PETROBANK
ENERGY AND RESOURCES LTD.

05008316

May 12, 2005

82-34812

SUPPL

Securities and Exchange Commission
Judiciary Plaza
450 – 5th Street NW
Washington D.C. 20549

Re: Petrobank Energy and Resources Ltd.

Dear Sir or Madam:

Pursuant to Regulation 12g3.2(b) please find enclosed documents made public and filed with Canadian Securities Regulators that form part of the continuous disclosure record of Petrobank Energy and Resources Ltd.

Sincerely,

(for) Corey C. Ruttan
Director of Corporate Finance and Investor Relations

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PETROBANK
ENERGY AND RESOURCES LTD.

NEWS RELEASE

PETROBANK ANNOUNCES FIRST QUARTER RESULTS

Calgary, Alberta – May 12, 2005 – Petrobank Energy and Resources Ltd. (Petrobank) is pleased to provide this operational update of our Canadian, Latin American and Heavy Oil Business Units, and our first quarter financial results.

FINANCIAL HIGHLIGHTS

The first quarter results reflect the going concern performance of the Company's production assets in Canada and Colombia. The Canadian comparative numbers for prior periods include the results from a number of properties that were sold by the Company during 2004.

- Excluding production from properties sold during 2004, Canadian production increased 48 percent year-over-year.
- Colombian oil sales averaged 1,072 bpd in the first quarter of 2005, a slight decrease from the fourth quarter of 2004 average of 1,155 bpd.
- Net debt was reduced from $121.4 million at the end of the first quarter of 2004 to $42.8 million at the end of the current period.
- Operating netbacks improved 31 percent and 42 percent in Canada and Colombia, respectively.

OPERATIONAL UPDATE

Canadian Business Unit

First quarter Canadian production averaged 1,927 boepd (84% gas), a 48 percent increase from the first quarter of 2004, excluding production from properties disposed during 2004. Canadian Business Unit production is expected to double by year-end through the execution of our $40 million capital program in 2005. The majority of the 2005 expenditures and resulting production additions are expected to occur between May and August at our Jumpbush property where we are planning a 58-well shallow gas drilling program and infrastructure expansion to handle up to 25 mmcfpd (working interest - 17.8 mmcfpd).

At Princeton, our initial CBM evaluation test well has been completed across a 120-foot interval in the targeted Black Coal zone. A planned fracture stimulation of the well has been delayed until later in May, due to equipment availability, and will be followed by a long-term testing program over several months. A more comprehensive pilot project will likely be required to assess the ultimate commerciality of our Princeton CBM asset, which is expected to commence in late-2005.

Latin American Business Unit

In Colombia, production averaged 1,072 barrels of oil per day from our Orito and Neiva blocks in the first quarter. Drilling has been completed on our Orito-116 well, which is targeting a large potential southwest extension to the main producing region of the Orito field. Drilling went smoothly and ahead of schedule but we experienced a series of equipment failures and well bore problems during logging and completion operations, which caused delays in testing the well. Well logs and the initial testing results are encouraging and we expect to be in a position to announce results in the near-term once stabilized production rates are obtained. With success, this well is expected to lead to a number of additional offsetting locations.

We are now finalizing contracts on three exploration blocks and one Technical Evaluation Area (TEA) in the Llanos Basin where we have identified a series of geological trends offering multi-pool/multi-zone prospects that can be effectively identified through the application of 3-D seismic. In addition, we are negotiating a new exploration block contiguous with our Orito block in the Putumayo Basin.

The first prospect on these new exploration lands is expected to be drilled on the Joropo Block in the first quarter of 2006. The location for this well has been selected based on 3-D seismic and is interpreted as an up-dip extension to an original well drilled off 2-D seismic in 1985. The discovery well encountered a thin oil zone over water and was abandoned at the time. A follow up 3-D seismic program shot in 2000, indicated that the original well was drilled down structure. The new fiscal terms for Colombian exploration have made the up-dip location a very compelling prospect.

We have completed a substantial portion of the required documentation for our planned initial public offering (IPO) of the Company's subsidiary, Petrominerales Colombia Ltd. (Petrominerales). The proposed IPO contemplates listing Petrominerales on the Toronto Stock Exchange (TSX) and contiguously on the Alternative Investment Market (AIM) in London. Current market conditions may not warrant fast tracking of the IPO process to meet a June timeframe, as such we are now focusing on the fall of 2005 for the IPO timing

Heavy Oil Business Unit

The $23.75 million WHITESANDS private equity financing was closed on April 12, 2005 with the Richardson Financial Group (RFG). Through this investment RFG will acquire a 16 percent interest in WHITESANDS Insitu Ltd. for $14 million and have also acquired 3 million common shares of Petrobank for $9.75 million. RFG have been early stage investors in other oil sands projects such as Western Oil Sands and OPTI Canada. Effective March 31, 2005, the WHITESANDS project also received an additional $9 million non-dilutionary financing commitment from Technology Partnerships Canada (TPC) bringing the total third party funding of the project to $32.75 million. Petrobank recently filed an application for further funding under the Innovative Energy Technologies Program of the Government of Alberta for up to $10 million.

Field activities at our WHITESANDS - THAI™ project ramped up during the first quarter. Field activities included drilling three exploration wells in the center of the leases to further define the extension of the McMurray channel edge. The remaining three (out of a total of nine) observation wells were also drilled on the project site. The exploration wells confirmed the presence of the McMurray channel further into the leases while the three wells on the project site reaffirmed the quality of the resource in the pilot area. The nine observation wells will now be used to aid the directional drilling of the three horizontal production wells.

Drilling of the three horizontal production wells will commence in early July with anticipated completion by mid-August. Drilling the vertical air injection wells, at the toe of the horizontal wells, along with the 17 additional observation wells will commence once the horizontal wells are completed.

Engineering for the pilot is in the final stages and equipment procurement is advancing. The plant will utilize modular construction methods where key elements of the project are manufactured offsite with final assembly at the project site. Construction activities are targeted to begin in early July with completion forecasted for early fourth quarter and startup before year-end. The estimated project capital cost is approximately $30 million, consistent with earlier estimates.

With substantially all of the funding requirements in place, the WHITESANDS project is on track for initial results early in the first quarter of 2006.

OUTLOOK

Petrobank has a number of important milestones in each of our Business Units to further validate our "vision to value" plan over the coming year, including:

- Results of our Orito-116 well and the potential follow-up locations;
- Testing of our Princeton CBM evaluation well;
- A step change in production capability from our May-August drilling and infrastructure expansion program at Jumpbush; and
- Start-up of our WHITESANDS-THAI™ project.

Relative to Petrobank's market capitalization and underlying asset value, Petrobank continues to offer our shareholders an extraordinary opportunity to participate in the upside associated with each of these high-impact projects.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis (MD&A) is dated May 11, 2005 and should be read in conjunction with the unaudited consolidated financial statements of the Company for the three months ended March 31, 2005, MD&A for the year ended December 31, 2004, and the audited consolidated financial statements for the year ended December 31, 2004. Additional information for the Company can be found at www.sedar.com. In addition to historical information, the MD&A contains forward-looking statements that reflect management's objectives and expectations as at the date of this report, which involve risks and uncertainties. The Company's actual results may differ materially from those anticipated in these forward-looking statements.

Natural gas volumes have been converted to barrels of oil equivalent (boe) so that six thousand cubic feet (mcf) of natural gas equals one barrel based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head. Boes may be misleading, particularly if used in isolation. This report contains financial terms that are considered non-GAAP measures such as cash flow from operations, cash flow per share, net debt, and operating netback. These measures are commonly utilized in the oil and gas industry and are considered informative for our shareholders. Specifically, cash flow from operations and cash flow per share reflect cash generated from operating activities before changes in non-cash working capital. We consider these measures important as they demonstrate our ability to generate sufficient cash to fund future growth opportunities and repay debt. All amounts are in Canadian dollars, unless otherwise stated.

Production

Oil and NGL production in Canada during the first quarter averaged 317 barrels per day (bpd), a decrease from the 1,417 bpd produced in the fourth quarter of 2004 and the 2,035 bpd produced in the first quarter of 2004. These decreases were due to the disposition of several properties throughout 2004 and a major disposition in December 2004 for proceeds of $96.1 million. The sale in December accounted for approximately 2,700 boepd and eliminated all of the Company's heavy oil production. First quarter natural gas production also decreased from prior periods as a result of the dispositions in 2004. The Company averaged 9.7 million cubic feet per day (mmcfpd) in the first quarter compared to 17.9 mmcfpd in the fourth quarter and 16.1 mmcfpd a year earlier. Total Canadian production for the first quarter was 1,927 boepd, a 56 percent decrease from the fourth quarter of 2004 and a 59 percent decrease from the same period last year. Excluding production from properties sold during 2004, Canadian production decreased 5 percent from the fourth quarter of 2004 and increased 48 percent from the first quarter of 2004.

Colombian oil sales averaged 1,072 bpd in the first quarter, a slight decrease from the fourth quarter average of 1,155 bpd and lower than the 1,702 bpd averaged in the first quarter of 2004. Production is expected to increase with planned well interventions and upon completion of the Orito-116 well.

Average Benchmark Prices

For the three months ended	**March 31, 2005**	Dec. 31, 2004	March 31, 2004
WTI crude oil (US$/bbl)	**49.84**	48.28	35.15
WTI crude oil (Cdn$/bbl)	**61.15**	58.94	46.32
Bow River heavy oil differential (US$/bbl)	**18.55**	19.16	9.00
NYMEX natural gas (US$/mmbtu) (1)	**6.27**	7.11	5.69
AECO (daily) natural gas (Cdn$/mcf)	**6.90**	6.61	6.43
US$/Cdn$ exchange rate	**0.82**	0.82	0.76

(1) Prices quoted are near-month contract prices for settlement during the next month.

Realized Prices

The average Canadian oil and NGL price received in the first quarter was $47.59 per barrel, a 144 percent increase from the $19.53 per barrel received in the fourth quarter of 2004 and an 80 percent increase from the $26.45 per barrel received in the first quarter of 2004. Canadian oil and NGL prices represented a US$10.24 discount to average WTI prices in the quarter compared to a US$11.37 discount to WTI in the fourth quarter of 2004 and a US$9.59 discount to WTI in the first quarter of 2004. The average price received increased significantly from 2004 periods due to hedges that expired on December 31, 2004 and the disposition of heavy oil production in the fourth quarter of 2004.

The average natural gas price received in the first quarter was $6.08 per mcf, a small increase from $5.80 per mcf received in the fourth quarter and consistent with the $6.09 per mcf received in the first quarter of 2004. In 2004, the natural gas price was impacted by a natural gas price collar on 10,000 mcfpd with a ceiling AECO price of $6.27 per mcf. This contract expired on December 31, 2004. Natural gas prices continue to reflect the impact of the Company's long-term physical natural gas sales and transportation contracts.

Oil sales prices in Colombia averaged US$40.04 per barrel in the first quarter, representing a US$9.80 per barrel (20% of WTI) discount to WTI compared to a discount of US$10.23 per barrel (21% of WTI) in the fourth quarter of 2004 and US$7.36 per barrel (21% of WTI) in the first quarter of 2004.

Royalties

Royalties decreased from $3.5 million in the first quarter of 2004 to $1.7 million in the current period. Canadian royalties as a percentage of revenue decreased from 22 percent in the first quarter of 2004 to 20 percent in the current period. Hedging losses recognized in the first quarter of 2004 did not impact royalties and resulted in higher royalty rates. Canadian royalty rates are expected to average approximately 22 percent throughout the remainder of 2005. Colombian royalties remained constant at a rate of 8 percent.

Production Expenses

Consolidated production expenses decreased to $2.0 million from $3.9 million in the fourth quarter and $4.1 million a year earlier. Production expenses per unit of production in Canada were $6.76 per boe, a decrease of 13 percent from $7.81 per boe in the fourth quarter, and consistent with $6.82 per boe in the first quarter of 2004. Production expenses in Colombia averaged $8.46 per barrel during the quarter, a 19 percent increase from the fourth quarter 2004 average of $7.08 per barrel and a 7 percent increase from the first quarter 2004 average of $7.89 per barrel. The increase in Colombia is primarily a result of the fixed nature of certain costs combined with lower production volumes.

General and Administrative Expenses

General and administrative expenses were $2.1 million in the first quarter of 2005 compared to $1.7 million a year earlier. The increase relates primarily to higher professional fees, and stock based compensation.

Interest on Bank Debt

The Company's credit facility was undrawn throughout the first quarter of 2005 compared to $22.6 million at the end of the same period a year earlier. As a result, interest on bank debt decreased from $0.5 million in the first quarter of 2004 to nil in 2005.

Interest on Subordinated Notes

Interest on subordinated notes totaled $2.5 million during the first quarter, compared to $2.8 million in the same period last year. The decrease relates to the repurchase of $14.3 million of notes on January 13, 2005. Following the redemption of an additional $17.2 million of subordinated notes in April 2005; interest on subordinated notes will be reduced to approximately $2.1 million per quarter.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion expense decreased to $3.6 million in the first quarter ($13.33 per boe) compared to $7.8 million in the fourth quarter of 2004 ($15.37 per boe) and $9.0 million ($15.47 per boe) in the first quarter of 2004. On a unit-of-production basis in Canada, the rate fell to $11.15 per boe compared to $13.42 in the first quarter of 2004. The rate decreased primarily as a result of reserve additions from fourth quarter 2004 drilling at Jumpbush. In Colombia, the rate was $17.25 per barrel in the first quarter of 2005, compared to $21.15 per barrel a year earlier. The decrease is a result of reserve additions recorded in the fourth quarter of 2004.

Other Income (Expense)

Due primarily to interest income earned on the Company's significant cash balance throughout the first quarter of 2005, other income totaled $0.3 million in the current period. Other expenses of $0.5 million a year earlier related primarily to the recognition of a mark-to-market loss on a contract disposed of in connection with the Wapella property disposition in January 2004.

Capital Taxes

The Company's first quarter capital taxes totaled $0.4 million (2004 - $0.3 million) including Large Corporations Tax in Canada and presumptive income taxes in Colombia.

Future Income Tax Recovery

The Company's first quarter future income tax recovery totaled $0.6 million compared to a $1.2 million recovery in the first quarter of 2004 due to a smaller net loss in the current period.

Capital Expenditures

Three months ended March 31,	2005	2004
Business Unit		
Canada	$ 3,469	$ 8,416
Heavy Oil	2,410	480
Latin America (Colombia)	4,901	5,817
Total	$ 10,780	$ 14,713

Canadian Business Unit activity related primarily to a major compressor installation and recompletions at Jumpbush, and completion of our first CBM evaluation test well at Princeton. Heavy Oil expenditures related to drilling observation wells at the WHITESANDS Insitu Ltd. - THAI™ pilot project site and exploration wells on the leases. Latin American expenditures related primarily to well interventions at Orito and drilling the Orito-116 well in Colombia.

Liquidity and Capital Resources

At March 31, 2005 net debt totaled $42.8 million, including the book value of outstanding subordinated notes ($82.8 million). The subordinated notes are not callable and mature in July 2006. Working capital at March 31, 2005 totaled $40.0 million and Petrobank's undrawn borrowing base under its senior secured credit facility was $10.0 million.

Effective March 31, 2005 Technology Partnerships Canada (TPC) announced their commitment to invest up to $9 million towards the development and field demonstration of the Company's THAI™ technology at the WHITESANDS pilot project. TPC's investments will be made quarterly based on 20.134 percent of eligible expenditures.

On April 12, 2005 the Company closed a $23.75 million financing involving an investment in Petrobank and its wholly owned subsidiary, WHITESANDS. The investor acquired a 16 percent interest in WHITESANDS for a $14 million equity commitment and 3 million common shares of Petrobank at a price of $3.25 per share for aggregate proceeds of $23.75 million.

On April 22, 2005 the Company redeemed an additional $17.2 million face value of notes, reducing the outstanding face value to $68.9 million. This redemption, along with the $14.3 million repurchase in January, results in annualized cash interest savings of $2.8 million until maturity on July 31, 2006.

Changes in Accounting Policies

Financial Instruments

Effective January 1, 2005 the Company retroactively adopted the revised recommendations of the Canadian Institute of Chartered Accountants (CICA) section 3861, "Financial Instruments – Disclosure and Presentation", on the classification of obligations that must or could be settled with an entity's own equity instruments. The new recommendation requires securities such as Petrobank's subordinated notes to be reclassified from equity to liabilities on the balance sheet. There is no impact on earnings per share but interest expense on the subordinated notes and the related future income tax recovery are deducted when calculating net income rather than net income attributable to common shareholders as previously reported. Note 2 discloses the impact of the adoption of the revised recommendations of CICA section 3861 on the consolidated financial statements.

SUMMARY OF QUARTERLY RESULTS

	2005	2004				2003		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Financial ($000s except where noted)								
Oil and natural gas revenue	**11,382**	17,028	18,700	18,175	19,474	20,540	13,962	14,747
Cash flow from operations [1]	**3,396**	4,388	6,166	6,215	6,628	6,424	3,562	4,277
Per share - basic and diluted ($)	**0.06**	0.08	0.11	0.11	0.12	0.12	0.08	0.09
Net income (loss)	**(248)**	6,630	(1,727)	(1,822)	(2,248)	(20,248)	(3,398)	(1,508)
Per share - basic and diluted ($)	**-**	0.12	(0.03)	(0.03)	(0.04)	(0.38)	(0.07)	(0.03)
Capital expenditures	**10,780**	14,272	8,921	9,995	14,713	27,338	28,065	24,696
Operations								
Canadian operating netbacks by product [2]								
Light/medium oil and NGL sales price ($/bbl)	**47.59**	21.05	27.03	29.54	27.50	26.81	28.09	28.28
Royalties	**9.76**	10.18	9.79	8.93	8.97	5.89	6.01	7.28
Production expenses	**9.99**	9.11	6.78	7.14	6.81	6.22	5.24	6.99
Operating netback	**27.84**	1.76	10.46	13.47	11.72	14.70	16.84	14.01
Heavy oil sales price ($/bbl)	**-**	15.96	26.95	22.36	24.46	22.95	24.86	27.14
Royalties	**-**	4.36	5.31	3.29	3.45	2.36	4.22	3.75
Production expenses	**-**	9.89	9.08	10.69	8.52	11.18	6.83	9.40
Operating netback	**-**	1.71	12.56	8.38	12.49	9.41	13.81	13.99
Natural gas sales price ($/mcf)	**6.08**	5.80	6.13	5.99	6.09	5.89	5.49	6.73
Royalties	**1.19**	1.18	1.10	1.08	1.20	0.88	0.82	1.00
Production expenses	**1.02**	1.18	1.08	0.94	1.06	1.26	1.79	1.51
Transportation expenses	**0.29**	0.23	0.23	0.30	0.28	0.28	0.51	0.39
Operating netback	**3.58**	3.21	3.72	3.67	3.55	3.47	2.37	3.83
Oil equivalent sales price ($/boe)	**38.30**	29.90	33.09	32.22	32.18	30.57	28.76	32.06
Royalties	**7.59**	7.53	7.20	6.79	7.15	5.12	5.35	6.29
Production expenses	**6.76**	7.81	6.90	6.77	6.82	7.55	7.06	8.06
Transportation expenses	**1.43**	0.93	0.85	1.02	0.97	0.85	0.83	0.77
Operating netback	**22.52**	13.63	18.14	17.64	17.24	17.05	15.52	16.94
Colombian operating netback ($/bbl)								
Oil sales price	**49.13**	46.45	48.69	45.62	36.63	31.66	31.37	29.74
Royalties	**3.93**	3.71	3.96	3.62	2.93	2.53	2.44	2.40
Production expenses	**8.46**	7.08	7.10	8.53	7.89	15.62	9.24	7.93
Operating netback	**36.74**	35.66	37.63	33.47	25.81	13.51	19.69	19.41
Average daily production								
Canada - light/medium oil and NGL (bbls)	**317**	993	1,065	1,288	1,332	2,147	2,097	2,097
Canada - heavy oil (bbls)	**-**	424	564	562	703	784	812	661
Canada - natural gas (mcf)	**9,662**	17,880	16,231	14,592	16,069	17,702	6,581	8,057
Total Canada (boe)	**1,927**	4,397	4,334	4,282	4,713	5,881	4,005	4,101
Colombia - oil (bbls)	**1,072**	1,155	1,229	1,354	1,702	1,374	1,166	1,028
Total Company (boe)	**2,999**	5,552	5,563	5,636	6,415	7,255	5,171	5,129

(1) 2003 and 2004 periods restated for change in accounting policy.
(2) Canadian sales prices are shown after hedging costs. The hedging costs relating to oil sales were net against the Canadian light/medium oil and NGL price, except for the Company's 300 bopd fixed price crude oil contract (WTI - US$27.74) that was net against the heavy oil sales price in 2004. The majority of these hedges expired on December 31, 2004.

Highlights

As at and for the three months ended March 31,	**2005**	2004	% change
Financial			
($000s, except where noted)			
Oil and natural gas revenue	**11,382**	19,474	(41)
Cash flow from operations [1]	**3,396**	6,628	(49)
Per share – basic and diluted ($) [2]	**0.06**	0.12	(50)
Net loss	**(248)**	(2,248)	(89)
Per share – basic and diluted ($)	**-**	(0.04)	
Capital expenditures	**10,780**	14,713	(27)
Total assets	**184,841**	223,205	(17)
Net debt [3]	**42,796**	121,396	(65)
Common shares outstanding (000s)			
Basic	**55,141**	54,651	1
Diluted	**60,682**	59,649	2
Operations [4]			
Canadian operating netback ($/boe except where noted)			
Oil and NGL revenue ($/bbl) [5]	**47.59**	26.45	80
Natural gas revenue ($/mcf) [5]	**6.08**	6.09	-
Oil and natural gas revenue [5]	**38.30**	32.18	19
Royalties	**7.59**	7.15	6
Production expenses	**6.76**	6.82	(1)
Transportation expenses	**1.43**	0.97	47
Operating netback	**22.52**	17.24	31
Colombian operating netback ($/bbl)			
Oil revenue	**49.13**	36.63	34
Royalties	**3.93**	2.93	34
Production expenses	**8.46**	7.89	7
Operating netback	**36.74**	25.81	42
Average daily production			
Canada - oil and NGL (bbls)	**317**	2,035	(84)
Canada - natural gas (mcf)	**9,662**	16,069	(40)
Total Canada (boe)	**1,927**	4,713	(59)
Colombia - oil (bbls)	**1,072**	1,702	(37)
Total Company (boe)	**2,999**	6,415	(53)

(1) Cash flow from operations before changes in other non-cash items. 2004 amount has been restated for change in accounting policy.
(2) Calculated based on cash flow from operations before changes in other non-cash items.
(3) Includes working capital (deficiency) and subordinated notes.
(4) 6 mcf of natural gas is equivalent to 1 barrel of oil equivalent (boe).
(5) 2004 Canadian sales prices are shown after hedging costs. The majority of these hedges expired on December 31, 2004.

Consolidated Balance Sheets

(Unaudited, thousands of Canadian dollars)

As at	March 31, 2005	December 31, 2004 (Restated per Note 2)
Assets		
Current assets		
Cash and cash equivalents	$ 47,403	$ 75,509
Accounts receivable and other current assets	13,603	13,063
	61,006	88,572
Capital assets	123,835	116,820
	$ 184,841	$ 205,392
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 21,034	$ 27,893
Obligations under gas sale and transportation contracts	6,273	6,477
Asset retirement obligations (Note 4)	2,705	2,870
Future income tax liability	14,889	15,492
Subordinated notes (Note 5)	82,768	95,862
	127,669	148,594
Shareholders' equity		
Common shares (Note 3)	73,596	73,157
Contributed surplus (Note 3)	708	525
Deficit	(17,132)	(16,884)
	57,172	56,798
	$ 184,841	$ 205,392

See accompanying notes to these consolidated financial statements.

Consolidated Statements of Operations and Retained Earnings

(Unaudited, thousands of Canadian dollars, except per share amounts)

Three months ended March 31,	2005	2004 (Restated per Note 2)
Revenues		
Oil and natural gas	$ 11,382	$ 19,474
Royalties	(1,695)	(3,519)
	9,687	15,955
Expenses		
Production	1,989	4,148
Transportation	248	416
General and administrative	2,148	1,699
Interest on bank debt	-	478
Interest on subordinated notes (Note 2)	2,548	2,824
Depletion, depreciation and accretion	3,600	9,033
	10,533	18,598
Loss before other items and taxes	(846)	(2,643)
Gain on repurchase of subordinated notes (Note 5)	134	-
Other income (expense)	267	(531)
Loss before taxes	(445)	(3,174)
Capital taxes	(406)	(263)
Future income tax recovery	603	1,189
Net loss	(248)	(2,248)
Deficit, beginning of period	(16,884)	(17,717)
Deficit, end of period	$ (17,132)	$ (19,965)
Basic and diluted loss per share (Note 3)	$ -	$ (0.04)

See accompanying notes to these consolidated financial statements.

Consolidated Statements of Cash Flow

(Unaudited, thousands of Canadian dollars)

Three months ended March 31,	2005	2004 (Restated per Note 2)
Operating Activities		
Net loss	$ (248)	$ (2,248)
Depletion, depreciation and accretion	3,600	9,033
Non-cash stock based compensation	204	82
Future income tax recovery	(603)	(1,189)
Amortization of discount on subordinated notes (Note 5)	577	575
Gain on repurchase of subordinated notes (Note 5)	(134)	-
Loss recorded on disposition of sales contract	-	375
Cash flow from operations	3,396	6,628
Changes in other non-cash items	(3,758)	(3,987)
	(362)	2,641
Financing Activities		
Repurchase of subordinated notes (Note 5)	(13,537)	-
Repayment of bank debt	-	(7,474)
Issuance of common shares (Note 3)	418	285
Repayment of debenture	-	(14,014)
Amortization of obligations under gas sale and transportation contracts	(204)	(202)
	(13,323)	(21,405)
Investing Activities		
Expenditures on capital assets	(10,780)	(14,713)
Proceeds on disposition of capital assets	-	38,137
Changes in other non-cash items	(3,641)	(4,660)
	(14,421)	18,764
Net change in cash position	(28,106)	-
Cash and cash equivalents, beginning of period	75,509	-
Cash and cash equivalents, end of period	$ 47,403	$ -

See accompanying notes to these consolidated financial statements.

Share Purchase Warrants

The 1,420,300 outstanding share purchase warrants allow holders to purchase an equivalent number of common shares at $4.00 per share on or before May 6, 2006.

Deferred Share Units

In March 2005, the Company granted 120,000 deferred share units under the Company's deferred share compensation plan that allows holders to receive one common share per unit upon payment of $0.05 per share. The units vest after three years and expire after ten years. The plan allows the Company to grant up to 500,000 units.

Earnings Per Share

Basic and diluted loss per share have been calculated based on net loss divided by the weighted average number of common shares outstanding for the three month period ended March 31, 2005 of 55,046,125 (2004 – 54,562,599). The diluted calculations for the three month periods ended March 31, 2005 and 2004 include nil additional shares for the potential impact of stock options, share purchase warrants, and deferred share units.

Stock Based Compensation

The fair value of stock options and deferred share units granted have been estimated on their respective grant dates using the Black Scholes option-pricing model using the following assumptions:

Three months ended March 31,	**2005**	2004
Risk free interest rate	**4.25%**	4.5%
Dividend rate	**0%**	0%
Expected life (years)	**4**	4
Expected volatility	**30%**	30%

The average values per option and deferred share unit granted during the period were $1.25 and $4.11 respectively, as at the date of grant.

Note 4 - Asset Retirement Obligations

Changes to asset retirement obligations were as follows:

Three months ended March 31,	**2005**	2004
Asset retirement obligations, beginning of period	**2,870**	9,602
Obligations incurred	**69**	303
Obligations disposed	**-**	(1,041)
Accretion expense	**59**	216
Changes in estimated future cash flows and other	**(293)**	(810)
Asset retirement obligations, end of period	**2,705**	8,270

The total undiscounted amount of estimated cash flows required to settle the obligations is $14.9 million (2004 - $25.4 million) using an inflation factor of 1.5 percent. The obligations have been recorded at their present value using a credit-adjusted risk free rate of 9 percent. Most of these obligations are not expected to be paid for several years extending up to 36 years in the future, and are expected to be funded from general Company resources at the time of settlement.

Note 5 – Subordinated Notes

Petrobank's subordinated notes are unsecured and subordinate to the Company's existing credit facility and any other senior debt that may be outstanding from time to time. Interest on the notes is payable quarterly at a rate of 9 percent per annum and the notes mature on July 31, 2006. The notes may be repaid at their face value prior to their maturity date and the Company has the option of issuing common shares, at market price, to settle quarterly interest payments as well as the principal amount. The notes were recorded at fair value on issuance and the discount to face value is being amortized to interest on subordinated notes over the term of the notes.

On January 13, 2005, the Company repurchased $14.3 million face value of outstanding subordinated notes through a substantial issuer bid at a price including accrued interest of $95 per $100 face value at a cost of $13.6 million. As a result of the transaction, the outstanding face value of the Company's subordinated notes was reduced to $86.1 million. The Company recorded a pre-tax gain of $0.1 million on this transaction.

In April 2005, Petrobank redeemed an additional $17.2 million of subordinated notes, further reducing the face value outstanding to $68.9 million (Note 7). This redemption, along with the $14.3 million repurchase in January, results in an annualized interest savings of $2.8 million until maturity on July 31, 2006.

	Carrying Value	Face Value
Balance at December 31, 2004	$ 95,862	$ 100,438
Amortization of discount	577	-
Repurchase	(13,671)	(14,302)
Balance at March 31, 2005	**$ 82,768**	**$ 86,136**

Note 6 – Commitments and Contingencies

The Company is negotiating contracts for four new exploration blocks and one technical evaluation area (TEA) in Colombia with the National Hydrocarbon Agency (ANH). Three of the exploration blocks and the TEA are in the Llanos Basin, and the remaining exploration block is in the Putumayo Basin. The first-phase commitments (12 to 24 months) include reprocessing 2-D seismic, shooting additional 2-D and 3-D seismic, and drilling one well on the Joropo Block in the Llanos Basin. Total first-phase commitments are estimated to be approximately US$6 million. Upon completion of the first-phase the Company has the option to proceed with second-phase commitments, including the drilling of prospective wells identified during the first-phase, or it can elect not to proceed with any further expenditures and return the block or TEA to the ANH.

Note 7 – Government Assistance

Effective March 31, 2005, Technology Partnerships Canada (TPC) announced their commitment to invest up to $9 million towards the development and field demonstration of the Company's THAI™ technology at the WHITESANDS pilot project. Under the TPC funding commitment, TPC has agreed to contribute 20.134 percent of eligible expenditures for the WHITESANDS project to a maximum of $9 million. Upon commercialization of the THAI™ technology TPC would be entitled to receive a royalty, based on gross business revenue, of up to three percent until no later than December 31, 2022. Petrobank may make claims on a quarterly basis, with the first claim to be made on June 30, 2005 covering the period beginning August 26, 2004. The funding agreement will automatically terminate if Petrobank does not make this initial claim.

Note 8 – Subsequent Events

On April 12, 2005, the Company closed a $23.75 million financing involving an investment in Petrobank and its wholly owned subsidiary, WHITESANDS Insitu Ltd. (WHITESANDS). The investor acquired a 16 percent interest in WHITESANDS for a $14 million equity commitment and 3 million common shares of Petrobank at a price of $3.25 per share for aggregate proceeds of $23.75 million. The investment in WHITESANDS is being made in four installments beginning with the $5 million received on closing, with the remaining $9 million to be invested in up to four additional tranches ending no later than April 15, 2006. Under the financing agreement, on an annual basis, the investor may request a third-party valuation of WHITESANDS and may require the Company to repurchase the investor's interest in WHITESANDS at fair market value. The Company has the option to fund this repurchase with cash or through the exchange of Petrobank common shares, valued at 95 percent of the 10-day weighted average trading price prior to the date of the exchange.

On April 22, 2005 the Company redeemed an additional 20 percent of the outstanding subordinated notes, reducing the outstanding face value to $68.9 million. The Company purchased $17.2 million face value of notes at a price of $100.5178 including accrued interest per $100 face value at a cost of $17.3 million. The redemption results in additional annual interest expense savings of $1.6 million until maturity on July 31, 2006. The Company expects to record a pre-tax loss of $0.7 million on this transaction in the second quarter as the notes were redeemed at face value, which is in excess of carrying value.

Note 9 – Segmented Information

Three months ended March 31,

	2005			2004 [1]		
	Canada and Other	Colombia	Total	Canada and Other	Colombia	Total
Revenues						
Oil and natural gas	$ 6,642	$ 4,740	$ 11,382	$ 13,801	$ 5,673	$ 19,474
Royalties	(1,316)	(379)	(1,695)	(3,065)	(454)	(3,519)
	5,326	4,361	9,687	10,736	5,219	15,955
Expenses						
Production	1,173	816	1,989	2,926	1,222	4,148
Transportation	248	-	248	416	-	416
General and administrative	1,278	870	2,148	1,022	677	1,699
Depletion, depreciation and accretion	1,934	1,666	3,600	5,757	3,276	9,033
Segmented income	$ 693	$ 1,009	$ 1,702	$ 615	$ 44	$ 659
Non-segmented expenses						
Interest on bank debt			-			(478)
Interest on subordinated notes			(2,548)			(2,824)
Gain on repurchase of subordinated notes			134			-
Other income (expense)			267			(531)
Capital taxes			(406)			(263)
Future income tax recovery			603			1,189
Net loss			$ (248)			$ (2,248)
Identifiable assets [2]	$108,045	$ 76,796	$184,841	$144,018	$ 79,187	$223,205
Capital expenditures [2]	$ 5,879	$ 4,901	$ 10,780	$ 8,896	$ 5,817	$ 14,713

[1] Restated per Note 2.
[2] Canada includes Heavy Oil Business Unit expenditures of $2.4 million in 2005 (2004 - $0.5 million), identifiable assets at March 31, 2005 of $12.1 million (2004 - $6.2 million), and no revenue and expenses.

Natural gas volumes have been converted to barrels of oil equivalent ("boe") so that six thousand cubic feet ("mcf") of natural gas equals one barrel based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head. Boes may be misleading, particularly if used in isolation.

Certain statements in this release are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995. Specifically, this press release contains forward-looking statements relating to, prospects for technologies which remain unproven and the expected amount and timing of capital projects. The reader is cautioned that assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the ability to economically test, develop and utilize the technologies described herein, the feasibility of the technologies, general economic, market and business conditions; fluctuations in oil and gas prices; the results of exploration and development of drilling and related activities; fluctuation in foreign currency exchange rates; the uncertainty of reserve estimates; changes in environmental and other regulations; risks associated with oil and gas operations; and other factors, many of which are beyond the control of the Company. There is no representation by Petrobank that actual results achieved during the forecast period will be the same in whole or in part as those forecast.

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