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PETROBANK
ENERGY AND RESOURCES LTD.

[redacted]

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November 14, 2005

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

SUPPL

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,

Corey C. Ruttan
Director of Corporate Finance and Investor Relations

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PETROBANK
ENERGY AND RESOURCES LTD.

NEWS RELEASE

PETROBANK CASH FLOW UP 94% OVER PREVIOUS QUARTER

Calgary, Alberta – November 14, 2005 – Petrobank Energy and Resources Ltd. ("Petrobank" or the "Company") is pleased to provide this operational update of our Canadian, Latin American and Heavy Oil Business Units, and our third quarter financial results.

HIGHLIGHTS

The third quarter results reflect the 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 sold by the Company during 2004.

- Cash flow from operations increased 44 percent from the third quarter of 2004 and 94 percent from the second quarter of 2005 to $8.9 million during the current period.
- The Company recorded third quarter net income of $3.2 million compared to a loss a year earlier of $1.7 million.
- Canadian production increased 66 percent year-over-year, excluding production from properties sold during 2004.
- Colombian oil sales averaged 1,073 bopd in the third quarter of 2005, compared to 1,024 bopd in the second quarter of 2005.
- Net debt was reduced by 56 percent from $124.9 million at the end of the third quarter of 2004 to $54.5 million at the end of the current period.
- Operating netbacks improved 97 percent and 22 percent in Canada and Colombia, respectively.
- Petrobank submitted an initial $1.6 million claim under the $9 million Technology Partnerships Canada funding commitment for the WHITESANDS - THAI™ pilot project.
- Issued 4 million common shares for gross proceeds of $38.6 million on October 20, 2005.
- Redeemed an additional $18.9 million of subordinated notes on November 4, 2005.

OPERATIONAL UPDATE

Heavy Oil Business Unit

Petrobank, through its 84 percent owned subsidiary WHITESANDS Insitu Ltd., is currently constructing the WHITESANDS pilot project to field-demonstrate our patented THAI™ heavy oil recovery process. THAI™ is an evolutionary in-situ combustion technology for the recovery of bitumen and heavy oil that combines a vertical air injection well with a horizontal production well. THAI™ integrates existing proven technologies and provides the opportunity to create a step change in the development of heavy oil resources globally. During the process, a high temperature combustion front is created underground where part of the oil in the reservoir is burned, generating heat, which reduces the viscosity of the remaining oil allowing it to flow by gravity to the horizontal production well. The combustion front sweeps the oil from the toe to the heel of the horizontal producing well, recovering up to an estimated 80 percent of the original-oil-in-place while partially upgrading the crude oil in-situ. Petrobank controls all intellectual property rights to the THAI™ process and related enhancements, including the patented CAPRI™ technology, which offers the potential for further in-situ upgrading through the use of a well-bore integrated catalyst. CAPRI™ will be tested after the THAI™ process has been satisfactorily evaluated at field scale in the WHITESANDS pilot.

THAI™ has many potential benefits over other in-situ recovery methods, such as SAGD (Steam Assisted Gravity Drainage). These benefits include higher resource recovery, lower production and capital costs, minimal usage of natural gas and fresh water, a partially upgraded crude oil product, reduced diluent requirements for transportation, and lower greenhouse gas emissions. The THAI™ process also has the potential to operate in lower pressure, lower quality, thinner and deeper reservoirs than current steam-based recovery processes.

The WHITESANDS pilot project is situated on a portion of our 45 sections (28,800 acres) of oil sands leases in the Christina Lake region of Alberta, which contains an estimated bitumen resource of 1.3 billion barrels in place, based on an independent assessment conducted by Fekete Associates Inc.

Project activities at our WHITESANDS - THAI™ project accelerated during the third quarter and we have now drilled and completed all three horizontal production wells with their related vertical air injection wells. We have also drilled the observation wells necessary for project start-up. The plant design incorporates modular production methods where key elements of the project have been manufactured off-site with final assembly on-site. On-site construction activities have commenced and the project is forecast to be complete by year-end with startup anticipated in early 2006. Pilot project expenditures totaled $10.6 million during the third quarter and total capital costs are estimated at $33 to $35 million.

Internationally, we continue to work with various state oil companies to jointly evaluate the THAI™ technology and potential resource accumulations in a variety of basins. The ultimate goal is to capture a global portfolio of heavy oil resources where the application of our THAI™ technology can lead to greatly improved recovery rates and significant long-term value growth for the Company. In support of this activity, we have recently been awarded two contracts covering 1,146,922 acres with heavy oil potential in Colombia.

Canadian Business Unit

Production during the third quarter averaged 2,465 boepd, and we continue to target an exit rate for the year of approximately 4000 boepd. Production is expected to expand through the balance of 2005 with the tie-in of additional wells at Jumpbush, Red Willow, and the continuing execution of our exploration and development drilling program at Red Willow and Macklin.

Jumpbush

Despite weather related delays, Petrobank drilled 57 of the 58 wells planned for Jumpbush in 2005 by the end of the third quarter. Our gas plant expansion, line looping and new field compression have all been completed and we expect the facility to reach full capacity of 25 mmcf/day once the remaining new wells are tied-in. Of the 57 wells drilled, all are completed but only 13 are presently tied-in and producing. Petrobank's remaining 2005 program consists of the tie-in of a further 39 wells and drilling one additional well. Six wells from the 2005 program were drilled for land retention purposes and will be on stream in 2006 as additional wells are drilled in the same vicinity.

Red Willow

Drilling operations commenced during the third quarter at Red Willow and we have drilled six wells to-date, resulting in one oil well and two gas wells, with three wells D&A. A large 3-D seismic program has been acquired and we have recently drilled one additional oil well. The planned program for the balance of 2005 consists of drilling an additional five to seven wells, and pipelining to bring on-stream our behind-pipe gas potential.

Macklin

Macklin is an exploration land block (4,336 gross acres – 100% working interest) in Saskatchewan along the Alberta border, with potential for Colony gas and Sparky and Cummings oil accumulations. In 2004, Petrobank acquired a 3-D seismic program over most of the lands and identified several exploratory locations. Since the beginning of July, two wells have been drilled, cased, and completed. The first well encountered a new Sparky oil reservoir and the second proved up the horizontal production capability of a Cummings oil reservoir. Each of these first two wells encountered both the Sparky and Cummings pools and allowed us to delineate an initial development drilling program. Based on strong initial performance from these wells a further five horizontal wells and one vertical well are planned for the balance of this year. A small facility will be required to manage the associated oil and water production from these zones.

Exploration

We currently have 315,000 net acres of undeveloped land and continue to build additional exploration and development land positions in southern Alberta and Saskatchewan close to our existing core areas, both through farm-ins and crown land sales. Petrobank drilled and cased one farm-in well in July and our current plans anticipate the acquisition of several 3-D seismic programs, with additional drilling to be based on results from these programs. This activity forms the basis for the potential creation of new core areas similar to Macklin and Red Willow. Our extensive undeveloped land position also includes fee simple lands in Alberta, Saskatchewan and Manitoba, which has allowed Petrobank to participate in the evolving Bakken light oil play.

Princeton

Petrobank, as operator, holds a 60 percent working interest in a unique land position at Princeton, British Columbia, where we own the Petroleum and Natural Gas rights (including CBM) as well as the coal rights over the entire basin totaling 38,000 acres. Our initial exploratory well flowed free methane with minor amounts of fresh water, indicating that the coal was fully gas saturated and would probably not require an extended de-watering period. Our near term efforts are focusing on refining the techniques for drilling and completion that will improve gas production rates as we move this project closer to commerciality. Additional delineation drilling, which could commence as early as 2006, will be required in advance of a possible large-scale commercial project.

Latin American Business Unit

Petrobank, through its Colombian subsidiary Petrominerales Colombia Ltd., has now executed contracts for five exploration blocks and three Technical Evaluation Areas ("TEAs") covering a total of 2.0 million acres in the Llanos and Putumayo Basins. We are presently working to finalize terms on additional contracts covering more than 600,000 acres. The Llanos exploration blocks are situated along a geological trend that offers multi-pool/multi-zone prospects. These blocks will be evaluated using 2-D and 3-D seismic, specialized processing technologies and North American exploration models. Two large TEAs in the basin, Rio Ariari (607,137 acres) and Chiguiro (539,785 acres), lie in the Colombian heavy oil fairway. These TEAs will be evaluated for conventional oil prospects as well as for heavy oil accumulations suitable for Petrobank's patented THAI™ technology. This acreage makes Petrobank one of the largest exploration landholders in the country. All new exploration blocks are governed by Colombia's new fiscal terms where we earn 100 percent of production subject only to an eight percent initial royalty rate.

First phase work commitments on these blocks typically range from geological studies for TEAs to seismic programs for the exploration blocks. On the Joropo Block, our first Llanos Basin exploration prospect will be drilled in the first quarter of 2006 and we have purchased long lead-time items and confirmed the availability of a drilling rig currently positioned in the Llanos Basin. The well location, based on 3-D seismic, will be located half a kilometer east of the original Joropo well, which was drilled in 1985. That well encountered a thin oil zone lying on water and drill-stem-tested 35.7 degree API oil with a water-cut of 83%. We believe our well will be approximately 25 feet up-dip to the original well. On the other exploration license areas, seismic programs are being planned for acquisition during the first half of 2006. Anticipated costs to fulfill the first-phase commitments on the 5 new exploration blocks and TEAs over the next 12 months are expected to be US$10 million.

Colombian production averaged 1,073 barrels of oil per day ("bopd") from our Orito and Neiva blocks during the third quarter, an increase from the second quarter average of 1,024 bopd. This minor increase is a result of the production obtained during the well testing phase of Orito-116. The Orito-116 well targeted a large southwest extension to the main producing region of the Orito field and tested both the Lower A unit sands and the Upper B, C, & D sands. Initial production tests in the lower A-sand units showed positive hydrocarbon potential with water cuts fluctuating between 80 and 90 percent at very low drawdown and inflow potential of greater than 5,000 barrels per day of total fluid. The upper B, C, and D sands tested at non-stimulated rates of 200 bopd with water cuts of less than 10 percent. The well was tested from these upper sands over an extended period to determine overall fluid rates and the decision was made to proceed with a completion that included under-reaming the B, C, and D sands and the upper portion of the A sands followed by the installation of a large volume electrical submersible pump ("ESP"). Upon successful installation of an appropriately sized ESP we expect the well to produce at initial rates between 500 and 800 bopd.

Long lead times along with logistical and operational difficulties delayed the installation of the ESP at Orito-116 and recent mechanical problems with the pump required us to source a larger and more sophisticated completion rig to conduct workover operations. During pump pulling operations, the completion string became lodged in the hole and we are currently undertaking extended fishing procedures to remove the tubing string, electrical cable and the ESP. A new ESP is available, if required, but the fishing operation has increased in complexity, and we now do not expect the well to be on production until December.

Orito-117, the second well to be drilled in the southwest extension area of the Orito field, has also been cased as a potential Caballos oil well. This well further confirmed our geological interpretation of the southwest extension of the Orito pool, and encountered the top of the Caballos formation a full 60 feet updip from the Orito-116 well. Completion operations have commenced on the Orito-117 well, and we anticipate initial flow rates from the well in the next two weeks. Presently, there is only one drilling rig in the entire Putumayo Basin and we have concluded that this rig is ill suited for platform-based, multi-well directional drilling operations. We are currently investigating importing new, state of the art drilling equipment for our next drilling phase, which will require a longer term commitment and which is expected to yield significant operational efficiencies and cost savings. We have, however, retained an option on the current rig to allow the Orito-118 well to be drilled this year. This well should spud later in November. We are also pursuing options to source an additional completion rig for Orito, capable of performing our more demanding completion operations and servicing our existing wells. This completion rig could also provide drilling services for an expanded development program at Neiva.

Originally, our plans for Petrominerales in 2005 included completing a small IPO as an initial step in the ultimate spin-out of this subsidiary. The IPO is now targeted for early to mid-2006 in order to complete the current three-well drilling program at Orito and to begin to crystallize value from our expanding exploration land base. This will also allow us to provide year-end financial statements and reserve report for Petrominerales as part of our corporate documentation.

OUTLOOK

Activity in all three of our business units has expanded considerably in 2005 and this trend is expected to continue through 2006. In Canada, our development success at Jumpbush and Red Willow provides the foundation for growth into new core areas that are being developed on our extensive land inventory. In Colombia, the first follow-up to our Orito-116 well is now in the completion phase, and our exploration program has captured a significant land base in some of Colombia's most prospective regions, including two large blocks that may yield prospects suitable for applying Petrobank's THAI™ technology. Our first exploratory well in the Colombian Llanos Basin will be drilled in early 2006. In our Heavy Oil Business

Unit, the WHITESANDS pilot project is under construction and on target to deliver initial results in early 2006. We continue to refine our existing technology base surrounding the THAI™ and CAPRI™ technologies, develop new patents, and pursue new resource capture opportunities both domestically and internationally. Our recently completed $38.6 million financing provides the resources necessary to accelerate the Company's suite of high-impact opportunities over the coming year.

Management's Discussion and Analysis

The following Management's Discussion and Analysis (MD&A) is dated November 11, 2005 and should be read in conjunction with the unaudited consolidated financial statements of the Company for the three and nine month periods ended September 30, 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 and asset retirement obligations settled. 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

Total Canadian production averaged 2,465 boepd during the third quarter, a 15 percent increase from the second quarter and a 43 percent decrease from the same period last year. Production from properties sold during 2004 accounted for 2,846 boepd (56 percent natural gas) in the third quarter of 2004 and eliminated all of the Company's heavy oil production. Excluding production from properties sold during 2004, Canadian production increased 66 percent from the third quarter of 2004. The Company expects to exit 2005 producing over 4,000 boepd in Canada with production increases forecast from the tie-in of wells at Jumpbush and additional drilling at Red Willow and Macklin.

Oil and NGL production in Canada during the third quarter averaged 551 barrels per day (bpd), an increase from the 273 bpd produced in the second quarter and a decrease from the 1,629 bpd produced in the third quarter of 2004. The decrease from the prior year period is due to a series of dispositions during 2004 including the $96.1 million sale in December 2004.

The Company averaged 11.5 million cubic feet per day (mmcfpd) of natural gas in the third quarter compared to 11.2 mmcfpd in the second quarter and 16.2 mmcfpd a year earlier. Production increased from the second quarter as a result of 13 wells being tied-in and producing at the Jumpbush property in late September. Fourth quarter production will continue to expand through the tie-in of an additional 39 wells, growing production at Jumpbush to an estimated 17.5 mmcfpd.

Colombian oil sales averaged 1,073 bpd in the third quarter, an increase from the second quarter average of 1,024 bpd and a decrease from the 1,229 bpd produced in the third quarter of 2004. Third quarter production increased over the second quarter primarily due to production from testing the Orito-116 well . Production is expected to increase upon finalization of the completion of the Orito-116 and Orito-117 wells.

Average Benchmark Prices and US$ Exchange Rate

For the three months ended	**September 30, 2005**	June 30, 2005	September 30, 2004
WTI crude oil (US$/bbl)	**63.19**	53.17	43.88
WTI crude oil (Cdn$/bbl)	**75.92**	66.14	57.33
NYMEX natural gas (US$/mmbtu) [1]	**8.49**	6.73	5.76
US$/Cdn$ exchange rate	**0.83**	0.80	0.77

(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 third quarter was $65.50 per barrel, a 3 percent increase from the $63.60 per barrel received in the second quarter and a 143 percent increase from the $27.00 per barrel received in the third quarter of 2004. The average price received increased significantly from 2004 periods due to higher commodity prices, 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 third quarter was $8.25 per mcf, a 25 percent increase from $6.60 per mcf received in the second quarter and a 35 percent increase from the $6.13 per mcf received in the third quarter of 2004. These increases are primarily a result of increased commodity prices. 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$50.15 per barrel in the third quarter, representing a US$13.04 per barrel (21% of WTI) differential to WTI compared to a differential of US$11.11 per barrel (21% of WTI) in the second quarter and US$6.61 per barrel (15% of WTI) in the third quarter of 2004. The lower differential in 2004 was a result of a fixed differential at WTI prices above $30.00 per barrel pursuant to the original marketing agreement for Orito production that was amended in December 2004.

Royalties

Royalties totaled $2.8 million in the current period, an increase from $2.2 million in the second quarter and a decrease from $3.3 million in the third quarter of 2004. Canadian royalties as a percentage of revenue decreased to 19.6 percent in the current period from 21.9 percent in the second quarter and 21.8 percent in the third quarter of 2004. Canadian royalty rates are expected to average approximately 22 percent through the remainder of 2005. Colombian royalties remained constant at a rate of 8 percent.

Production Expenses

Consolidated production expenses decreased to $2.2 million from $2.3 million in the second quarter and $3.6 million in the third quarter of 2004. Production expenses per unit of production in Canada were $5.81 per boe, a decrease of 18 percent from $7.12 per boe in the second quarter and a decrease of 16 percent from $6.90 per boe in the third quarter of 2004. Per unit expenses decreased from the prior year period primarily due to increased production at Jumpbush, which maintains per unit costs that are less than the majority of properties sold in the fourth quarter of 2004.

Production expenses in Colombia averaged $9.41 per barrel during the quarter, a 7 percent decrease from the second quarter average of $10.09 per barrel and a 33 percent increase from the third quarter 2004 average of $7.10 per barrel. The decrease from the second quarter average is a result of the fixed nature of certain costs combined with increased production. The increase in per unit operating costs from the prior year period 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 $2.0 million in the third quarter of 2005, a decrease from $2.2 million in the second quarter and a slight increase from $1.9 million in the comparative 2004 period.

Interest on Bank Debt

The Company's credit facility was undrawn throughout the third quarter of 2005 compared to $27.8 million drawn at the end of the same period a year earlier. As a result, interest on bank debt decreased from $0.3 million in the third quarter of 2004 to nil in 2005.

Interest on Subordinated Notes

Interest on subordinated notes totaled $2.0 million during the third quarter, compared to $2.9 million during the same period last year due to the repurchase of $31.5 million of subordinated notes in 2005. Subsequent to September 30, 2005 the Company repurchased an additional $19.0 million face value of subordinated notes further reducing the outstanding face value to $49.9 million. As a result, interest on subordinated notes will decrease to $1.7 million in the fourth quarter of 2005 and to $1.5 million per quarter thereafter until expiry on July 31, 2006.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion expense increased to $4.0 million in the third quarter ($12.36 per boe) from $3.8 million in the second quarter ($13.13 per boe) and decreased from $8.1 million ($15.86 per boe) in the third quarter of 2004. On a unit-of-production basis in Canada, the rate fell to $9.87 per boe compared to $14.16 in the third 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 $18.07 per barrel in the third quarter of 2005, compared to $21.87 per barrel a year earlier. The decrease is a result of reserve additions recorded in the fourth quarter of 2004.

Capital Taxes

The Company's third quarter capital taxes totaled $0.6 million (2004 - $0.5 million) including Large Corporations Tax in Canada and presumptive income taxes in Colombia.

Future Income Taxes

The Company's third quarter future income tax expense totaled $0.9 million compared to a recovery of $0.9 million in the third quarter of 2004. A future income tax expense was recorded in the current period as a result of net income before taxes of $4.6 million in the current period compared to a net loss before taxes of $2.2 million a year earlier.

Cash Flow from Operations

Cash flow from operations totaled $8.9 million during the quarter, increases of 44 percent from the third quarter of 2004 and 94% from the second quarter of 2005. Despite the disposition of 66 percent of third quarter 2004 Canadian production cash flow increased as a result of an improvement in average oil quality, the expiry of certain hedges, increased commodity prices along with lower operating costs and interest expense. The increase over the prior quarter is primarily a result of increased production and commodity prices.

Net Income (Loss)

Net income totaled $3.2 million in the third quarter of 2005, a significant improvement over the $1.7 million loss recorded in the comparative 2004 period. Production declines resulting from the disposition of properties in the fourth quarter of 2004 were largely offset by new production additions and higher commodity prices with the increase resulting primarily from lower depletion depreciation and accretion expense, and lower interest expense.

Capital Expenditures

Three months ended September 30,		2005		2004
Business Unit				
Canada	$	**16,395**	$	6,690
Heavy Oil		**10,636**		599
Latin America (Colombia)		**5,063**		1,632
Total	$	**32,094**	$	8,921

Nine months ended September 30,		2005		2004
Business Unit				
Canada	$	**28,586**	$	22,226
Heavy Oil		**15,707**		1,536
Latin America (Colombia)		**15,423**		9,867
Total	$	**59,716**	$	33,629

Canadian Business Unit expenditures during the third quarter related primarily to the Jumpbush property, including drilling, completions and the plant expansion. Significant expenditures were also incurred at the Red Willow and Macklin properties for drilling, completions, and facilities, as well as workovers at the Red Willow and Princeton properties.

Heavy Oil expenditures increased from prior quarters as activity at the WHITESANDS Insitu Ltd. (WHITESANDS) - THAI™ pilot project site accelerated during the third quarter. Site preparation and facilities design work were substantially completed, and the first of three horizontal production wells was drilled during the quarter.

Latin American expenditures related primarily to completion operations on the Orito-116 well and spudding the Orito-117 well, as well as initial geological and surface studies on recently acquired exploration blocks.

Liquidity and Capital Resources

At September 30, 2005 net debt totaled $54.5 million, including the book value of outstanding subordinated notes ($67.2 million). The subordinated notes are not callable and mature in July 2006. Working capital excluding outstanding subordinated notes at September 30, 2005 totaled $12.7 million.

Petrobank maintains a senior secured credit facility with a maximum borrowing base of $20 million. In addition, a further $15 million credit facility is available to fund the acquisition and/or development of producing or proved non-producing petroleum and natural gas reserves in Canada. This development facility provides funding flexibility for projects such as the Company's Jumpbush development program.

Warrant holders have exercised a total of 452,600 warrants in 2005 at an exercise price of $4.00 per share, resulting in cash proceeds of $1.8 million. The total number of warrants outstanding has been reduced to 967,700, which upon exercise would result in additional proceeds of $3.9 million.

On October 20, 2005 the Company issued four million shares at a price of $9.65 per common share for gross proceeds of $38.6 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. The Company recently filed initial claims totaling $1.6 million relating to expenditures incurred between August 26, 2004 and September 30, 2005 which is to be received before the end of the year.

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
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Financial ($000s except where noted)								
Oil and natural gas revenue	**17,983**	13,206	11,382	17,028	18,700	18,175	19,474	20,540
Cash flow from operations [1]	**8,877**	4,575	3,396	4,388	6,166	6,215	6,628	6,424
Per share - basic and diluted ($)	**0.15**	0.08	0.06	0.08	0.11	0.11	0.12	0.12
Net income (loss)	**3,170**	4,702	(248)	6,630	(1,727)	(1,822)	(2,248)	(20,248)
Per share - basic and diluted ($)	**0.05**	0.08	-	0.12	(0.03)	(0.03)	(0.04)	(0.38)
Capital expenditures	**32,094**	16,842	10,780	14,272	8,921	9,995	14,713	27,338
Operations								
Canadian operating netbacks by product [2]								
Light/medium oil and NGL sales price ($/bbl)	**66.45**	63.60	47.59	21.05	27.03	29.54	27.50	26.81
Royalties	**14.12**	13.94	9.76	10.18	9.79	8.93	8.97	5.89
Production expenses	**7.05**	10.82	9.99	9.11	6.78	7.14	6.81	6.22
Operating netback	**45.28**	38.84	27.84	1.76	10.46	13.47	11.72	14.70
Heavy oil sales price ($/bbl)	**52.14**	-	-	15.96	26.95	22.36	24.46	22.95
Royalties	**0.91**	-	-	4.36	5.31	3.29	3.45	2.36
Production expenses	**5.95**	-	-	9.89	9.08	10.69	8.52	11.18
Operating netback	**45.28**	-	-	1.71	12.56	8.38	12.49	9.41
Natural gas sales price ($/mcf)	**8.25**	6.60	6.08	5.80	6.13	5.99	6.09	5.89
Royalties	**1.60**	1.45	1.19	1.18	1.10	1.08	1.20	0.88
Production expenses	**0.91**	1.10	1.02	1.18	1.08	0.94	1.06	1.26
Transportation expenses	**0.23**	0.21	0.29	0.23	0.23	0.30	0.28	0.28
Operating netback	**5.51**	3.84	3.58	3.21	3.72	3.67	3.55	3.47
Oil equivalent sales price ($/boe)	**53.07**	42.63	38.30	29.90	33.09	32.22	32.18	30.57
Royalties	**10.41**	9.35	7.59	7.53	7.20	6.79	7.15	5.12
Production expenses	**5.81**	7.12	6.76	7.81	6.90	6.77	6.82	7.55
Transportation expenses	**1.08**	1.13	1.43	0.93	0.85	1.02	0.97	0.85
Operating netback	**35.77**	25.03	22.52	13.63	18.14	17.64	17.24	17.05
Colombian operating netback ($/bbl)								
Oil sales price	**60.24**	52.34	49.13	46.45	48.69	45.62	36.63	31.66
Royalties	**4.82**	4.19	3.93	3.71	3.96	3.62	2.93	2.53
Production expenses	**9.41**	10.09	8.46	7.08	7.10	8.53	7.89	15.62
Operating netback	**46.01**	38.06	36.74	35.66	37.63	33.47	25.81	13.51
Average daily production								
Canada - light/medium oil and NGL (bbls)	**514**	273	317	993	1,065	1,288	1,332	2,147
Canada - heavy oil (bbls)	**37**	-	-	424	564	562	703	784
Canada - natural gas (mcf)	**11,485**	11,245	9,662	17,880	16,231	14,592	16,069	17,702
Total Canada (boe)	**2,465**	2,147	1,927	4,397	4,334	4,282	4,713	5,881
Colombia - oil (bbls)	**1,073**	1,024	1,072	1,155	1,229	1,354	1,702	1,374
Total Company (boe)	**3,538**	3,171	2,999	5,552	5,563	5,636	6,415	7,255

[1] 2003 and 2004 periods restated for change in accounting policy.
[2] 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

	Three months ended September 30, 2005	2004	% change	Nine months ended September 30, 2005	2004	% change
Financial						
($000s, except where noted)						
Oil and natural gas revenue	**17,983**	18,700	**(4)**	**42,571**	56,349	**(24)**
Cash flow from operations [1]	**8,877**	6,166	**44**	**16,848**	19,009	**(11)**
Per share – basic and diluted ($) [2]	**0.15**	0.11	**36**	**0.29**	0.35	**(17)**
Net income (loss)	**3,170**	(1,727)		**7,624**	(5,797)	
Per share – basic and diluted ($)	**0.05**	(0.03)		**0.13**	(0.11)	
Capital expenditures	**32,094**	8,921	**260**	**59,716**	33,629	**78**
Total assets	**215,829**	217,259	**(1)**	**215,829**	217,259	**(1)**
Net debt [3]	**54,526**	124,872	**(56)**	**54,526**	124,872	**(56)**
Common shares outstanding, end of period (000s)						
Basic	**59,148**	54,732	**8**	**59,148**	54,732	**8**
Diluted	**64,333**	59,433	**8**	**64,333**	59,433	**8**
Operations [4]						
Canadian operating netback ($/boe except where noted)						
Oil and NGL revenue ($/bbl) [5]	**65.50**	27.00	**143**	**60.16**	26.97	**123**
Natural gas revenue ($/mcf) [5]	**8.25**	6.13	**35**	**7.03**	6.09	**15**
Oil and natural gas revenue [5]	**53.07**	33.09	**60**	**45.34**	32.58	**39**
Royalties	**10.41**	7.20	**45**	**9.24**	7.07	**31**
Production expenses	**5.81**	6.90	**(16)**	**6.52**	6.85	**(5)**
Transportation expenses	**1.08**	0.85	**27**	**1.20**	0.95	**26**
Operating netback	**35.77**	18.14	**97**	**28.38**	17.71	**60**
Colombian operating netback ($/bbl)						
Oil revenue	**60.24**	48.69	**24**	**53.97**	42.94	**26**
Royalties	**4.82**	3.96	**22**	**4.32**	3.45	**25**
Production expenses	**9.41**	7.10	**33**	**9.31**	7.83	**19**
Operating netback	**46.01**	37.63	**22**	**40.34**	31.66	**27**
Average daily production						
Canada - oil and NGL (bbls)	**551**	1,629	**(66)**	**381**	1,833	**(79)**
Canada - natural gas (mcf)	**11,485**	16,231	**(29)**	**10,805**	15,588	**(31)**
Total Canada (boe)	**2,465**	4,334	**(43)**	**2,182**	4,431	**(51)**
Colombia - oil (bbls)	**1,073**	1,229	**(13)**	**1,056**	1,428	**(26)**
Total Company (boe)	**3,538**	5,563	**(36)**	**3,238**	5,859	**(45)**

(1) Cash flow from operations before changes in other non-cash working capital and asset retirement obligations settled. 2004 amount has been restated for change in accounting policy.

(2) Calculated based on cash flow from operations before changes in other non-cash working capital and asset retirement obligations settled.

(3) Includes working capital (deficiency) and subordinated notes.

(4) 6 mcf of natural gas is equivalent to 1 barrel of oil equivalent (boe).

(5) 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	September 30, 2005	December 31, 2004 (Restated – Note 2)
Assets		
Current assets		
Cash and cash equivalents	**$ 28,215**	$ 75,509
Accounts receivable and other current assets	**22,875**	13,063
	51,090	88,572
Capital assets (Note 8)	**164,739**	116,820
	$ 215,829	$ 205,392
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	**$ 38,429**	$ 27,893
Subordinated notes (Note 6)	**67,187**	-
	105,616	27,893
Obligations under gas sale and transportation contracts	**5,859**	6,477
Asset retirement obligations (Note 5)	**3,832**	2,870
Future income tax liability	**14,338**	15,492
Subordinated notes (Note 6)	**-**	95,862
	129,645	148,594
Non-controlling interest (Note 3)	**8,406**	-
Shareholders' equity		
Common shares (Note 4)	**85,819**	73,157
Contributed surplus (Note 4)	**1,219**	525
Deficit	**(9,260)**	(16,884)
	77,778	56,798
	$ 215,829	$ 205,392

Commitments and contingencies (Note 7)

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 September 30, 2005	Three months ended September 30, 2004 (Restated - Note 2)	Nine months ended September 30, 2005	Nine months ended September 30, 2004 (Restated - Note 2)
Revenues				
Oil and natural gas	**$ 17,983**	$ 18,700	**$ 42,571**	$ 56,349
Royalties	**(2,836)**	(3,320)	**(6,747)**	(9,932)
	15,147	15,380	**35,824**	46,417
Expenses				
Production	**2,248**	3,554	**6,569**	11,378
Transportation	**246**	339	**714**	1,150
General and administrative	**1,967**	1,875	**6,338**	5,661
Interest on bank debt	**-**	264	**-**	993
Interest on subordinated notes	**2,047**	2,896	**6,720**	8,564
Depletion, depreciation and accretion	**4,023**	8,117	**11,411**	25,518
	10,531	17,045	**31,752**	53,264
Income (loss) before other items and taxes	**4,616**	(1,665)	**4,072**	(6,847)
Gain (Note 3)	**-**	-	**4,744**	-
Loss on repurchase of subordinated notes (Note 6)	**-**	-	**(542)**	-
Other income (expense)	**(26)**	(492)	**545**	(1,045)
Net income (loss) before taxes	**4,590**	(2,157)	**8,819**	(7,892)
Capital taxes	**(567)**	(505)	**(1,512)**	(1,042)
Future income taxes	**(853)**	935	**317**	3,137
Net income (loss)	**3,170**	(1,727)	**7,624**	(5,797)
Deficit, beginning of period	**(12,430)**	(21,787)	**(16,884)**	(17,717)
Deficit, end of period	**$ (9,260)**	$ (23,514)	**$ (9,260)**	$ (23,514)
Basic and diluted earnings (loss) per share (Note 4)	**$ 0.05**	$ (0.03)	**$ 0.13**	$ (0.11)

See accompanying notes to these consolidated financial statements.

Consolidated Statements of Cash Flow
(Unaudited, thousands of Canadian dollars)

	Three months ended September 30, 2005	Three months ended September 30, 2004 (Restated - Note 2)	Nine months ended September 30, 2005	Nine months ended September 30, 2004 (Restated - Note 2)
Operating Activities				
Net income (loss)	**$ 3,170**	$ (1,727)	**$ 7,624**	$ (5,797)
Depletion, depreciation and accretion	**4,023**	8,117	**11,411**	25,518
Non-cash stock based compensation	**348**	89	**782**	255
Future income taxes	**853**	(935)	**(317)**	(3,137)
Amortization of discount on subordinated notes	**483**	622	**1,550**	1,795
Gain	**-**	-	**(4,744)**	-
Loss on repurchase of subordinated notes	**-**	-	**542**	-
Loss recorded on disposition of sales contract	**-**	-	**-**	375
Cash flow from operations	**8,877**	6,166	**16,848**	19,009
Asset retirement obligations settled	**(170)**	(38)	**(207)**	(165)
Changes in other non-cash working capital	**(4,132)**	5,048	**(9,084)**	56
	4,575	11,176	**7,557**	18,900
Financing Activities				
Issuance of common shares (Note 4)	**2,385**	-	**12,236**	410
Repurchase / redemption of subordinated notes (Note 6)	**-**	-	**(30,767)**	-
Issuance of shares by subsidiary (Note 3)	**-**	-	**12,651**	-
Issuance (repayment) of bank debt	**-**	3,003	**-**	(2,256)
Repayment of debenture	**-**	-	**-**	(14,014)
Amortization of obligations under gas hedging contracts	**(208)**	(204)	**(618)**	(608)
Changes in other non-cash working capital	**-**	-	**(3,800)**	-
	2,177	2,799	**(10,298)**	(16,468)
Investing Activities				
Expenditures on capital assets	**(32,094)**	(8,921)	**(59,716)**	(33,629)
Proceeds on disposition of capital assets	**-**	550	**-**	42,861
Changes in other non-cash working capital	**18,096**	(5,604)	**15,163**	(11,664)
	(13,998)	(13,975)	**(44,553)**	(2,432)
Net change in cash position	**(7,246)**	-	**(47,294)**	-
Cash and cash equivalents, beginning of period	**35,461**	-	**75,509**	-
Cash and cash equivalents, end of period	**$ 28,215**	$ -	**$ 28,215**	$ -

See accompanying notes to these consolidated financial statements.

Notes to the Consolidated Financial Statements

As at and for the three and nine month periods ended September 30, 2005
(All tabular amounts are expressed in thousands of Canadian dollars, except share amounts)

Note 1 – Significant Accounting Policies

The interim consolidated financial statements as at and for the three and nine month periods ended September 30, 2005 should be read in conjunction with the audited consolidated financial statements as at and for the year ended December 31, 2004. The notes to these interim consolidated financial statements do not conform in all respects to the note disclosure requirements of generally accepted accounting policies for annual financial statements. These interim consolidated financial statements are prepared using the same accounting policies and methods of computation as disclosed in the audited consolidated financial statements as at and for the year ended December 31, 2004 except as described in Note 2. Certain prior period amounts have been reclassified to conform with current presentation.

Note 2 – Changes in Accounting Policies

Financial Instruments

Effective January 1, 2005 the Company retroactively adopted the new 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. For the three and nine month periods ended September 30, 2004 there is no impact on earnings per share but interest expense on the subordinated notes (3 months - $2.9 million; 9 months - $8.6 million) and the related future income tax recovery (3 months - $1.0 million; 9 months - $2.8 million) are deducted when calculating net income rather than the net income attributable to common shareholders as previously reported.

Note 3 – Non-Controlling Interest

On April 12, 2005 the Company sold a 16 percent interest in its previously wholly owned subsidiary, WHITESANDS Insitu Ltd. (WHITESANDS) for proceeds of $14 million ($12.7 million net of issuance costs). The reduction in the Company's interest in WHITESANDS resulted in a pre-tax gain of $4.7 million. The cash investment in WHITESANDS totaled $8.9 million to September 30, 2005, with the remaining $3.8 million receivable in up to two 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 exchange.

Note 4 – Share Capital

As at September 30, 2005 the Company had outstanding 59,148,096 common shares, 4,076,776 stock options, 967,700 share purchases warrants, and 140,000 deferred share units.

Common Share Continuity	Number	Amount
Balance at December 31, 2004	54,956,396	$ 73,157
Exercise of stock options	739,100	1,572
Issued through private placement	3,000,000	9,750
Share issue costs	-	(896)
Tax effect of share issue costs	-	338
Issued through warrants exercise	452,600	1,810
Transfer from contributed surplus related to stock options exercised	-	88
Balance at September 30, 2005	**59,148,096**	**$ 85,819**

On October 20, 2005 the Company issued four million shares at a price of $9.65 per common share for gross proceeds of $38.6 million.

Stock Option Continuity	Number	Weighted - Average Exercise Price
Balance at December 31, 2004	3,381,751	$ 2.47
Granted	1,684,500	5.28
Exercised	(739,100)	(2.13)
Expired/cancelled	(250,375)	(2.62)
Balance at September 30, 2005	**4,076,776**	**$ 3.68**

Share Purchase Warrants

The 967,700 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 2005 the Company has granted 140,000 outstanding 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 earnings (loss) per share have been calculated based on net income (loss) divided by the weighted average number of common shares outstanding for the three month period ended September 30, 2005 of 58,817,874 (2004 – 54,732,396) and for the nine month period ended September 30, 2005 of 57,252,574 (2004 – 54,659,883). The diluted calculations include 1,691,709 (2004 – nil) additional shares for the three month period and 748,401 (2004 – nil) additional shares for the nine month period ended September 30, 2005 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 September 30,	**2005**	2004
Risk free interest rate	**4.25%**	4.5%
Dividend rate	**0%**	0%
Expected life (years)	**4**	4
Expected volatility	**50%**	30%

The average value per option and deferred share unit granted during the three and nine month periods ended September 30, 2005 were $3.61 and $1.98 respectively, as at the date of grant.

Note 5 - Asset Retirement Obligations

Changes to asset retirement obligations were as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2005	2004	**2005**	2004
Asset retirement obligations, beginning of period	**$ 2,870**	$ 7,909	**$ 2,870**	$ 9,602
Obligations incurred	**796**	126	**1,015**	529
Obligations settled	**(170)**	(38)	**(207)**	(165)
Obligations disposed	**-**	(367)	**-**	(1,533)
Accretion expense	**65**	178	**185**	580
Changes in estimated future cash flows and other	**271**	12	**(31)**	(1,193)
Asset retirement obligations, end of period	**$ 3,832**	$ 7,820	**$ 3,832**	$ 7,820

The total undiscounted amount of estimated cash flows required to settle the obligations is $18.1 million (2004 - $24.1 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 8.5 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 6 – 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. The Company recorded a pre-tax gain of $0.1 million on this transaction.

On April 22, 2005 the Company repurchased $17.2 million face value of notes at par resulting in a pre-tax loss of $0.7 million.

	Carrying Value	Face Value
Balance at December 31, 2004	$ 95,862	$ 100,438
Amortization of discount	1,550	-
Repurchased – January 13, 2005	(13,671)	(14,302)
Repurchased – April 22, 2005	(16,554)	(17,227)
Balance at September 30, 2005	**$ 67,187**	**$ 68,909**

On November 4, 2005, the Company repurchased an additional $18.9 million face value of notes at par resulting in a pre-tax loss of $0.4 million. In separate transactions subsequent to September 30, 2005, the Company repurchased an additional $0.1 million face value of notes through a normal course issuer bid. Cumulatively, these repurchases will further reduce the outstanding face value to $49.9 million.

Note 7 – Commitments and Contingencies

To date, the Company has signed a total of five new exploration contracts in Colombia with the National Hydrocarbon Agency (ANH). Four of the blocks are located in the Llanos Basin, while the remaining block is located in the Putumayo Basin adjacent to our existing Orito block. First-phase work commitments over the next 12 months are expected to total US$9.2 million and include reprocessing 2-D and 3-D seismic, shooting additional 2-D seismic, and drilling one well on the Joropo Block in the Llanos Basin. Upon completion of the first-phase the Company can elect to return the block to the ANH or proceed to a second-phase by drilling one well.

The Company has also signed contracts with the ANH for three new technical evaluation areas (TEA's) in the Llanos Basin with work commitments over the next 12 months that are expected to total US$1.0 million. The TEA's cover larger land areas than exploration blocks and require commitments to reprocess and evaluate existing 2-D seismic, and perform regional studies including the feasibility of the Company's patented THAI^{TM} heavy oil recovery process. Upon expiry of the contract, the Company has the option to negotiate an exploration block within the TEA. During the contract period, the Company also has a right of first refusal over any exploration blocks proposed within the TEA.

The Company is committed to spend US$2.1 million over five years for air compression rental at the WHITESANDS pilot project.

Petrobank is committed to payments under operating leases for office space, net of sub-lease arrangements, as follows:

Remainder of 2005	$ 138
2006	661
2007	301
	$ 1,100

Note 8 – Technology Partnerships Canada Financing

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 three separate revenue streams. The first stream is based on three percent of WHITESANDS pilot project revenues earned after January 1, 2006 with initial payments due May 1, 2010. The second stream is based on 0.6 percent of WHITESANDS Insitu Ltd. revenues (excluding pilot revenues) earned after January 1, 2009 with initial payments due May 1, 2010. The third stream is based on three percent of all third-party THAI™ licensing revenues earned after January 1, 2008 with initial payments due May 1, 2009. If, as of December 31, 2017 the cumulative royalty paid from the three royalty streams has not reached $26.2 million, royalty payments will continue until $26.2 million has been paid or until December 31, 2022, whichever occurs first.

The Company recently filed initial claims totaling $1.6 million relating to expenditures incurred between August 26, 2004 and September 30, 2005 which is to be received before the end of the year. Future claims will be made on a quarterly basis. Funding under this program is accounted for in accordance with CICA Handbook section 3800 "Government Assistance", whereby benefits receivable are recorded as a reduction in the related capital expenditures.

Note 9 – Segmented Information

Three months ended September 30,

	2005			2004 [1]		
	Canada and Other	Colombia	Total	Canada and Other	Colombia	Total
Revenues						
Oil and natural gas	$ 12,036	$ 5,947	$ 17,983	$ 13,194	$ 5,506	$ 18,700
Royalties	(2,360)	(476)	(2,836)	(2,872)	(448)	(3,320)
	9,676	5,471	15,147	10,322	5,058	15,380
Expenses						
Production	1,319	929	2,248	2,751	803	3,554
Transportation	246	-	246	339	-	339
General and administrative	1,124	843	1,967	1,209	666	1,875
Depletion, depreciation and accretion	2,239	1,784	4,023	5,644	2,473	8,117
Segmented income	$ 4,748	$ 1,915	$ 6,663	$ 379	$ 1,116	$ 1,495
Non-segmented expenses						
Interest on bank debt			-			(264)
Interest on subordinated notes			(2,047)			(2,896)
Other expense			(26)			(492)
Capital taxes			(567)			(505)
Future income taxes			(853)			935
Net income (loss)			$ 3,170			$ (1,727)
Identifiable assets [2]	$130,983	$ 84,846	$215,829	$145,188	$ 72,071	$217,259
Capital expenditures [2]	$ 27,031	$ 5,063	$ 32,094	$ 7,289	$ 1,632	$ 8,921

[1] Restated - Note 2.
[2] Canada includes Heavy Oil Business Unit expenditures of $10.6 million in 2005 (2004 - $0.6 million), identifiable assets at September 30, 2005 of $43.3 million (2004 - $7.3 million), and no operating revenues and expenses.

Nine months ended September 30,

	2005			2004 [1]		
	Canada and Other	Colombia	Total	Canada and Other	Colombia	Total
Revenues						
Oil and natural gas	$ 27,007	$ 15,564	$ 42,571	$ 39,549	$ 16,800	$ 56,349
Royalties	(5,502)	(1,245)	(6,747)	(8,584)	(1,348)	(9,932)
	21,505	14,319	35,824	30,965	15,452	46,417
Expenses						
Production	3,884	2,685	6,569	8,314	3,064	11,378
Transportation	714	-	714	1,150	-	1,150
General and administrative	3,687	2,651	6,338	3,561	2,100	5,661
Depletion, depreciation and accretion	6,292	5,119	11,411	17,098	8,420	25,518
Segmented income	$ 6,928	$ 3,864	$ 10,792	$ 842	$ 1,868	$ 2,710
Non-segmented expenses						
Interest on bank debt			-			(993)
Interest on subordinated notes			(6,720)			(8,564)
Gain			4,744			-
Loss on repurchase of subordinated notes			(542)			-
Other income (expense)			545			(1,045)
Capital taxes			(1,512)			(1,042)
Future income taxes			317			3,137
Net income (loss)			$ 7,624			$ (5,797)
Identifiable assets [2]	$130,983	$ 84,846	$215,829	$145,188	$ 72,071	$217,259
Capital expenditures [2]	$ 44,293	$ 15,423	$ 59,716	$ 23,762	$ 9,867	$ 33,629

[1] Restated - Note 2.
[2] Canada includes Heavy Oil Business Unit expenditures of $15.7 million in 2005 (2004 - $1.5 million), identifiable assets at September 30, 2005 of $43.3 million (2004 - $7.3 million), and no operating revenues and expenses.

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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