		(1,153)		6,894		7,623
Proved plus probable		**1,798**		2,143		7,912		11,853
Finding and development cost – $/BOE								
Proved	**$**	**18.40**		n/a	$	7.79	$	13.43
Proved plus probable	**$**	**15.99**	$	7.31	$	7.23	$	8.58

(1) RESERVES ARE BASED ON FORECAST PRICES AND COSTS.
(2) INCLUDES ACTIVITIES OF STORM ENERGY INC. PRIOR TO THE PLAN OF ARRANGEMENT EFFECTIVE AUGUST 23, 2002.
(3) RESERVES AND COSTS FOR 2002 ARE PRESENTED ON AN ESTABLISHED BASIS (PROVED PLUS PROBABLE RISKED AT 50%).

FINDING, DEVELOPMENT AND ACQUISITION COSTS

Company Gross Reserves Including the Effect of Acquisitions and Dispositions[1]

		2004		2003		2002[2][3]		Three-Year Total
Capital expenditures – $M		**154,825**		36,805		40,140		231,770
Net change in future development capital – $M								
Proved		**18,594**		(94)		14,140		32,640
Proved plus probable		**21,360**		1,579		17,703		40,642
Total capital including change in future development capital – $M								
Proved		**173,419**		36,711		54,280		264,410
Proved plus probable		**176,185**		38,384		57,843		272,412
Reserve additions – MBOE								
Proved		**12,501**		1,247		6,894		20,642
Proved plus probable		**15,480**		4,869		7,912		28,261
Finding and development cost – $/BOE								
Proved	**$**	**13.87**	$	29.44	$	7.87	$	12.81
Proved plus probable	**$**	**11.38**	$	7.88	$	7.31	$	9.64

(1) RESERVES ARE BASED ON FORECAST PRICES AND COSTS.
(2) INCLUDES ACTIVITIES OF STORM ENERGY INC. PRIOR TO THE PLAN OF ARRANGEMENT EFFECTIVE AUGUST 23, 2002.
(3) RESERVES AND COSTS FOR 2002 ARE PRESENTED ON AN ESTABLISHED BASIS (PROVED PLUS PROBABLE RISKED AT 50%).

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, 2004 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 February 28, 2005 and should be read in conjunction with the Trust's audited consolidated financial statements for the years ended December 31, 2004 and 2003, together with accompanying notes.**

Throughout this Management's Discussion and Analysis, we use the term funds flow from operations ("funds flow" before changes in non-cash working capital). 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.

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 2004 PERFORMANCE

Performance in 2004 reflects the strong commodity price environment, the quality of our assets, and the execution of our business strategy. Focus' strategy is to surface value on our existing assets, maintain cost efficiencies, maintain financial strength and acquire quality assets. Production of the Trust increased 16 percent and proved plus probable reserves increased 40 percent through development programs at our key properties, and through two acquisitions of quality natural gas properties which have development potential.

The Trust continues to expand its operational focus, with a 50 percent increase in field expenditures, a 57 percent increase in net wells drilled, and the addition of a new core area at Medicine Hat. Natural gas continues to be the primary emphasis of the Trust. During the year, we completed two significant natural gas acquisitions, targeted natural gas with 23 of the 24 wells drilled, and increased natural gas reserves by 54 percent. Natural gas and the associated natural gas liquids represented 80 percent of 2004 production and 86 percent of year-end proved plus probable reserves.

Focus had strong financial performance during 2004 and maintained its financial strength. Funds from operations increased due to robust commodity prices, additional production volumes and maintaining operating efficiencies. The $89.6 million of funds from operations were used to fully fund field capital expenditures of $25.2 million, distributions of $61.4 million, reclamation fund contributions and actual abandonment and reclamation expenditures of $1.0 million, with the remaining $2.0 million applied to debt.

Funds flow from operations increased to $2.49 per Unit and cash distributions declared were $1.80 per Unit, with two distribution increases during the year. The distribution policy is aimed at achieving consistency of distributions and sustainability through balancing funds flow compared to distributions and capital programs.

OPERATIONS SUMMARY

	Three Months Ended December 31, 2004	Years Ended December 31, 2004	2003	Change
Average daily production				
Barrels of oil equivalent (@ 6:1)	**9,807**	**9,782**	8,548	14%
% Natural gas	**73%**	**73%**	67%	9%
Average product prices realized[1]				
Crude oil sales (CDN$/bbl)	**$ 56.33**	**$ 51.43**	$ 42.69	20%
Financial hedging settlements (CDN$/bbl)	**$ (15.05)**	**$ (11.01)**	$ (1.95)	464%
	$ 41.28	**$ 40.43**	$ 40.74	(1)%
NGLs (CDN$/bbl)	**$ 48.48**	**$ 43.73**	$ 34.24	28%
NGL price / Crude oil price	**86%**	**85%**	80%	6%
Natural gas sales (CDN$/mcf)	**$ 7.25**	**$ 7.02**	$ 6.96	1%
Transportation system charges	**$ (0.61)**	**$ (0.61)**	$ (0.60)	2%
Financial hedging settlements (CDN$/mcf)	**$ -**	**$ -**	$ (0.82)	(100)%
	$ 6.64	**$ 6.41**	$ 5.55	16%
Reference prices & differential to Focus price, net to transportation				
Crude oil (Edm. Light Price CDN$/bbl)	**$ 57.74**	**$ 52.62**	$ 42.89	23%
Differential (CDN$/bbl)	**$ (1.41)**	**$ (1.18)**	$ (0.20)	506%
Natural gas (AECO daily CDN$/mcf)	**$ 6.57**	**$ 6.55**	$ 6.70	(2)%
Differential (CDN$/mcf)	**$ 0.07**	**$ (0.14)**	$ (0.34)	(58)%
Barrels of oil equivalent (@6:1)	**$ 44.34**	**$ 42.93**	$ 41.08	5%
Differential (including NGLs vs crude oil)	**$ (0.60)**	**$ (1.42)**	$ (1.86)	(24)%
Production revenue before transportation system charges and hedging settlements ($thousands)				
Crude oil, before hedging settlements	**9,891**	**37,704**	36,694	3%
Financial hedging settlements	**(2,634)**	**(8,040)**	(1,678)	379%
NGLs	**3,233**	**10,715**	6,067	77%
Natural gas, before hedging settlements	**28,743**	**109,793**	87,153	26%
Financial hedging settlements	**-**	**-**	(10,221)	(100)%
Mark to market adjustment	**-**	**-**	1,353	(100)%
	39,233	**150,173**	119,367	26%
Funds flow per BOE				
Production revenue before transportation system charges and hedging settlements	**$ 46.40**	**$ 44.19**	$ 41.85	6%
Financial hedging settlements	**(2.92)**	**(2.25)**	(3.81)	(41)%
Transportation system charges	**(2.66)**	**(2.68)**	(2.62)	2%
Realized price[1]	**40.82**	**39.27**	35.41	11%
Royalties, net of ARTC	**9.36**	**(9.52)**	(9.78)	(3)%
Production expenses	**(3.76)**	**(3.29)**	(3.39)	(3)%
Field netback	**27.71**	**26.46**	22.24	19%
Facility income	**0.58**	**0.73**	0.84	(13)%
Interest income	**0.05**	**0.06**	0.02	212%
Technical Services Agreement	**-**	**-**	(0.67)	(100)%
General and administrative, cash portion	**(1.21)**	**(1.13)**	(0.81)	39%
Interest and financing and other	**(0.93)**	**(0.70)**	(0.44)	58%
Current and large corporations tax	**(0.44)**	**(0.40)**	(0.07)	452%
Funds flow from operations	**$ 25.76**	**$ 25.02**	$ 21.09	19%
Funds flow from operations/field netback	**93%**	**95%**	95%	0%
Royalty rate (before hedging settlements)	**19%**	**20%**	22%	(8)%

(1) NET OF SETTLEMENTS FOR FINANCIAL HEDGING INSTRUMENTS AND TRANSPORTATION SYSTEM CHARGES

Seasonality of Operations

Many of Focus' natural gas properties are in areas of British Columbia which are only accessible by road in the winter. This includes Tommy Lakes and Kotcho-Cabin. These areas represent approximately 70 percent of our production. The majority of the Trust's capital program is conducted at Tommy Lakes in the first and fourth quarters when winter conditions allow us to access the area. Capital expenditures at Tommy Lakes represented 64 percent of the total field capital expenditures during 2004, and 66 percent in 2003.

The winter access issue, especially for the Tommy Lakes winter development program, significantly impacts the operating results of Focus. This seasonality of operations and results is reflected in the following areas:

- Capital expenditures are highest in the first and fourth quarters of the year. The Tommy Lakes winter development program commences as soon as there is access and is completed as soon as possible.
- The natural gas wells at Tommy Lakes are brought on stream in February and March. Production volumes for natural gas and natural gas liquids are highest at the end of the first quarter and into the second quarter. These wells have strong flush production and then drop down to their stabilized production rate within 12 months.
- Higher production volumes during these initial months of flush production result in a corresponding increase in the revenue, royalties and operating expenses reported.
- Production expenses per BOE are the highest in the first and fourth quarters when these properties are accessible for maintenance and the restocking of supplies.
- As the operator of these properties, the Trust recovers general and administrative expenses from joint venture capital programs based on a percentage of the total capital program managed. As a result, most of the recovery of general and administrative expenses will be in the first and fourth quarters of the year.

Production

2004 Q4 compared with 2004 Q3:

- Overall production on a BOE basis during the fourth quarter declined 3.8 percent from the previous quarter. Oil volumes were generally held flat, and natural gas volumes were four percent lower.
- Natural gas volumes added through development activities were slowed in the fourth quarter due to issues associated with land access, weather and the availability of oilfield equipment. For the two wells drilled at Pouce Coupe during the second half of 2004, one well came on stream in late November 2004, and the other well is expected to come on stream in the first quarter of 2005.
- Production of natural gas in the fourth quarter of 2004 increased 32 percent compared to the same period of 2003. The composition of production is increasingly weighted towards natural gas, with 73 percent natural gas and another seven percent of natural gas liquids.
- The wells at Tommy Lakes from last winter's drilling program continued to transition from the flush production phase. Reduced production rates at Kotcho-Cabin were in line with expectations.

2004 compared with 2003:

- Overall average production was 14 percent higher in 2004 compared with 2003.
- A significant increase in natural gas and natural gas liquids production occurred as a result of the 2004 acquisition of additional interests at Tommy Lakes in April. Production at Tommy Lakes represented 59 percent of overall production in the fourth quarter of 2004.
- Additional natural gas volumes were added in September as the Trust acquired a new core property at Medicine Hat.
- Focus continued to replace production volumes through successful drilling programs at Tommy Lakes, Pouce Coupe and Loon Lake.

- The production pattern for 2003 and 2004 is consistent with higher volumes of natural gas and NGLs peaking in the second quarter. This pattern is expected to continue for 2005 as the 2004-2005 winter drilling program at Tommy Lakes commenced in December 2004, and the new production will come on stream late in the first quarter of 2005.
- The majority of our oil properties have experienced natural declines in production rates. Capital expenditures for the oil properties have been directed towards our operated properties at Loon Lake and Golden.

Pricing and Price Risk Management

Natural Gas

- *The net realized price for the fourth quarter of 2004 of $6.64 per mcf is $0.07 higher than the AECO daily reference price* of $6.57 per mcf. This differential for the fourth quarter of 2004 is largely due to the forward physical sales contracts for natural gas being higher than the AECO daily reference price. Generally, Focus has a negative differential on natural gas of approximately $0.35 to $0.40 per mcf versus the AECO reference price resulting from the deductions to the delivery point for transportation system charges in British Columbia being only partially offset by the higher heat content of the natural gas.
- The net natural gas price realized by Focus in 2004 of $6.41 per mcf increased 16 percent from the $5.55 per mcf realized in 2003. During 2004 the net realized price achieved by Focus was $0.14 per mcf off of the AECO daily reference price. For 2003 the difference was $1.15 per mcf due to financial hedging costs and a wider differential.
- There were no settlements of financial instruments for natural gas in 2004. Price protection and stability in 2004 has been achieved through the use of forward physical sales contracts. Focus put price protection on 53 percent of natural gas volumes during 2004. The average natural gas price under these contracts was $7.13 per mcf, compared with the AECO reference price of $6.55 per mcf. Production income for 2003 included a hedging cost of $8.9 million for financial instruments associated with natural gas.

Crude Oil

- *The price realized by Focus for crude oil, after settlement of financial hedges, was $41.28 per barrel for the fourth quarter* of 2004 versus $37.20 for the comparable period in 2003.
- The net realized price of crude oil for Focus was relatively flat through 2003 and 2004 due to price protection in place.
- With continued strong oil prices in 2004, there was a hedging cost of $2.6 million or $15.05 per barrel, for the fourth quarter of 2004, and a hedging cost of $8.0 million or $11.01 per barrel for 2004. The hedging arrangements in place for 2004 expired on December 31, 2004 and the financial hedging arrangements for 2005 are shown in the table below.

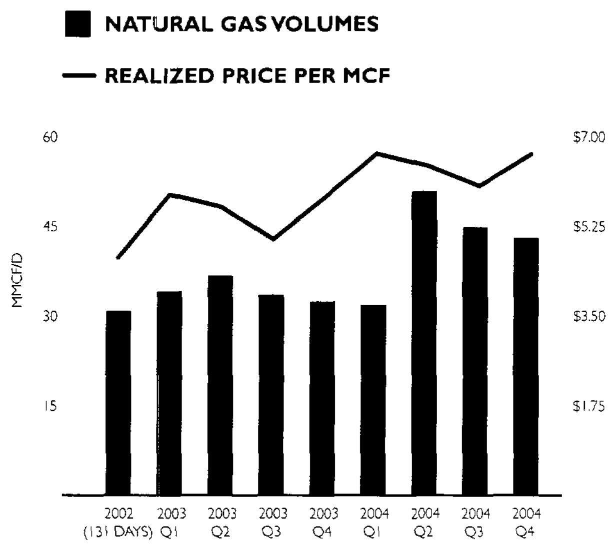
Price Protection		2005				2006
(volume and reference price)		Q1	Q2	Q3	Q4	Q1
Natural gas	Mmcf/d	30.0	22.6	22.6	15.7	12.2
	CDN$/mcf	$ 8.35	$ 7.65	$ 7.65	$ 8.08	$ 8.49
Crude oil	bbls/d	1,200	1,200	1,200	800	–
	CDN$/bbl	$ 50.37	$ 50.37	$ 50.70	$ 49.56	–

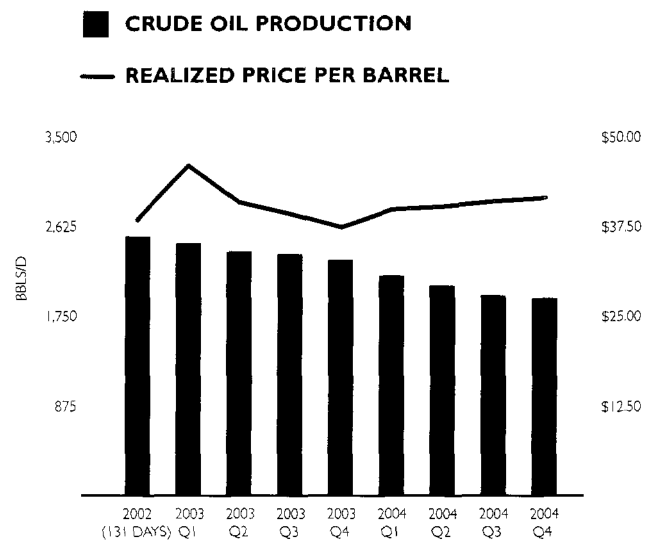
NOTE THAT THE PRICE PROTECTED WITH FINANCIAL INSTRUMENTS IS THE SWAP PRICE OR THE FLOOR OF A CONTRACT.

A full description of the outstanding financial instruments and physical sales contracts and their estimated mark to market values is contained in Notes 12 and 13 of the financial statements.

Production Revenue

- The results for 2004 and 2003 have been restated to present transportation system charges as a separate expense on the income statements. Previously, the transportation system charges were netted against production revenue.
- Production revenue for the three months ended December 31, 2004 was $39.2 million, consisting of 73 percent natural gas sales, 19 percent crude oil sales, and eight percent sales of natural gas liquids. Focus has increased its weighting of volumes to natural gas and natural gas liquids with the acquisitions and through development programs which primarily target natural gas opportunities. Production revenue for the fourth quarter of 2004 was $1.2 million higher than the third quarter of 2004 due to a seven percent increase in production revenue per BOE offsetting a four percent decrease in production.
- Production revenue for 2004 increased 26 percent to $150 million. Compared with 2003, there was a 14 percent increase in average daily production and an 11 percent increase in revenue per BOE.





Production Expenses

	2004				2003			
	Q4	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Production expenses per BOE	**$ 3.76**	**$ 3.31**	**$ 2.52**	**$ 3.78**	$ 3.70	$ 3.51	$ 3.04	$ 3.36

- The pattern of production expenses being highest in the first and fourth quarters and lowest in the second and third quarters is consistent with the nature of our operations and the results of 2003.
- Production expenses for 2004 averaged $3.29 per BOE compared with $3.39 per BOE for 2003.
- Production expenses per BOE are down year-over-year reflecting the increased volumes at Tommy Lakes and the emphasis that Focus places on minimizing the cost structure of the Trust.
- Average production expenses for 2005 are forecast to be in the range of $3.40 to $3.50 per BOE.

General and Administrative Expenses

(thousands)	Three Months Ended December 31, 2004	Three Months Ended December 31, 2003	Years Ended December 31, 2004	Years Ended December 31, 2003
Cash G&A expenses(1)	**$ 1,557**	$ 1,230	**$ 5,713**	$ 3,763
Overhead recoveries	**(465)**	(269)	**(1,667)**	(1,221)
Total cash G&A expenses	**1,092**	961	**4,046**	2,542
Non-cash G&A expense(2)	**276**	164	**1,174**	839
Trust Unit Rights Plan expense(3)	**126**	157	**306**	246
Net G&A reported	**$ 1,494**	$ 1,282	**$ 5,526**	$ 3,627
Cash-based G&A per BOE	**$ 1.21**	$ 1.06	**$ 1.13**	$ 0.81
Net reported G&A per BOE	**$ 1.66**	$ 1.83	**$ 1.54**	$ 1.16

(1) AMOUNTS PAID FOR THE TECHNICAL SERVICES AGREEMENT IN THE FIRST HALF OF 2003 WERE REPORTED SEPARATELY ON THE CONSOLIDATED STATEMENTS OF INCOME AND ACCUMULATED INCOME, AND NOT INCLUDED AS PART OF GENERAL AND ADMINISTRATIVE EXPENSES. THE TECHNICAL SERVICES AGREEMENT EXPIRED JUNE 30, 2003.

(2) GROSS GENERAL AND ADMINISTRATIVE EXPENSES FOR 2004 INCLUDED $2.3 MILLION ASSOCIATED WITH THE EXECUTIVE BONUS PLAN (2003 - $1.7 MILLION). HALF OF THIS AMOUNT IS 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.

(3) 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 10 OF THE NOTES TO THE FINANCIAL STATEMENTS.

Cash-based general and administrative expenses were $1.21 per BOE for the fourth quarter and $1.13 per BOE for 2004. This compares with $1.06 per BOE for the fourth quarter of 2003 and $0.81 per BOE for 2003. Increased general and administrative expenses in 2004 result from increased staff levels and office expenses corresponding to the expiry of the Technical Services Agreement on June 30, 2003, and strengthening our technical group as part of the organic growth initiatives and expanded operations.

Interest and Financing Expenses

Interest and financing expenses increased $1.1 million to $2.5 million in 2004 compared to $1.4 million in 2003 commensurate with higher debt balances. Long-term debt was $74.5 million at December 31, 2004 compared to $21.3 million at December 31, 2003. Bank debt was utilized to partially fund the Tommy Lakes acquisition and to fund the acquisition of interests at Medicine Hat. Financing expenses increased $0.3 million to $0.4 million in 2004 as the Trust restructured and increased its bank credit facilities to a syndicated credit facility with four Canadian financial institutions.

Depletion and Depreciation

The depletion and depreciation rate increased to $10.42 per BOE in the fourth quarter of 2004 compared to $8.09 per BOE in the fourth quarter of 2003. The increase reflects actual capital expenditures and updated estimates of proved reserves. In addition, the acquisitions at Tommy Lakes and Medicine Hat increased the depletion rate as the Trust recorded a higher proportionate cost per BOE of proved reserves compared to the existing asset base of the Trust. The depletion rate of $10.42 per BOE in the fourth quarter of 2004 includes $0.22 per BOE related to the estimated asset retirement obligation.

Asset Retirement Obligation

In the first quarter of 2004, we adopted the CICA new section 3110, Asset Retirement Obligations. This new standard requires that companies recognize the liability associated with future site reclamation costs in the financial statements at the time when the liability is incurred. This liability is initially measured at fair value and subsequently adjusted for the accretion of the discount amount and any changes in the underlying cash flows. The asset retirement cost is capitalized to the related asset and amortized into earnings over time. The impact of the adoption of this new accounting policy is described in Notes 3 and 6 of the financial statements.

The asset retirement obligation increased $4.0 million to $11.4 million at December 31, 2004 from $7.4 million at December 31, 2003. The increase reflects additional liabilities associated with the properties acquired during the year as well as new drilling activity. Accretion expense increased by $0.2 million to $0.6 million in 2004 from $0.4 million in 2003 commensurate with the increase in the asset retirement obligation liability.

Income and Other Taxes

Income and other taxes include a future income tax recovery of $4.2 million in 2004 compared to a recovery of $0.8 million in 2003. The recovery of future income tax results from a reduction in corporate income tax rates in 2004 as well as from distributions to Unitholders which transfers taxable income from the Trust to individual Unitholders.

Capital Expenditures

Capital expenditures for field operations increased to $11.3 million in the fourth quarter of 2004 as Focus continued activity at Pouce Coupe and initiated the winter development program at Tommy Lakes. The Trust drilled eight wells at several of our key development areas during the quarter. Five wells were drilled at Tommy Lakes and one well at each of the Pouce Coupe, Loon Lake and Sylvan Lake properties.

For 2004, total capital expenditures for field operations were $25.2 million, excluding the amount recorded for asset retirement obligations. Sixty-four percent was spent at Tommy Lakes, 20 percent at other natural gas areas, 10 percent for development work at Loon Lake, and six percent in other areas. Focus continues to maximize the value of our existing asset base and acquired properties through the drill bit. Capital investment in 2004 has been focused on natural gas development opportunities and those projects which we operate and control.

Focus invested $129.7 million during 2004 to acquire high-quality natural gas properties which have long reserve life indices and significant development opportunities.

The most significant acquisition completed during the year was the purchase of additional working interests in Tommy Lakes on April 1, 2004 for $110 million. Tommy Lakes is a high-quality, long-life natural gas property which has a large accumulation of natural gas in place. It is the principal natural gas producing asset of the Trust. This property is operated by Focus, has low operating costs and a decline rate of less than 14 percent. The Tommy Lakes area contains the main development opportunities for Focus.

On September 1, 2004 Focus invested $18.6 million for the acquisition of interests at Medicine Hat, excluding the associated amounts recorded for asset retirement obligations and future income tax. With this transaction, Focus acquired a new shallow gas property in southeastern Alberta with approximately 10.8 Bcf of natural gas reserves, associated facilities and 5,760 net acres of undeveloped land. This is a long reserve life property which has significant opportunities for infill and step-out drilling. Additional interests in this property were acquired during the fourth quarter for $1.1 million.

Focus will be actively drilling in 2005 with a capital budget for field operations of $27 to $30 million. Development is expected to continue at Tommy Lakes, Pouce Coupe, Loon Lake and Sylvan Lake. Our first round of drilling at Medicine Hat is expected to occur during the first half of 2005. Capital investment in 2005 will be disciplined and directed towards the best opportunities. There will clearly be a continued emphasis on natural gas development and on those projects that we operate.

Liquidity and Capital Resources

As at December 31, 2004 Focus had a working capital deficit of $6.6 million compared with a working capital deficit of $3.3 million at December 31, 2003. The working capital deficit has increased from the $2.5 million at September 30, 2004, due to the significant winter development program which commenced in the fourth quarter of 2004. 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, 2004 was $74.5 million compared with $21.3 million at December 31, 2003 and $72.7 million at September 30, 2004. The increase in long-term debt during 2004 resulted from the acquisitions during the year which were financed with $59.3 million of long-term debt. Focus had a $100 million revolving syndicated credit facility among four financial institutions and a $10 million operating facility at December 31, 2004. The credit facility revolves until May 26, 2005.

Long-term debt less working capital increased $56.5 million during 2004. This change primarily resulted from the following factors.

- The acquisition on April 1, 2004 for $110 million was financed with the issuance of Trust Units for net proceeds of $70.4 million and $39.6 million from bank credit facilities.
- The acquisitions at Medicine Hat of $19.7 million were financed with bank credit facilities.
- Proceeds of $0.8 million from the issuance of equity pursuant to the exercise of Unit Appreciation Rights
- Funds flow from operations were $89.6 million, of which $61.4 million in distributions were declared to Unitholders, $25.2 million was invested in capital expenditures for field operations, $1.0 million was paid to the reclamation fund and $2.0 million went to debt repayment.

Focus plans to finance its program for development drilling and enhancement of production primarily through investing approximately 25 to 30 percent of funds flow. Capital expenditures, including acquisitions, above this level will be financed through a combination of cash flow, debt and equity by issuing Units from treasury.

Capitalization Table

(thousands except per-Unit amounts)		**December 31, 2004**		December 31, 2003
Long-term debt	**$**	**74,500**	$	21,337
Plus: Working capital deficiency		**6,658**		3,304
Total debt	**$**	**81,158**	$	24,641
Units outstanding and issuable for Exchangeable Shares		**37,223**		31,822
Market price	**$**	**19.97**	$	15.00
Market capitalization	**$**	**743,343**	$	477,330
Total capitalization	**$**	**824,501**	$	501,971
Total debt as a percentage of total capitalization		**9.8%**		4.9%
Funds flow	**$**	**89,567**	$	65,808
Total debt to funds flow		**0.9**		0.4

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 cash flow. Our distribution policy incorporates the withholding of approximately 25 percent of cash flow for the financing of capital expenditures to provide more sustainable distributions. Cash distributions are essentially taxed to the Unitholders as ordinary income.

Focus declared distributions of $1.80 per Unit in respect of 2004 production. Distributions were increased twice during 2004. Distributions per Unit in 2004 were $0.14 for the first quarter, $0.15 for the second and third quarters and $0.16 for the fourth quarter. On January 14th, 2005 Focus announced a continuation of the distribution policy of monthly distributions of $0.16 per Unit for the first quarter of 2005.

The Exchangeable Shares of FET Resources Ltd. are convertible into Trust Units of Focus based on the exchange ratio, which is adjusted monthly to reflect the cash distribution paid on the Trust Units. Cash distributions are not paid on the Exchangeable Shares and the cash flow related to the Exchangeable Shares is retained by the Trust for reduction of debt or for additional capital expenditures. The initial exchange ratio was one Trust Unit for one Exchangeable Share. The exchange ratio at December 31, 2004 was 1.27833. Effective March 15, 2005 the exchange ratio is 1.30129 Trust Units for one Exchangeable Share.

Payout Ratio	**Year Ended December 31, 2004**		Year Ended December 31,2003	
Funds flow from operations (thousands)	**$**	**89,567**	$	65,808
Funds flow from operations per Total Unit (weighted average Total Trust Units, including Exchangeable Shares converted at the average exchange ratio)	**$**	**2.49**	$	2.16
Distributions per Unit declared	**$**	**1.80**	$	1.665
Payout ratio - per-Unit basis		**72%**		77%
Cash distributions declared to Unitholders; Exchangeable Shares do not receive cash distributions (thousands)	**$**	**61,439**	$	42,342
Payout ratio - dollar basis		**69%**		64%

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.

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

Contractual Obligations(1)

($thousands)	Total	2005	2006-2007	2008-2009	2010 and thereafter
Office premises	2,193	74	707	1,028	384
Operating leases	396	132	264	–	–
Mineral and surface leases(2)	4,318	720	1,439	1,439	720
Transportation and processing	23,971	9,420	9,433	2,515	2,603
Asset retirement obligations(3)	10,922	215	427	310	9,970
Total contractual obligations	41,800	10,561	12,270	5,292	13,677

(1) THE TABLE DOES NOT INCLUDE THE TRUST'S OBLIGATIONS FOR FINANCIAL INSTRUMENTS AND PHYSICAL SALES CONTRACTS WHICH ARE FULLY DISCLOSED IN NOTES 12 AND 13 OF THE FINANCIAL STATEMENTS.

(2) THE TRUST MAKES PAYMENTS FOR MINERAL AND SURFACE LEASES. THE TABLE INCLUDES PAYMENTS FOR EACH OF THE YEARS 2005 TO 2010 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 2010 HAVE NOT BEEN INCLUDED IN THE TABLE, BUT WOULD CONTINUE AT THE SAME YEARLY RATE IF THERE WAS NO CHANGE TO THE UNDERLYING PROPERTIES.

(3) BASED ON THE ESTIMATED TIMING OF EXPENDITURES TO BE MADE IN FUTURE PERIODS

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, 2004.

Focus has not entered into any guarantee or off balance sheet arrangements that would adversely impact the Trust's financial position or results of operations.

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, not a cash basis. 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 the end of the year, and each Unitholder receives a pro rata share of that payable amount.

For 2004, cash distributions will be 97.5 percent return on capital (taxable) and 2.5 percent return of capital (tax deferred). For a more detailed breakdown as well as tax information for U.S. investors, please visit our website at www.focusenergytrust.com.

2004 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 2004 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 2004 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 Units are held through a broker or other intermediary then the Unitholder will receive a T3 Supplementary slip directly from the Unitholder's broker or intermediary, not from the transfer agent (Valiant Trust Company) nor from Focus, no later than March 31, 2005.
- If the Unitholder is a registered holder then the Unitholder will receive a T3 Supplementary slip directly from Valiant Trust Company.
- The amount reported in Box (26) on the T3 Supplementary slip, "Other Income", should be reported on the 2004 T1 Income Tax Return.

Taxable Income Allocated to Unitholders for 2004 and Taxation Treatment

- For those Unitholders who held their Focus Energy Trust Units outside of a registered plan, the return on capital or income portion is reported in Box (26) of the T3 Supplementary slip, "Other Income", and should be reported on the 2004 T1 Income Tax Return.
- In most circumstances, the return of capital portion will reduce the Unitholder's adjusted cost base of their Focus Energy Trust Units. This is discussed in more detail below.
- 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, 2004.

Record Date	Payment Date	Distribution Paid	Taxable Income (Box 26 Other Income)	Return of Capital Amount
January 31, 2004	February 16, 2004	$ 0.14	$ 0.1365	$ 0.0035
February 29, 2004	March 15, 2004	$ 0.14	$ 0.1365	$ 0.0035
March 31, 2004	April 15, 2004	$ 0.14	$ 0.1365	$ 0.0035
April 30, 2004	May 17, 2004	$ 0.15	$ 0.1462	$ 0.0038
May 31, 2004	June 15, 2004	$ 0.15	$ 0.1462	$ 0.0038
June 30, 2004	July 15, 2004	$ 0.15	$ 0.1462	$ 0.0038
July 31, 2004	August 16, 2004	$ 0.15	$ 0.1462	$ 0.0038
August 31, 2004	September 15, 2004	$ 0.15	$ 0.1462	$ 0.0038
September 30, 2004	October 15, 2004	$ 0.15	$ 0.1462	$ 0.0038
October 31, 2004	November 15, 2004	$ 0.16	$ 0.1560	$ 0.0040
November 30, 2004	December 15, 2004	$ 0.16	$ 0.1560	$ 0.0040
December 31, 2004	January 17, 2005	$ 0.16	$ 0.1560	$ 0.0040
Total		$ 1.800	$ 1.7547	$ 0.0453

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. The adjusted cost base of the Units is required in the calculation of a capital gain or capital loss (if capital property to the Unitholder) upon the disposition of the Units.

Should a Unitholder's adjusted cost base ever be reduced below zero, that negative amount is deemed to be a capital gain and the adjusted cost base is deemed to be nil. The capital gain is reported on Schedule 3 of the T1 Income Tax Return.

2004 United States Tax Information

The following information is being provided to assist U.S. individual Unitholders of Focus Energy Trust ("Focus") in reporting distributions received from Focus during 2004 on their Internal Revenue Service ("IRS") Form 1040 – U.S. Individual Income Tax Return ("Form 1040") for 2004.

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 2004, 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 20 of the IRS 2004 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.

  For the non-taxable portion of distributions, if any, ("Non-Taxable Return of Capital"), a taxpayer must reduce the cost (or other basis) by the amount of non-taxable distributions in calculating the gain or loss on sale of Focus Units. If the amount of "Non-Taxable Return of Capital" exceeds your cost (or other basis), report the excess as a capital gain.

  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 overwithheld 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 2004 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 above information is not meant to be an exhaustive discussion of all possible U.S. 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 own tax advisors as to their particular tax consequences of holding Trust Units.

Management and Financial Reporting Systems

The Trust's management and internal control systems are designed to provide assurance that accurate and timely internal and external information is communicated to users of that information. These systems are continually being reviewed for opportunities for enhancement.

Update on Financial Reporting and Regulatory Matters

The following new accounting policies impacted the Trust in 2004:

- Asset Retirement Obligations

  In 2004, the Trust adopted the CICA new section 3110, Asset Retirement Obligations. This new standard requires that companies recognize the liability associated with future site reclamation costs in the financial statements at the time when the liability is incurred. This liability is initially measured at fair value and subsequently adjusted for the accretion of the discount amount and any changes in underlying cash flows. The asset retirement cost is capitalized to the related asset and amortized into earnings over time. The impact of this new accounting policy is described in Notes 3 and 6 of the financial statements.

- Oil and Gas Accounting – Full Cost

  In 2004, the Trust adopted the recommendations contained in the Accounting Guideline 16, "Oil and Gas Accounting – Full Cost".

  The guideline impacts the cost impairment test or ceiling test. The cost impairment test is a two stage test which is to be performed annually. The first stage of the test determines if the cost pool has been impaired. An impairment occurs when the carrying amount of an asset is not recoverable and exceeds its fair value. The carrying amount is not recoverable if it exceeds the sum of the undiscounted cash flows from proved reserves plus unproved costs using management's best estimate of future prices. The second stage of the test involves measurement of the impairment. The impairment is measured as the amount by which the carrying amount of capitalized assets exceeds the future discounted cash flows from proved plus probable reserves. The discount rate used is the company's risk free rate. The guideline requires disclosure of future prices used in the measurement of impairment.

  Adoption of this new guideline resulted in no changes to net income, petroleum and natural gas assets or any other reported amounts in the consolidated financial statements.

- Hedging Relationships

  In 2004, the Trust adopted Accounting Guideline 13, "Hedging Relationships", which deals with the identification, designation, documentation and measurement of effectiveness of hedging relationships for the purposes of applying hedge accounting. It also establishes conditions for applying or discontinuing hedge accounting.

  The Trust has determined that all financial instruments met the criteria of effective hedges in 2004.

- Transportation System Charges

  Effective for fiscal years beginning on or after October 1, 2003, the CICA issued Handbook Section 1100 "Generally Accepted Accounting Principles", which defines the sources of GAAP that companies must use and effectively eliminates industry practice as a source of GAAP. In prior years, it had been industry practice for companies to net transportation system charges against revenue rather than showing the charges as a separate expense on the income statement. Effective January 1, 2004, the Trust has recorded revenue gross of transportation system charges and a transportation system charge on the income statement. Prior periods have been reclassified for comparative purposes. This adjustment has no impact on net income or cash flow for the Trust.

- EIC-151, Exchangeable Securities Issued by Subsidiaries of Income Trusts

  In 2005, the Trust will be required to adopt the recommendations contained in EIC-151, Exchangeable Securities Issued by Subsidiaries of Income Trusts. The abstract will require the Trust to reclassify the amounts recorded as exchangeable shares from Unitholders' capital to non-controlling interests. The revision will be effective for periods on or after June 30, 2005. This accounting policy change is required to be applied retroactively and as a result, the financial statements will be restated.

Other future possible accounting policy changes include:

- Variable Interest Entities

  In June 2003 the CICA issued Accounting Guideline 15, "Consolidation of Variable Interest Entities", which deals with the consolidation of entities that are subject to control on a basis other than ownership of voting interests. This guideline is effective for annual and interim periods beginning on or after November 1, 2004.

  The Trust has assessed that this new guideline is not applicable based on the current structure of the Trust.

- Financial Instruments - Recognition and Measurement, Hedges, and Comprehensive Income

  The CICA has issued three exposure drafts on financial instruments which will apply to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006. It will require the following:
  - all trading financial instruments will be recognized on the balance sheet and will be fair valued through the income statement;
  - all remaining financial assets will be recorded at cost and amortized through the financial statements;
  - a new statement for comprehensive income that will include certain gains and losses on translation of assets and liabilities; and
  - an update to Accounting Guideline 13 to incorporate the fair value changes not recorded in the income statement to be recorded through the comprehensive income statement.

The Trust has not assessed the future impact on the financial statements at this time.

- Changes in Accounting Policies and Estimates and Errors

  The CICA has proposed a new Handbook section 1506 "Changes in accounting policies and estimates, and errors" to provide guidance around when and how an entity is permitted to change an accounting policy as well as establish appropriate disclosures to explain the effects of changes in accounting policy, estimates and corrections of errors.

- Subsequent Events

  The CICA has proposed to extend the period during which subsequent events are required to be considered. This period is between the balance sheet date and when the financial statements are authorized for issue. In addition, disclosure is required as to the date the financial statements were authorized for issue and who provided that authorization.

SUMMARY OF QUARTERLY RESULTS

The following table provides a summary of results for each of the last eight quarters. 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.
- Focus operates the majority of its capital programs during the winter season. As such, the majority of the capital expenditures and associated overhead recoveries occur in the winter months. The winter drilling programs have resulted in increased production, which is strongest in the second quarter due to the initial flush production from the new wells.
- Our main natural gas properties are in winter-only access areas of British Columbia, and production expenses per BOE are the highest in the first and fourth quarters when these properties are accessible for maintenance and the restocking of supplies. The weighting of production towards natural gas has increased, and natural gas production generally has lower production expenses on a per-BOE basis.
- Focus has completed acquisitions at Loon Lake in June 2003, Tommy Lakes in April 2004 and Medicine Hat in September 2004. The acquisitions were funded through the use of existing bank credit facilities and the issuance of equity in June 2003 and March 2004.
- Focus was created in August 2002 and has continually been developing its organization with the addition of professional and technical staff.

The table below highlights Focus' quarterly performance for the years ended December 31, 2004 and 2003. Refer to page 44 for more detailed quarterly information.

Quarter Ended	**2004**				2003			
(thousands of dollars, except per-Unit amounts)	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Oil and gas revenues, before royalties[(1)]	**39,233**	**37,979**	**42,284**	**30,677**	28,088	28,806	31,979	30,494
Net income	**15,451**	**13,546**	**17,286**	**13,346**	10,456	10,608	12,449	7,960
Per Unit – basic	**$ 0.42**	**$ 0.37**	**$ 0.47**	**$ 0.41**	$ 0.33	$ 0.34	$ 0.42	$ 0.27
– diluted	**$ 0.41**	**$ 0.36**	**$ 0.47**	**$ 0.41**	$ 0.33	$ 0.33	$ 0.43	$ 0.27

(1) RESTATED AT DECEMBER 31, 2004 TO BREAK OUT THE TRANSPORTATION SYSTEM CHARGES SEPARATELY (INCREASES REVENUE AND RECORDS THIS EXPENSE SEPARATELY)

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 mature properties 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. maintaining a product mix to balance exposure to commodity prices;
6. conducting rigorous reviews of all property acquisitions;
7. monitoring pricing trends and developing a mix of contractual arrangements for the marketing of products with creditworthy counterparties;
8. maintaining a hedging program to hedge commodity prices and foreign exchange currency rates with creditworthy counterparties;
9. ensuring strong third-party operators for non-operated properties;
10. adhering to the Trust's safety program and keeping abreast of current operating best practices;
11. 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;
12. carrying insurance to cover losses and business interruption;
13. establishing and building cash resources to fund future site reclamation costs.

OUTLOOK

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' 2005 outlook. No acquisitions are assumed for the purposes of these forecasts.

In 2005, Focus will continue its active drilling and development programs on its major 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 2005 Expectations	
Average annual production	10,000 - 10,500 BOE/D
Weighting to natural gas	75%
Production expenses per BOE	$ 3.40 – $ 3.50
Cash G&A expenses per BOE	$ 1.25 – $ 1.35
Capital expenditures - field	$ 27 million - $ 30 million
Average annual payout ratio	70% – 80%
Approximate taxable portion of distributions	100%
Funds from operations / net debt	Under 1x

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.

		Change	Change to Funds Flow $000s	Change to Funds Flow $ / Unit
Business Environment				
Price per barrel of crude oil (US$ WTI)	$	1.00	771	0.021
Price per mcf of natural gas (CDN$ AECO)	$	0.25	3,017	0.081
US / CDN exchange rate	$	0.01	1,095	0.029
Interest rate on debt		1%	745	0.020
Operations				
Oil production - bbls/d		100	1,381	0.037
Gas production - mcf/d		1,000	1,700	0.046
Operating expenses ($ per BOE)	$	0.25	935	0.065
Cash G&A expenses ($ per BOE)	$	0.25	935	0.025

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;
- 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
February 28, 2005

William D. Ostlund
Vice President, Finance and Chief Financial Officer

AUDITOR'S REPORT

To the Unitholders of Focus Energy Trust:

We have audited the consolidated balance sheet of Focus Energy Trust as at December 31, 2004 and 2003 and the consolidated statements of income and accumulated income and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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 that 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, 2004 and 2003 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

Calgary, Alberta, Canada
February 28, 2005

CONSOLIDATED BALANCE SHEETS

	Years Ended, December 31, 2004	2003
ASSETS		
Current assets		
Cash and cash equivalents	**$ 43,732**	$ –
Accounts receivable	**20,220,594**	20,043,512
Prepaid expenses and deposits	**1,697,846**	1,092,559
	21,962,172	21,136,071
Petroleum and natural gas properties and equipment [note 4]	**302,454,785**	174,974,307
Goodwill [note 5]	**5,100,000**	–
Reclamation fund [note 7]	**1,922,519**	1,030,000
	$ 331,439,476	$ 197,140,378
LIABILITIES		
Current		
Accounts payable and accrued liabilities	**$ 22,864,458**	$ 20,515,765
Cash distributions payable	**5,755,784**	3,924,783
	28,620,242	24,440,548
Long-term debt [note 8]	**74,500,000**	21,336,532
Asset retirement obligation [note 6]	**11,461,469**	7,442,069
Future income taxes [note 15]	**43,727,120**	41,686,533
	158,308,831	94,905,682
UNITHOLDERS' EQUITY		
Unitholders' capital [note 9]	**139,335,147**	63,267,421
Exchangeable Shares [note 9]	**1,546,884**	5,160,995
Contributed surplus	**498,516**	245,524
Accumulated income	**145,289,496**	85,661,322
Accumulated cash distributions	**(113,539,398)**	(52,100,566)
	173,130,645	102,234,696
Commitments and contingencies [note 17]		
	$ 331,439,476	$ 197,140,378

SEE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Approval on behalf of the Board:

STUART G. CLARK
DIRECTOR

GERALD A. ROMANZIN
DIRECTOR

CONSOLIDATED STATEMENTS OF INCOME AND ACCUMULATED INCOME

	Years Ended, December 31, 2004	2003 (Restated – Note 3)
Revenue		
Production revenue	**$ 150,172,892**	$ 119,366,943
Royalties	**(34,551,035)**	(30,789,864)
Alberta Royalty Tax Credit	**475,080**	287,512
Facility income	**2,597,273**	2,611,767
Interest income	**229,301**	64,128
	118,923,511	91,540,486
Expenses		
Transportation system charges [note 3]	**9,584,180**	7,534,600
Production	**11,790,150**	10,590,468
Technical Services Agreement	**–**	2,100,000
General and administrative	**5,525,776**	3,627,275
Interest and financing	**2,515,545**	1,386,761
Depletion and depreciation [note 4]	**32,007,125**	25,065,441
Accretion of asset retirement obligation [note 6]	**664,001**	420,078
	62,086,777	50,724,623
Income before income and other taxes	**56,836,734**	40,815,863
Income and other taxes [note 15]		
Future income tax expense (reduction)	**(4,212,000)**	(854,505)
Current and large corporations tax	**1,420,560**	224,366
	(2,791,440)	(630,139)
Net income for the period	**59,628,174**	41,446,002
Accumulated income, beginning of period		
As previously reported	**85,820,667**	44,348,355
Retroactive adjustment for changes in accounting policies	**(159,345)**	(133,035)
As restated	**85,661,322**	44,215,320
Accumulated income, end of period	**$ 145,289,496**	$ 85,661,322
Net income per Unit [note 14]		
Basic	**$ 1.66**	$ 1.36
Diluted	**$ 1.65**	$ 1.36

SEE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED STATEMENTS OF CASH FLOWS

		Years Ended, December 31,		
		2004		2003
				(Restated – Note 3)
Operating activities				
Net income for the period	**$**	**59,628,174**	$	41,446,002
Add non-cash items:				
Non-cash general and administrative expenses [note 10]		**1,479,707**		1,084,483
Unrealized (gain) loss on commodity contract		**–**		(1,353,067)
Depletion and depreciation		**32,007,125**		25,065,441
Accretion on asset retirement obligation		**664,001**		420,078
Future income tax expense		**(4,212,000)**		(854,505)
Funds flow from operations		**89,567,007**		65,808,432
Net change in non-cash working capital items		**1,940,194**		6,145,326
		91,507,201		71,953,758
Financing activities				
Proceeds from issue of Trust Units (net of costs)		**70,419,265**		23,891,651
Proceeds from exercise of Unit Appreciation Rights		**854,040**		158,048
Increase (decrease) in long-term debt		**53,163,468**		(30,464,468)
Cash distributions		**(59,607,831)**		(40,925,594)
		64,828,942		(47,340,363)
Investing activities				
Capital asset additions		**(25,156,145)**		(16,809,155)
Acquisition expenditures [note 5]		**(130,181,848)**		(22,175,416)
Proceeds on disposal of capital assets		**–**		1,958,669
Reclamation fund contributions and actual expenditures		**(1,016,677)**		(1,291,346)
Net change in non-cash working capital items		**62,259**		(1,001,181)
		(156,292,411)		(39,318,429)
Increase in cash and cash equivalents during the period		**43,732**		(14,705,034)
Cash and cash equivalents, beginning of period		**–**		14,705,034
Cash and cash equivalents, end of period	**$**	**43,732**	$	–

SEE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2004 AND 2003 (AUDITED)

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").

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.

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. and FET Gas Production Ltd. and Focus B.C. Trust, and its share of two 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 subject to a separate impairment test.

d) 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, 2004 resulting in no impairment amount.

e) 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.

f) 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 has been made in the Trust.

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.

g) 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 10. 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 2003 rights granted. The pro forma impact for rights granted for the period from August 23, 2002 to December 31, 2002 using the fair value method is disclosed in Note 10.

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.

h) Per-Unit Amounts

Net income per Unit is calculated using the weighted average number of Units outstanding during the year, including the weighted average number of Exchangeable Shares outstanding converted at the exchange ratio at the end of each month. Diluted net income per Unit is calculated using the treasury stock method 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.

i) 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.

j) 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.

k) 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.

l) 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.

m) Comparative Figures

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

3. CHANGES IN ACCOUNTING POLICIES

a) Petroleum and Natural Gas Properties and Equipment

Petroleum and natural gas assets are evaluated 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. Effective January 1, 2004, the Trust adopted the new accounting standard relating to full cost accounting. There were no changes to net income, petroleum and natural gas assets or any other reported amounts in the consolidated financial statements as a result of adopting this guideline.

The new guideline impacts the cost impairment test or ceiling test. The cost impairment test is a two- stage test. The first stage of the test determines if the cost pool has been impaired. Impairment occurs when the carrying amount of an asset is not recoverable and exceeds its fair value. The carrying amount is not recoverable if it exceeds the sum of the undiscounted cash flows from proved reserves plus unproved costs using management's best estimate of future prices. The second stage of the test involves measurement of the impairment. The impairment is measured as the amount by which the carrying amount of capitalized assets exceeds the future discounted cash flows from proved plus probable reserves. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate.

Prior to January 1, 2004 the ceiling test amount was the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost or market of unproved properties and the cost of major development projects less estimated future costs for administration, financing, site restoration and income taxes. The cash flows were estimated using period-end prices and costs.

b) Asset Retirement Obligation

The Trust has adopted 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 Trust's 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.

Previously, the Trust recognized a provision for estimated future removal and site restoration costs calculated on the unit-of-production method over the remaining proved reserves.

The effect of this change in accounting policy has been recorded retroactively with restatement of prior periods. The effect of the adoption is presented below as increases (decreases).

Balance Sheets		December 31, 2003
Petroleum and natural gas properties and equipment increased for historic asset retirement costs	$	4,069,393
Record new asset retirement obligation	$	7,442,069
Reverse historic provision for future site restoration		(3,083,021)
Adjust future income taxes		(130,310)
Adjust accumulated income		(159,345)
Increase in liabilities and Unitholders' equity	$	4,069,393

Statements of Income		Year ended December 31, 2004		Year ended December 31, 2003
Accretion expense	$	(664,001)	$	(420,078)
Depletion and depreciation on asset retirement costs		(552,952)		(644,727)
Less: Amortization of estimated future removal and site restoration liability under previous policy		2,397,535		1,000,633
Net income impact of new policy, before tax	$	1,180,582	$	(64,172)
Basic and diluted net income per share before tax	$	0.04		–

c) Financial Derivatives

Effective January 1, 2004 the Trust has implemented the new accounting guideline relating to hedging relationships. The new policy addresses the identification, designation, documentation and effectiveness of hedging transactions for the purposes of applying hedge accounting. It also establishes the conditions for applying or discontinuing hedge accounting. Under the new guideline hedging transactions must be documented and it must be demonstrated that the hedges are sufficiently effective in order to continue accrual hedge accounting.

The hedges in effect at December 31, 2004 and December 31, 2003 met the criteria of effective hedges.

d) Transportation System Charges

Effective for fiscal years beginning on or after October 1, 2003, the CICA issued Handbook Section 1100 "Generally Accepted Accounting Principles", which defines the sources of GAAP that companies must use and effectively eliminates industry practice as a source of GAAP. In prior years, it had been industry practice for companies to net transportation system charges against revenue rather than showing the charges as a separate expense on the income statement. Effective January 1, 2004, the Trust has recorded revenue gross of transportation system charges and a transportation system charge on the income statement. Prior periods have been reclassified for comparative purposes. This adjustment has no impact on net income or cash flow for the Trust.

4. PETROLEUM AND NATURAL GAS PROPERTIES AND EQUIPMENT

		2004		2003
Petroleum and natural gas properties and equipment, at cost	$	450,493,107	$	291,005,504
Accumulated depletion and depreciation		(148,038,322)		(116,031,197)
Petroleum and natural gas properties and equipment, at cost, net	$	302,454,785	$	174,974,307

The petroleum and natural gas properties and equipment, at cost, and the accumulated depletion and depreciation 2004 balances include \$9.8 million and \$2.8 million related to the asset retirement obligation, respectively. The 2003 balances have been restated due to the adoption of the asset retirement obligation method of recording the future cost associated with removal, site restoration and asset retirement costs. As a result of this restatement, petroleum and natural gas properties and equipment, at cost, has increased by \$6.3 million and accumulated depletion and depreciation has increased by \$2.2 million.

The calculation of depletion and depreciation in 2004 included an estimate of $47.5 million (2003 - $28.4 million) for future development costs and $4.1 million (2003 – nil) for future asset retirement costs associated with proved undeveloped reserves. Unproved property costs of $3.1 million (2003 - $1.8 million) and estimated net realizable value of production equipment and facilities of $21.9 million (2003 - $12.6 million) were excluded from the depletion calculation.

The Trust performed a cost impairment test at December 31, 2004 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 2005 to 2009 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 present value of future net revenues from the Trust's proved plus probable reserves exceeded 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, 2004 are as follows.

Consultant's Price Forecasts	2005	2006	2007	2008	2009
Crude Oil - WTI ($US / bbl)	$ 42.00	$ 40.00	$ 37.50	$ 35.00	$ 33.00
Natural Gas AECO ($CDN / Mmbtu)	$ 6.78	$ 6.52	$ 6.26	$ 6.00	$ 5.73

5. ACQUISITION EXPENDITURES

Area	Effective	Year ended December 31, 2004	Year ended December 31, 2003
Lanaway, Alberta	May 1, 2003	$ (39,885)	$ 4,741,298
Loon Lake, Alberta	June 1, 2003	(103,530)	17,434,118
Tommy Lakes, B.C.	April 1, 2004	110,074,959	–
Medicine Hat, Alberta	September 1, 2004	18,607,466	–
Medicine Hat, Alberta	October 1, 2004	1,144,700	–
Other		15,604	–
		$ 129,699,314	$ 22,175,416

Acquisition of Tommy Lakes Partnership April 1, 2004

On April 1, 2004 the Trust acquired the Tommy Lakes Partnership, which owns interests in the natural gas producing area of Tommy Lakes, British Columbia. The Tommy Lakes Partnership is owned 99 percent by Focus B.C. Trust and one percent by FET Resources Ltd., both of which are wholly owned subsidiaries of Focus Energy Trust. This acquisition was accounted for using the purchase method, with results of operations included from the date of acquisition. The future income tax recorded for this transaction only relates to the one percent ownership by FET Resources Ltd., and no future income tax has been recorded with respect to the interest owned by Focus B.C. Trust.

The following summarizes the estimated fair value of the assets acquired and liabilities assumed at the date of the acquisition.

Petroleum and natural gas properties and equipment	$111,583,959
Asset retirement obligation	(877,109)
Future income tax	(631,891)
	$110,074,959

Acquisition of Private Company September 1, 2004

FET Resources Ltd. acquired a private company on September 1, 2004 for cash consideration of $19,090,000. This acquisition was accounted for using the purchase method, with results of operations included from the date of acquisition. Immediately after the acquisition, the private company was wound up into FET Resources Ltd.

The following summarizes the estimated fair value of the assets acquired and liabilities assumed at the date of the acquisition.

Petroleum and natural gas properties and equipment	$20,190,000
Goodwill	5,100,000
Asset retirement obligation	(1,061,838)
Future income tax	(5,620,696)
	$18,607,466
Net working capital	482,534
	$19,090,000

Effective October 1, 2004, additional interests were purchased in the Medicine Hat area for cash consideration of $1,144,700.

6. 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 $31.2 million which will be incurred between 2005 and 2020. The majority of the costs will be incurred after 2019. A credit-adjusted risk-free rate of 7.0 percent and an inflation rate of 1.5 percent for estimates prior to the fourth quarter of 2004 and 2.0 percent for revisions and changes thereafter were used to calculate the fair value of the asset retirement obligation.

A reconciliation of the asset retirement obligation is provided below.

		December 31, 2004		December 31, 2003
Balance, beginning of period	$	7,442,069	$	6,001,112
Accretion expense		664,001		420,078
Liabilities incurred				
Acquisitions		1,938,947		961,685
Development activity and change in estimates		1,540,610		79,745
Settlement of liabilities		(124,158)		(20,551)
Balance, end of period	$	11,461,469	$	7,442,069

7. RECLAMATION FUND

		2004		2003
Balance as at January 1	$	1,030,000	$	–
Contributions		892,519		1,030,000
Balance as at December 31	$	1,922,519	$	1,030,000

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. Interest earned will form part of the reclamation fund. 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.

8. LONG-TERM DEBT

The Trust has a $100 million revolving syndicated credit facility among four Canadian financial institutions with an extendible 364-day revolving period and a one-year amortization period. In addition, the Trust has a $10 million demand operating line of credit. At December 31, 2004, the available borrowings under these facilities were reduced by $3.0 million by 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, 2004 is approximately 3.6 percent.

The credit facility will revolve until May 26, 2005, 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 five percent and the remaining 85 percent at the end of the term.

9. UNITHOLDERS' CAPITAL AND EXCHANGEABLE SHARES

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 the Unitholder, up to a maximum of $250,000 per annum. This limitation may be waived at the discretion of the Trust.

Trust Units of Focus Energy Trust

(including conversion of Exchangeable Shares)	Number of Units		Consideration	
	2004	2003	2004	2003
Trust Units outstanding (see (a) below)	35,973,651	28,034,233	$ 139,335,147	$ 63,267,421
Trust Units issuable on conversion of Exchangeable Shares[(I)] (see (b) below)	1,249,371	3,788,258	1,546,884	5,160,995
Balance as at December 31	37,223,022	31,822,491	$ 140,882,031	$ 68,428,416

(I) THE EXCHANGE RATIO AT DECEMBER 31, 2004 WAS 1.27833 (DECEMBER 31, 2003 – 1.16718) TRUST UNITS FOR EACH EXCHANGEABLE SHARE.

(a) Trust Units of Focus Energy Trust	Number of Units		Consideration	
	2004	2003	2004	2003
Balance as at January 1	28,034,233	22,804,905	$ 63,267,421	$ 33,908,902
Issued on conversion of Exchangeable Shares[(I)]	2,760,027	3,037,076	3,614,111	4,467,384
Issued pursuant to the Executive Bonus Plan[(II)]	72,391	71,752	1,127,813	841,434
Issued for cash[(III)]		2,100,000		25,410,000
Issued for cash[(IV)]	5,000,000		74,500,000	
Trust Unit issue expenses			(4,080,735)	(1,518,347)
Exercise of Unit Appreciation Rights[(V)]	107,000	20,500	906,537	158,048
Balance as at December 31	35,973,651	28,034,233	$ 139,335,147	$ 63,267,421

(I) ISSUED ON CONVERSION OF EXCHANGEABLE SHARES TO TRUST UNITS WITH THE CONSIDERATION RECORDED BEING EQUAL TO THE BOOK VALUE OF THE EXCHANGEABLE SHARES EXCHANGED

(II) 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.

(III) ISSUED FOR CASH JUNE 25, 2003 PURSUANT TO A SHORT FORM PROSPECTUS DATED JUNE 17, 2003

(IV) ISSUED FOR CASH MARCH 23, 2004 PURSUANT TO A SHORT FORM PROSPECTUS DATED MARCH 15, 2004

(V) EXERCISE OF UNIT APPRECIATION RIGHTS INCLUDES CASH CONSIDERATION OF $854,040 AND CONTRIBUTED SURPLUS CREDIT OF $52,497.

(b) Exchangeable Shares of FET Resources Ltd.	Number of Shares		Consideration	
	2004	2003	2004	2003
Balance as at January 1	3,245,650	5,964,335	$ 5,160,995	$ 9,628,379
Exchanged for Trust Units[(I)]	(2,268,304)	(2,718,685)	(3,614,111)	(4,467,384)
Balance as at December 31	977,346	3,245,650	$ 1,546,884	$ 5,160,995

(I) CANCELLATION ON CONVERSION TO TRUST UNITS WITH THE CONSIDERATION RECORDED BEING EQUAL TO THE BOOK VALUE OF THE EXCHANGEABLE SHARES EXCHANGED

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, 2004, a total of 2,268,304 Exchangeable Shares were converted into 2,760,027 Trust Units at exchange ratios prevailing at the time. At December 31, 2004, the exchange ratio was 1.27833 Trust Units for each Exchangeable Share. Cash distributions are not paid on the Exchangeable Shares. On the tenth anniversary of the issuance of the Exchangeable Shares, subject to extension of such date by the Board of Directors of the Company, the Exchangeable Shares will be redeemed for Trust Units at a price equal to the value of that number of Trust Units based on the exchange ratio as at the last business day prior to the redemption date. The Company may redeem all but not less than all of the outstanding Exchangeable Shares at any time when the aggregate number of issued and outstanding Exchangeable Shares is less than 1,000,000. The Company will, at least 45 days prior to any redemption date, provide the registered holders with written notice of the prospective redemption. The redemption price is equal to that described previously. The Exchangeable Shares of FET Resources Ltd. are listed for trading on the Toronto Stock Exchange under the symbol FTX.

10. 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 1,500,000 rights, but the number of Units reserved for issuance upon the exercise of rights shall not at any time exceed five percent of the aggregate number of issued and outstanding Units of the Trust and including the number of Units which may be issued on the exchange of the outstanding Exchangeable Shares. To December 31, 2004 a total of 107,000 Units had been issued under the Plan, and 1,393,000 Units are reserved for issuance under 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. 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. The rights have a life of five years and vest equally over a four-year period commencing on the first anniversary of the grant.

	2004		2003	
	Number of Rights	Weighted Average Exercise Price	Number of Rights	Weighted Average Exercise Price
Balance as at January 1, 2004	665,500	$ 9.74	320,000	$ 9.39
Granted	571,150	$ 16.31	376,000	$ 12.19
Exercised	(107,000)	$ 7.42	(20,500)	$ 7.71
Cancelled	(16,550)	$ 14.01	(10,000)	$ 12.08
Before reduction of exercise price	1,113,100	$ 13.27	665,500	$ 11.07
Reduction of exercise price	–	$ (1.49)	–	$ (1.33)
Balance as at December 31, 2004	1,113,100	$ 11.78	665,500	$ 9.74

- The average exercise price at the grant date is $13.74.
- The average contractual life of the rights outstanding is 3.79 years.
- The number of rights exercisable at December 31, 2004 is 123,250.
- The average value at the grant date for the year ended December 31, 2004 is $3.41 ($2.58 for 2003).

The Trust prospectively adopted the fair value method in 2003 for rights granted subsequent to January 1, 2003. The fair value of rights is estimated using a modified Black Scholes option pricing model.

The Trust has recorded non-cash compensation expense of $305,489 for the year ended December 31, 2004. The Trust recorded non-cash compensation expense of $245,524 for the year ended December 31, 2003.

Had the Trust used the fair value method for rights granted between August 23, 2002 and December 31, 2002, pro forma net income would have decreased by $137,133 (2003 - $136,758).

Pro Forma Results		2004		2003
Net income as reported	$	59,628,174	$	41,446,002
Less: Compensation expense for rights issued in 2002		(137,133)		(136,758)
Pro forma net income	$	59,491,041	$	41,309,244
Net income per Trust Unit – basic				
As reported	$	1.66	$	1.36
Pro forma	$	1.66	$	1.36
Net income per Trust Unit – diluted				
As reported	$	1.66	$	1.36
Pro forma	$	1.66	$	1.36

The fair value of rights granted in 2004 was estimated using a modified Black Scholes option pricing model with the following weighted average assumptions: risk-free interest rate of 3.93 percent, volatility of 34 percent, life of 4.8 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.

11. CASH DISTRIBUTIONS PAYABLE

The Trust has net income for each year which includes all interest income from the Company, and other income, which accrues to the Trust to the end of the year. Under the Trust Indenture, taxable income of the Trust for each year will be paid or payable by way of cash distributions to the Unitholders.

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 receives a pro rata share of the payable amount.

12. 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, 2004, which have no book value, was a cost of $332,000.

Financial Contracts	Daily Quantity		Contract Price		Price Index	Term
Crude oil – fixed price	400 bbls	$	49.61	Cdn/bbl	WTI	January 2005 – December 2005
	400 bbls	$	49.50	Cdn/bbl	WTI	January 2005 – December 2005
	400 bbls	$	52.00-58.40	Cdn/bbl	WTI	January 2005 – March 2005
	400 bbls	$	52.00-56.15	Cdn/bbl	WTI	April 2005 – June 2005
	400 bbls	$	53.00-60.00	Cdn/bbl	WTI	July 2005 – September 2005*
Natural gas – fixed price	5,000 GJ	$	5.85-6.95	Cdn/GJ	AECO	April 2005 – October 2005*

* CONTRACT ENTERED INTO SUBSEQUENT TO DECEMBER 31, 2004

13. 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, 2004, which have no book value, would have resulted in a net payment to the Trust of approximately $7,176,000.

Physical Contracts	Daily Quantity	Contract Price		Term
Natural gas – fixed price				
	26,500 GJ	$ 7.25	Cdn/GJ	November 2004 – March 2005
	5,275 GJ	$ 7.00	Cdn/GJ	November 2004 – October 2005
	5,000 GJ	$ 6.36	Cdn/GJ	April 2005 – October 2005
	7,000 GJ	$ 8.77	Cdn/GJ	January 2005
	15,500 GJ	$ 7.01	Cdn/GJ	April 2005 – October 2005
	7,000 GJ	$ 7.25	Cdn/GJ	November 2005 – March 2006*
	7,000 GJ	$ 7.62	Cdn/GJ	November 2005 – March 2006*

* CONTRACT ENTERED INTO SUBSEQUENT TO DECEMBER 31, 2004

14. PER UNIT AMOUNTS AND SUPPLEMENTARY CASH FLOW INFORMATION

Basic per-Unit calculations are based on the weighted average number of Trust Units. Diluted calculations include additional Trust Units for the dilutive impact of rights outstanding pursuant to the Rights Plan and the number of Trust Units exercisable on conversion of Exchangeable Shares.

Basic per-Unit calculations for the year ending December 31 are based on the weighted average number of Trust Units outstanding in 2004 of 35,903,047 (2003 of 30,493,373).

Diluted calculations include additional Trust Units for the dilutive impact of the Rights Plan and for the weighted average number of Trust Units exercisable on conversion of Exchangeable Shares of 327,465 for the year ended December 31, 2004 (129,990 for the year ended December 31, 2003).

Supplementary cash flow information for the year ended December 31 is as follows.

	2004	2003
Interest paid	$ 1,986,119	$ 1,345,300
Interest received	75,666	18,003
Taxes paid	1,453,298	(862,688)
Cash distributions paid	59,607,831	40,925,594

15. INCOME TAXES

Effective April 1, 2004, the Alberta government enacted a reduction in corporate income tax rates from 12.5 percent to 11.5 percent. In 2003, Royal Assent was received legislating the reduction of the 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 Trust's expected future income tax rate is approximately 35 percent at December 31, 2004 compared to 37 percent at December 31, 2003. The Trust recorded a future income tax recovery of $4.2 million in 2004.

The Trust recognized future income tax liabilities of $6.3 million in 2004 related to the acquisitions of the Tommy Lakes partnership interest and of a private company.

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.

		2004		2003
Income before income and other taxes	$	56,836,734	$	40,815,863
Statutory combined federal and provincial income tax rate		39.40%		40.98%
Expected income tax expense at statutory rates	$	22,396,371	$	16,726,341
Add (deduct) the income tax effect of:				
Non-deductible Crown charges		9,415,168		10,659,788
Resource allowance		(7,977,986)		(9,077,768)
Alberta Royalty Tax Credit		(163,804)		(117,822)
Reduction in corporate tax rate		(2,152,283)		(3,250,000)
Income attributable to the Trust, not subject to income tax		(24,177,995)		(16,259,305)
Capital tax		1,073,342		879,340
Other		(1,204,253)		(190,713)
Income and other taxes	$	(2,791,440)	$	(630,139)

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

		2004		2003
Capital assets in excess of tax value	$	48,849,568	$	48,640,477
Provision for asset retirement obligation		(4,014,953)		(2,743,147)
Non-capital losses		–		(2,662,029)
Other		(1,107,495)		(1,548,768)
Future income taxes	$	43,727,120	$	41,686,533

16. RELATED PARTY TRANSACTIONS

During 2004, the Trust paid $212,600 for legal services (2003 - $97,730) provided by a firm in which a current director is a partner.

17. COMMITMENTS AND CONTINGENCIES

The Trust is involved in litigation and 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.

QUARTERLY INFORMATION

SUMMARY OF QUARTERLY RESULTS

	2004				2003				2002	
(000s OF DOLLARS, EXCEPT AS INDICATED)	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3[1] 39 Days
FINANCIAL										
Oil and gas revenues, before transportation system changes and royalties[2]	**39,233**	**37,979**	**42,284**	**30,677**	28,088	28,806	31,979	30,494	26,032	9,216
Funds flow from operations	**23,241**	**21,926**	**25,961**	**18,438**	17,129	15,200	16,764	16,715	14,184	4,818
Per Total Unit - basic	**$0.63**	**$0.59**	**$0.70**	**$0.57**	$0.54	$0.48	$0.57	$0.57	$0.49	$0.17
Cash distributions per Trust Unit	**$0.48**	**$0.45**	**$0.45**	**$0.42**	$0.42	$0.42	$0.42	$0.41	$0.33	$0.11
Payout ratio (per-Unit basis)	**77%**	**76%**	**64%**	**74%**	78%	87%	74%	71%	68%	66%
Net income	**15,451**	**13,546**	**17,286**	**13,346**	10,456	10,608	12,449	7,960	8,738	1,422
Per Unit - basic	**$0.42**	**$0.37**	**$0.47**	**$0.41**	$0.33	$0.34	$0.42	$0.27	$0.30	$0.05
Capital expenditures	**11,325**	**1,529**	**857**	**11,445**	4,749	2,796	50	9,214	3,666	481
Acquisition expenditures , net	**1,190**	**18,580**	**109,945**	**(15)**	142	13	20,062	–	605	–
Long-term debt plus working capital	**81,158**	**75,235**	**60,690**	**(39,893)**	23,611	23,650	27,545	38,767	36,534	38,076
Per unit - basic	**$2.18**	**$2.03**	**$1.64**	**$(1.08)**	$0.74	$0.75	$0.87	$1.33	$1.26	$1.33
Times funds flow from operations[3]	**0.9**	**0.9**	**0.6**	**(0.5)**	0.3	0.4	0.4	0.6	0.6	0.8
Total Trust Units - outstanding (000s)	**37,223**	**37,094**	**37,016**	**36,923**	31,822	31,667	31,493	29,180	28,966	28,736
Wtgd average Total Trust Units (000s)	**37,163**	**37,057**	**36,980**	**32,386**	31,759	31,631	29,458	29,106	29,106	28,605
OPERATIONS										
Average daily production										
Crude oil (bbls/d)	**1,903**	**1,932**	**2,027**	**2,122**	2,278	2,336	2,361	2,444	2,469	2,608
NGLs (bbls/d)	**724**	**776**	**703**	**472**	460	508	501	471	464	441
Natural gas (mcf/d)	**43,080**	**44,903**	**50,913**	**31,902**	32,476	33,593	36,815	34,158	32,911	26,101
BOE (@6:1)	**9,807**	**10,191**	**11,215**	**7,911**	8,151	8,443	8,997	8,608	8,419	7,400
Natural gas weighting	**73%**	**73%**	**76%**	**67%**	66%	66%	68%	66%	65%	59%
Average net product prices realized[4]										
Crude oil (CDN$/bbl)	**$41.28**	**$40.79**	**$40.07**	**$39.66**	$37.20	$39.07	$40.64	$45.84	$37.90	$38.83
NGLs (CDN$/bbl)	**$48.48**	**$45.48**	**$39.62**	**$39.59**	$29.66	$34.18	$30.78	$42.59	$35.70	$33.80
Natural gas (CDN$/mcf)	**$6.64**	**$6.01**	**$6.41**	**$6.65**	$5.78	$4.97	$5.60	$5.84	$4.83	$3.89
Netback per BOE										
Revenue[3]	**$40.82**	**$37.72**	**$38.85**	**$39.92**	$35.15	$32.67	$35.32	$38.50	$31.96	$29.41
Royalties, net of ARTC	**(9.36)**	**(9.22)**	**(9.45)**	**(10.20)**	(8.48)	(8.63)	(9.65)	(12.31)	(8.52)	(7.41)
Production expenses	**(3.76)**	**(3.31)**	**(2.52)**	**(3.78)**	(3.70)	(3.51)	(3.04)	(3.36)	(3.05)	(3.19)
Netback per BOE	**$27.71**	**$25.19**	**$26.88**	**$25.94**	$22.97	$20.53	$22.63	$22.83	$20.40	$18.81
Funds flow from operations per BOE	**$25.76**	**$23.39**	**$25.44**	**$25.61**	$22.84	$19.57	$20.48	$21.57	$18.31	$16.70
Wells drilled (gross)	**8**	**5**	**–**	**11**	10	4	–	9	7	–
TRUST UNIT TRADING STATISTICS										
Unit prices (based on daily closing price)										
High	**$21.39**	**$18.50**	**$15.95**	**$15.23**	$15.30	$14.50	$12.85	$11.74	$10.50	$9.10
Low	**$18.08**	**$15.37**	**$14.60**	**$12.90**	$13.25	$11.95	$10.80	$10.05	$8.85	$10.65
Close	**$19.97**	**$18.08**	**$15.50**	**$14.83**	$15.00	$13.46	$12.09	$11.30	$10.15	$10.63
Daily average trading volume	**139,144**	**101,752**	**106,869**	**112,614**	74,437	85,641	81,199	110,116	108,098	160,462

(1) THE ABOVE INFORMATION ONLY INCLUDES OPERATIONS OF FOCUS ENERGY TRUST WHICH COMMENCED OPERATIONS ON AUGUST 23, 2002.
(2) RESTATED AT DECEMBER 31, 2004 TO BREAK OUT THE TRANSPORTATION SYSTEM CHARGES SEPARATELY (INCREASES REVENUE AND RECORDS THIS NEW EXPENSE)
(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.

SENIOR MANAGEMENT

Derek W. Evans
President and C.E.O.

William D. Ostlund
Vice President, Finance and C.F.O.

Dennis M. Lawrence
Vice President, Engineering

Bryce H. Murdoch
Vice President, Geology

Al S. Pickering
Vice President, Land

David W. Sakal
Vice President, Operations

A. Kim Schoenroth
Controller

Grant A. Zawalsky
Corporate Secretary

DIRECTORS

Matthew J. Brister(3)(4)(5)
John A. Brussa(3)
Stuart G. Clark(1)(2)
Derek W. Evans
James H.McKelvie(2)(3)
Gerry A. Romanzin(2)(4)(5)

(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

HEAD OFFICE

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STOCK EXCHANGE LISTING

TSX Listings:
Focus Energy Trust: FET.UN
FET Resources Ltd.: FTX
(Exchangeable Shares)

SOLICITORS

Burnet, Duckworth & Palmer LLP
Calgary, Alberta, Canada

AUDITORS

KPMG LLP
Calgary, Alberta, Canada

BANKERS

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

ENGINEERING CONSULTANTS

Paddock Lindstrom & Associates Ltd.
Calgary, Alberta

McDaniel and Associates 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	Unites States dollar

FOR FURTHER INFORMATION CONTACT:

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FOCUS ENERGY TRUST

RENEWAL ANNUAL INFORMATION FORM

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GLOSSARY OF TERMS

"ABCA" means the *Business Corporations Act* (Alberta), R.S.A. 2000, c. B-9, as may be amended, including the regulations promulgated thereunder;

"AcquisitionCo" means FET Rèsources Ltd., a wholly owned subsidiary of the Trust;

"Affiliate" or **"Associate"** when used to indicate a relationship with a person or company, means the same as set forth in the *Securities Act* (Alberta);

"Arrangement" means the transaction described under the heading "General Development of the Business - History and Development - Focus Energy Trust" being the plan of arrangement involving the Trust, AcquisitionCo, Storm and Storm Energy Ltd. completed on August 23, 2002 under the ABCA pursuant to which, among other things, the Trust indirectly acquired all of the issued and outstanding common shares of Storm, certain growth assets of Storm were acquired by Storm Energy Ltd. and the shares of Storm Energy Ltd. were distributed to the former holders of common shares of Storm;

"ARTC" means credits or rebates in respect of Crown royalties which are paid or credited by the Crown, including those paid or credited under the *Alberta Corporate Tax Act* which are commonly known as "Alberta Royalty Tax Credits";

"Board of Directors" or **"Board"** means the Board of Directors of FET Resources or its successors;

"business day" means a day, which is not a Saturday, Sunday or statutory holiday, when banks in the place at which any action is required to be taken hereunder are generally open for the transaction of commercial banking business;

"Call Right" means the Liquidation Call Right, the Redemption Call Right and the Retraction Call Right, collectively, as such terms are defined in the Exchangeable Share Provisions;

"crude oil" or **"oil"** means a mixture, consisting mainly of pentanes and heavier hydrocarbons, that may contain sulphur compounds, that is liquid at the conditions under which its volume is measured or estimated, but excluding such liquids obtained from the processing of natural gas;

"Current Market Price of a Trust Unit" means, in respect of a Trust Unit on any date, the weighted average trading price of the Trust Units on the TSX for the ten (10) trading days preceding that date, or, if the Trust Units are not then listed on the TSX, on such other stock exchange or automated quotation system on which the Trust Units are listed or quoted, as the case may be, as may be selected by the Board of Directors for such purpose; provided, however, that if in the opinion of the Board of Directors, the public distribution or trading activity of Trust Units for that period does not result in a weighted average trading price which reflects the fair market value of a Trust Unit, then the Current Market Price of a Trust Unit shall be determined by the Board of Directors, in good faith and in its sole discretion, and provided further that any such selection, opinion or determination by such Board of Directors shall be conclusive and binding;

"Distribution" means a distribution paid by the Trust in respect of the Trust Units, expressed as an amount per Trust Unit;

"Distribution Record Date" means the last day of each calendar month or such other date as may be determined from time to time by the Trustee, except that December 31 shall in all cases be a Distribution Record Date;

"Exchange Ratio" means the exchange ratio used to determine the number of Trust Units a holder of Exchangeable Shares is entitled to receive upon an exchange of such shares, and at any time and in respect of each Exchangeable Share, shall initially be equal to one, and shall be cumulatively adjusted between the time at which that Exchangeable Share was issued and the time as of which the Exchange Ratio is being calculated by: (i) increasing the Exchange Ratio on each Distribution Payment Date by an amount, rounded to the nearest five (5) decimal places, equal to a fraction having as its numerator the Distribution, expressed as an amount per Trust Unit, paid on that Distribution Payment Date, and having as its denominator the Current Market Price of a Trust Unit on the first business day following the Distribution Record Date for such Distribution; and (ii) decreasing the Exchange Ratio on each record date for the payment of dividends to holders of Exchangeable Shares by FET Resources, if any, by an amount, rounded to the nearest five (5) decimal places, equal to a fraction having as its numerator the amount of the dividend payable to holders of Exchangeable Shares, expressed as an amount per Exchangeable Share, and having as its denominator the Current Market Price of a Trust Unit on the date that is seven (7) business days prior to that dividend record date. The Exchange Ratio shall also be adjusted in the event of certain other reorganizations or distributions in respect of the Trust Units as necessary on an economic equivalency basis;

"**Exchangeable Shares**" means the Series A Exchangeable Shares in the capital of FET Resources;

"**FET Resources**" means FET Resources Ltd., the corporation resulting from the amalgamation of Storm and AcquisitionCo pursuant to the Arrangement;

"**Focus**" or the "**Trust**" means Focus Energy trust, a trust established under the laws of Alberta pursuant to the Trust Indenture;

"**Focus BC**" means Focus B.C. Energy trust, a trust established under the laws of Alberta;

"**Insolvency Event**" means the institution by FET Resources of any proceeding to be adjudicated to be a bankrupt or insolvent or to be wound up, or the consent of FET Resources to the institution of bankruptcy, dissolution, insolvency or winding-up proceedings against it, or the filing of a petition, answer or consent seeking dissolution or winding-up under any bankruptcy, insolvency or analogous laws, including without limitation the *Companies Creditors' Arrangement Act* (Canada) and the *Bankruptcy and Insolvency Act* (Canada), and the failure by FET Resources to contest in good faith any such proceedings commenced in respect of FET Resources within fifteen (15) days of becoming aware thereof, or the consent by FET Resources to the filing of any such petition or to the appointment of a receiver, or the making by FET Resources of its inability to pay its debts generally as they become due, or FET Resources not being permitted, pursuant to solvency requirements of applicable law, to redeem any retracted Exchangeable Shares pursuant to section 6.6 of the Exchangeable Share Provisions;

"**Market Redemption Price**" means the price per Trust Unit equal to the lesser of (i) 90% of the "market price", as calculated under the Trust Indenture, of the Trust Units on the principal market on which the Trust Units are tendered to the Trust for redemption; and (ii) the "closing market price", as calculated under the Trust Indenture, on the principal market on which the Trust Units are quoted for trading on the date the Trust Units are so tendered for redemption;

"**McDaniel**" means McDaniel and Associates Consultants Ltd., independent geological and petroleum engineering consultants of Calgary, Alberta;

"**McDaniel Report**" means the independent engineering evaluation of the Trust's oil, NGL and natural gas interests prepared by McDaniel dated February 7, 2005 and effective December 31, 2004;

"**natural gas**" means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir which, under atmospheric conditions, is essentially gas but which may contain liquids. The natural gas reserve estimates are reported on a marketable basis; that is, the gas which is available to a transmission line after removal of certain hydrocarbons and non-hydrocarbon compounds present in the raw natural gas and which meets specifications for use as a domestic, commercial or industrial fuel;

"**natural gas liquids**" or "**NGLs**" means those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants or recovered from field separators, scrubbers or other gathering facilities. These liquids include the hydrocarbon components ethane, propane, butanes and pentanes plus, or a combination thereof;

"**Non-Resident**" means (i) a Person who is not a resident of Canada for the purposes of the *Tax Act* or (ii) a partnership that is not a Canadian partnership for the purposes of the *Tax Act*;

"**Notes**" means the unsecured, subordinate promissory notes issued by AcquisitionCo (now FET Resources) under the Arrangement;

"**NPI Agreement**" means the net profits interest agreement, as amended from time to time, dated August 23, 2002, between FET Resources and the Trust;

"**Paddock**" means Paddock Lindstrom & Associates Ltd., independent geological and petroleum engineering consultants of Calgary, Alberta;

"**Paddock Report**" means the independent engineering evaluation of the Trust's oil, NGL and natural gas interests prepared by Paddock dated January 12, 2005 and effective December 31, 2004;

"**Permitted Investments**" means (i) obligations issued or guaranteed by the government of Canada or any province of Canada or any agency or instrumentality thereof, (ii) term deposits, guaranteed investment certificates, certificates of deposit or bankers' acceptances of or guaranteed by any Canadian chartered bank or other financial institutions the short-term debt or deposits of which have been rated at least A or the equivalent by Standard & Poor's Corporation, Moody's Investors Service, Inc. or Dominion Bond Rating Service Limited, and (iii) commercial paper rated at least A or the equivalent by Dominion Bond Rating Service Limited, in each case maturing within 180 days after the date of acquisition;

"**person**" means any individual, partnership, association, body corporate, trustee, executor, administrator, legal representative, government, regulatory authority or other entity;

"**Petroleum Substances**" means petroleum, natural gas and related hydrocarbons (except coal) including, without limitation, all liquid hydrocarbons, and all other substances, including sulphur, whether gaseous, liquid or solid and whether hydrocarbon or not, produced in association with such petroleum, natural gas or related hydrocarbons;

"***pro rata*** **share**" of any particular amount in respect of a holder of a Trust Unit at any time shall be the product obtained by multiplying the number of Trust Units that are owned by that Trust Unitholder at that time by the quotient obtained when the particular amount is divided by the total number of all Trust Units that are issued and outstanding at that time;

"**Redearth Partnership**" means the Redearth Partnership among Harvest Operations Corp., Redearth Energy Inc. and FET Resources with respect to the Redearth Assets;

"**Special Resolution**" means a resolution proposed to be passed as a special resolution at a meeting of Trust Unitholders (including an adjourned meeting) duly convened for the purpose and held in accordance with the provisions of the Trust Indenture at which two or more holders of at least 5% of the aggregate number of Trust Units then outstanding are present in person or by proxy and passed by the affirmative votes of the holders of not less than 66⅔% of the Trust Units represented at the meeting and voted on a poll upon such resolution. For the purposes of determining such percentage, the holder of any Special Voting Right who is present at the meeting shall be regarded as representing outstanding Trust Units equivalent in number to the votes attaching to such Special Voting Right;

"**Special Voting Right**" means the special voting right of the Trust, issued and certified under the Trust Indenture for the time being outstanding and entitled to the benefits and subject to the limitations set forth therein;

"**Storm**" means Storm Energy Inc., a predecessor corporation to FET Resources, incorporated under the ABCA;

"**Subsequent Investment**" means those investments which the Trust is permitted to make pursuant to the Trust Indenture;

"**Subsidiary**" means, in relation to any person, any body corporate, partnership, joint venture, association or other entity of which more than 50% of the total voting power of shares or units of ownership or beneficial interest entitled to vote in the election of directors (or members of a comparable governing body) is owned or controlled, directly or indirectly, by such person;

"**Support Agreement**" means the support agreement entered into between the Trust and AcquisitionCo on August 23, 2002;

"**Tax Act**" means the *Income Tax Act* (Canada), R.S.C. 1985, c.1, 5th Supplement, as amended;

"**Tommy Lakes Partnership**" means Tommy Lakes Partnership, a general partnership formed under the laws of Alberta, the partners of which are FET Resources and Focus BC;

"**Trust Indenture**" means the trust indenture dated as of July 15, 2002 between Valiant Trust Company and Storm as amended from time to time;

"**Trust Subsidiary**" means FET ExchangeCo Ltd., a wholly-owned subsidiary of the Trust;

"**Trust Unit**" means a unit of the Trust, each unit representing an equal undivided beneficial interest therein;

"**Trust Unitholders**" or "**Unitholders**" means the holders from time to time of the Trust Units;

"**Trustee**" means Valiant Trust Company or such other trustee, from time to time, of Focus Energy Trust;

"**TSX**" means the Toronto Stock Exchange;

"**United States**" or "**US**" means the United States of America;

"**Voting and Exchange Trust Agreement**" means the voting and exchange trust agreement entered into on August 23, 2002; and

"**Voting and Exchange Trust Agreement Trustee**" means Valiant Trust Company, the initial trustee under the Voting and Exchange Trust Agreement, or such other trustee, from time to time appointed thereunder.

Words importing the singular number only include the plural, and *vice versa*, and words importing any gender include all genders. All dollar amounts set forth in this Annual Information Form are in Canadian dollars, except where otherwise indicated.

ABBREVIATIONS

Oil and Natural Gas Liquids

bbls	barrels
Mbbls	thousand barrels
MMbbls	million barrels
NGLs	natural gas liquids
stb	stock tank barrels of oil
Mstb	thousand stock tank barrels of oil
Mboe	thousand barrels of oil equivalent
MMboe	million barrels of oil equivalent
boe/d	barrels of oil equivalent per day
bbls/d	barrels of oil per day

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Bcf	billion cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
m^3	cubic metres
MMbtu	million British Thermal Units
MMbtu/d	millions of British Thermal Units per day
GJ	gigajoule
GJ/d	gigajoules per day

Other

BOE or boe	means barrel of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one bbl of oil. The conversion factor used to convert natural gas to oil equivalent is not necessarily based upon either energy or price equivalents at this time.
WTI	means West Texas Intermediate.
°API	means the measure of the density or gravity of liquid petroleum products derived from a specific gravity.
psi	means pounds per square inch.

CONVERSION

The following table sets forth certain conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls	6.289
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
gigajoules	MMbtu	0.948

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

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 events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that 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 do not represent fair market value of reserves..

In particular, this Annual Information Form, and the documents incorporated by reference, contain forward-looking statements pertaining to the following:

- oil and natural gas production levels;
- capital expenditure programs;
- the quantity of the oil and natural gas reserves;
- projections of commodity prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development; and
- treatment under governmental regulatory regimes.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Information Form:

- volatility in market prices for oil and natural gas;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- fluctuations in foreign exchange or interest rates and stock market volatility;
- failure to realize the anticipated benefits of acquisitions; and
- the other factors discussed under "Risk Factors".

These factors should not be construed as exhaustive. Neither the Trust nor FET Resources undertakes any obligation to publicly update or revise any forward-looking statements. See "Management's Discussion and Analysis".

Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this annual information form and the documents incorporated by reference herein are expressly qualified by this cautionary statement. Neither the Trust nor FET Resources undertakes any obligation to publicly update or revise any forward-looking statements.

FOCUS ENERGY TRUST

General

The Trust is an open-end unincorporated investment trust governed by the laws of the Province of Alberta and created pursuant to the Trust Indenture. The head and principal office of the Trust is located at Suite 3250, 205 - 5th Avenue S.W., Calgary, Alberta, T2P 2V7. The Trust was established to:

- invest in securities of FET Resources and participate in the Arrangement;
- acquire the net profits interest under the NPI Agreement;
- acquire or invest in other securities of FET Resources and in the securities of any other entity including without limitation bodies corporate, partnerships or trusts, and borrowing funds or otherwise obtaining credit for that purpose;
- dispose of any part of the property of the Trust, including, without limitation, any securities of FET Resources;
- temporarily hold cash and investments for the purposes of paying the expenses and the liabilities of the Trust, make other Permitted Investments as contemplated by the Trust Indenture, pay amounts payable by the Trust in connection with the redemption of any Units, and make distributions to Unitholders; and
- pay costs, fees and expenses associated with the foregoing purposes or incidental thereto.

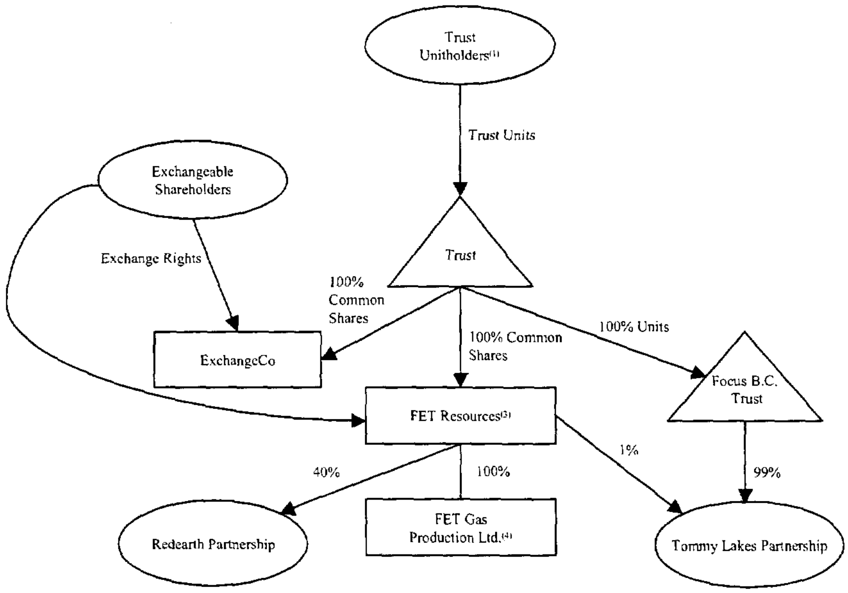
Inter-Corporate Relationships

The following table provides the name, the percentage of voting securities owned by the Trust and the jurisdiction of incorporation, continuance or formation of the Trust's subsidiaries, partnerships and trusts either, direct and indirect, as at the date hereof.

	Percentage of voting securities (directly or indirectly)	Nature of Entity	Jurisdiction of Incorporation/Formation
FET Resources Ltd.	100%	Corporation	Alberta
FET Gas Production Ltd.	100%	Corporation	Alberta
Focus B.C. Trust	100%	Trust	Alberta
Tommy Lakes Partnership	100%	General Partnership	Alberta
Redearth Partnership	40%	General Partnership	Alberta

Organizational Structure of the Trust

The following diagram sets forth the organizational structure of the Trust as at the date hereof.



Notes:

1. The Unitholders own 100% of the Trust.
2. Cash flow represents payments made by FET Resources and Focus B.C. Trust to the Trust in respect of interest payments on the Notes, income received by the Trust under the NPI Agreement, interest payment on a promissory note issued by Focus B.C. Trust and distributions made by Focus B.C. Trust. In addition to such amounts, prepayments in respect of principal on the Notes may be made from time to time by FET Resources to the Trust before the maturity of the Notes.
3. FET Resources is a subsidiary of the Trust. The Trust will invest funds raised through any subsequent issuance of Units in additional securities of FET Resources to enable FET Resources to make capital expenditures. In addition, the Trust may reinvest a portion of the income received from FET Resources as well as any repayments of principal on the Notes in securities of FET Resources to enable FET Resources to make capital expenditures.
4. FET Gas Production Ltd. is a wholly owned subsidiary of FET Resources.

In accordance with the terms of the Trust Indenture and the Special Voting Right issued to the Trustee, holders of Units and holders of FET Exchangeable Shares are entitled to direct the Trust as to how to vote in respect of all matters to be placed before the Trust, including the election of directors of FET Resources, approving the Trust's financial statements, and appointing the auditors of the Trust.

GENERAL DEVELOPMENT OF THE BUSINESS

History and Development

Focus Energy Trust was established on August 23, 2002 for the purpose of implementing the Arrangement pursuant to Section 193 of the ABCA. The purpose of the Arrangement was to effect a reorganization that resulted in AcquisitionCo acquiring all of the common shares of Storm and each shareholder of Storm (other than Non-Residents or Tax-Exempt Shareholders) receiving: (i) at the election of such shareholder, either Trust Units or Exchangeable Shares, or a combination thereof; and (ii) common shares of Storm Energy Ltd. Non-Resident and Tax-Exempt Shareholders only received Trust Units and common shares of Storm Energy Ltd. for their common shares of Storm. AcquisitionCo and Storm subsequently amalgamated to form FET Resources. As a result of the completion of the Arrangement the Trust became the owner of all of the common shares of FET Resources and all of the Notes. Prior to the completion of the Arrangement, the common shares of Storm were listed and posted for trading on the TSX. On August 30, 2002, the Trust Units, Exchangeable Shares and the common shares of Storm Energy Ltd. began trading on the TSX.

On June 4, 2003 the Trust announced the completion of the Loon Lake Acquisition for $20.8 million, before closing adjustments and the subsequent exercise of a right of first refusal by another working interest owner. At the time of the acquisition, the Loon Lake Property was comprised of 50 gross (20.6 net) producing oil wells producing 385 barrels per day of 38° API oil and 80 Mcf per day of natural gas. The Loon Lake Acquisition includes both unit and non-unit interests at the Loon Lake Property. Approximately 84% of acquired production and 87% of the acquired reserves are represented by a 41.5% working interest in the Loon Slave Point G-Unit, which is operated by FET Resources. The Loon Lake Property also includes a five year drilling option to earn a 50% interest in 21 sections of undeveloped lands, and ownership in oil processing and power generation facilities. The Loon Lake Acquisition originally included a 50% working interest in 15 sections of land and 5 standing natural gas wells at FET Resources' Tommy Lakes natural gas property in northeastern British Columbia but subsequent to closing another working interest owner exercised its right of first refusal. The Trust received $3.2 million in proceeds upon exercise of the right of first refusal. FET Resources acquired the properties from Storm Energy Ltd., which had three directors in common with FET Resources. The approval of the transaction was made by the unrelated directors of FET Resources based on an independent engineering evaluation.

On June 25, 2003, Focus issued 2,100,000 Trust Units at a price of $12.10 per Trust Unit for gross proceeds of $25,410,000 pursuant to a final Short Form Prospectus dated June 17, 2003.

On March 5, 2004 Focus announced the proposed acquisition of the Tommy Lakes Partnership and on April 1, 2004, Focus announced the completion of the acquisition of the Tommy Lakes Partnership in which it acquired additional working interests at its Tommy Lakes property in northeastern British Columbia for $110 million before closing adjustments. The acquisition was financed with a combination of debt drawn from Focus' existing credit facilities and a bought-deal financing of $74.5 million. Tommy Lakes is a high quality long life natural gas property which has a large accumulation of natural gas in place, and it is the principal natural gas producing asset of the Trust. This property is operated by Focus, has low operating costs and a decline rate of less than 14%. The Tommy Lakes area also contains the main development opportunities of Focus. The interests acquired had average production for January and February 2004 of approximately 11.7 MMcf per day of natural gas and 250 barrels per day of natural gas liquids. Total proved and probable reserves for the property at the time of acquisition were 11.7 million barrels of oil equivalent, being 62.4 Bcf of natural gas and 1.3 million barrels of natural gas liquids. Proven reserves represented 76.5% of total proved and probable reserves. Reserves are based on an independent engineering evaluation conducted by Paddock Lindstrom & Associates Ltd. effective April 1, 2004 and prepared in accordance with National Instrument 51-101. The acquisition represented 20,060 gross acres of undeveloped land (11,040 net acres), and the associated ownership in natural gas gathering and processing facilities.

On March 23, 2004, Focus issued 5,000,000 Trust Units at a price of $14.90 per Trust Unit for gross proceeds of $74,500,000 pursuant to a final Short Form Prospectus dated March 15, 2004.

On September 1, 2004, Focus announced that it had acquired a private company with gas assets in South Eastern Alberta for $18.5 million before closing adjustments. The acquisition was financed with debt drawn from Focus' existing credit facilities. The acquired company had average production of approximately 1.7 MMcf per day (283 BOE/d) in June of 2004. Production is 100% operated with an average working interest of 85%. Total proved and probable reserves as of September 1, 2004 were 10.8 Bcf of natural gas (1.8 million barrels of oil equivalent). Proven reserves represented 83% of total proven and probable reserves. Reserves are based on the Trust's internal evaluation which was prepared in accordance with National Instrument 51-101. The properties acquired included 5,760 gross acres of undeveloped land (5,760 net acres) and the associated ownership in natural gas gathering and compression facilities. The acquisition of this shallow gas (Second White Specs, Medicine Hat and Milk River) production provides the trust with an operating presence in one of the largest gas fairways in the Western Canadian Basin.

Description of the Business and Operations

Focus Energy Trust

The Trust is a limited purpose trust and is restricted to:

- investing in shares of AcquisitionCo and acquiring the common shares of Storm and the Notes pursuant to the Arrangement;
- acquiring the net profits interest under the NPI Agreement;
- acquiring or investing in other securities of FET Resources and in the securities of any other entity including without limitation bodies corporate, partnerships or trusts, and borrowing funds or otherwise obtaining credit for that purpose;
- disposing of any part of the property of the Trust, including, without limitation, any securities of FET Resources;
- temporarily holding cash and investments for the purposes of paying the expenses and the liabilities of the Trust, make other Permitted Investments as contemplated by the Trust Indenture, pay amounts payable by the Trust in connection with the redemption of any Trust Units, and making distributions to Unitholders; and
- paying costs, fees and expenses associated with the foregoing purposes or incidental thereto.

The Trustee is prohibited from acquiring any investment which (a) would result in the cost amount to the Trust of all "foreign property" (as defined in the Tax Act) which is held by the Trust to exceed the amount prescribed by section 5000 of the Tax Regulations or (b) would result in the Trust not being considered either a "unit trust" or a "mutual fund trust" for purposes of the Tax Act.

The Trustee may declare payable to the Unitholders all or any part of the net income of the Trust. Currently, the only income to be received by the Trust is from the interest received on the principal amount of Notes, under the NPI Agreement and distributions made by Focus BC. The Trust has been making monthly cash distributions to Trust Unitholders (since October 15, 2002) of the interest income earned from the Notes and the income earned under the NPI Agreement, after expenses, if any, and any cash redemptions of Trust Units.

FET Resources Ltd.

FET Resources is actively engaged in the business of oil and natural gas exploitation, development, acquisition and production in the provinces of British Columbia and Alberta. The business plan of FET Resources is to maximize returns to the Trust from FET Resources' oil and natural gas properties and related assets. Where possible, FET Resources intends to expand its reserve base through the selective addition of high-quality, long-life reserves with low risk development opportunities.

In reviewing potential properties or acquisitions, FET Resources will consider a number of factors, including: (i) the present value of the future revenue from such properties from the proved producing, total proved and proved plus probable reserves, (ii) the amount of potential for additional reservoir development, (iii) whether sufficient infrastructure exists in the prospect to provide for increased activity, (iv) the cost of any potential development, (v) investments in properties that exhibit medium to long life reserves, and (vi) the ability of FET Resources to enhance the value of acquired properties through additional exploitation efforts and additional development drilling. **The Board of Directors may, in its discretion, approve asset or corporation acquisitions or investments that do not conform to these guidelines based upon the Board's consideration of the qualitative aspects of the subject properties including risk profile, technical upside, reserve life and asset quality.**

Significant Acquisitions and Significant Dispositions

Neither the Trust nor FET Resources made any significant acquisitions or dispositions in the fiscal year ended December 31, 2004, other than the acquisition of interests at Tommy Lakes.

In 2005 to date, neither the Trust nor FET Resources made any significant acquisitions or dispositions.

Principal Properties

The following is a description of Focus' principal oil and natural gas properties as of December 31, 2004. The term "net", when used to describe Focus' share of production, means Focus' interest share after deduction of royalty obligations. The term "gross", when used to describe Focus' share of production, means Focus' interest share before deduction of royalty obligations. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2004. Reserve amounts are stated, before deduction of royalties, as at December 31, 2004 based on escalating cost and price assumptions as evaluated in the Paddock and McDaniel Reports (as defined below) prepared by Paddock Lindstrom and Associates Ltd. and McDaniel and Associates Consultants Ltd. (see "Statement of Reserves Data and Other Oil and Gas Information").

All of the Trust's producing properties are located onshore in Canada, specifically in six main areas in Alberta and British Columbia. These are comprised of the natural gas dominated areas of Tommy Lakes, Kotcho-Cabin, Pouce Coupe, Sylvan Lake, and Medicine Hat and the oil dominated area of Red Earth. The Trust has a high working interest in these properties which averages 71 percent, and 87 percent of the production is operated by the Trust. Discussion of these areas follows.

Tommy Lakes, British Columbia

The Trust's largest single asset and main natural gas producing property is the Tommy Lakes area in northeastern British Columbia. The main producing zone at Tommy Lakes is the areally extensive blanket sand of the Triassic Halfway formation. Total pool original gas in place is in excess of 600 Bcf, of which approximately 27 percent has been produced to date. Although the reservoir is thick (more than 10 metres) and continuous, permeability is low, requiring all wells to be fracture stimulated to achieve stabilized rates of 600 to 800 Mcf per day, with liquids recovered at 20 barrels per million cubic feet.

During 2004, Focus' gross production from the Tommy Lakes property averaged 29.4 MMcf per day of natural gas and 569 bbls per day of natural gas liquids from 82 (78 net) wells. The base decline rate on the existing production is approximately 12 percent per year. Production at the property is compressed at four Focus-operated facilities and delivered into the Duke (Westcoast) system for further processing and delivery to markets.

On April 1, 2004 Focus acquired additional working interests at Tommy Lakes for $110 million. The acquisition increased our working interest in the western portion of the property to 100 percent and brought our overall average working interest up to approximately 95 percent. At December 31, 2004, Tommy Lakes represented approximately 65 percent of the Trust's reserves.

Subsequent to year-end the Trust has successfully completed its 11-well (9.7 net) winter drilling program at Tommy Lakes. All 11 wells were cased and have been placed on production. This year's winter program set out to achieve four main objectives:

- further efficient infill development of the Halfway A Pool;
- selective Halfway step-out drilling to continue to extend the economic boundaries of the pool;
- testing of secondary zones such as the Bluesky and Doig;
- the implementation of well design and program execution initiatives designed to maximize our cost efficiencies.

The program was successful in achieving all of these objectives and the overall winter program at Tommy Lakes came in as per our expectations in terms of production rates and reserves. Based upon this continued success, Focus anticipates that the Tommy Lakes property will continue to be the main development area for the Trust, with at least two more years of similar sized development programs.

Kotcho-Cabin, British Columbia

At Kotcho and Cabin the Trust is producing from two sour high pressure gas pools along a dolomitized reef edge in the Devonian Slave Point formation. Production from both properties is processed through 100 percent Focus-owned dehydration and water disposal facilities and delivered to the Duke (Westcoast) system.

During 2004, Focus' gross production from this area averaged 8.1 MMcf per day of natural gas. At Kotcho, volumes have decreased over the course of the year due to the onset of water production from the pool. Recently volumes appear to be stabilizing, which is typical of offsetting Slave Point production. We continue to monitor production closely and pursue the appropriate strategies to ensure that recovery from the pool is maximized. To this end, in the first quarter of 2005 the Trust will participate in the drilling of 1well at Kotcho targeting the Slave Point.

Pouce Coupe, Alberta

At Pouce Coupe the Trust produces natural gas and associated NGLs from the Triassic Montney and Doig formations. Focus' gross production from this property in 2004 averaged 2.9 MMcf per day and 29 bbls per day of natural gas liquids. The majority of production is compressed at a 100% Focus-owned facility and then delivered to a third party plant for further processing and delivery onto the TransCanada pipeline system.

Activity at Pouce Coupe has been concentrated on downspacing within the Montney reservoir. Offsetting operators have commonly downspaced the Montney to 4 wells per section and in specific cases appear to be testing the economics of 8 well per section spacing. Focus drilled 2 wells into the Montney in late 2004 with good success, and anticipates drilling 2 more wells in 2005, which would bring the spacing on our lands to 4 wells per section.

Sylvan Lake, Alberta

Sylvan Lake is a multi-zone area which produces both gas and light oil from a number of formations ranging in depth from 400 to 2,200 metres. The primary producing zones are the Shunda, Pekisko, Lower Mannville, and Edmonton. In 2004, Focus' gross production from the area averaged 1.7 MMcf per day of natural gas, and 154 bbls per day of oil and natural gas liquids. Production at Sylvan Lake is processed through the Focus-operated Sylvan Lake gas plant, in which the Trust holds an average working interest of 60 percent. The Trust owns excess capacity in this plant which generates material third party processing income.

In 2004 the Trust participated in the drilling of 5 (2.2 net) wells at Sylvan Lake, all targeting the Edmonton sand. All of these wells were successfully completed for gas, and the Trust anticipates a similar sized drilling program for 2005.

Medicine Hat, Alberta

Effective September 1, 2004, Focus acquired producing assets at Medicine Hat in southeastern Alberta for total consideration of \$13.5 million. Effective October 1, 2004 the Trust acquired additional minor interests in the property for total consideration of \$1.1 million. The property produces sweet natural gas from the Milk River, Medicine Hat and Second White Specks formations. Average working interest in the production is 90 percent, and the gas is compressed at two Focus-operated facilities. Focus' gross production from the Medicine Hat property averaged 1.9 MMcf per day during the fourth quarter of 2004.

The Trust anticipates the first round of infill drilling on the Medicine Hat property will occur in late Q1 or early Q2 2005, dependant on weather conditions and equipment availability. Pending the success of this program further development drilling is targeted for Q3 2005.

Red Earth, Alberta

The Trust's light oil production is concentrated in the Red Earth area, within which the main producing properties are Golden, Loon Lake, Loon Lake North, Evi, and Kitty. In 2004 Focus' gross production from the Red Earth area averaged 1,913 bbls per day of 38° API light sweet crude. Approximately 44 percent of the Red Earth production is operated by Focus.

The majority of the Trust's development activity within the Red Earth area is concentrated at Loon Lake, which was acquired in June 2003. The main productive horizon at Loon Lake is the Slave Point G pool, which is a light oil reservoir under active waterflood. During 2004, the Trust drilled 1 well (0.5 net) and recompleted 2 others (0.8 net) into the Slave Point G pool, with encouraging results. Activities in 2005 will include further infill and step-out drilling as well as waterflood optimization.

All the assets in these areas, excluding the Golden and Loon Lake properties, are held indirectly through a partnership with Harvest Operations Corp.. The Trust has a 40 percent interest in the partnership. The Trust owns an average 91 percent working interest in the Golden area and an average 39 percent working interest in the Loon Lake area.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "Statement") is dated March 16, 2005. The effective date of the Statement is December 31, 2004 and the preparation date of the Statement is February 7, 2005.

Disclosure of Reserves Data

The reserves data set forth below (the "Reserves Data") is based upon an evaluation conducted by Paddock Lindstrom and Associates Ltd. ("Paddock") dated January 12, 2005 (the "Paddock Report"), and an evaluation conducted by McDaniel and Associates Consultants Ltd. ("McDaniel") dated February 7, 2005 (the "McDaniel Report"). The effective date of both the Paddock Report and the McDaniel Report is December 31, 2004. The Reserves Data summarizes the oil, liquids and natural gas reserves of Focus and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs. The Reserves Data conforms with the requirements of National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. Paddock and McDaniel were engaged to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of Focus' reserves are in Canada and, specifically, in the provinces of Alberta and British Columbia.

Disclosure provided herein in respect of BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the constant prices and costs assumptions and forecast prices and costs assumptions will be attained and variances could be material.

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.

Focus is not taxable under the existing structure. The Alberta Securities Commission has advised that Focus will be exempt from disclosing after tax future net revenue as part of its statement of reserves data.

Reserves Data – Constant Prices and Costs

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2004
CONSTANT PRICES AND COSTS

	RESERVES					
	LIGHT AND MEDIUM OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
PROVED						
Developed Producing	3,330	2,913	102,359	78,108	1,909	1,503
Developed Non-Producing	195	183	10,891	8,275	114	93
Undeveloped	738	676	35,274	27,289	578	463
TOTAL PROVED	4,263	3,773	148,524	113,672	2,601	2,059
PROBABLE	1,477	1,290	46,116	35,024	786	625
TOTAL PROVED PLUS PROBABLE	5,740	5,063	194,640	148,696	3,387	2,684

	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)
PROVED					
Developed Producing	536,481	410,893	336,987	288,192	253,460
Developed Non-Producing	43,618	32,431	25,834	21,429	18,273
Undeveloped	153,665	97,337	68,588	50,993	39,125
TOTAL PROVED	733,764	540,661	431,409	360,614	310,857
PROBABLE	231,875	133,550	89,199	64,933	49,965
TOTAL PROVED PLUS PROBABLE	965,638	674,210	520,608	425,547	360,822

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2004
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	WELL ABANDONMENT COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)
Proved Reserves	1,252,768	265,687	199,038	46,914	7,365	733,764
Proved Plus Probable Reserves	1,642,576	350,324	256,112	62,587	7,915	965,638

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2004
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	78,786
	Natural Gas (including by-products but excluding solution gas from oil wells)	352,623
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	96,646
	Natural Gas (including by-products but excluding solution gas from oil wells)	423,962

Reserves Data – Forecast Prices and Costs

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2004
FORECAST PRICES AND COSTS

	RESERVES					
	LIGHT AND MEDIUM OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
PROVED						
Developed Producing	3,306	2,903	102,229	77,995	1,909	1,505
Developed Non-Producing	195	184	10,883	8,267	114	92
Undeveloped	736	681	35,258	27,311	578	463
TOTAL PROVED	4,237	3,768	148,370	113,573	2,601	2,060
PROBABLE	1,460	1,288	46,092	35,002	786	626
TOTAL PROVED PLUS PROBABLE	5,697	5,056	194,462	148,575	3,387	2,686

	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)
PROVED					
Developed Producing	498,370	385,354	319,752	276,508	245,609
Developed Non-Producing	40,163	30,075	24,212	20,295	17,470
Undeveloped	147,308	89,167	61,750	45,548	34,785
TOTAL PROVED	685,840	504,596	405,713	342,351	297,863
PROBABLE	226,249	125,062	82,082	59,331	45,559
TOTAL PROVED PLUS PROBABLE	912,089	629,658	487,795	401,682	343,422

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2004
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	WELL ABANDONMENT COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)
Proved Reserves	1,260,610	269,446	247,115	47,522	10,687	685,840
Proved Plus Probable Reserves	1,680,687	360,458	331,884	63,805	12,451	912,089

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2004
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	69,912
	Natural Gas (including by-products but excluding solution gas from oil wells)	335,801
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	85,405
	Natural Gas (including by-products but excluding solution gas from oil wells)	402,390

Definitions and Other Notes

In the tables set forth above in "Disclosure of Reserves Data" and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1. **"Gross"** means:

   (a) in relation to Focus' interest in production and reserves, its "Trust gross reserves", which are Focus' interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of Focus;

   (b) in relation to wells, the total number of wells in which Focus has an interest; and

   (c) in relation to properties, the total area of properties in which Focus has an interest.

2. **"Net"** means:

   (a) in relation to Focus' interest in production and reserves, Focus' interest (operating and non-operating) share after deduction of royalties, plus Focus' royalty interest in production or reserves.

   (b) in relation to wells, the number of wells obtained by aggregating Focus' working interest in each of its gross wells; and

(c) in relation to Focus' interest in a property, the total area in which Focus has an interest multiplied by the working interest owned by Focus.

3. **"Development costs"** means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, road building, and relocating public roads, gas lines and power lines;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

4. **"Development well"** means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

5. **"Service well"** means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

6. Definitions used for reserve categories are as follows:

The following definitions apply to both estimates of individual reserves entities and the aggregate of reserves for multiple entities.

Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

(a) analysis of drilling, geological, geophysical and engineering data;

(b) the use of established technology; and

(c) specified economic conditions (see the discussion of "Economic Assumptions" below).

Reserves are classified according to the degree of certainty associated with the estimates.

(a) Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(b) Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

"Economic Assumptions" will be the prices and costs used in the estimate, namely:

(a) constant prices and costs as at the last day of Focus' financial year; and

(b) forecast prices and costs.

Development and Production Status

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

(a) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

  (i) Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainly.

  (ii) Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(b) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

7. Forecast prices and costs

Future prices and costs that are:

(a) generally acceptable as being a reasonable outlook of the future; and

(b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which Focus is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

The forecast summary table under "Pricing Assumptions" identifies benchmark reference prices that apply to Focus.

8. Constant prices and costs

Prices and costs used in an estimate that are:

(a) Focus' prices and costs as at the effective date of the estimation, held constant throughout the estimated lives of the properties to which the estimate applies; and

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which Focus is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

For the purposes of paragraph (a), Focus' prices are the posted prices for oil and the spot price for gas, after historical adjustments for transportation, quality and other factors.

9. The Alberta royalty tax credit (ARTC) is included in the cumulative cash flow amounts. ARTC is based on the program announced November 1989 by the Alberta government with modifications effective January 1, 1995.

10. Estimated future abandonment and reclamation costs related to a property have been taken into account by Paddock and McDaniel in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom, there was deducted the reasonable estimated future well abandonment costs.

11. Numbers may not add due to rounding.

12. Both the constant and forecast price and cost assumptions assumed the continuance of current laws and regulations.

13. The extended character of all factual data supplied to Paddock and McDaniel were accepted by Paddock and McDaniel as represented. No field inspection was conducted.

Pricing Assumptions

The following sets forth the benchmark reference prices, as at December 31, 2004, reflected in the Constant Price Case and Forecast Price Case Reserves Data. These price assumptions were provided to Focus by Paddock.

SUMMARY OF PRICING ASSUMPTIONS
as of December 31, 2004
CONSTANT PRICES AND COSTS

Year	OIL Edmonton Par Price 40° API ($Cdn/bbl)	NATURAL GAS AECO Gas Price ($Cdn/MMBtu)	NATURAL GAS LIQUIDS FOB Field Gate ($Cdn/BBL)
2004	47.25	6.78	38.62

Note:
(1) Prices are benchmark reference prices as at December 31, 2004.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
as of December 31, 2004
FORECAST PRICES AND COSTS

Year	WTI Cushing Oklahoma ($US/bbl)	OIL Edmonton Par Price 40° API ($Cdn/bbl)	NATURAL GAS AECO Gas Price ($Cdn/MMBtu)	NATURAL GAS LIQUIDS FOB Field Gate ($Cdn/BBL)	INFLATION RATES[1] %/Year	EXCHANGE RATE[2] ($US/$Cdn)
Forecast						
2005	42.00	50.22	6.78	41.04	2%	0.82
2006	40.00	47.76	6.52	38.53	2%	0.82
2007	37.50	44.69	6.26	35.69	2%	0.82
2008	35.00	41.62	6.00	32.34	2%	0.82
2009	33.00	39.16	5.73	30.43	2%	0.82
2010	33.50	39.75	5.85	30.88	2%	0.82
2011	34.00	40.34	5.96	31.35	2%	0.82
2012	34.50	40.92	6.08	31.81	2%	0.82
2013	35.00	41.51	6.21	32.27	2%	0.82
2014	35.50	42.10	6.33	32.74	2%	0.82
2015	36.00	42.68	6.46	33.20	2%	0.82
2016	36.50	43.27	6.59	33.66	2%	0.82
2017	37.00	43.85	6.72	34.13	2%	0.82
2018	37.50	44.44	6.85	34.59	2%	0.82
2019	38.00	45.02	6.99	35.10	2%	0.82
Escalate thereafter at	2% / year	2% / year	2% / year	2% / year		

Notes:
(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices, after hedging, realized by Focus for the year ended December 31, 2004, were $6.41/Mcf for natural gas, $40.43/bbl for crude oil, and $43.73/bbl for natural gas liquids.

Reconciliations of Changes in Reserves and Future Net Revenue

RECONCILIATION OF
COMPANY GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL			NATURAL GAS			NATURAL GAS LIQUIDS		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)
December 31 2003	4,962	1,536	6,498	96,488	29,872	126,360	1,603	434	2,037
Discoveries	0	0	0	1,912	455	2,367	25	4	28
Extensions	29	15	44	0	0	0	0	0	0
Improved Recovery	0	0	0	2,294	307	2,602	48	6	55
Technical Revisions	(51)	(92)	(143)	5,752	(1,070)	4,682	171	35	206
Economic Factors	0	0	0	0	0	0	0	0	0
Acquisitions	24	1	25	57,554	16,527	74,081	1,003	307	1,310
Dispositions	0	0	0	0	0	0	0	0	0
Production	(727)	0	(727)	(15,630)	0	(15,630)	(248)	0	(248)
December 31, 2004	4,237	1,460	5,697	148,370	46,092	194,462	2,601	786	3,387

Note:

(1) Technical revisions include revisions to properties acquired during the year of;
Natural Gas (MMcf) : Proved 4,115, Probable 2,297, Proved Plus Probable 6,412
Natural Gas Liquids (Mbbl) : Proved 113, Probable 34, Proved Plus Probable 147

RECONCILIATION OF
COMPANY NET RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL			NATURAL GAS			NATURAL GAS LIQUIDS		
FACTORS	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (MMcf)	Net Probable (MMcf)	Net Proved Plus Probable (MMcf)	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)
December 31,2003	4,343	1,353	5,696	72,889	22,202	95,091	1,258	341	1,599
Discoveries	0	0	0	1,472	353	1,825	20	3	23
Extensions	27	14	41	0	0	0	0	0	0
Improved Recovery	0	0	0	1,753	234	1,987	39	5	44
Technical Revisions	(28)	(72)	(100)	4,322	(633)	3,689	106	24	130
Economic Factors	(19)	(7)	(26)	550	212	762	25	5	30
Acquisitions	19	1	20	44,403	12,635	57,038	807	247	1,054
Dispositions	0	0	0	0	0	0	0	0	0
Production	(575)	0	(575)	(11,817)	0	(11,817)	(195)	0	(195)
December 31, 2004	3,768	1,288	5,056	113,573	35,002	148,575	2,060	626	2,686

Note:

(1) Technical revisions include revisions to properties acquired during the year of;
Natural Gas (MMcf) : Proved 2,948, Probable 1,816, Proved Plus Probable 4,764
Natural Gas Liquids (Mbbl) : Proved 91, Probable 28, Proved Plus Probable 119

RECONCILIATION OF CHANGES IN
NET PRESENT VALUES OF FUTURE NET REVENUE
DISCOUNTED AT 10% PER YEAR
PROVED RESERVES
CONSTANT PRICES AND COSTS

PERIOD AND FACTOR	2004 (M$)
Estimated Future Net Revenue at Beginning of Year	323,020
Sales and Transfers of Oil and Gas Produced, Net of Production Costs and Royalties	(97,320)
Net Change in Prices, Production Costs and Royalties Related to Future Production	21,974
Changes in Previously Estimated Development Costs Incurred During the Period	213
Changes in Estimated Future Development Costs	(9,256)
Extensions and Improved Recovery	5,702
Discoveries	5,239
Acquisitions of Reserves	125,673
Dispositions of Reserves	0
Net Change Resulting from Revisions in Quantity Estimates	23,862
Accretion of Discount	32,302
Estimated Future Net Revenue at End of Year	431,409

Additional Information Relating to Reserves Data

Undeveloped Reserves

Proved Undeveloped Reserves

The Trust attributes proved undeveloped reserves to infill drilling locations that are planned to be drilled into known pools with existing infrastructure in place. These are reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved undeveloped reserves. The majority of the Trust's current proved undeveloped reserves are located at Tommy Lakes and Loon Lake, and will be developed within the next two years.

Probable Undeveloped Reserves

The Trust attributes probable undeveloped reserves to infill drilling locations that are planned to be drilled into known pools with existing infrastructure in place. These reserves are additional undeveloped reserves that are less certain to be recovered than proved undeveloped reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable undeveloped reserves. The majority of the Trust's current probable undeveloped reserves are located at Tommy Lakes and Loon Lake, and will be developed within the next three years.

Significant Factors or Uncertainties

The recovery of the Proven Undeveloped and Probable reserves will occur primarily through the drilling of additional wells into the Tommy Lakes Halfway A Gas Pool and the Loon Lake Slave Point G Oil Pool. The recovery of these reserves will be dependent on these future wells exhibiting similar performance characteristics to the existing wells drilled into the pool. In the case of Tommy Lakes, as the property is only accessible for drilling, completion and tie-in operations during the winter months, the specific timing of the development is dependent on weather conditions and access to the required equipment and services.

For 2004 approximately 56% of the Trust's production was from the Tommy Lakes area. All of this production is processed through the Jedney #2 Gas Plant owned and operated by Westcoast Gas Services Inc. Any disruption to the operation of the Jedney #2 Plant would have a significant impact on the production volumes of the Trust.

Future Development Costs

The following table sets forth development costs deducted in the estimation of Focus' future net revenue attributable to the reserve categories noted below.

Year	Forecast Prices and Costs				Constant Prices and Costs			
	Proved Reserves		Proved Plus Probable Reserves		Proved Reserves		Proved Plus Probable Reserves	
	0%	10%	0%	10%	0%	10%	0%	10%
2005	25,183	24,011	26,760	25,515	25,151	23,981	26,706	25,463
2006	20,503	17,772	21,345	18,502	20,049	17,378	20,859	18,080
2007	1,652	1,302	15,516	12,226	1,557	1,227	14,865	11,713
Thereafter	184	90	184	90	157	77	157	77
Total	47,522	43,175	63,805	56,333	46,914	42,662	62,587	55,334

The Trust expects that the future development costs outlined above will be funded through internally-generated cash flow. As a result, there will be no cost of funding and no impact on reserves or future net revenue.

Other Oil and Gas Information

Oil And Gas Wells

The following table sets forth the number and status of wells in which Focus has a working interest as at December 31, 2004.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	194.0	84.8	42.0	17.7	90.0	69.6	10.0	7.7
British Columbia	0.0	0.0	0.0	0.0	88.0	81.6	13.0	10.3
Total	194.0	84.8	42.0	17.7	178.0	151.2	23.0	18.0

Properties with no Attributable Reserves

The following table sets out Focus' undeveloped land holdings as at December 31, 2004.

	Undeveloped Acres	
	Gross	Net
Alberta	16,729	11,645
British Columbia	18,027	15,231
Total	34,756	26,876

Focus expects that rights to explore, develop and exploit 64 net acres of its undeveloped land holdings will expire by December 31, 2005.

Additional Information Concerning Abandonment and Reclamation Costs

The Trust estimates abandonment and reclamation costs for surface leases, wells, facilities and pipelines based primarily on a review of current costs for abandonment and reclamation of similar entities. The Trust expects to incur abandonment and reclamation costs for 272 net wells. The total estimated amount of such costs, net of estimated salvage value is $9.0 million on an undiscounted basis, or $2.6 million at a discount rate of 10%. Only well level abandonment costs were included in the determination of discounted future net revenue presented above. For the constant price case, at a discount rate of 10%, $1.6 million of costs were included and $0.2 million of costs were excluded. For the escalating price case, at a discount rate of 10%, $2.3 million of costs were included and $0.3 million of costs were excluded. The Trust expects to incur abandonment and reclamation costs of $0.2 million in 2005, $0.2 million in 2005 and $0.2 million in 2006.

Capital Expenditures

The following tables summarize capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to Focus' activities for the year ended December 31, 2004:

	($ millions)
Property acquisition costs	
Proved properties	$129.7
Development costs	$25.2
Total	$154.9

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which Focus participated during the year ended December 31, 2004:

	Gross	Net
Light and Medium Oil	1	0.5
Natural Gas	22	13.3
Service	0	0.0
Dry	1	0.8
Total:	24	14.6

The Trust's most important current and likely development activities are concentrated at Tommy Lakes and Loon Lake. At Tommy Lakes the Trust will continue to develop the Halfway A gas pool, and anticipates drilling approximately 10 gross wells per year into the pool in each of the next three winter drilling seasons. At Loon Lake, development activity is primarily focused on the Slave Point G oil pool, into which the Trust anticipates drilling approximately 6 to 8 gross wells per year in each of the next three years.

Production Estimates

The following table sets out the volume of Focus' production estimated for the year ended December 31, 2005 which is reflected in the estimate of future net revenue disclosed in the tables contained under "Disclosure of Reserves Data".

	Light and Medium Oil *(bbls/d)*	Natural Gas *(Mcf/d)*	Natural Gas Liquids *(bbls/d)*	BOE *(BOE/d)*
2005	1,744	48,767	824	10,696

Forecast 2005 production for the Tommy Lakes property is 6,130 boe/d, consisting of 32,663 Mcf/d of natural gas and 686 Bbl/d of natural gas liquids. This represents approximately 57% of total 2005 forecast production.

Production History, Prices Received And Capital Expenditures

The following tables set forth certain information in respect of production, product prices received, royalties, operating expenses, netbacks received, and capital expenditures made by Focus for each quarter in the two most recently completed financial years of Focus. In calculating BOE amounts, natural gas is converted to oil equivalent using 6 Mcf of natural gas equalling 1 barrel of oil equivalent.

	Quarters Ended			
	2004			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production[1]				
Light and Medium Crude Oil (bbls/d)	1,903	1,932	2,027	2,122
Gas (Mcf/d)	43,080	44,903	50,913	31,902
NGLs (bbls/d)	724	776	703	472
Combined (BOE/d)	9,807	10,191	11,215	7,911
Average Price Received (including hedging settlements)				
Light and Medium Crude Oil ($/Bbl)	41.28	40.79	40.07	39.66
Gas ($/Mcf)	6.64	6.01	6.41	6.65
NGLs ($/bbl)	48.48	45.48	39.62	39.59
Combined ($/BOE)	40.82	37.72	38.85	39.92
Royalties Paid				
Light and Medium Crude Oil ($/Bbl)	11.55	12.11	10.27	9.32
Gas ($/Mcf)	1.47	1.44	1.59	1.81
NGLs ($/Bbl)	11.26	9.10	7.85	9.09
Combined ($/BOE)	9.36	9.22	9.45	10.20
Operating Expenses ($/BOE)	3.76	3.31	2.52	3.78
Netback Received ($/BOE) [2]	27.71	25.19	26.88	25.94
Capital Expenditures ($ thousands)	12,516	20,106	110,802	11,431
Development (including drilling and facilities)	11,320	1,502	830	11,392
Corporate	6	26	27	54
Property Acquisitions, net of proceeds of divestitures	1,190	18,578	109,945	(15)

Notes:

(1) Before deduction of royalties.

(2) Netbacks are calculated by subtracting royalties and operating costs from revenues.

	Quarters Ended 2003 Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production[1]				
Light and Medium Crude Oil (bbls/d)	2,278	2,336	2,361	2,444
Gas (Mcf/d)	32,475	33,593	36,815	34,158
NGLs (bbls/d)	460	508	501	471
Combined (BOE/d)	8,151	8,443	8,997	8,608
Average Price Received (including hedging settlements)				
Light and Medium Crude Oil ($/Bbl)	37.20	39.07	40.64	45.84
Gas ($/Mcf)	5.78	4.97	5.60	5.83
NGLs ($/bbl)	29.66	34.18	30.78	42.59
Combined ($/BOE)	35.12	32.65	35.31	38.49
Royalties Paid				
Light and Medium Crude Oil ($/Bbl)	8.26	8.97	10.00	12.85
Gas ($/Mcf)	1.45	1.46	1.64	2.06
NGLs ($/Bbl)	8.86	7.00	7.35	10.31
Combined ($/BOE)	8.48	8.63	9.65	12.31
Operating Expenses ($/BOE)	3.70	3.51	3.04	3.36
Netback Received ($/BOE) [2]	22.94	20.51	22.62	22.82
Capital Expenditures ($ thousands)	4,750	22,858	62	9,355
Exploration (including drilling)	4,731	2,742	(90)	9,206
Development	19	54	139	7
Property Acquisitions, net of proceeds of divestitures	-	20,062	13	142

Notes:
(1) Before deduction of royalties.
(2) Netbacks are calculated by subtracting royalties and operating costs from revenues.

The following table indicates Focus' average daily gross production from its important fields for the year ended December 31, 2004:

	Light and Medium Crude Oil (bbls/d)	Gas (Mcf/d)	NGLS (bbls/d)	BOE (BOE/d)
Tommy Lakes	-	29,391	569	5,468
Kotcho-Cabin	-	8,156	-	1,359
Red Earth	1,453	-	-	1,453
Loon Lake	460	-	-	460
Pouce Coupe	9	2,865	20	506
Sylvan Lake	74	1,679	80	434
Medicine Hat	-	615	-	102
Total	1,996	42,706	669	9,782

Cyclical and Seasonal Impact of Industry

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 supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas producing regions. Any decline in oil and natural gas prices could have an adverse effect on the Trust's financial condition.

Renegotiation or Termination of Contracts

As at the date hereof, the Trust does not anticipate that any aspect of its business will be materially affected in the current fiscal year by the renegotiation or termination of contracts or subcontracts.

Competitive Conditions

The Trust is a member of the petroleum industry, which is highly competitive at all levels. The Trust competes with other companies and other energy trusts and income funds for all of its business inputs, including exploitation and development prospects, access to commodity markets, property and corporate acquisitions, and available capital. The Trust strives to be competitive by maintaining a strong financial condition and by utilizing current technologies to enhance exploitation, development and operational activities.

Environmental Considerations

The Trust is pro-active in its approach to environmental concerns. Procedures are in place to ensure that due care is taken in the day-to-day management of its oil and gas properties. All government regulations and procedures are followed in strict adherence to the law. The Trust believes in well abandonment and site restoration in a timely manner to ensure minimal damage to the environment and lower overall costs to the Trust.

In the first quarter of 2004, Focus adopted the CICA new section 3110, Asset Retirement Obligations. This new standard requires that companies recognize the liability associated with future site reclamation costs in the financial statements at the time when the liability is incurred. This liability is initially measured at fair market and subsequently adjusted for the accretion of the discount amount and any changes in the underlying cash flows. The asset retirement cost is capitalized to the related asset and amortized into earnings over time. Further information is provided in the audited consolidated financial statements of the Trust for the year ended December 31, 2004 which are included in the Trust's 2004 Annual Report.

The Trust has established a reclamation fund for the purpose of funding estimated future environmental and reclamation obligations. The funding related to the operations of the Trust was $1.9 million at December 31, 2004.

Marketing and Future Commitments

Focus utilizes a hedging program to manage exposure to fluctuations in commodity prices, to provide greater certainty and stability to distributions, to protect Unitholder return on investment and to help ensure profitability of specific properties or acquisitions. This program is monitored by the Board of Directors and implemented by the Risk Management Committee. Focus uses financial instruments and physical forward sales as part of this risk management program. All of the commodity and foreign exchange contracts are with parties that represent minimal counterparty risk.

Focus, as of February 28, 2005, has a combination of fixed price arrangements and collars that provide price protection in 2005 on an average 25,247 Mcf per day of natural gas production at a reference price of CDN$7.92 per Mcf. With respect to crude oil, fixed price swaps and collars represent 1,100 bbls per day of oil production with a reference price of CDN$50.31 per barrel. The following table details financial instruments and physical contracts currently in place as part of the Trust's hedging program for 2005 and 2006.

Financial Contracts	Daily Quantity	Contract Price		Price Index	Term
Crude oil - fixed price & collars	400bbls	$ 49.61	Cdn	WTI	January 2005 – December 2005
	400 bbls	$ 49.50	Cdn	WTI	January 2005 – December 2005
	400 bbls	$52.00 – 58.40	Cdn	WTI	January 2005 – March 2005
	400 bbls	$52.00 – 56.15	Cdn	WTI	April 2005 – June 2005
	400 bbls	$53.00 – 60.00	Cdn	WTI	July 2005 – September 2005
Natural gas - collar	5,000 GJs	$5.85 – 6.95	Cdn	AECO	April 2005 – October 2005

Physical Contracts	Daily Quantity	Contract Price		Term
Natural gas – fixed price	26,500 GJ	$7.25	Cdn	November 2004 – March 2005
	5,275GJ	$7.00	Cdn	November 2004 – October 2005
	5,000 GJ	$6.36	Cdn	April 2005 – October 2005
	7,000 GJ	$8.77	Cdn	January 2005
	15,500 GJ	$7.01	Cdn	April 2005 – October 2005
	7,000 GJ	$7.25	Cdn	November 2005 – March 2006
	7,000 GJ	$7.62	Cdn	November 2005 – March 2006

Human Resources

As at March 4, 2005, FET Resources had 41 permanent, full time employees in the field and in the corporate head office.

ADDITIONAL INFORMATION RESPECTING FOCUS ENERGY TRUST

Trust Units

An unlimited number of Trust Units may be created and issued pursuant to the Trust Indenture. Each Trust Unit shall entitle the holder thereof to one vote at any meeting of the holders of Trust Units and represents an equal fractional undivided beneficial interest in any distribution from the Trust (whether of net income, net realized capital gains or other amounts) and in any net assets of the Trust in the event of termination or winding-up of the Trust. All Trust Units outstanding from time to time shall be entitled to equal shares of any distributions by the Trust, and in the event of termination or winding-up of the Trust, in any net assets of the Trust. All Trust Units shall rank among themselves equally and rateably without discrimination, preference or priority. Each Trust Unit is transferable, is not subject to any conversion or pre-emptive rights and entitles the holder thereof to require the Trust to redeem any or all of the Trust Units held by such holder (see "Redemption Right") and to one vote at all meetings of Trust Unitholders for each Trust Unit held.

The Trust Units do not represent a traditional investment and should not be viewed by investors as "shares" in either FET Resources or the Trust. As holders of Trust Units in the Trust, the Trust Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring "oppression" or "derivative" actions. The price per Trust Unit will be a function of anticipated distributable income from FET Resources and the ability of FET Resources to effect long term growth in the value of the Trust. The market price of the Trust Units will be sensitive to a variety of market conditions including, but not limited to, interest rates, commodity prices and the ability of the Trust to acquire additional assets. Changes in market conditions may adversely affect the trading price of the Trust Units.

The Trust Units are not "deposits" within the meaning of the *Canada Deposit Insurance Corporation Act* (Canada) and are not insured under the provisions of that Act or any other legislation. Furthermore, the Trust is not a trust company and, accordingly, is not registered under any trust and loan company legislation as it does not carry on or intend to carry on the business of a trust company.

Special Voting Rights

In order to allow the Trust flexibility in pursuing corporate acquisitions, the Trust Indenture allows for the creation of Special Voting Rights which will enable the Trust to provide voting rights to holders of Exchangeable Shares and, in the future, to holders of other exchangeable shares that may be issued by FET Resources or other subsidiaries of the Trust in connection with other exchangeable share transactions.

An unlimited number of Special Voting Rights may be created and issued pursuant to the Trust Indenture. Holders of Special Voting Rights shall not be entitled to any distributions of any nature whatsoever from the Trust and shall be entitled to such number of votes at meetings of Trust Unitholders as may be prescribed by the Board of Directors in the resolution authorizing the issuance of any Special Voting Rights. Except for the right to vote at meeting of the Trust Unitholders, the Special Voting Rights shall not confer upon the holders thereof any other rights.

Under the terms of the Voting and Exchange Trust Agreement, the Trust will issue a Special Voting Right to the Voting and Exchange Trust Agreement Trustee for the benefit of every Person who received Exchangeable Shares pursuant to the Arrangement.

Trust Unitholder Limited Liability

The Trust Indenture provides that no Trust Unitholder will be subject to any liability in connection with our obligations and affairs and, in the event that a court determines Trust Unitholders are subject to any such liabilities, the liabilities will be enforceable only against, and will be satisfied only out of our assets. Pursuant to the Trust Indenture, we will indemnify and hold harmless each Trust Unitholder from any costs, damages, liabilities, expenses, charges and losses suffered by a Trust Unitholder resulting from or arising out of such Trust Unitholder not having such limited liability.

The Trust Indenture provides that all written instruments signed by or on our behalf must contain a provision to the effect that such obligation will not be binding upon Trust Unitholders personally. Personal liability may also arise in respect of claims against us that do not arise under contracts, including claims in tort, claims for taxes and possibly certain other statutory liabilities. The possibility of any personal liability of this nature arising is considered unlikely. The *Income Trusts Liability Act* (Alberta) came into force on July 1, 2004. The legislation provides that a Trust Unitholder will not be, as a beneficiary, liable for any act, default, obligation or liability of the trustee that arises after the legislation came into force. For additional information see "Risk Factors – Unitholder Limited Liability".

Our operations will be conducted, upon the advice of counsel, in such a way and in such jurisdictions as to avoid as far as possible any material risk of liability on the Trust Unitholders for claims against us.

Issuance of Trust Units

The Trust Indenture provides that Trust Units, including rights, warrants and other securities to purchase, to convert into or to exchange into Trust Units, may be created, issued, sold and delivered on such terms and conditions and at such times as the Trustee, upon the recommendation of the Board of Directors may determine. The Trust Indenture also provides that FET Resources may authorize the creation and issuance of debentures, notes and other evidences of indebtedness of the Trust which debentures, notes or other evidences of indebtedness may be created and issued from time to time on such terms and conditions to such persons and for such consideration as FET Resources may determine.

Cash Distributions

The Trustee may declare payable to the Unitholders all or any part of the net income of the Trust earned from interest income on the Notes, income generated under the NPI Agreement, interest income on the promissory note issued by Focus B.C. Trust and distributions made by Focus BC, less all expenses and liabilities of the Trust due and accrued and which are chargeable to the net income of the Trust. In addition, Trust Unitholders may, at the discretion of the Board of Directors, receive distributions in respect of prepayments of principal on the Notes made by FET Resources to the Trust before the maturity of the Notes. It is anticipated however, that the Trust will reinvest a substantial portion of the repayments of principal on the Notes to make capital expenditures to develop the business of FET Resources with a view to enhancing FET Resources' cash flow from operations.

It is expected that essentially all of the cash distributions to Trust Unitholders will be taxed as ordinary income. Cash distributions have been made, and are expected to be made on the 15th day of each month to Trust Unitholders of record on the immediately preceding Distribution Record Date.

Redemption Right

Trust Units are redeemable at any time on demand by the holders thereof upon delivery to the Trust of the certificate or certificates representing such Trust Units, accompanied by a duly completed and properly executed notice requiring redemption. Upon receipt of the notice to redeem Trust Units by the Trust, the holder thereof shall only be entitled to receive a price per Trust Unit (the "Market Redemption Price") equal to the lesser of: (i) 90% of the "market price" of the Trust Units on the principal market on which the Trust Units are quoted for trading during the 10 trading day period commencing immediately after the date on which the Trust Units are tendered to the Trust for redemption; and (ii) the closing market price on the principal market on which the Trust Units are quoted for trading on the date that the Trust Units are so tendered for redemption.

For the purposes of this calculation, "market price" will be an amount equal to the simple average of the closing price of the Trust Units for each of the trading days on which there was a closing price; provided that, if the applicable exchange or market does not provide a closing price but only provides the highest and lowest prices of the Trust Units traded on a particular day, the market price shall be an amount equal to the simple average of the average of the highest and lowest prices for each of the trading days on which there was a trade; and provided further that if there was trading on the applicable exchange or market for fewer than five of the 10 trading days, the market price shall be the simple average of the following prices established for each of the 10 trading days: the average of the last bid and last ask prices for each day on which there was no trading; the closing price of the Trust Units for each day that there was trading if the exchange or market provides a closing price; and the average of the highest and lowest prices of the Trust Units for each day that there was trading, if the market provides only the highest and lowest prices of Trust Units traded on a particular day. The closing market price shall be: an amount equal to the closing price of the Trust Units if there was a trade on the date; an amount equal to the average of the highest and lowest prices of the Trust Units if there was trading and the exchange or other market provides only the highest and lowest prices of Trust Units traded on a particular day; and the average of the last bid and last ask prices if there was no trading on the date.

The aggregate Market Redemption Price payable by the Trust in respect of any Trust Units surrendered for redemption during any calendar month shall be satisfied by way of a cash payment on the last day of the following month. The entitlement of Trust Unitholders to receive cash upon the redemption of their Trust Units is subject to the limitation that the total amount payable by the Trust in respect of such Trust Units and all other Trust Units tendered for redemption in the same calendar month and in any preceding calendar month during the same year shall not exceed $250,000; provided that, the Trust may, in its sole discretion, waive such limitation in respect of any calendar month. If this limitation is not so waived, the Market Redemption Price payable by the Trust in respect of Trust Units tendered for redemption in such calendar month shall be paid on the last day of the following month as follows: (i) firstly, by the Trust distributing Notes having an aggregate principal amount equal to the aggregate Market Redemption Price of the Trust Units tendered for redemption, and (ii) secondly, to the extent that the Trust does not hold Notes having a sufficient principal amount outstanding to effect such payment, by the Trust issuing its own promissory notes to the Unitholders who exercised the right of redemption having an aggregate principal amount equal to any such shortfall, which promissory notes, (herein referred to as "Redemption Notes") shall have terms and conditions substantially identical to those of the Notes.

If at the time Trust Units are tendered for redemption by a Trust Unitholder, the outstanding Trust Units are not listed for trading on the TSX and are not traded or quoted on any other stock exchange or market which FET Resources considers, in its sole discretion, provides representative fair market value price for the Trust Units or trading of the outstanding Trust Units is suspended or halted on any stock exchange on which the Trust Units are listed for trading or, if not so listed, on any market on which the Trust Units are quoted for trading, on the date such Trust Units are tendered for redemption or for more than five trading days during the 10 trading day period, commencing immediately after the date such Trust Units were tendered for redemption then such Trust Unitholder shall, instead of the Market Redemption Price, be entitled to receive a price per Trust Unit (the "Appraised Redemption Price") equal to 90% of the fair market value thereof as determined by FET Resources as at the date on which such Trust Units were tendered for redemption. The aggregate Appraised Redemption Price payable by the Trust in respect of Trust Units tendered for redemption in any calendar month shall be paid on the last day of the third following month by, at the option of the Trust: (i) a cash payment; or (ii) a distribution of Notes and/or Redemption Notes as described above.

It is anticipated that this redemption right will not be the primary mechanism for holders of Trust Units to dispose of their Trust Units. Notes or Redemption Notes which may be distributed in specie to Trust Unitholders in connection with a redemption will not be listed on any stock exchange and no market is expected to develop in such Notes or Redemption Notes. Notes or Redemption Notes may not be qualified investments for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans.

Meetings of Trust Unitholders

The Trust Indenture provides that meetings of Trust Unitholders must be called and held for, among other matters, the election or removal of the Trustee, the appointment or removal of the auditors of the Trust, the approval of amendments to the Trust Indenture (except as described under "Amendments to the Trust Indenture"), the sale of the property of the Trust as an entirety or substantially as an entirety, and the commencement of winding-up the affairs of the Trust. Meetings of Trust Unitholders will be called and held annually for, among other things, the election of the directors of FET Resources and the appointment of the auditors of the Trust.

A meeting of Trust Unitholders may be convened at any time and for any purpose by the Trustee and must be convened, except in certain circumstances, if requisitioned by the holders of not less than 5% of the Trust Units then outstanding by a written requisition. A requisition must, among other things, state in reasonable detail the business purpose for which the meeting is to be called. Trust Unitholders may attend and vote at all meetings of Trust Unitholders either in person or by proxy and a proxyholder need not be a Trust Unitholder. Two persons present in person or represented by proxy and representing in the aggregate at least 5% of the votes attaching to all outstanding Trust Units shall constitute a quorum for the transaction of business at all such meetings. For the purposes of determining such quorum, the holders of any issued Special Voting Rights who are present at the meeting shall be regarded as representing outstanding Trust Units equivalent in number to the votes attaching to such Special Voting Rights.

The Trust Indenture contains provisions as to the notice required and other procedures with respect to the calling and holding of meetings of Trust Unitholders in accordance with the requirements of applicable laws.

Reporting to Trust Unitholders

The financial statements of the Trust will be audited annually by an independent recognized firm of chartered accountants. The audited financial statements of the Trust, together with the report of such chartered accountants, will be mailed by the Trustee to Trust Unitholders and the unaudited interim financial statements of the Trust will be mailed to Trust Unitholders within the periods prescribed by securities legislation. The year end of the Trust is December 31.

The Trust is subject to the continuous disclosure obligations under all applicable securities legislation.

Takeover Bids

The Trust Indenture contains provisions to the effect that if a takeover bid is made for the Trust Units and not less than 90% of the Trust Units (other than Trust Units held at the date of the takeover bid by or on behalf of the offeror or associates or affiliates of the offeror) are taken up and paid for by the offeror, the offeror will be entitled to acquire the Trust Units held by Trust Unitholders who did not accept the takeover bid on the terms offered by the offeror.

The Trustee

Valiant Trust Company is the trustee of the Trust. The Trustee is responsible for, among other things, accepting subscriptions for Trust Units and issuing Trust Units pursuant thereto and maintaining the books and records of the Trust and providing timely reports to holders of Trust Units. The Trust Indenture provides that the Trustee shall exercise its powers and carry out its functions thereunder as Trustee honestly, in good faith and in the best interests of the Trust and the Trust Unitholders and, in connection therewith, shall exercise that degree of care, diligence and skill that a reasonably prudent trustee would exercise in comparable circumstances.

The initial term of the Trustee's appointment is until the third annual meeting of Trust Unitholders. The Unitholders shall, at the third annual meeting of the Unitholders, re-appoint, or appoint a successor to the Trustee for an additional three year term, and thereafter, the Unitholders shall reappoint or appoint a successor to the Trustee at the annual meeting of Unitholders three years following the reappointment or appointment of the successor to the Trust. The Trustee may also be removed by Special Resolution of the Trust Unitholders. Such resignation or removal becomes effective upon the acceptance or appointment of a successor trustee.

Delegation of Authority, Administration and Trust Governance

The Board of Directors of FET Resources has generally been delegated the significant management decisions of the Trust. In particular, the Trustee has delegated to FET Resources responsibility for any and all matters relating to the following: (i) an offering; (ii) ensuring compliance with all applicable laws, including in relation to an offering; (iii) all matters relating to the content of any offering documents, the accuracy of the disclosure contained therein, and the certification thereof; (iv) all matters concerning the terms of, and amendment from time to time of the material contracts of the Trust; (v) all matters concerning any underwriting or agency agreement providing for the sale of Trust Units or rights to Trust Units; (vi) all matters relating to the redemption of Trust Units; (vii) all matters relating to the voting rights on any investments in the Trust Fund or any Subsequent Investments; (viii) all matters relating to the specific powers and authorities as set forth in the Trust Indenture.

Liability of the Trustee

The Trustee, its directors, officers, employees, shareholders and agents shall not be liable to any Trust Unitholder or any other person, in tort, contract or otherwise, in connection with any matter pertaining to the Trust or the property of the Trust, arising from the exercise by the Trustee of any powers, authorities or discretion conferred under the Trust Indenture, including, without limitation, any action taken or not taken in good faith in reliance on any documents that are, prima facie, properly executed, any depreciation of, or loss to, the property of the Trust incurred by reason of the sale of any asset, any inaccuracy in any evaluation provided by any other appropriately qualified person, any reliance on any such evaluation, any action or failure to act of FET Resources, or any other person to whom the Trustee has, with the consent of FET Resources, delegated any of its duties hereunder, or any other action or failure to act (including failure to compel in any way any former trustee to redress any breach of trust or any failure by FET Resources to perform its duties under or delegated to it under the Trust Indenture or any other contract), unless such liabilities arise out of the gross negligence, wilful default or fraud of the Trustee or any of its directors, officers, employees or shareholders. If the Trustee has retained an appropriate expert, adviser or legal counsel with respect to any matter connected with its duties under the Trust Indenture, the Trustee may act or refuse to act based on the advice of such expert, adviser or legal counsel, and the Trustee shall not be liable for and shall be fully protected from any loss or liability occasioned by any action or refusal to act based on the advice of any such expert, adviser or legal counsel. In the exercise of the powers, authorities or discretion conferred upon the Trustee under the Trust Indenture, the Trustee is and shall be conclusively deemed to be acting as Trustee of the assets of the Trust and shall not be subject to any personal liability for any debts, liabilities, obligations, claims, demands, judgments, costs, charges or expenses against or with respect to the Trust or the property of the Trust. In addition, the Trust Indenture contains other customary provisions limiting the liability of the Trustee.

Amendments to the Trust Indenture

The Trust Indenture may be amended or altered from time to time by Special Resolution.

The Trustee may, without the approval of any of the Trust Unitholders, amend the Trust Indenture for the purpose of:

- ensuring the Trust's continuing compliance with applicable laws or requirements of any governmental agency or authority of Canada or of any province;
- ensuring that the Trust will satisfy the provisions of each of subsections 108(2) and 132(96) of the Tax Act as from time to time amended or replaced;
- ensuring that such additional protection is provided for the interests of Trust Unitholders as the Trustee may consider expedient;
- removing or curing any conflicts or inconsistencies between the provisions of the Trust Indenture or any supplemental indenture and any other agreement of the Trust or any offering document pursuant to which securities of the Trust are issued with respect to the Trust, or any applicable law or regulation of any jurisdiction, provided that in the opinion of the Trustee the rights of the Trustee and of the Trust Unitholders are not prejudiced thereby; and
- curing, correcting or rectifying any ambiguities, defective or inconsistent provisions, errors, mistakes or omissions, provided that in the opinion of the Trustee the rights of the Trustee and of the Trust Unitholders are not prejudiced thereby.

Termination of the Trust

The Trust Unitholders may vote to terminate the Trust at any meeting of the Trust Unitholders duly called for that purpose, subject to the following: (a) a vote may only be held if requested in writing by the holders of not less than 20% outstanding Trust Units; (b) a quorum of 50% of the issued and outstanding Trust Units is present in person or by proxy; and (c) the termination must be approved by Special Resolution of Trust Unitholders.

Unless the Trust is earlier terminated or extended by vote of the Trust Unitholders, the Trustee shall commence to wind-up the affairs of the Trust on December 31, 2099. In the event that the Trust is wound-up, the Trustee will sell and convert into money the property of the Trust in one transaction or in a series of transactions at public or private sale and do all other acts appropriate to liquidate the property of the Trust, and shall in all respects act in accordance with the directions, if any, of the Trust Unitholders in respect of termination authorized pursuant to the Special Resolution authorizing the termination of the Trust. After paying, retiring or discharging or making provision for payment, retirement or discharge of all known liabilities and obligations of the Trust, and providing for indemnity against any other outstanding liabilities and obligations, the Trustee shall distribute the remaining part of the proceeds of the sale of the assets together with any cash forming part of the property of the Trust among the Trust Unitholders in accordance with their pro rata share.

ADDITIONAL INFORMATION RESPECTING FET RESOURCES LTD.

Management of FET Resources

The Board of Directors is currently comprised of the six members indicated below. Each director is elected or appointed to serve until the next annual meeting of the Trust Unitholders or until a successor is elected or appointed.

The following table sets forth certain information respecting FET Resources' directors:

Name and Municipality of Residence	Position Held and Period Served as a Director	Principal Occupations During Past Five Years	Trust Units / Exchangeable Shares Beneficially Owned or over which Control or Discretion is Exercised as at March 15, 2005
Derek W. Evans Calgary, Alberta	President, Chief Executive Officer and Director since August 23, 2002	President and Chief Executive Officer of FET Resources since August 23, 2002; Prior thereto, from May 2001 to August 2002, Mr. Evans was Vice President, Business Development for Storm, and from July 1998 to September 2000, Mr. Evans was Senior Vice President, Operations of Renaissance Energy Ltd.	37,753 / 72,992
Matthew J. Brister(3)(4)(5) Calgary, Alberta	Director since August 23, 2002	Independent Businessman; Prior thereto, Mr. Brister was President and Chief Executive Officer of Storm Energy Ltd. and prior thereto, Mr. Brister was the President and Chief Executive Officer of Storm Energy Inc.	1,948,179 / nil
John A. Brussa(4) Calgary, Alberta	Director since August 23, 2002	Senior Partner at Burnet, Duckworth & Palmer, LLP.	nil / nil
Stuart G. Clark (1)(2) Calgary, Alberta	Chairman since January 9, 2003 and a Director since August 23, 2002	Independent Businessman; Prior thereto, Mr. Clark was the Senior Vice President, Finance and Chief Financial Officer of Storm Energy Inc. Mr. Clark serves on the Board of Directors of Storm Exploration Inc. and Rock Energy Inc.	982,611 / 12,000
James H. McKelvie (2)(4) Toronto, Ontario	Director since June 19, 2003	Independent Businessman; Prior thereto, Mr. McKelvie was Chief Financial Officer of Energy Savings Income Fund	14,865 / nil
Gerry A. Romanzin(2)(3)(5) Calgary, Alberta	Director since August 23, 2002	Independent Businessman; Prior thereto, Executive Vice president of TSX Venture Exchange from November 1999 to April 2002 and acting President of TSX Venture Exchange from December 2001 to April 2002; and prior thereto, Executive Vice president of Alberta Stock Exchange from June 1995 to November 1999.	nil / nil

Notes:

(1) Chairman
(2) Member of the Audit Committee.
(3) Member of the Reserves Committee.
(4) Member of the Compensation Committee.
(5) Member of the Corporate Governance Committee.

The following table sets forth certain information respecting FET Resources' officers who are not directors:

Name and Municipality of Residence	Position Held and Period Served as a Director	Principal Occupations During Past Five Years	Trust Units / Exchangeable Shares Beneficially Owned or over which Control or Discretion is Exercised as at March 15, 2005
William D. Ostlund Calgary, Alberta	Vice-President, Finance and Chief Financial Officer	Vice-President Finance and Chief Financial Officer of FET Resources since August 23, 2002; Prior thereto, Mr. Ostlund was Vice President, Finance and Chief Financial Officer for Reserve Royalty Corporation form June 1997 to July 2000.	41,134 / 6,655
Dennis M. Lawrence Calgary, Alberta	Vice President, Engineering	Vice President, Engineering of FET Resources since September 2002; Prior thereto, Mr. Lawrence was a Research Analyst for FirstEnergy Capital Corp. from October 2000 to August 2002.	28,355 / 2,000
Bryce H. Murdoch Calgary, Alberta	Vice President, Geology	Vice President, Geology of FET Resources since October 2003; Prior thereto, Mr. Murdoch was Geology Manager in the Southern Alberta and Southern Saskatchewan and the Lloydminister Business Units at Husky Energy from August 2000 to September 2003.	7,593 / nil
Al S. Pickering Calgary, Alberta	Vice President, Land	Vice President, Land of FET Resources since June 2003; Prior thereto, Mr. Pickering was an independent land consultant, and a Land Manager with Renaissance Energy Ltd. from January 1997 to August 2000.	15,449 / nil
David W. Sakal Calgary, Alberta	Vice President, Operations	Vice President, Operations of FET Resources since August 2002; Prior thereto, Mr. Sakal was General Manager for Husky Energy Inc. East Central Business Unit from August 2000 to February 2001 and from July 1998 to August 2000, Mr. Sakal was Operating Manager for the Central District of Renaissance Energy Ltd.	22,355 / 36,496

The percentage of Trust Units of the Trust that are owned, directly or indirectly, by all directors and officers of FET Resources as a group is 8.5% (3,098,294 Trust Units). The percentage of Exchangeable Shares of the Trust that are owned, directly or indirectly, by all directors and officers of FET Resources as a group is 16.5% (130,143 Exchangeable Shares). Based upon the exchange ratio of 1.30129 in effect on March 15, 2005, directors and officers of FET Resources as a group owned, directly or indirectly, securities of the Trust equivalent to 3,252,783 units or 8.7% of the outstanding Trust Units and Exchangeable Shares of FET Resources..

Corporate Cease Trade Orders or Bankruptcies

No director, officer or promoter of the Corporation has, within the last 10 years, been a director, officer or promoter of any reporting issuer that, while such person was acting in that capacity, was the subject of a cease trade or similar order or an order that denied the company access to any statutory exemption for a period of more than 30 consecutive days or was declared a bankrupt or made a voluntary assignment in bankruptcy, made a proposal under any legislation relating to bankruptcy or been subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver-manager or trustee appointed to hold the assets of that person except for Mr. John Brussa was a director of Imperial Metals Limited, a corporation engaged in both oil and gas and mining operations, in the year prior to that corporation implementing a plan of arrangement under the Company Act (British Columbia) and under the Companies' Creditors Arrangement Act (Canada) which resulted in the separation of its two businesses and the creation of two public corporations: Imperial Metals Corporation and IEI Energy Inc. (now Rider Resources Ltd.).

Penalties or Sanctions

No director, officer or promoter of the Corporation, within the last 10 years, has been subject to any penalties or sanctions imposed by a court or securities regulatory authority relating to trading in securities, promotion or management of a publicly traded issuer or theft or fraud.

Personal Bankruptcies

No director, officer or promoter of the Corporation, or a shareholder holding sufficient securities of the Corporation to affect materially the control of the Corporation, or a personal holding company of any such persons, has, within the last 10 years, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or being subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold the assets of the individual.

Conflicts of Interest

Directors and officers of the Corporation may, from to time, be involved with the business and operations of other oil and gas issuers, in which case a conflict may arise. See "Risk Factors".

Distribution Policy

FET Resources is authorized to issue an unlimited number of common shares and an unlimited number of exchangeable shares issuable in series, of which an unlimited number of Series A Exchangeable Shares (the "Exchangeable Shares") are authorized. Upon completion of the Arrangement, the Trust became the sole holder of the issued and outstanding common shares of FET Resources. The Trust is also the sole holder of the approximately $332 million principal amount of the Notes outstanding at January 31, 2005.

Common Shares

Each common share entitles its holder to receive notice of and to attend all meetings of the shareholders of FET Resources and to one vote at such meetings. The holders of common shares will be, at the discretion of the board of directors of FET Resources and subject to applicable legal restrictions, and subject to certain preferences of holders of Exchangeable Shares, entitled to receive any dividends declared by the board of directors on the common shares to the exclusion of the holders of Exchangeable Shares, subject to the proviso that no dividends shall be paid on the common shares unless all declared dividends on the outstanding Exchangeable Shares have been paid in full. The holders of common shares will be entitled to share equally in any distribution of the assets of FET Resources upon the liquidation, dissolution, bankruptcy or winding-up of FET Resources or other distribution of its assets among its shareholders for the purpose of winding-up its affairs. Such participation is subject to the rights, privileges, restrictions and conditions attaching to the Exchangeable Shares and any other shares having priority over the common shares.

Exchangeable Shares

The following is a summary description of the material provisions of the Exchangeable Shares and the related ancillary and indirect rights of holders of Exchangeable Shares under the terms of the Voting and Exchange Trust Agreement and the Support Agreement.

Each Exchangeable Share will have economic rights (including the right to have the Exchange Ratio adjusted to account for distributions paid to Unitholders) and voting attributes (through the benefit of the Special Voting Right granted to the Voting and

Exchange Trust Agreement Trustee) equivalent to those of the Trust Units into which they are exchangeable from time to time. In addition, holders of Exchangeable Shares will have the right to receive Trust Units at any time in exchange for their Exchangeable Shares, on the basis of the Exchange Ratio in effect at the time of the exchange. Fractional Trust Units will not be delivered on any exchange of Exchangeable Shares. In the event that the Exchange Ratio in effect at the time of an exchange would otherwise entitle a holder of Exchangeable Shares to a fractional Trust Unit, the number of Trust Units to be delivered will be rounded down to the nearest whole number of Trust Units. **Holders of Exchangeable Shares will not receive cash distributions from the Trust or FET Resources rather, the Exchange Ratio will be adjusted to account for distributions paid to Unitholders.**

Ranking

The Exchangeable Shares rank rateably with shares of any other series of exchangeable shares of FET Resources and prior to any common shares of FET Resources and any other shares ranking junior to the Exchangeable Shares with respect to the payment of dividends, if any, that have been declared and the distribution of assets in the event of the liquidation, dissolution or winding-up of FET Resources.

Dividends

Holders of Exchangeable Shares will be entitled to receive cash dividends if, as and when declared by the board of directors of FET Resources. FET Resources anticipates that it may from time to time declare dividends on the Exchangeable Shares up to but not exceeding any cash distributions on the Trust Units into which such Exchangeable Shares are exchangeable. In the event that any such dividends are paid, the Exchange Ratio will be correspondingly reduced to reflect such dividends.

Certain Restrictions

FET Resources will not, without obtaining the approval of the holders of the Exchangeable Shares as set forth below under the subheading "Amendment and Approval":

(a) pay any dividend on the common shares of FET Resources or any other shares ranking junior to the common shares, other than stock dividends payable in common shares or any other shares ranking junior to the Exchangeable Shares;

(b) redeem, purchase or make any capital distribution in respect of the common shares of FET Resources or any other shares ranking junior to the Exchangeable Shares;

(c) redeem or purchase any other shares of FET Resources ranking equally with the Exchangeable Shares with respect to the payment of dividends or on any liquidation distribution; or

(d) amend the articles or by-laws of FET Resources in any manner that would affect the rights or privileges of the holders of Exchangeable Shares.

The above restrictions shall not apply if all declared dividends on the outstanding Exchangeable Shares shall have been paid in full.

Liquidation or Insolvency of FET Resources

In the event of the liquidation, dissolution or winding-up of FET Resources or any other proposed distribution of the assets of FET Resources among its shareholders for the purpose of winding up its affairs, a holder of Exchangeable Shares will be entitled to receive from FET Resources, in respect of each such Exchangeable Share, that number of Trust Units equal to the Exchange Ratio as at the effective date of such event.

Upon the occurrence of such an event, the Trust and Trust Subsidiary will each have the overriding right to purchase all but not less than all of the Exchangeable Shares then outstanding (other than Exchangeable Shares held by the Trust or any subsidiary of the Trust) at a purchase price per Exchangeable Share to be satisfied by the issuance or delivery, as the case may be, of that number of Trust Units equal to the Exchange Ratio at such time and, upon the exercise of this right, the holders thereof will be obligated to sell such Exchangeable Shares to the Trust or Trust Subsidiary, as applicable. This right may be exercised by either the Trust or Trust Subsidiary.

Upon the occurrence of an Insolvency Event, the Voting and Exchange Trust Agreement Trustee on behalf of the holders of the Exchangeable Shares will have the right to require the Trust or Trust Subsidiary to purchase any or all of the Exchangeable Shares then outstanding and held by such holders at a purchase price per Exchangeable Share to be satisfied by the issuance or delivery, as the case may be, of that number of Trust Units equal to the Exchange Ratio at such time, as described under the subheading "Voting and Exchange Trust Agreement - Optional Exchange Right".

Automatic Exchange Right on Liquidation of the Trust

The Voting and Exchange Trust Agreement provides that in the event of a Trust liquidation event, as described below, the Trust or Trust Subsidiary will be deemed to have purchased all outstanding Exchangeable Shares and each holder of Exchangeable Shares will be deemed to have sold their Exchangeable Shares immediately prior to such Trust liquidation event at a purchase price per Exchangeable Share to be satisfied by the issuance or delivery, as the case may be, of that number of Trust Units equal to the Exchange Ratio at such time. "Trust liquidation event" means:

- any determination by the Trust to institute voluntary liquidation, dissolution or winding-up proceedings in respect of the Trust or to effect any other distribution of assets of the Trust among the Unitholders for the purpose of winding up its affairs; or

- the earlier of, the Trust's receiving notice of and the Trust's otherwise becoming aware of, any threatened or instituted claim, suit, petition or other proceedings with respect to the involuntary liquidation, dissolution or winding up of the Trust or to effect any other distribution of assets of the Trust among the Unitholders for the purpose of winding up its affairs in each case where the Trust has failed to contest in good faith such proceeding within 30 days of becoming aware thereof.

Retraction of Exchangeable Shares by Holders and Retraction Call Right

Subject to the Retraction Call Right of the Trust and Trust Subsidiary described below, a holder of Exchangeable Shares will be entitled at any time to require FET Resources to redeem any or all of the Exchangeable Shares held by such holder for a retraction price (the "Retraction Price") per Exchangeable Share equal to the value of that number of Trust Units equal to the Exchange Ratio as at the date of redemption (the "Retraction Date"), to be satisfied by the delivery of such number of Trust Units. Fractional Trust Units will not be delivered. Any amount payable on account of the Retraction Price that includes a fractional Trust Unit will be rounded down to the nearest whole number of Trust Units. Holders of the Exchangeable Shares may request redemption by presenting to FET Resources or the transfer agent for the Exchangeable Shares a certificate or certificates representing the number of Exchangeable Shares the holder desires to have redeemed, together with a duly executed retraction request and such other documents as may be reasonably required to effect the redemption of the Exchangeable Shares. Subject to extension as described below, the redemption will become effective on the Retraction Date, which will be seven business days after the date on which FET Resources or the transfer agent receives the retraction notice. Unless otherwise requested by the holder and agreed to by FET Resources, the Retraction Date will not occur on such seventh business day if such day would occur between any Distribution Record Date and the Distribution Payment Date that corresponds to such Distribution Record Date. In this case, the Retraction Date will instead occur on such Distribution Payment Date. The reason for this is to ensure that the Exchange Ratio used in connection with such redemption is increased to account for the Distribution.

When a holder requests FET Resources to redeem the Exchangeable Shares, the Trust and Trust Subsidiary will have an overriding right (the "Retraction Call Right") to purchase on the Retraction Date all but not less than all of the Exchangeable Shares that the holder has requested FET Resources to redeem at a purchase price per Exchangeable Share equal to the Retraction Price, to be satisfied by the delivery of that number of Trust Units equal to the Exchange Ratio at such time. At the time of a Retraction Request by a holder of Exchangeable Shares, FET Resources will immediately notify the Trust and Trust Subsidiary. The Trust or Trust Subsidiary must then advise FET Resources within two business days as to whether the Retraction Call Right will be exercised. A holder may revoke his or her Retraction Request at any time prior to the close of business on the last business day immediately preceding the Retraction Date, in which case the holder's Exchangeable Shares will neither be purchased by the Trust or Trust Subsidiary nor be redeemed by FET Resources. If the holder does not revoke his or her Retraction Request, the Exchangeable Shares that the holder has requested FET Resources to redeem will on the Retraction Date be purchased by the

Trust or Trust Subsidiary or redeemed by FET Resources, as the case may be, in each case at a purchase price per Exchangeable Share equal to the Retraction Price. In addition, a holder of Exchangeable Shares may elect to instruct the Voting and Exchange Trust Agreement Trustee to exercise the optional exchange right (the "Optional Exchange Right") to require the Trust or Trust Subsidiary to acquire such holder's Exchangeable Shares in circumstances where neither the Trust nor Trust Subsidiary have exercised the Retraction Call Right. See *"Exchangeable Shares - Voting and Exchange Trust Agreement - Optional Exchange Right"*.

The Retraction Call Right may be exercised by either the Trust or Trust Subsidiary. If, as a result of solvency provisions of applicable law, FET Resources is not permitted to redeem all Exchangeable Shares tendered by a retracting holder, FET Resources will redeem only those Exchangeable Shares tendered by the holder as would not be contrary to such provisions of applicable law. The holder of any Exchangeable Shares not redeemed by FET Resources will be deemed to have required the Trust to purchase such unretracted Exchangeable Shares in exchange for Trust Units on the Retraction Date pursuant to the Optional Exchange Right. See *"Exchangeable Shares - Voting and Exchange Trust Agreement - Optional Exchange Right"*.

Redemption of Exchangeable Shares

Subject to applicable law and the Redemption Call Right of the Trust and Trust Subsidiary, FET Resources:

(a) will, on August 23, 2012, subject to extension of such date by the board of directors of FET Resources (the "Automatic Redemption Date"), redeem all but not less than all of the then outstanding Exchangeable Shares for a redemption price per Exchangeable Share equal to the value of that number of Trust Units equal to the Exchange Ratio as at the last business day prior to that Redemption Date (as that term is defined below) (the "Redemption Price"), to be satisfied by the delivery of such number of Trust Units; and

(b) may, at any time when the aggregate number of issued and outstanding Exchangeable Shares is less than 1,000,000 (other than Exchangeable Shares held by the Trust and its subsidiaries and as such shares may be adjusted from time to time) (the "De Minimus Redemption Date" and, collectively with the Automatic Redemption Date, a "Redemption Date"), redeem all but not less than all of the then outstanding Exchangeable Shares for the Redemption Price per Exchangeable Share (unless contested in good faith by the Trust).

FET Resources will, at least 45 days prior to any Redemption Date, provide the registered holders of the Exchangeable Shares with written notice of the prospective redemption of the Exchangeable Shares by FET Resources.

The Trust and Trust Subsidiary will have the right (the "Redemption Call Right"), notwithstanding a proposed redemption of the Exchangeable Shares by FET Resources on the applicable Redemption Date, pursuant to the Exchangeable Share Provisions, to purchase on any Redemption Date all but not less than all of the Exchangeable Shares then outstanding (other than Exchangeable Shares held by the Trust or its subsidiaries) in exchange for the Redemption Price per Exchangeable Share and, upon the exercise of the Redemption Call Right, the holders of all of the then outstanding Exchangeable Shares will be obliged to sell all such shares to the Trust or Trust Subsidiary, as applicable. If either the Trust or Trust Subsidiary exercises the Redemption Call Right, then FET Resources' right to redeem the Exchangeable Shares on the applicable Redemption Date will terminate. The Redemption Call Right may be exercised by either the Trust or Trust Subsidiary.

Voting Rights

Except as required by applicable law, the holders of the Exchangeable Shares are not entitled as such to receive notice of or attend any meeting of the shareholders of FET Resources or to vote at any such meeting. Holders of Exchangeable Shares will have the notice and voting rights respecting meetings of the Trust that are provided in the Voting and Exchange Trust Agreement. See *"Voting and Exchange Trust Agreement - Voting Rights"*.

Amendment and Approval

The rights, privileges, restrictions and conditions attaching to the Exchangeable Shares may be changed only with the approval of the holders thereof. Any such approval or any other approval or consent to be given by the holders of the Exchangeable Shares will be sufficiently given if given in accordance with applicable law and subject to a minimum requirement that such approval or consent be evidenced by a resolution passed by not less than two-thirds of the votes cast thereon (other than shares beneficially owned by the Trust, or any of its subsidiaries and other affiliates) at a meeting of the holders of the Exchangeable Shares duly called and held at which holders of at least 10% of the then outstanding Exchangeable Shares are present in person or represented by proxy. In the event that no such quorum is present at such meeting within one-half hour after the time appointed therefor, then the meeting will be adjourned to such place and time (not less than ten days later) as may be determined at the original meeting and the holders of Exchangeable Shares present in person or represented by proxy at the adjourned meeting will constitute a quorum thereat and may transact the business for which the meeting was originally called. At the adjourned meeting, a resolution passed by the affirmative vote of not less than two-thirds of the votes cast thereon (other than shares beneficially owned by the Trust or any of its subsidiaries and other affiliates) will constitute the approval or consent of the holders of the Exchangeable Shares.

Actions by the Trust under the Support Agreement and the Voting and Exchange Trust Agreement

Under the Exchangeable Share Provisions, FET Resources will agree to take all such actions and do all such things as are necessary or advisable to perform and comply with its obligations under, and to ensure the performance and compliance by the Trust and Trust Subsidiary with its obligations under, the Support Agreement and the Voting and Exchange Trust Agreement.

Non-Resident and Tax-Exempt Holders

Exchangeable Shares will not be issued to persons who are Non-Residents or who are exempt from tax under Part I of the Tax Act. The obligation of FET Resources, the Trust or Trust Subsidiary to deliver Trust Units to a Non-Resident holder in respect of the exchange of such holder's Exchangeable Shares may be satisfied by delivering such Trust Units to the transfer agent who shall sell such Trust Units on the stock exchange on which they are listed and deliver the proceeds of sale to the Non-Resident holder.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

The Mandate and Terms of Reference of the Audit Committee of the board of director's is attached hereto as Schedule "A". The members of the Audit Committee are Gerry A. Romanzin, Stuart G. Clark and James H. McKelvie.

Composition of the Audit Committee

The members of the Audit Committee are independent (in accordance with National Instrument 52-110) and are financially literate.

Relevant Education and Experience

Mr. Romanzin was the Executive Vice President of the TSX Venture Exchange from November 1999 to April 2002 where he was responsible for overseeing the Corporate Finance and regional operations. In addition, he assumed the role of Acting President of the TSX Venture Exchange from December 2001 to April 2002. Mr. Romanzin is a chartered accountant and was a financial analyst with the Alberta Securities Commission for four years prior to joining the Alberta Stock Exchange in 1987. Mr. Romanzin was the Executive Vice President of the Alberta Stock Exchange from June 1995 to its change to the TSX Venture Exchange in November 1999. Mr. Romanzin obtained a Bachelor of Commerce degree from the University of Calgary and is a member of the Institute of Chartered Accountants of Alberta.

Mr. Clark has a Bachelor of Commerce (Honours) degree from the University of Manitoba. Mr. Clark was the Vice President, Finance and Chief Financial Officer of Storm from November 1998 to November 8, 2001 when he assumed the office of Executive Director. From January, 1986 to July, 1998, Mr. Clark was employed by Pinnacle Resources Ltd. (Pinnacle) in positions of increasing responsibility, the last being Executive Vice President and Chief Financial Officer. Pinnacle was a publicly traded oil and gas company listed on the TSX and Montreal Exchange prior to its acquisition by Renaissance Energy Ltd. in July 1998. Mr. Clark was a director of Pinnacle from January 1986 to July 1998 and a director of Quadron Resources Ltd., a publicly traded oil and gas company, which was listed on the TSX prior to its acquisition by HCO Energy Ltd. in June 1995, from April 1989 to May 1994. Mr. Clark was a director of Avid Oil and Gas Ltd., a publicly traded oil and gas company that was listed on the TSX and the TSX Venture Exchange prior to its acquisition by Husky Energy Ltd. in July 2001.

Mr. McKelvie was the Chief Financial Officer and a director of Ontario Energy Savings Corp., an operating subsidiary of the Energy Savings Income Fund to his retirement in May 2004. Prior to August 1997, Mr. McKelvie served as Managing Director, Vice President Finance and a director of Clairvest Group Inc., after which he served as Chairman of Ketch Energy Ltd. until January 2005. Mr. McKelvie also served as a Director of Tarragon Oil and Gas Limited from 1987 to 1998. Mr. McKelvie received his C.A. designation in 1977 when he was employed by Deloitte, Haskins + Sells (now Deloitte & Touche LLP).

Pre-Approval of Policies and Procedures

The Audit Committee pre-approves all audit and non-audit services to be provided to the Trust or any of its' subsidiaries.

External Auditor Service Fees

Audit Fees

The aggregate fees billed by the Trust's external auditor, KPMG LLP, in 2004 for annual audit services were $39,000 related to the 2003 consolidated financial statements, $26,000 related to 2004 first, second and third quarter reviews, and $75,000 for services rendered in connection with public offering documents and for French translation services. KPMG LLP was appointed the external auditors of the Trust at the Annual Meeting of Unitholders held on May 15, 2003. Prior to the appointment of KPMG LLP, Deloitte & Touche LLP was the external auditors of the Trust. In 2003, KPMG LLP aggregate billings related to the 2003 first, second and third quarter reviews were $22,000 and $31,000 for services rendered in connection with public offering documents and for French translation services. The aggregate fees billed by Deloitte & Touche in 2003 for annual audit services were $77,000 related to the 2002 consolidated financial statements, $17,000 related to 2002 third quarter review, and $22,000 for services rendered in connection with public offering documents and for French translation services.

Tax Fees

The aggregate fees billed in each of the last two fiscal years for professional services rendered by the Trust's external auditor for assistance with tax return preparation and tax-related consultation were $58,000 in 2004 and $21,000 in 2003. In 2003, Deloitte and Touche LLP aggregate billings were $59,000 for assistance with tax return preparation and tax-related consultation services.

VOTING AND EXCHANGE TRUST AGREEMENT

Voting Rights

In accordance with the Voting and Exchange Trust Agreement, the Trust will have issued a Special Voting Right to Valiant Trust Company, the Voting and Exchange Trust Agreement Trustee, for the benefit of the holders (other than the Trust and Trust Subsidiary) of the Exchangeable Shares. The Special Voting Right will carry a number of votes, exercisable at any meeting at which Trust Unitholders are entitled to vote, equal to the number of Exchangeable Shares. With respect to any written consent sought from the Trust Unitholders, each vote attached to the Special Voting Right will be exercisable in the same manner as set forth above.

Each holder of an Exchangeable Share on the record date for any meeting at which Trust Unitholders are entitled to vote will be entitled to instruct the Voting and Exchange Trust Agreement Trustee to exercise that number of votes attached to the Special Voting Right which relate to the Exchangeable Shares held by such holder. The Voting and Exchange Trust Agreement Trustee will exercise each vote attached to the Special Voting Right only as directed by the relevant holder and, in the absence of instructions from a holder as to voting, will not exercise such votes.

The Voting and Exchange Trust Agreement Trustee will send to the holders of the Exchangeable Shares the notice of each meeting at which the Trust Unitholders are entitled to vote, together with the related meeting materials and a statement as to the manner in which the holder may instruct the Voting and Exchange Trust Agreement Trustee to exercise the votes attaching to the Special Voting Right, at the same time as the Trust sends such notice and materials to the Trust Unitholders. The Voting and Exchange Trust Agreement Trustee will also send to the holders copies of all information statements, interim and annual financial statements, reports and other materials sent by the Trust to the Trust Unitholders at the same time as such materials are sent to the Trust Unitholders. To the extent such materials are provided to the Voting and Exchange Trust Agreement Trustee by the Trust, the Voting and Exchange Trust Agreement Trustee will also send to the holders all materials sent by third parties to Trust

Unitholders, including dissident proxy circulars and tender and exchange offer circulars, as soon as possible after such materials are first sent to Trust Unitholders.

All rights of a holder of Exchangeable Shares to exercise votes attached to the Special Voting Right will cease upon the exchange of all such holder's Exchangeable Shares for Trust Units. With the exception of administrative changes for the purpose of adding covenants for the protection of the holders of the Exchangeable Shares, making necessary amendments or curing ambiguities or clerical errors (in each case provided that the board of directors of Trust Subsidiary and FET Resources are of the opinion that such amendments are not prejudicial to the interests of the holders of the Exchangeable Shares), the Voting and Exchange Trust Agreement may not be amended without the approval of the holders of the Exchangeable Shares.

Optional Exchange Right

Upon the occurrence and during the continuance of:

(a) an Insolvency Event; or

(b) circumstances in which the Trust or Trust Subsidiary may exercise a Call Right, but elect not to exercise such Call Right;

a holder of Exchangeable Shares will be entitled to instruct the Trustee to exercise the Optional Exchange Right with respect to any or all of the Exchangeable Shares held by such holder, thereby requiring the Trust or Trust Subsidiary to purchase such Exchangeable Shares from the holder. Immediately upon the occurrence of (i) an Insolvency Event, (ii) any event which will, with the passage of time or the giving of notice, become an Insolvency Event, or (iii) the election by the Trust and Trust Subsidiary not to exercise a Call Right which is then exercisable by the Trust and Trust Subsidiary, FET Resources, the Trust or Trust Subsidiary will give notice thereof to the Trustee. As soon as practicable thereafter, the Trustee will then notify each affected holder of Exchangeable Shares (who has not already provided instructions respecting the exercise of the Optional Exchange Right) of such event or potential event and will advise such holder of its rights with respect to the Optional Exchange Right.

The purchase price payable by the Trust or Trust Subsidiary for each Exchangeable Share to be purchased under the Optional Exchange Right will be satisfied by the issuance of that number of Trust Units equal to the Exchange Ratio as at the last business day prior to the day of closing of the purchase and sale of such Exchangeable Share under the Exchange Right (the "Exchange Price").

If, as a result of solvency provisions of applicable law, FET Resources is unable to redeem all of a holder's Exchangeable Shares which such holder is entitled to have redeemed in accordance with the Exchangeable Share Provisions, the holder will be deemed to have exercised the Optional Exchange Right with respect to the unredeemed Exchangeable Shares and the Trust or Trust Subsidiary will be required to purchase such shares from the holder in the manner set forth above.

SUPPORT AGREEMENT

The Trust Support Obligation

Under the Support Agreement, the Trust agrees that:

(a) the Trust will take all actions and do all things necessary to ensure that FET Resources is able to pay to the holders of the Exchangeable Shares the Liquidation Amount in the event of a liquidation, dissolution or winding-up of FET Resources, the Retraction Price in the event of the giving of a Retraction Request by a holder of Exchangeable Shares, or the Redemption Price in the event of a redemption of Exchangeable Shares by FET Resources; and

(b) the Trust will not vote or otherwise take any action or omit to take any action causing the liquidation, dissolution or winding-up of FET Resources.

The Support Agreement will also provide that the Trust will not issue or distribute to the holders of all or substantially all of the outstanding Trust Units:

(a) additional Trust Units or securities convertible into Trust Units;

(b) rights, options or warrants for the purchase of Trust Units; or

(c) units or securities of the Trust other than Trust Units, evidences of indebtedness of the Trust or other assets of the Trust;

unless the same or an equivalent distribution is made to holders of Exchangeable Shares, an equivalent change is made to the Exchangeable Shares, such issuance or distribution is made in connection with a distribution reinvestment plan instituted for holders of Trust Units or a unitholder rights protection plan approved for holders of Trust Units by the board of directors of AcquisitionCo or the approval of holders of Exchangeable Shares has been obtained.

In addition, the Trust may not subdivide, reduce, consolidate, reclassify or otherwise change the terms of the Trust Units unless an equivalent change is made to the Exchangeable Shares or the approval of the holders of Exchangeable Shares has been obtained.

In the event of any proposed take-over bid, issuer bid or similar transaction affecting the Trust Units, the Trust will use reasonable efforts to take all actions necessary or desirable to enable holders of Exchangeable Shares to participate in such transaction to the same extent and on an economically equivalent basis as the Trust Unitholders.

The Support Agreement also provides that, as long as any outstanding Exchangeable Shares are owned by any person or entity other than the Trust or any of its respective subsidiaries and other affiliates, the Trust will, unless approval to do otherwise is obtained from the holders of Exchangeable Shares, remain the direct or indirect beneficial owner collectively of more than 50% of all of the issued and outstanding voting securities of FET Resources, provided that the Trust will not be in violation of this obligation if a party acquires all or substantially all of the assets of the Trust. With the exception of administrative changes for the purpose of adding covenants for the protection of the holders of the Exchangeable Shares, making certain necessary amendments or curing ambiguities or clerical errors (in each case provided that the board of directors of FET Resources and the Trustee are of the opinion that such amendments are not prejudicial to the interests of the holders of the Exchangeable Shares), the Support Agreement may not be amended without the approval of the holders of the Exchangeable Shares.

Under the Support Agreement, the Trust will agree to not exercise any voting rights attached to the Exchangeable Shares owned by it or any of its respective subsidiaries and other affiliates on any matter considered at meetings of holders of Exchangeable Shares (including any approval sought from such holders in respect of matters arising under the Support Agreement).

Delivery of Trust Units

The Trust will agree to make such filings and seek such regulatory consents and approvals as are necessary so that the Trust Units issuable upon the exchange of Exchangeable Shares will be issued in compliance with applicable securities laws in Canada and may be traded freely on the TSX or such other exchange on which the Trust Units may be listed, quoted or posted for trading from time to time.

NOTES

The following section is a summary of the material attributes and characteristics of the Notes issued pursuant to the provisions of a note indenture (the "Note Indenture") dated on August 23, 2002 and made between AcquisitionCo and Valiant Trust Company, as trustee (the "Note Trustee"). The Notes were issued under the Note Indenture.

Terms and Issue of Notes

Pursuant to the Plan of Arrangement, Notes were issued to the Trust and to former Shareholders. Notes issued to former holders of common shares of Storm were transferred by such holders to the Trust in return for Trust Units. Accordingly, the Note Indenture provided that initially only one global Note certificate was issued and represented all Notes issued under the Arrangement. The global Note certificate was issued to the Note Trustee in trust for the Trust and such Shareholders. The Note

Trustee, on behalf of such Shareholders recorded the transfer of the Notes represented by such certificate to the Trust pursuant to the Plan of Arrangement, without recourse to the Trust, and received certificates representing Trust Units for delivery to such Shareholders, all as contemplated by the Plan of Arrangement. Upon receipt of the certificates representing the Trust Units, the Note Trustee provided a receipt and distributed such certificates to such Shareholders.

The unsecured Notes bear interest from the date of issue at 14% per annum. Interest is payable for each month during the term on the 10th day of the month following such month. The first interest payment was paid on October 10, 2002 for the period commencing on August 23, 2002 and ending on September 30, 2002.

Although pursuant to the terms of the Note Indenture, FET Resources is permitted to make payments against the principal amount of the Notes outstanding from time to time without notice or bonus, FET Resources is not required to make any payment in respect of principal until December 1, 2032, subject to extension in the limited circumstances provided in the Note Indenture.

In contemplation of the possibility that Notes may be distributed to Trust Unitholders upon the redemption of their Trust Units, the Note Indenture provides that if persons other than the Trust (the "Non-Fund Holders") own Notes having an aggregate principal amount in excess of $1,000,000, either the Trust or the Non-Fund Holders shall be entitled, among other things, to require the Note Trustee to exercise the powers and remedies available under the Note Indenture upon an event of default and, with the Trust, the Non-Fund Holders may provide consents, waivers or directions relating generally to the variance of the Note Indenture and the rights of noteholders. The Note Indenture allows the Trust flexibility to delay payments of interest or principal otherwise due to it while payment is made to other noteholders, and to allow other noteholders to be paid out before the Trust. Any delayed payments will be due 5 days after demand.

Principal and interest on the Notes will be payable in lawful money of Canada directly to the holders of Notes at their address set forth in the register of holders of Notes. The Trust is the holder of all of the issued and outstanding Notes.

Ranking

The Notes are unsecured debt obligations of FET Resources and rank *pari passu* with all other unsecured indebtedness of FET Resources, but subordinate to all secured debt.

Events of Default

The Note Indenture provides that any of the following shall constitute an Event of Default: (i) default in payment of the principal of the Notes when required; (ii) the failure to pay all of the interest obligations on the Notes for a period of 90 days; (iii) if FET Resources has defaulted and a demand for payment has been made under any material instrument, indenture or document evidencing indebtedness of more than $5 million and FET Resources has failed to remedy such default within applicable curative periods; (iv) certain events of winding-up, liquidation, bankruptcy, insolvency, receivership or seizure; (v) default in the observance or performance of any other covenant or condition of the Note Indenture and continuance of such default for a period of 30 days after notice in writing has been given by the Note Trustee to FET Resources specifying such default and requiring FET Resources to rectify the same; (vi) FET Resources ceasing to carry on its business other than as contemplated in this Information Circular; and (vii) material default by FET Resources under material agreements if property having a fair market value in excess of $5 million is liable to forfeiture or termination.

NPI AGREEMENT

Coincident with the Arrangement becoming effective, FET Resources and the Trust entered into the NPI Agreement, pursuant to which FET Resources granted and set over to the Trust the right to receive certain payments (the "NPI") on petroleum and natural gas rights held by FET Resources from time to time. As consideration for the granting of the NPI, in addition to all amounts previously paid by the Trust to FET Resources, the Trust agreed to pay FET Resources an amount (the "Deferred Purchase Price Obligation") equal to (a) the portion of acquisition costs ("Future Acquisition Costs") for petroleum and natural gas rights and related tangibles and miscellaneous interests beneficially owned by FET Resources from time to time ("Property Interests") acquired after the date of the NPI Agreement which are attributable to "Canadian resource property" (as defined in the Tax Act) payable at the time of incurring such Future Acquisition Costs, plus (b) drilling, completion, equipping and other costs ("Capital Expenditures") in respect of the Property Interests payable at the time of incurring such Capital Expenditures, plus (c) the portion of indebtedness incurred in respect of such Future Acquisition Costs and Capital Expenditures payable at the time of satisfaction by FET Resources of such indebtedness. In addition, the Trust will pay over to FET Resources, to satisfy the Deferred Purchase Price Obligation, the net proceeds of any issue of Trust Units or the proceeds from the disposition of the NPI on any petroleum and natural gas rights held by FET Resources. FET Resources shall not be obligated to pay an amount as a Deferred Purchase Price Obligation except to the extent the Trust has such proceeds available.

Pursuant to the terms of the NPI Agreement, the Trust is entitled to a payment from FET Resources for each month equal to the amount by which ninety-nine (99%) percent of the gross proceeds from the sale of production attributable to the Property Interests for such month (the "NPI Revenues") exceed ninety-nine (99%) percent of certain deductible production costs for such period. FET Resources may acquire and fund additional Property Interests from residual revenues, the Deferred Purchase Price Obligation, borrowings or from its working capital.

If FET Resources wishes to dispose of any Property Interests which will result in proceeds in excess of a threshold amount, the Board of Directors shall approve such disposition, however, if the asset value (calculated in accordance with the terms of the NPI Agreement) of any interests included in such disposition is greater than a threshold percentage of the asset value of all the Property Interests held by FET Resources, such disposition must be approved by a special resolution of the Unitholders. The term of the NPI Agreement will be for so long as there are petroleum and natural gas rights to which the NPI applies.

CASH DISTRIBUTIONS

The following is a summary of the distributions paid by Focus from its inception in August of 2002 to December 31, 2004.

For the 2002 Period Ended	Distributions per Unit	Payment Date
September 30	$0.11	October 15, 2002
October 31	0.11	November 15, 2002
November 30	0.11	December 16, 2002
December 31	0.11	January 15, 2003
Total:	**$0.44**	

For the 2003 Period Ended	Distributions per Unit	Payment Date
January 31	$0.135	February 17, 2003
February 28	$0.135	March 17, 2003
March 31	$0.135	April 15, 2003
April 30	$0.14	May 15, 2003
May 31	$0.14	June 16, 2003
June 30	$0.14	July 15, 2003
July 31	$0.14	August 15, 2003
August 31	$0.14	September 15, 2003
September 30	$0.14	October 15, 2003
October 30	$0.14	November 17, 2003
November 30	$0.14	December 15, 2003
December 31	$0.14	January 15, 2004
Total:	**$1.665**	

For the 2004 Period Ended	Distributions per Unit	Payment Date
January 31	$0.14	February 16, 2004
February 29	$0.14	March 15, 2004
March 31	$0.14	April 15, 2004
April 30	$0.15	May 17, 2004
May 31	$0.15	June 15, 2004
June 30	$0.15	July 15, 2004
July 31	$0.15	August 16, 2004
August 31	$0.15	September 15, 2004
September 30	$0.15	October 15, 2004
October 30	$0.16	November 15, 2004
November 30	$0.16	December 15, 2004
December 31	$0.16	January 17, 2005
Total:	**$1.80**	

MARKET FOR SECURITIES

The Trust Units are listed for trading on the TSX under the symbol "FET.UN". The Exchangeable Shares are listed for trading on the TSX under the symbol "FTX".

The following table sets forth the high and low closing trading prices and the aggregate volume of trading of the Trust Units as reported by the TSX for the periods indicated.

	Price Range		
	High ($)	**Low ($)**	**Average Daily Volume**
2004			
January	15.08	14.20	109,397
February	14.64	13.10	111,363
March	15.03	14.65	105,725
April	15.21	14.60	116,477
May	15.25	14.75	128,230
June	15.95	14.75	78,277
July	16.21	15.60	63,674
August	16.55	15.50	71,452
September	18.37	16.05	154,343
October	20.39	18.28	156,900
November	20.94	18.79	172,103
December	20.95	19.50	85,983
2005			
January	21.41	19.49	90,827
February	22.45	21.00	131,947
March 1 to 8th	22.60	20.91	104,100

The following table sets forth the high and low closing trading prices and the aggregate volume of trading of the Exchangeable Shares as reported by the TSX for the periods indicated.

	Price Range		
	High ($)	Low ($)	Average Daily Volume
2004			
January	17.77	16.55	381
February	16.60	15.14	980
March	17.70	16.60	196
April	18.25	17.00	724
May	18.21	17.00	110
June	19.00	18.08	118
July	20.00	18.80	5,162
August	20.50	19.75	300
September	23.21	20.25	519
October	25.50	22.83	570
November	27.00	24.00	332
December	26.67	24.84	581
2005			
January	27.50	25.05	325
February	28.80	27.09	430
March 1st to 7th	29.25	27.25	540

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of Focus are KPMG LLP, Chartered Accountants, Calgary, Alberta. Valiant Trust Company, at its principal office in Calgary, Alberta, is the transfer agent and registrar of Trust Units and Exchangeable Shares.

RISK FACTORS

The following is a summary of certain risk factors relating to the business of the Trust and FET Resources. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this Annual Information Form.

Reserves Estimates

The reserve and recovery information contained in the Paddock Report and the McDaniel Report are only estimates and the actual production and ultimate reserves from the properties may be greater or less than the estimates prepared by Paddock and McDaniel.

Volatility of Oil and Natural Gas Prices

The Trust's operational results and financial condition will be dependent on the prices received by FET Resources for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on FET Resources' ability to satisfy its obligations under the Notes and on the amounts, if any, paid to the Trust under the NPI Agreement, thereby decreasing the amount of Distributable Cash to be distributed to holders of Trust Units.

Changes in Legislation

There can be no assurance that income tax laws and government incentive programs relating to the oil and gas industry, such as the status of mutual fund trusts and the resource allowance, will not be changed in a manner which adversely affects Unitholders.

Investment Eligibility

If the Trust ceases to qualify as a mutual fund trust, the Trust Units will cease to be qualified investments for RRSPs, RRIFs, DPSPs and RESPs ("Exempt Plans") which will have adverse tax consequences to Exempt Plans or their annuitants or beneficiaries. Notes or Redemption Notes acquired on a redemption of Trust Units may not be qualified investments for Exempt Plans.

Operational Matters

The operation of oil and gas wells involves a number of operating and natural hazards which may result in blowouts, environmental damage and other unexpected or dangerous conditions resulting in damage to FET Resources and possible liability to third parties. FET Resources will maintain liability insurance, where available, in amounts consistent with industry standards. Business interruption insurance may also be purchased for selected facilities, to the extent that such insurance is available. FET Resources may become liable for damages arising from such events against which it cannot insure or against which it may elect not to insure because of high premium costs or other reasons. Costs incurred to repair such damage or pay such liability may impair FET Resources 's ability to satisfy its obligations under the Notes or otherwise reduce the amount received by the Trust under the NPI Agreement.

Continuing production from a property, and to some extent the marketing of production therefrom, are largely dependent upon the ability of the operator of the property. To the extent the operator fails to perform these functions properly, revenue may be reduced. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent. Although satisfactory title reviews are generally conducted in accordance with industry standards, such reviews do not guarantee or certify that a defect in the change of title may not arise to defeat the claim of FET Resources or its subsidiaries to certain properties. Such circumstances could impair FET Resources' ability to satisfy its obligations under the Notes or otherwise reduce the amount received by the Trust under the NPI Agreement.

Environmental Concerns

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines or issuance of clean up orders in respect of FET Resources or its assets. Such legislation may be changed to impose higher standards and potentially more costly obligations on FET Resources. Although the Trust has established a reclamation fund for the purpose of funding its currently estimated future environmental and reclamation obligations based on its current knowledge, there can be no assurance that the Trust will be able to satisfy its actual future environmental and reclamation obligations.

Debt Service

FET Resources may, from time to time, finance a significant portion of its operations through debt. Amounts paid in respect of interest and principal on debt incurred by FET Resources may impair FET Resources' ability to satisfy its obligations under the Notes or otherwise reduce the amount received by the Trust under the NPI Agreement. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service before payment by FET Resources of its obligations under the Notes or the NPI Agreement. Ultimately, this may result in lower levels of Distributable Cash for the Trust.

Lenders will be provided with security over substantially all of the assets of FET Resources. If FET Resources becomes unable to pay its debt service charges or otherwise commits an event of default such as bankruptcy, a lender may foreclose on or sell the assets of FET Resources.

Delay in Cash Distributions

In addition to the usual delays in payment by purchases of oil and natural gas to the operators of the properties, and by the operator to FET Resources, payments between any of such parties may also be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blowouts or other accidents, recovery by the operator of expenses incurred in the operation of the properties or the establishment by the operator of reserves for such expenses.

Taxation of FET Resources

FET Resources is subject to taxation in each taxation year on its income for the year, after deducting interest paid to the Trust pursuant to the Note Indenture and after deducting payments, if any, made to the Trust with respect to the NPI Agreement. During the period that Exchangeable Shares issued by FET Resources are outstanding, a portion of the cash flow from operations will be subject to tax to the extent that there are not sufficient resource pool deductions, capital cost allowances or utilization of prior years non-capital losses to reduce taxable income to zero. FET Resources intends to deduct, in computing its income for tax purposes, the full amount available for deduction in each year associated with the income tax resource pools, undepreciated capital costs ("UCC") and non-capital losses carried forward from Storm, if any, plus resource pools and UCC created by capital expenditures of FET Resources. If there are not sufficient resource pools, UCC and non-capital losses carried forward to shelter the income of FET Resources, then cash taxes would be payable by FET Resources. In addition, there can be no assurance that taxation authorities will not seek to challenge the amount of interest expense. If such a challenge were to succeed against FET Resources, it could materially adversely affect the amount of distributable cash available.

Further, interest on the Notes accrues at the Trust level for income tax purposes whether or not actually paid. The Trust Indenture provides that an amount equal to the taxable income of the Trust will be distributed each year to Unitholders in order to reduce the Trust's taxable income to zero. Where interest payments on the Notes are due but not paid in whole or in part, the Trust Indenture provides that any additional amount necessary to be distributed to Unitholders may be distributed in the form of Units rather than in cash. Unitholders will be required to include such additional amount in income even thought they do not receive a cash distribution.

Depletion of Reserves

The Trust has certain unique attributes which differentiate it from other oil and gas industry participants. Distributions of Distributable Cash in respect of properties, absent commodity price increases or cash effective acquisition and development activities, will decline over time in a manner consistent with declining production from typical oil, natural gas and natural gas liquids reserves. FET Resources will not be reinvesting cash flow in the same manner as other industry participants. Accordingly, absent capital injections, FET Resources' initial production levels and reserves will decline.

FET Resources' future oil and natural gas reserves and production, and therefore its cash flows, will be highly dependent on FET Resources success in exploiting its reserve base and acquiring additional reserves. Without reserve additions through acquisition or development activities, FET Resources' reserves and production will decline over time as reserves are exploited.

Net Asset Value

The net asset value of the assets of the Trust from time to time will vary dependent upon a number of factors beyond the control of management, including oil and gas prices. The trading prices of the Trust Units from time to time is also determined by a number of factors which are beyond the control of management and such trading prices may be greater than the net asset value of the Trust's assets.

Residual Liabilities of Storm

Pursuant to the Arrangement, FET Resources is the corporation resulting from the amalgamation of AcquisitionCo and Storm. As a result, FET Resources owns, directly or indirectly, all of the assets of Storm other than the Storm Energy Ltd. assets, which were transferred to Storm Energy Ltd. coincident with the Arrangement becoming effective. Although Storm Energy Ltd. assumed all of the liabilities of Storm relating to the Storm Energy Ltd. assets, as the successor entity to Storm, FET Resources retained all other liabilities of Storm, including liabilities relating to corporate and income tax matters.

Return of Capital

Trust Units will have no value when reserves from the underlying assets of the Trust can no longer be economically productive and, as a result, cash distributions do not represent a "yield" in the traditional senses as they represent both return of capital and return on investment.

Conflict of Interest

Certain of FET Resources' directors are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA.

Nature of Trust Units

The Trust Units do not represent a traditional investment in the oil and natural gas sector and should not be viewed by investors as shares in FET Resources. The Trust Units represent a fractional interest in the Trust. As holders of Trust Units, Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring "oppression" or "derivative" actions. The Trust's sole assets will be its shares in FET Resources, the Notes, the NPI Agreement and other investments in securities. The price per Trust Unit is a function of anticipated Distributable Cash, the underlying assets of the trust and management's ability to effect long-term growth in the value of the Trust. The market price of the Trust Units will be sensitive to a variety of market conditions including, but not limited to, interest rates and the ability of the Trust to acquire suitable oil and natural gas properties. Changes in market conditions may adversely affect the trading price of the Trust Units.

The Trust Units are not "deposits" within the meaning of the *Canada Deposit Insurance Corporation Act* (Canada) and are not insured under the provisions of that Act or any other legislation. Furthermore, the Trust is not a trust company, and accordingly, is not registered under any trust and loan company legislation as it does not carry on or intend to carry on the business of a trust company.

Unitholder Limited Liability

The Trust Indenture provides that no Trust Unitholder will be subject to any liability in connection with our obligations and affairs and, in the event that a court determines Trust Unitholders are subject to any such liabilities, the liabilities will be enforceable only against, and will be satisfied only out of our assets. Pursuant to the Trust Indenture, we will indemnify and hold harmless each Trust Unitholder from any costs, damages, liabilities, expenses, charges and losses suffered by a Trust Unitholder resulting from or arising out of such Trust Unitholder not having such limited liability.

The Trust Indenture provides that all written instruments signed by or on our behalf must contain a provision to the effect that such obligation will not be binding upon Trust Unitholders personally. Personal liability may also arise in respect of claims against us that do not arise under contracts, including claims in tort, claims for taxes and possibly certain other statutory liabilities. The possibility of any personal liability of this nature arising is considered unlikely. The *Income Trusts Liability Act* (Alberta) came into force on July 1, 2004. The legislation provides that a Trust Unitholder will not be, as a beneficiary, liable for any act, default, obligation or liability of the trustee that arises after the legislation came into force.

Our operations will be conducted, upon the advice of counsel, in such a way and in such jurisdictions as to avoid as far as possible any material risk of liability on the Trust Unitholders for claims against us.

LEGAL PROCEEDINGS

There are no legal proceedings which the Trust or any subsidiary of the Trust is a party or of which any of their property is subject which are material to the Trust and the Trust is not aware of any such proceedings that are contemplated or pending.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors and senior officers of the Trust, any unitholder who beneficially owns more than 10% of the outstanding units, or any known associate or affiliate of such persons, in any transaction within the last fiscal year and in any proposed transaction which has materially affected or would materially affect the Trust.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contracts entered into by us within the most recently completed financial year, or before the most recently completed financial year but are still material and are still in effect, are the following:

(a) the Trust Indenture;

(b) the Exchangeable Share provisions and the support agreement and the voting and exchange agreement;

(c) the note indenture creating the Notes; and

(d) the trust unit rights incentive plan.

Copies of each of these documents have been filed on SEDAR at *www.sedar*.com.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Trust during, or related to, the Trust's most recently completed financial year other than Paddock Lindstrom and Associates and McDaniel and Associates, the Trust's independent engineering evaluators and KPMG LLP, the Trust's auditors.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associate or affiliate of the Corporation.

ADDITIONAL INFORMATION

Additional information relating to Focus may be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of securities and interests of insiders in material transactions, where applicable, is contained in the Information Circular of the Trust dated March 15, 2005. Additional financial information is provided in Focus' financial statements for the year ended December 31, 2004.

The Trust shall provide to any person, upon request to the Chief Financial Officer of FET Resources:

1. when the securities of the Trust are in the course of a distribution pursuant to a preliminary short form prospectus or a short form prospectus:

    (a) one copy of the Annual Information Form of the Trust, together with one copy of any document, or the pertinent pages of any document, incorporated by reference in the Annual Information Form;

    (b) one copy of the comparative financial statements of Focus for its most recently completed fiscal period for which financial statements have been filed, together with the accompanying report of the auditor and one copy of the most recent interim financial statements of the Trust that have been filed, if any, for any period after the end of its most recently completed financial year;

    (c) one copy of the Information Circular of the Trust in respect of its most recent annual and special meeting of Unitholders; and

    (d) one copy of any other documents that are incorporated by reference into the preliminary short form prospectus or the short form prospectus and which are not required to be provided under items (a) to (c) above; or

2. at any other time, one copy of any documents referred to in items (1)(a), (b) and (c) above, provided that the Trust may require the payment of a reasonable charge if the request is made by a person who is not a security holder of the Trust.

For additional copies of this Annual Information Form and the materials listed in the preceding paragraphs, please contact:

Focus Energy Trust
Suite 3250, 205 - 5th Avenue S.W.
Calgary, Alberta T2P 2V7
Phone: (403) 781-8409
Fax: (403) 781-8408

SCHEDULE A – BOARD OF DIRECTORS COMMITTEE MANDATES

Audit Committee

MANDATE & TERMS OF REFERENCE OF THE AUDIT COMMITTEE

Role and Objective

The Audit Committee (the "Committee") is a committee of the board of directors of FET Resources Ltd. ("FET") to which the board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for board of director approval, the audited financial statements and other mandatory disclosure releases containing financial information. The objectives of the Committee, with respect to FET and Focus Energy Trust (the "Trust") (hereinafter collectively referred to as "Focus"), are as follows:

1. To assist directors meet their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Focus and related matters;
2. To provide better communication between directors and external auditors;
3. To enhance the external auditor's independence;
4. To increase the credibility and objectivity of financial reports; and
5. To strengthen the role of the outside directors by facilitating in-depth discussions between directors on the Committee, management and external auditors.

Membership of Committee

1. The Committee shall be comprised of at least three (3) directors of FET, none of whom are members of management of FET and all of whom are "unrelated directors" (as such term is used in the Report of the Toronto Stock Exchange on Corporate Governance in Canada) and "independent" (as such term is used in Multilateral Instrument 52–110 – Audit Committee ("MI 52–110")).
2. The Board of Directors shall have the power to appoint the Committee Chairman, who shall be an unrelated director.
3. All of the members of the Committee shall be "financially literate" and at least one member shall be an "audit committee financial expert". The Board of Directors of FET has adopted the definition for "financial literacy" and the definition of "audit committee financial expert" used in MI 52–110.

Meetings

1. At all meetings of the Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall not be entitled to a second or casting vote. In the event of an equal number of votes, the Committee will attempt to access any missing members, or have the matter decided by the full Board of Directors.
2. A quorum for meetings of the Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee shall be the same as those governing the board.
3. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee shall be taken. The Chief Financial Officer shall attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.
4. The Committee shall forthwith report the results of meetings and reviews undertaken and any associated recommendations to the board.
5. The Committee shall meet with the external auditor at least quarterly and at such other times as the external auditor and the audit Committee consider appropriate.
6. The Committee shall meet with the external reserve evaluators in conjunction with the Reserves Committee at least once per year (in connection with the preparation of the year end reserves).

Mandate and Responsibilities of Committee

1. It is the responsibility of the Committee to oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting.

2. It is the responsibility of the Committee to satisfy itself on behalf of the board with respect to the adequacy and effectiveness of Focus's Internal Control Systems.

3. It is a primary responsibility of the Committee to review the annual financial statements of Focus prior to their submission to the board of directors for approval. The process should include but not be limited to:

   - reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;
   - reviewing significant accruals, reserves or other estimates such as the cost impairment calculation;
   - reviewing accounting treatment of unusual or non-recurring transactions;
   - reviewing the Trust's status as a "mutual fund trust" under the *Income Tax Act* (Canada).
   - ascertaining compliance with covenants under loan agreements and Trust Indenture;
   - reviewing adequacy of the reclamation fund;
   - reviewing disclosure requirements for commitments and contingencies;
   - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
   - reviewing unresolved differences between management and the external auditors;
   - obtain explanations of significant variances with comparative reporting periods.

4. The Committee is to review the financial statements, prospectuses, management discussion and analysis (MD&A), annual information forms (AIF) and all public disclosure containing audited or unaudited financial information before release and prior to board approval. The Committee must be satisfied that adequate procedures are in place for the review of Focus' disclosure of all other financial information and shall periodically access the accuracy of those procedures.

5. With respect to the appointment of external auditors by the board, the Committee shall:

   - recommend to the board the appointment of external auditors;
   - recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and confirmation that the external auditors shall report directly to the Committee;
   - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and
   - review and approve any non-audit services to be provided by the external auditors' firm and consider the impact on the independence of the auditors.

6. Review with external auditors (and internal auditor if one is appointed by Focus) their assessment of the internal controls of Focus, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Focus and its subsidiaries.

7. The Committee will pre–approve all non–audit services to be provided to Focus or its subsidiaries by the external auditors. The Committee may delegate to one or more members the authority to pre–approve non–audit services, provided that the member report to the Committee at the next scheduled meeting such pre–approval and the member comply with such other procedures as may be established by the Committee from time to time.

8. The Committee shall review risk management policies and procedures of Focus

9. The Committee shall establish a procedure for:

- the receipt, retention and treatment of complaints received by Focus regarding accounting, internal accounting controls or auditing matters; and
- the confidential, anonymous submission by employees of Focus of concerns regarding questionable accounting or auditing matters.

10. The Committee shall have the authority to investigate any financial activity of Focus. All employees of FET are to cooperate as requested by the Committee.

11. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at the expense of Focus without any further approval of the board.

Reserves Committee

Charter of the Reserves Committee of the Board of Directors

RESERVES COMMITTEE PURPOSE

The Reserves Committee (the "Committee") is appointed by the Board of Directors (the "Board") to assist the Board in fulfilling its responsibility for the stewardship of Focus Energy Trust (the "Trust") and FET Resources Ltd. (the "Corporation") in overseeing the business and affairs of the Corporation. The Committee's primary duties and responsibilities are to assume responsibility for assisting the Board in respect of annual independent review of the Trust's petroleum and natural gas reserves and reporting to the Board in respect thereof.

RESERVES COMMITTEE COMPOSITION, PROCEDURES AND ORGANIZATION

The Committee shall consist of at least two directors as determined by the Board, the majority of whom shall be independent (as required by National Instrument 51-101) and unrelated directors (as defined by the rules of the Toronto Stock Exchange). Committee members shall also meet the independence requirements of the regulatory bodies to which the Corporation may be subject to.

The Board shall appoint the members of the Committee and may at any time remove or replace any member of the Committee and may fill any vacancy in the Committee. The Board shall appoint a member of the Committee as chair of the Committee. If a Committee Chair is not designated by the Board, or is not present at a meeting of the Committee, the members of the Committee may designate a chair by majority vote of the Committee membership. The Secretary of the Corporation, or in his or her absence, an alternative secretary designated by the Committee, shall act as Secretary of the Committee.

The quorum for meetings shall be a majority of the members of the Committee present in person or by telephone or other telecommunications device that permits all persons participating in the meeting to speak and to hear each other.

The Committee shall meet at least annually at such times and at such locations as may be requested by the chair of the Committee and at such times as any member of the Committee may request.

RESERVES COMMITTEE RESPONSIBILITIES AND DUTIES

The overall duties and responsibilities of the Committee shall be as follows:

- in conjunction with the Corporation's senior engineering management, meet with the independent evaluating engineers being considered for appointment to review their qualifications and independence to ensure the independent evaluating engineers being considered for appointment are technically qualified and competent, are independent of management and to establish the terms of their engagement;

- after consultation with the Corporation's senior engineering management, recommend to the Board the appointment of the independent evaluating engineers to assist the Corporation in the annual review of its petroleum and natural gas reserves;

- in consultation with the Corporation's senior engineering management determine the scope of the annual review of the petroleum and natural gas reserves by the independent evaluating engineers, having regard to regulatory reporting requirements;

- review both the procedures for providing petroleum and natural gas reserves information to the independent evaluating engineers and the information used by the independent evaluating engineers to enable the independent evaluating engineers to provide a report that will meet regulatory reporting requirements;

- in consultation with the Corporation's senior engineering management and the independent evaluating engineers:

- determine whether any restrictions affect the ability of the independent evaluating engineers to report on reserves data without reservations; and

- review the reserves data and the report of the independent evaluating engineers.

- ensure the disclosure to the public on the Corporation's petroleum and natural gas reserves is in compliance with regulatory requirements;

- review any proposals to change the independent evaluating engineers and/or resolve any differences between the independent evaluating engineers and management;

- meet on an annual basis with the Corporation's senior engineering management and/or the independent evaluating engineers of the Corporation to review and consider the evaluation of the Corporation's petroleum and natural gas reserves;

- meet separately with the independent evaluating engineers and/or senior engineering management when the Committee deems it desirable and advise the Board on the results of such meeting;

- co-ordinate meetings with the Audit Committee of the Corporation, the Corporation's senior engineering management, independent evaluating engineers and auditors as required to address matters of mutual concern in respect of the Corporation's evaluation of petroleum and natural gas reserves;

- review annually the Committee charter and recommend any changes to the Board; and

- to maintain minutes of meetings and periodically report to the Board on significant results of the foregoing activities.

Compensation Committee

MANDATE & TERMS OF REFERENCE OF THE COMPENSATION COMMITTEE

Role and Objective

The Compensation Committee (the "Committee") is a committee of the board of directors of FET Resources Ltd. ("FET") to which the board has delegated its responsibility for oversight of the overall human resources policies and procedures including all compensation matters of FET and Focus Energy Trust (the "Trust") (hereinafter collectively referred to as "Focus"). The objectives of the Committee, with respect to Focus are as follows:

1. To assist the directors in meeting their responsibilities in respect of overall human resources policies and procedures including recruitment, performance management, compensation, benefit programs, resignation/terminations, training and development, succession planning and organizational planning and design.
2. To review all compensation and benefit proposals for the officers of FET and make recommendations to the board.
3. To review all in consultation with the board, undertake an annual performance review with the CEO and review the CEO's appraisal of the performance of the officers of FET.
4. To review all employment contracts and other agreements for employees of FET and make recommendations to the board.
5. To review all compensation plans of Focus including the Trust Unit Rights Incentive Plan and the Executive Bonus Plan.
6. To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee and management.

Membership of Committee

7. The Committee shall be comprised of at least two (2) directors of FET, none of whom are members of management of FET and at least half of whom are "unrelated directors" (as such term is used in the Report of the Toronto Stock Exchange on Corporate Governance in Canada).
8. The Board of Directors shall have the power to appoint the Committee Chairman, who shall be an unrelated director.

Meetings

9. At all meetings of the Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall not be entitled to a second or casting vote.
10. A quorum for meetings of the Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee shall be the same as those governing the board.
11. Meetings of the Committee should be scheduled to take place at least once per year. Minutes of all meetings of the Committee shall be taken. The Chief Executive Officer shall attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.
12. The Committee shall forthwith report the results of meetings and reviews undertaken and any associated recommendations to the board.

Mandate and Responsibilities of Committee

13. It is a primary responsibility of the Committee to all aspects of Focus' human resources policies and procedures. The process should include but not be limited to:
    - review overall salary increases for employees of FET and make recommendations to the board.
    - review all compensation and benefit proposals for officers of FET and make recommendations to the board.
    - in consultation with the board, undertake an annual performance review of the CEO, and review the CEO's appraisal of the officers of FET.
    - review all employment contracts and make recommendations to the board.

- review all proposed compensation plans and any amendments to all compensation plans of Focus.

14. The Committee may retain persons having special expertise and/or obtain independent professional advise to assist in filling their responsibilities at the expense of Focus without any further approval of the board.

Corporate Governance & Nominating Committee

MANDATE & TERMS OF REFERENCE OF THE CORPORATE GOVERNANCE & NOMINATING COMMITTEE

Role and Objective

The Corporate Governance and Nominating Committee (the "Committee") is a committee of the board of directors of FET Resources Ltd. ("FET") which has been constituted to assist the board in respect of the development and monitoring of Focus's approach to corporate governance, the nomination of directors for appointment to the board and the appointment of directors to committees of the board. The objectives of the Corporate Governance and Nominating Committee, with respect to FET and Focus Energy Trust (hereinafter referred to as "Focus"), are as follows:

Membership of Committee

1. The Committee shall be comprised of at least two (2) directors of the Corporation, none of whom are members of management of the Corporation and a majority of whom are "unrelated directors" (as such term is used in the Report of the Toronto Stock Exchange on Corporate Governance in Canada).
2. The Board of Directors shall have the power to appoint the Committee Chairman, who shall be an unrelated director.

Meetings

3. At all meetings of the Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall not be entitled to a second or casting vote.
4. A quorum for meetings of the Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee shall be the same as those governing the board.
5. Meetings of the Committee should be scheduled to take place at least once per year. Minutes of all meetings of the Committee shall be taken.
6. The Committee shall forthwith report the results of meetings and reviews undertaken and any associated recommendations to the board.

Mandate and Responsibilities of Committee

The mandate and responsibilities of the Corporate Governance and Nominating Committee shall be as set forth below:

7. Develop for approval by the board and periodically review the Corporation's approach to corporate governance matters.
8. Review and recommend to the board for approval reports concerning the Corporation's corporate governance practices as required by The Toronto Stock Exchange and any other regulatory authority.
9. Make recommendations to the board as to which directors should be classified as "related" directors or "unrelated" directors pursuant to any such report.
10. Act as a forum for concerns of individual directors in respect of matters that are not readily or easily discussed in a full board meeting, including the performance of management or individual members of management or the performance of the board or individual members of the board. The chairman of the Committee shall be responsible to develop a response to any such concerns.
11. Develop and recommend to the board for approval and periodically review structures and procedures designed to ensure that the board can function independently of management.
12. Subject to limitations in the unanimous shareholders agreement, consider, and from time to time make recommendations to the full board as to the appropriate size of the board.
13. Periodically review and recommend to the board for approval the remuneration of the directors (including remuneration for serving on a committee of the board) and any other arrangements pursuant to which monies are payable to a director or a party related to a director.
14. Develop for approval by the board and periodically review orientation and education programs for new directors.

15. Develop for approval by the board and periodically review procedures for assessing the effectiveness of the board as a whole, the committees of the board and the contribution of each individual director.

16. Annually review and recommend to the board the appointments to each committee of the board and any changes to the terms of reference of the committees.

17. Review, and report to the full board on matters relating to the nomination of directors and in so doing:

    (a) develop criteria for selection of directors and procedures to identify possible nominees;

    (b) review and assess qualifications of board nominees;

    (c) submit to the board for consideration and decision names of the nominees to be brought forward to the next annual shareholders meeting or to be appointed to fill vacancies in between annual meetings;

    (d) through the chairman of the Committee, approach nominees;

    (e) consider and recommend to the full board appropriate retirement ages of directors;

    (f) determine if any board members' qualifications or credentials since his or her appointment have changed or other circumstances arisen so as to warrant a recommendation that such member resign.

    (g) assess performance or effectiveness of:

        - Board as a whole
        - Board Committees
        - Individual directors

18. Review, and report to the full board, the performance of the CEO on an annual basis.

19. Through outside counsel, maintain a summary of the duties and liabilities of directors and periodically update and provide such summary to the directors.

20. Periodically review and monitor Focus's communication policy with a view to determining whether Focus is communicating effectively with Unitholders, other stakeholders, the investment community and the public generally.

21. Review and consider the engagement at the expense of Focus of professional and other advisors to an individual director(s) when so requested by such directors(s).

22. Review such other matters of a corporate governance nature as may be directed by the board from time to time.

23. Engage or instruct management to engage on behalf of the Corporation such professional and other advisors as the Committee considers appropriate in performing its obligations hereunder.

24. The Committee may retain persons having special expertise and/or obtain independent professional advise to assist in filling their responsibilities at the expense of Focus without any further approval of the board.

SCHEDULE B – FORM 51-101F2 REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

FORM 51-101F2

REPORT ON RESERVES DATA

BY

INDEPENDENT QUALIFIED RESERVES

EVALUATOR

Report on Reserves Data

To the board of directors of Focus Energy Trust (the "Company"):

1) We have evaluated the Company's reserves data as at December 31, 2004. The reserves data consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2004 using forecast prices and costs; and

(ii) the related estimated future net revenue; and

(b) (i) proved oil and gas reserves estimated as at December 31, 2004 using constant prices and costs; and

(ii) the related estimated future net revenue.

2) The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

We carried out our evaluation in accordance with the standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy and Petroleum (Petroleum Society).

3) Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4) The following tables set forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2004, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

			Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves	Audited	Evaluated	Reviewed	Total
Paddock Lindstrom & Associates	January 12, 2005	Canada	0	406,824	0	406,824
McDaniel & Associates	February 7, 2005	Canada	0	80,972	0	80,972
Totals			0	487,796	0	487,796

5) In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6) We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7) Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

PADDOCK LINDSTROM AND ASSOCIATES, Calgary, Canada

"D.L. Paddock" — March 14, 2005

D.L. Paddock, P. Eng. — **Date**

McDANIEL AND ASSOCIATES, Calgary, Canada

"B.H. Emslie" — March 16, 2005

B.H. Emslie, P. Eng. — **Date**

SCHEDULE C – FORM 51-101F3 REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

FORM 51-101F3

REPORT OF

MANAGEMENT AND DIRECTORS

ON OIL AND GAS DISCLOSURE

Report of Management and Directors on Reserves Data and Other Information

Management of Focus Energy Trust (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2004 using forecast prices and costs; and

(ii) the related estimated future net revenue; and

(b) (i) proved oil and gas reserves estimated as at December 31, 2004 using constant prices and costs; and

(ii) the related estimated future net revenue.

Independent qualified reserves evaluators have evaluated the Company's reserves data. The report of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Company has:

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluators;

(b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluators.

The Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed the information with management. The board of directors has, on the recommendation of the Reserves Committee, approved

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(b) the filing of the report of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

FOCUS ENERGY TRUST, Calgary, Canada

"Derek W. Evans"	March 23, 2005
Derek W. Evans, P. Eng.	**Date**
President and Chief Executive Officer	
"Dennis M. Lawrence"	March 23, 2005
Dennis M. Lawrence, P. Eng.	**Date**
Vice President, Engineering	
"Matthew J. Brister"	March 23, 2005
Matthew J. Brister	**Date**
Director	
"Gerry A.. Romanzin"	March 24, 2005
Gerry A. Romanzin	**Date**
Director	