PETROBANK
ENERGY AND RESOURCES LTD.

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November 14, 2006

SEC MAIL PROCESSING
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WASH, D.C. 210 SECTION

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

Re: Petrobank Energy and Resources Ltd.

SUPPL

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,

TRodier

Tanya Rodier
for:

Corey C. Ruttan
Vice-President Finance

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FINANCIAL

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PETROBANK
ENERGY AND RESOURCES LTD.

NEWS RELEASE

PETROBANK ENERGY AND RESOURCES LTD. TO PRESENT AT THE FIRSTENERGY/SOCIÉTÉ GÉNÉRALE ENERGY GROWTH CONFERENCE IN TORONTO, ONTARIO

Calgary, November 9, 2006/CNW/ - Notification of live webcast event:

Petrobank Energy and Resources Ltd. (TSX / OSLO : PBG)
Live webcast presentation
Tuesday, November 14, 2006, 9:45 AM EST (7:45 AM MST)

To listen and view this online event, please visit:

http://www.firstenergy.com/conf/EG06/PBG.html

The presentation will be available in an archived version at this link for 30 days following the live presentation.

For more information on the webcast please visit www.firstenergy.com or contact:

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PETROBANK
ENERGY AND RESOURCES LTD.

NEWS RELEASE

PETROBANK ANNOUNCES THIRD QUARTER RESULTS AND CONTINUED SUCCESS AT WHITESANDS

Calgary, Alberta – November 13, 2006 – (TSX: PBG, OSLO: PBG) Petrobank Energy and Resources Ltd. ("Petrobank" or the "Company") is pleased to announce third quarter financial and operating results. The Company's third quarter 2006 interim report, including financial statements and management's discussion and analysis, is available on the Company's website at www.petrobank.com, filed on SEDAR at www.sedar.com, and filed on the Oslo Børs website at www.oslobors.no.

HIGHLIGHTS

The third quarter results are highlighted as follows:

- At our WHITESANDS project we began combustion operations and produced first oil from the world's first THAI™ well pair, initiated the Pre-Ignition Heating Cycle ("PIHC") on the second of three well pair and drilled five successful exploration wells on our oil sands leases.
- The Company drilled 46 (40.5 net) conventional oil and gas wells in Canada.
- Conventional production averaged 4,939 boepd in the third quarter of 2006, a 40 percent increase over the comparative 2005 period.
- Funds flow from operations increased 67 percent to $14.8 million.
- Net income increased by 63 percent to $5.2 million.
- In July 2006, the Company closed a new $120 million credit facility and used a portion of the proceeds to repay the remaining $50 million of 9% subordinated notes that were outstanding.

FINANCIAL & OPERATING HIGHLIGHTS

	Three months ended September 30, 2006	2005	% change	Nine months ended September 30, 2006	2005	% change
Financial						
($000s, except where noted)						
Oil and natural gas revenue	**24,639**	17,983	37	**73,499**	42,571	73
Funds flow from operations [1]	**14,788**	8,877	67	**45,368**	16,848	169
Per share – basic ($)	**0.22**	0.15	47	**0.68**	0.29	134
– diluted ($)	**0.21**	0.15	40	**0.66**	0.29	128
Net income	**5,169**	3,170	63	**20,486**	7,624	169
Per share – basic ($)	**0.08**	0.05	60	**0.31**	0.13	138
– diluted ($)	**0.07**	0.05	40	**0.30**	0.13	131
Capital expenditures	**57,904**	32,094	80	**158,356**	59,716	165
Total assets	**395,654**	215,829	83	**395,654**	215,829	83
Net debt [2]	**70,366**	54,526	29	**70,366**	54,526	29
Common shares outstanding, end of period (000s)						
Basic	**67,293**	59,148	14	**67,293**	59,148	14
Diluted	**71,346**	64,333	11	**71,346**	64,333	11
Operations [3]						
Canadian operating netback ($/boe except where noted)						
Natural gas revenue ($/mcf) [4]	**5.39**	8.25	(35)	**6.23**	7.03	(11)
Oil and NGL revenue ($/bbl)	**72.13**	65.50	10	**64.52**	60.16	7
Oil and natural gas revenue [4]	**44.28**	53.07	(17)	**44.61**	45.34	(2)
Royalties	**6.00**	10.41	(42)	**6.94**	9.24	(25)
Production expenses	**8.63**	5.81	49	**6.47**	6.52	(1)
Transportation expenses	**0.42**	1.08	(61)	**0.43**	1.20	(64)
Operating netback	**29.23**	35.77	(18)	**30.77**	28.38	8
Colombian operating netback ($/bbl)						
Oil revenue	**64.58**	60.24	7	**63.20**	53.97	17
Royalties	**5.16**	4.82	7	**5.07**	4.32	17
Production expenses	**7.80**	9.41	(17)	**7.56**	9.31	(19)
Operating netback	**51.62**	46.01	12	**50.57**	40.34	25
Average daily production						
Canada – natural gas (mcf)	**10,578**	11,485	(8)	**13,267**	10,805	23
Canada – oil and NGL (bbls)	**756**	551	37	**802**	381	110
Total Canada (boe)	**2,519**	2,465	2	**3,013**	2,182	38
Colombia – oil (bbls)	**2,420**	1,073	126	**2,133**	1,056	102
Total Company (boe)	**4,939**	3,538	40	**5,146**	3,238	59

(1) Calculated based on cash flow before changes in non-cash working capital and asset retirement obligations settled.
(2) Includes working capital (deficiency) and subordinated notes. The subordinated notes were repaid on July 31, 2006.
(3) 6 mcf of natural gas is equivalent to 1 barrel of oil equivalent ("boe").
(4) Canadian sales prices are shown after forward gas sales contracts.

OPERATIONAL UPDATE

Heavy Oil Business Unit

THAI™ combustion operations at WHITESANDS during the third quarter of 2006 continued to confirm the effectiveness of the THAI™ technology in our first well pair. Two additional key operational milestones were achieved in the third quarter with the initiation of the Pre-Ignition Heating Cycle ("PIHC") on the second well pair and the shipment of the first produced oil from the project.

Air injection and combustion was initiated on the first of the three project wells on July 20, 2006, and we have been continually injecting air into the vertical well of this center well pair. During the first three weeks of air injection, in-situ combustion ignition was confirmed as we measured various indicators of the combustion reaction, including significantly rising temperatures in the reservoir zone, production of combustion gases and rising horizontal well bore temperatures. This trend continued through the third quarter with recorded reservoir temperatures reaching as high as 800 degrees Centigrade. Combustion gas analysis consistently demonstrated a high ratio of carbon dioxide to carbon monoxide, indicating a very high level of conversion of oxygen, hydrocarbon gases indicative of thermocracking of oil in-situ, and free hydrogen generated from high temperature reactions, all indicators of efficient high temperature combustion. These data also suggest that we are upgrading the oil in-situ. We are very early in the process of building out the combustion front in the first THAI™ well pair and estimate that only approximately 7,000 m^3 of the reservoir has been affected by combustion at the toe of the horizontal well, which is less than one percent to total reservoir volume expected to be affected by combustion over the life of each THAI™ well pair.

Since initiating THAI™ production operations, the gross production capability from the first horizontal well has consistently exceeded 1,000 barrels of fluid per day with the potential production capability double our initial forecast rate. High productive capacity has meant that we have had to manage operations to match well flow with current plant capability. The composition of produced fluids continues to be variable, consisting of a combination of condensed steam from the Pre-Ignition Heating Cycle ("PIHC"), reservoir water, bitumen, and sand. Bitumen production rates, while variable, increased over the quarter. During October we saw a significant rise in bitumen production and we produced approximately 4,000 barrels of bitumen. This production was not rateable on a daily basis since the plant facilities were not on stream for the entire period. However, during this period, when producing at high gross fluid rates, we experienced an average 30 percent bitumen cut. While facility bottlenecks and well and plant maintenance operations during the quarter reduced the ability to produce continuously and at the higher rates, air injection operations were not curtailed and have increased over the quarter, indicating an expanding area of combustion.

Surface facilities have been able to handle a wide range of fluid rates and temperatures, however we have experienced facilities downtime and reduced production due to equipment commissioning issues, adjustments to manage higher than design well production capability, and sand production. These facilities issues necessitate ongoing operational adjustments and sand clean-out procedures in the surface facilities and the horizontal well. As reported previously, the produced sand is very fine-grained, indicating that a sand-bridging structure within the reservoir has yet to be fully established. This is most likely a result of our transition from the earlier steam injection operations to combustion operations, and may have been impacted by earlier horizontal well procedures at the beginning of the THAI™ production phase. While we expect the produced sand to be minimized as the combustion front expands and a consistent rateable flow regime is established, we are also enhancing our sand handling capability to minimize plant down time. These facilities modifications are underway and are expected to be in place by the end of November.

Modified PIHC operations began late in the third quarter for the second well pair and we expect to initiate the PIHC for the third well pair in November. The modified PIHC operations are designed to reduce the amount of steam and time required to create reservoir mobility before initiating air injection and combustion.

We are still in the very early stages of the THAI™ process and in a state of continual adjustment of our operations. This continuous improvement process is consistent with starting up the first field scale demonstration of a new technology, allowing us to modify certain aspects of our surface facilities and operating procedures. We foresee an ongoing process of technical improvement and innovation as we enhance our ability to produce significant volumes of oil using the THAI™ process.

Additional Resource Delineation

During the second quarter of 2006, we reported that the estimated gross bitumen-in-place on a portion of the 62 sections of oil sands leases owned by our 84 percent subsidiary, WHITESANDS Insitu Ltd. had increased to 1.6 billion barrels, based on a May 2006 Fekete Associates Ltd. resource evaluation. In addition, a recoverable reserve and resource assessment by McDaniel Associates Ltd. ("McDaniel") effective May 1, 2006 estimated an initial gross recoverable bitumen volume, based on Steam Assisted Gravity Drainage ("SAGD") technology, of up to 537 million barrels, which includes 25 million barrels of gross probable reserves and 70 million barrels of gross probable plus possible reserves.

During the third quarter of 2006 we drilled five oil sands exploration wells on areas of the leases we believed to contain considerable additional recoverable resources. Weather and ground conditions prevented us from drilling an additional four planned wells, which will now be incorporated into our winter drilling program. The five new wells all intersected significant McMurray channel of a quality equal to or better than previous wells. All of these wells were cored and logged and will be incorporated into an updated McDaniel recoverable resource report. The initial McDaniel report included only 13 sections of our lands, those with at least one drill hole per section, and excluded a number of sections with McMurray channel indicated by our 3-D seismic and/or areas on trend with known McMurray channel. The additional ten well winter drilling program is also expected to delineate significant new recoverable bitumen resources. We have requested an update to the McDaniel report to reflect the impact of the most recent drilling program, and we anticipate a further update will follow our winter drilling program. We also plan to update the reserve evaluation based on the THAI™ recovery process which we believe will have a higher recovery rate, and hence greater recoverable reserves than the SAGD-based estimates.

Project Development

In addition to the ongoing delineation of the recoverable resource potential of our lands we are also evaluating a potential project site for a THAI™ expansion project of approximately 10,000 barrels per day. We have been in the early stages of evaluating a new project area proximal to the current pilot site, to optimize infrastructure, and have selected a preliminary project area. Project scoping and preliminary engineering are expected to commence early in 2007.

A CAPRI™ test is anticipated by mid 2007, this will either be through a modification of one of the three current horizontal wells, or in a well drilled specifically for CAPRI™.

The THAI™ Process

THAI™ is an evolutionary in-situ gravity assisted 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.

THAI™ has many potential benefits over other in-situ recovery methods, such as SAGD. These potential 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.

THAI™ can also be applied to other heavy oil deposits and it is our strategy to initiate projects in mobile oil reservoirs in Canada and/or internationally. Our 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, Petrobank's 80.7 percent owned subsidiary, Petrominerales Ltd. (TSX: PMG), is evaluating two heavy oil Technical Evaluation Areas in Colombia covering 0.8 million acres for the potential application of THAI™.

Canadian Business Unit

Canadian Business Unit production averaged 2,519 boe per day ("boepd") in the third quarter of 2006, compared to 2,465 boepd in the third quarter of 2005 and 3,017 boepd in the second quarter of 2006. Our 2006 program has, to date, experienced delays due to weather conditions, regulatory approval and equipment availability. At the end of the third quarter we began to bring on initial production additions from our successful 2006 projects that allowed us to exit the quarter producing approximately 3,000 boepd. During the third quarter, activity increased dramatically with the drilling of 46 (40.5 net) wells, compared to only 17 (14.1 net) wells in the second quarter and 12 (8.7 net) in the first quarter of the year. The majority of the impact of this 2006 program will be realized through production additions during the fourth quarter. The first new production in 2006 from our Jumpbush drilling program was tied-in to our facility at the end of the third quarter. We currently have approximately nine million cubic feet of natural gas per day ("mmcfpd") of behind-pipe capacity awaiting tie-in. The recent drop in natural gas prices had encouraged Petrobank to accelerate our low risk light oil drilling program and defer our gas drilling programs. Results to date on the light oil plays in both the Bakken and the Torquay zones of southeast Saskatchewan and southwest Manitoba are very encouraging and will result in significant new oil production being added during the fourth quarter.

Canadian Business Unit Drilling Results

	Q1		Q2		Q3		Q4 To Date		Year to date		
Property	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Success %
Jumpbush/Milo	4.0	2.8	14.0	11.6	29.0	25.1	1.0	1.0	48.0	40.5	100%
Red Willow	2.0	2.0	1.0	1.0	4.0	4.0	1.0	1.0	8.0	8.0	75%
Innes - Bakken	-	-	-	-	3.0	3.0	2.0	2.0	5.0	5.0	80%
Sinclair - Torquay	-	-	-	-	6.0	6.0	5.0	5.0	11.0	11.0	100%
Other operated	3.0	3.0	1.0	1.0	2.0	2.0	-	-	6.0	6.0	67%
Non-operated	3.0	0.9	1.0	0.5	2.0	0.4	-	-	6.0	1.8	72%
Total	12.0	8.7	17.0	14.1	46.0	40.5	9.0	9.0	84.0	72.3	92%
% gas	42%	44%	88%	86%	72%	72%	22%	22%	65%	65%	

Jumpbush

The majority of our 2006 Jumpbush wells were drilled in the third quarter. To date, we have drilled 44 (37.0 net) wells, 31 (23.9 net) of which have been tied-in and another 13 (13 net) wells are currently awaiting tie-in. Prior to year-end, additional compression will also be added to increase production from all of the wells drilled and tied-in this year. The 13 remaining wells to be tied-in have been tested at 3.6 mmcfpd but we expect the first month's contribution will be approximately 2.0 mmcfpd. We have one additional well planned to be drilled and tied-in this year. We continue to work on planning and regulatory approvals for a 50 to 100 well program next year.

Milo

Milo is just south and east of the Jumpbush property, where we have been extending our Jumpbush exploration model, pursuing Belly River zones with high initial production rates. In 2006, four (3.5 net) wells have been drilled, three (2.5 net) wells during the third quarter. This gas is more complicated to tie-in as we need to utilize third party pipelines and facilities. Currently the four wells have tested at aggregate rates of 2.25 mmcfpd, and we anticipate aggregate initial production from the wells of approximately 1.1 mmcfpd. Through the balance of 2006 we plan to tie-in the four wells and drill a fifth well. We continue to expand our inventory of opportunities on this trend and are confident in the exploration model we are employing to identify lands of interest and add to our inventory of drilling locations.

Red Willow

High deliverability Mannville zones that can be either oil or gas bearing characterize the Red Willow property. To date in 2006, eight wells (8.0 net) have been drilled, with four of those drilled in the third quarter and one more drilled in the fourth quarter. Our drilling resulted in one oil well and five gas wells. The best results have come from the last four gas wells drilled with three of these wells testing at combined rates of 5.3 mmcfpd. We anticipate the first month contribution from all four wells to be approximately 5.5 mmcfpd. Through the balance of 2006 we plan to tie-in these four wells and drill a horizontal well into an existing Glauconite zone oil pool.

Innes area – Bakken Resource Play

The Bakken resource play of southeast Saskatchewan generally requires horizontal wells with specialized fracture stimulations to create economic production of light oil. Petrobank initially participated in this play as a partner in wells operated by other companies testing the initial viability of extracting light oil from this geographically extensive, low permeability reservoir. In 2006 we have participated in four (0.81 net) joint interest wells to date. Furthermore, we expect to participate in an additional three (0.75 net) non-operated wells to be drilled by year-end. We have utilized the experience gained from these early joint ventures to high-grade and expand our 100 percent working interest acreage, further increasing our strong land position in the Bakken play. In the third quarter we began drilling our own 100 percent working interest wells. So far five horizontal wells have been drilled and the rig is currently drilling the horizontal section of our sixth well. The first two of these wells have been fracture stimulated and we expect to have production from our stimulated wells on-stream during the month of November, and we expect to have another five horizontal wells drilled by year-end. We have a large inventory of opportunities in this area and our success to date means we have added many more development locations to this inventory. Petrobank will monitor performance from this relatively new play before providing comments on additions to our production.

Sinclair / Ryerson area – Torquay play

The Torquay play, like the Bakken play, is a relatively new light oil play in southeast Saskatchewan and southwestern Manitoba. Petrobank was able to monitor this play through farm-out agreements on a small part of our fee-simple lands located in Manitoba. Through late 2005 and 2006 Petrobank continued to assess this new opportunity and expand our land position in Saskatchewan and Manitoba on the trend. Starting in the third quarter, we have now drilled 11, 100 percent working interest wells, all of which are cased as potential oil wells. In the Ryerson area, a new pool has been discovered and to date we have drilled seven development wells, four of which are producing with all seven expected to be on-line within two weeks. Our remaining exploration wells are being evaluated and we anticipate drilling a minimum of five more exploration or development wells by year-end. Our inventory of development locations has expanded rapidly as a result of our success in the area to-date. Again, we will be monitoring the performance from this relatively new play before providing comments on additions to our production.

Exploration

Petrobank is further positioning itself in new exploration areas with higher impact plays to compliment our large inventory of low-risk gas and light oil opportunities. This program is growing and we have acquired 5,120 acres of exploration lands on new prospects during 2006. We will continue to add to our land position and mature our exploration ideas in these new areas with seismic and technical work in preparation for drilling in 2007.

Latin American Business Unit - Petrominerales Ltd. ("Petrominerales")

During the third quarter the activities of Petrominerales, Petrobank's 80.7 percent owned subsidiary, were focused on continuing development in Orito, implementing our pilot fracture stimulation program in Neiva and preparing for a significant exploration drilling program in the Llanos and Putumayo Basins which will begin during the first quarter of 2007.

Third quarter 2006 production averaged 2,420 bpd compared to 2,612 bpd in the second quarter of 2006 and 1,073 bpd in the third quarter of 2005. The significant increase from the prior year period is mainly due to the success of the Orito-117 and 118 completions at the end of the first quarter of 2006 which proved-up a significant southwest extension to the Orito field. The decrease from the prior quarter is mainly a result of certain wells being taken off production during the period for the re-work and recompletion programs outlined below, and due to natural declines.

Orito

We have now completed drilling three wells in the Orito field since June 2006, the Orito-119 well, the redrill of the Orito-116 location and the Orito-124 well.

The Orito-119 well was completed in the upper Caballos sands using a slim hole drilling design. Due to a lack of pressure integrity behind the production liner, a remedial cement job was attempted on the well. With this poor cement job, we were unable to apply our revised fracture stimulation program to the productive intervals in this well and initial oil production from the well has been limited to approximately 60 bpd. If this well exhibits improving productive capability as it cleans up following completion, we plan to install an electrical submersible pump to optimize the productive capability of the well.

Following the Orito-119 well, the rig drilled the sidetrack of the Orito-116 well, also incorporating our slim-hole drilling design, which reached total depth of 6,525 feet on July 4, 2006. As expected, the sidetrack well encountered a similar high quality series of Caballos sands as in the original 116 well which was our original confirmation of the southwest extension to the field, initially testing at rates of more than 1,000 bpd. Unfortunately, the sidetracked well appears to have experienced a casing collapse, similar to the one which occurred in the original 116 well and has now been abandoned. Based on these two well results and similar issues associated with the Orito-113 recompletion discussed below, Petrominerales will be eliminating slim-hole drilling design from our future development plans.

Following the Orito-116 sidetrack, the rig commenced drilling Orito-124, which reached total depth of 8,134 feet on October 3, 2006. We are in the process of completing the Orito-124 well, in the prolific southwest extension area of the field. Log analysis indicates significant hydrocarbon reserves in the Caballos B, C and D sands. Initial tests of the Caballos "B2" and "B3" reservoirs indicate oil productivity, and we are currently in the process of fracture stimulating these sands. Immediately thereafter we plan to fracture stimulate the C and D sands and put the well on test. The Orito-122 well is now drilling at a depth of 6,600 feet and we expect to reach total depth within the next week. The Orito-122 well is expected to prove the updip extension of the oil zone and more fully define the potential of this undrilled area. A successful well in this region of the field has the potential to further increase our inventory of development drilling locations.

In addition to this recent drilling, we also performed re-completions on the Orito-113 and Orito-115 wells. We re-entered the Orito-113 well in an attempt to recover lost production due to near wellbore damage and the well was also deepened to the Upper Caballos A sand. A slim hole liner was set in the previous open-hole productive interval to facilitate further fracture stimulation and zonal isolation. During our pre-stimulation operations, pressure communication behind the liner was observed, and the subsequent fracture stimulation was postponed. We installed a liner top packer to achieve annular isolation and performed a remedial cement job to allow for a successful fracture stimulation of the Caballos zone in that well. The well is currently cleaning up at rates of approximately 250 bpd. The Orito-115 well was also re-completed with a production liner and a fracture stimulation program. The well was placed back on-line recently, and is currently cleaning up with oil production rates of approximately 80 bpd, well in excess of the well's pre-stimulation potential.

Our second drilling rig, contracted for 16 months, has been further delayed and it is not expected to arrive in Orito before mid December. We are assessing the possibility of moving this rig directly to our Llanos exploration program to avoid high mobilization and demobilization costs associated with moving it into Orito where it would most likely only be capable of drilling one additional development well prior to returning to the Llanos Basin to commence our exploration program. Irrespective of our short-term plans, the rig will ultimately be moved to Orito to accelerate our development drilling program.

Neiva

At Neiva, we completed our initial phase of fracture stimulations involving five test wells in the Honda and Doima-Chicoral reservoirs. The DT-56 (Doima-Chicoral) stimulation was highly successful, increasing gross oil production rates from 86 to 170 bpd. The Honda formation fracture stimulations included the installations of progressive cavity pumps ("PCPs") and initially has resulted in significant increases in production. Based on positive initial results, we plan to drill at least three new Doima-Chicoral wells incorporating our fracture stimulation design into the completions. We will continue to monitor the Honda fracture stimulations and expect to be able to expand this program to more than 50 additional Honda locations at Neiva. We have also recently completed the conversion of two wells to water injectors as part of an initial pilot water flood program in the Honda reservoir. We commenced water injection on November 1st and expect response in the surrounding wells during the first half of 2007.

Exploration

Petrominerales has completed the first phase exploration commitments, which included acquiring 3-D seismic and interpretation of existing data on the first five of our exploration blocks, evaluating key, prospective portions of each block. Beginning in February 2007, we will begin a five-well drilling program to test the initial prospects on each of the Casanare Este, Casimena, Corcel and Las Aguilas blocks, as well as our second test on the Joropo block. In addition, Petrominerales has signed two exploration licenses (Mapache and Castor) covering a significant portion of the original Chicago Technical Evaluation Agreement ("TEA"). The recently signed Mapache block covers 107,705 acres and our proposal includes a first phase commitment to acquire 40 square kilometers of 3-D seismic and to drill two exploration wells, which are scheduled for the first quarter of 2008. The Castor block, which was just approved by the National Hydrocarbon Agency, covers 110,265 acres and our proposal includes the acquisition of an initial 30 square kilometer 3-D seismic survey and drilling one well. Petrominerales has also been evaluating the heavy oil potential of our two TEAs in the southern Llanos Basin, where there is evidence of an extensive heavy oil belt. We have begun negotiations to change the entire Rio Ariari TEA to an exploration block covering slightly more than 600,000 acres. Our proposal includes a first phase work commitment of 100 kilometers of 2-D seismic. We hope to complete negotiations on the Rio Ariari exploration license by the end of the month. We have also submitted a proposal to convert approximately 177,500 acres of the original Chiguiro TEA into an exploration license and we are evaluating our first right of refusal on a third party proposal over another portion of the original TEA area covering approximately 125,000 acres. Petrominerales has a license to use Petrobank's THAI™ technology and is evaluating the technology's applicability to these Llanos Basin heavy oil deposits.

Upon acceptance of these most recent exploration proposals, Petrominerales' exploration land base will total 2.0 million acres in nine exploration blocks and two TEAs.

Petrobank Energy and Resources Ltd.

Petrobank Energy and Resources Ltd. is a Calgary-based oil and natural gas exploration and production company with operations in western Canada and Colombia. The Company operates high-impact projects through three business units. The Canadian Business Unit combines conventional oil and gas operations with two higher potential coalbed methane opportunities. The Latin American Business Unit is operated by Petrobank's 80.7% owned, TSX-listed subsidiary, Petrominerales Ltd. (trading symbol: PMG), which produces oil through two Incremental Production Contracts in Colombia and has exploration contracts and Technical Evaluation Agreements covering a total of 2.0 million acres in the Llanos and Putumayo Basins. WHITESANDS Insitu Ltd., Petrobank's 84% owned subsidiary, owns 39,680 acres of oil sands leases with an estimated 1.6 billion barrels of bitumen-in-place and operates the WHITESANDS project to field-demonstrate Petrobank's 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.

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, the expected amount and timing of capital projects and the results of operations. 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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Petrominerales

STRENGTH in our resources

Q3·06

FINANCIAL & OPERATING HIGHLIGHTS

	Three months ended September 30, 2006	Three months ended September 30, 2005 (1)	% change	Nine months ended September 30, 2006 (1)	Nine months ended September 30, 2005 (1)	% change
Financial						
(US$000s, except where noted)						
Crude oil revenue	**12,818**	4,953	159	**32,638**	12,739	156
Funds flow from operations (2)	**8,202**	2,668	207	**22,044**	6,182	257
Per share – basic and diluted ($) (3)	**0.09**	0.03	200	**0.26**	0.08	225
Net income	**4,252**	1,182	260	**12,121**	1,996	507
Per share – basic and diluted ($) (3)	**0.04**	0.01	300	**0.14**	0.03	367
Capital expenditures	**21,696**	4,216	415	**49,748**	12,601	295
Total assets	**178,570**	72,908	145	**178,570**	72,908	145
Cash and working capital (deficit)	**28,341**	(810)		**28,341**	(810)	
Common shares outstanding, end of period (000s)						
Basic	**95,000**	79,000	20	**95,000**	79,000	20
Diluted	**98,090**	79,000	24	**98,090**	79,000	24
Operations						
Operating netback ($/bbl)						
Crude oil revenue	**57.57**	50.17	15	**56.05**	44.19	27
Royalties	**4.60**	4.01	15	**4.50**	3.54	27
Production expenses	**6.97**	7.84	(11)	**6.70**	7.61	(12)
Operating netback	**46.00**	38.32	20	**44.85**	33.04	36
Average daily crude oil production (bbls)	**2,420**	1,073	126	**2,133**	1,056	102

(1) Amounts in the periods ending on or before June 30, 2006 have been translated and restated in US$ from the previously reported Canadian dollar amounts. See "Change in Accounting Policy" within Management's Discussion and Analysis ("MD&A").

(2) Calculated based on cash flow from operations before changes in non-cash working capital.

(3) Assumed weighted average number of basic and diluted shares totalled 78,999,900 prior to incorporation on April 20, 2006. See "Formation of the Company" within MD&A.

REPORT TO SHAREHOLDERS

Highlights

(The results throughout this report are expressed in United States dollars, except where noted)

The third quarter results continue to reflect the impact of the Company's drilling and completion at Orito and Neiva and the completion of the initial public offering and TSX listing of Petrominerales Ltd. ("Petrominerales") (TSX:PMG) on June 29, 2006, generating gross proceeds to the Company of Cdn$60 million. The results are highlighted as follows:

- Oil production averaged 2,420 bpd in the third quarter of 2006, a 126 percent increase over the comparative 2005 period.
- Funds flow from operations increased 207 percent to $8.2 million.
- Net income increased 260 percent to $4.3 million.
- Operating netbacks improved 20 percent to $46.00 per barrel.

Operational Update

During the third quarter the activities of Petrominerales, an 80.7 percent owned subsidiary of Petrobank Energy and Resources Ltd. (Petrobank"), were focused on continuing development in Orito, implementing our pilot fracture stimulation program in Neiva and preparing for a significant exploration drilling program in the Llanos and Putumayo Basins which will begin during the first quarter of 2007.

Third quarter 2006 production averaged 2,420 bpd compared to 2,612 bpd in the second quarter of 2006 and 1,073 bpd in the third quarter of 2005. The significant increase from the prior year period is mainly due to the success of the Orito-117 and 118 completions at the end of the first quarter of 2006 which proved-up a significant southwest extension to the Orito field. The decrease from the prior quarter is mainly a result of certain wells being taken off production during the period for the re-work and recompletion programs outlined below, and due to natural declines.

Orito

We have now completed drilling three wells in the Orito field since June 2006, the Orito-119 well, the redrill of the Orito-116 location and the Orito-124 well.

The Orito-119 well was completed in the upper Caballos sands using a slim hole drilling design. Due to a lack of pressure integrity behind the production liner, a remedial cement job was attempted on the well. With this poor cement job, we were unable to apply our revised fracture stimulation program to the productive intervals in this well and initial oil production from the well has been limited to approximately 60 bpd. If this well exhibits improving productive capability as it cleans up following completion, we plan to install an electrical submersible pump to optimize the productive capability of the well.

Following the Orito-119 well, the rig drilled the sidetrack of the Orito-116 well, also incorporating our slim-hole drilling design, which reached total depth of 6,525 feet on July 4, 2006. As expected, the sidetrack well encountered a similar high quality series of Caballos sands as in the original 116 well which was our original confirmation of the southwest extension to the field, initially testing at rates of more than 1,000 bpd. Unfortunately, the sidetracked well appears to have experienced a casing collapse, similar to the one which occurred in the original 116 well and has now been abandoned. Based on these two well results and similar issues associated with the Orito-113 recompletion discussed below, Petrominerales will be eliminating slim-hole drilling design from our future development plans.

Following the Orito-116 sidetrack, the rig commenced drilling Orito-124, which reached total depth of 8,134 feet on October 3, 2006. We are in the process of completing the Orito-124 well, in the prolific southwest extension area of the field. Log analysis indicates significant hydrocarbon reserves in the

D sands. Initial tests of the Caballos "B2" and "B3" reservoirs indicate oil are currently in the process of fracture stimulating these sands. Immediately fracture stimulate the C and D sands and put the well on test. The Orito-122 well is h of 6,600 feet and we expect to reach total depth within the next week. The Orito- to prove the updip extension of the oil zone and more fully define the potential of A successful well in this region of the field has the potential to further increase our ment drilling locations.

recent drilling, we also performed re-completions on the Orito-113 and Orito-115 ed the Orito-113 well in an attempt to recover lost production due to near wellbore ll was also deepened to the Upper Caballos A sand. A slim hole liner was set in the productive interval to facilitate further fracture stimulation and zonal isolation. During n operations, pressure communication behind the liner was observed, and the re stimulation was postponed. We installed a liner top packer to achieve annular formed a remedial cement job to allow for a successful fracture stimulation of the that well. The well is currently cleaning up at rates of approximately 250 bpd. The as also re-completed with a production liner and a fracture stimulation program. The ced back on-line recently, and is currently cleaning up with oil production rates of nately 80 bpd, well in excess of the well's pre-stimulation potential.

ur second drilling rig, contracted for 16 months, has been further delayed and it is not expected to arrive in Orito before mid December. We are assessing the possibility of moving this rig directly to our Llanos exploration program to avoid high mobilization and demobilization costs associated with moving it into Orito where it would most likely only be capable of drilling one additional development well prior to returning to the Llanos Basin to commence our exploration program. Irrespective of our short-term plans, the rig will ultimately be moved to Orito to accelerate our development drilling program.

Neiva

At Neiva, we completed our initial phase of fracture stimulations involving five test wells in the Honda and Doima-Chicoral reservoirs. The DT-56 (Doima-Chicoral) stimulation was highly successful, increasing gross oil production rates from 86 to 170 bpd. The Honda formation fracture stimulations included the installations of progressive cavity pumps ("PCPs") and initially has resulted in significant increases in production. Based on positive initial results, we plan to drill at least three new Doima-Chicoral wells incorporating our fracture stimulation design into the completions. We will continue to monitor the Honda fracture stimulations and expect to be able to expand this program to more than 50 additional Honda locations at Neiva. We have also recently completed the conversion of two wells to water injectors as part of an initial pilot water flood program in the Honda reservoir. We commenced water injection on November 1st and expect response in the surrounding wells during the first half of 2007.

Exploration

Petrominerales has completed the first phase exploration commitments, which included acquiring 3-D seismic and interpretation of existing data on the first five of our exploration blocks, evaluating key, prospective portions of each block. Beginning in February 2007, we will begin a five-well drilling program to test the initial prospects on each of the Casanare Este, Casimena, Corcel and Las Aguilas blocks, as well as our second test on the Joropo block. In addition, Petrominerales has signed two exploration licenses (Mapache and Castor) covering a significant portion of the original Chicago Technical Evaluation Agreement ("TEA"). The recently signed Mapache block covers 107,705 acres and our proposal includes a first phase commitment to acquire 40 square kilometers of 3-D seismic and to drill two exploration wells, which are scheduled for the first quarter of 2008. The Castor block, which was just approved by the National Hydrocarbon Agency, covers 110,265 acres and our proposal includes the acquisition of an initial 30 square kilometer 3-D seismic survey and drilling one well. Petrominerales has also been evaluating the heavy oil potential of our two TEAs in the southern Llanos evidence of an extensive heavy oil belt. We have begun negotiations to change the en to an exploration block covering slightly more than 600,000 acres. Our proposal inc work commitment of 100 kilometers of 2-D seismic. We hope to complete negotiations exploration license by the end of the month. We have also submitted a proposal to convert 177,500 acres of the original Chiguiro TEA into an exploration license and we are evalua right of refusal on a third party proposal over another portion of the original TEA ar approximately 125,000 acres. Petrominerales has a license to use Petrobank's THAI™ technol evaluating the technology's applicability to these Llanos Basin heavy oil deposits.

Upon acceptance of these most recent exploration proposals, Petrominerales' exploration land bas total 2.0 million acres in nine exploration blocks and two TEAs.

Outlook

Petrominerales continues to enjoy strong cash flows as a result of increasing production and high world oil prices that coupled with existing financial resources has positioned us to execute our near-term growth strategy. We have guaranteed access to drilling equipment and a balanced inventory of high impact development opportunities and exciting exploration prospects to be drilled over the coming months.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") is dated November 10, 2006. Effective July 1, 2006, management has decided to change the reporting currency of Petrominerales Ltd. ("Petrominerales" or the "Company") from Canadian dollars (Cdn$) to United States dollars ($). All current period figures and the restated comparative figures, contained herein, are expressed in United States dollars, unless otherwise stated. The MD&A should be read in conjunction with the unaudited consolidated financial statements and accompanying notes of the Company as at and for the three and nine month periods ended September 30, 2006, the unaudited consolidated financial statements and accompanying notes and MD&A of the company as at and for the six months ended June 30, 2006, as well as the audited consolidated financial statements and accompanying notes and MD&A of Petrominerales Colombia Ltd. for the year ended December 31, 2005. Readers are also encouraged to read the Company's Final Long Form Prospectus dated June 13, 2006 in conjunction with this MD&A. Additional information for the Company can be found on SEDAR at www.sedar.com or at www.petrominerales.com.

Other than historical information, the MD&A contains forward-looking statements that are generally identifiable as any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events of performance (often, but not always, through the use of words or phrases such as "will likely result," "expected," "is anticipated," "believes," "estimated," "intends," "plans," "projection" and "outlook") are not historical facts and may be forward-looking and may involve estimates, assumptions and uncertainties which could cause actual results or outcomes to differ materially from those expressed in such forward-looking statements. 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: 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. Accordingly, there is no representation by Petrominerales that actual results achieved during the forecast period will be the same in whole or in part as those forecast. Further, any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events, except as required by applicable securities laws.

This report contains financial terms that are not considered measures under Canadian generally accepted accounting principles ("GAAP"), such as funds flow from operations, funds flow per share, and operating netback. These measures are commonly utilized in the oil and gas industry and are considered informative for our shareholders. Specifically, funds flow from operations and funds flow per share reflect cash generated from operating activities before changes in other non-cash working capital. These measures are considered important as they demonstrate the Company's ability to generate sufficient cash to fund future growth opportunities.

Formation of the Company

Petrominerales was incorporated in the Bahamas on April 20, 2006 as a wholly owned subsidiary of Petro International Ltd., which in turn is a wholly owned subsidiary of Petrobank Energy and Resources Ltd. ("Petrobank"), for the purpose of acquiring all of the issued and outstanding common shares of Petrominerales Colombia Ltd., previously a wholly owned subsidiary of Petro International Ltd., in connection with the initial public offering of the common shares of the Company (the "IPO"). The Company acquired all of the issued and outstanding common shares of Petrominerales Colombia Ltd. from Petro International Ltd. in exchange for 78,999,900 common shares of the Company. The acquisition of Petrominerales Colombia Ltd. by the Company is a non-arms length transaction and as such has been recorded by the Company at carrying value. The Company's financial statements presented

for comparative purposes reflect the financial position, results of operations and
Company had been combined with Petrominerales Colombia Ltd. since inception.

On June 29, 2006, the Company completed the IPO issuing 16 million new common sha
for total gross proceeds of Cdn$60 million (Cdn$55.6 million net of costs).

Revenue

In the third quarter of 2006, crude oil revenue before royalties more than doubled to $12.8 mil
$5.0 million in the third quarter of 2005. Related oil production in the third quarter of 2006 incre
126 percent from the third quarter of 2005 levels to 2,420 barrels per day ("bpd"), while the averag
price increased by 15 percent over the third quarter of 2005 to $57.57 per barrel. On a year to date b
revenue increased by 156 percent to $32.6 million in 2006 from $12.7 million in the same period in 20
Related production in the first nine months of 2006 increased by 102 percent to 2,133 bpd compared
1,056 bpd in the first nine months of 2005 while the average sales price increased by 27 percent to
$56.05 per barrel from $44.19 per barrel received in the first nine months of 2005.

Average Daily Crude Oil Production

Crude oil production increased by 126 percent to 2,420 bpd in the third quarter of 2006 from 1,073 bpd averaged in the third quarter of 2005. Production in the first nine months of 2006 increased by 102 percent to 2,133 bpd compared to 1,056 bpd in the same period of 2005. These significant production increases are due mainly to the completion of the Orito-117 and 118 wells late in the first quarter of 2006 that were on production for the entire second and third quarter.

Realized Prices

Oil sales prices in Colombia averaged $57.57 per barrel in the third quarter, representing a $12.97 per barrel (18% of average WTI price of $70.54 per barrel) discount to WTI compared to a discount of $13.02 per barrel (21% of average WTI price of $63.19 per barrel) in the third quarter of 2005. On a year to date basis, sales prices averaged $56.05 per barrel in the first nine months of 2006, representing a $12.21 per barrel discount (18% of average WTI price of $68.26 per barrel) compared to an average price of $44.19 per barrel in the first nine months of 2005, representing a discount of $11.42 per barrel (21% of average WTI price of $55.61 per barrel). The discounts to WTI decreased in 2006 as an increased percentage of production is coming from higher quality Orito oil.

Royalties

Royalties are fixed at a rate of eight percent until the Company's net production per field exceeds 5,000 bpd. Due to the fixed royalty rate, royalty expense increased in proportion with revenue to $1.0 million in the third quarter of 2006 from $0.4 million in the third quarter of 2005, and to $2.6 million in the first nine months of 2006 from $1.0 million in the first nine months of 2005.

Production Expenses

Production expenses increased to $1.6 million ($6.97 per barrel) in the third quarter of 2006 compared to $0.8 million ($7.84 per barrel) in the third quarter of 2005, and increased to $3.9 million ($6.70 per barrel) in the first nine months of 2006 compared to $2.2 million ($7.61 per barrel) in the first nine months of 2005. Ecopetrol, the state oil company and the Company's partner, is responsible for primary production operations at Orito and Neiva at a cost (subject to annual inflation, currency and other adjustments) of $4.14 per barrel and $2.25 per barrel, respectively. The Company's remaining production expenses are primarily fixed which results in lower per barrel production costs as production increases.

General and Administrative Expenses

General and administrative expenses increased by 70 percent in the third quarter to $1.2 million from $0.7 million in the third quarter of 2005 and to $3.0 million in the first nine months of 2006 from $2.2 million in the first nine months of 2005. The increases were primarily due to management fees paid to Petrobank, and costs associated with operating a publicly owned entity.

Stock-Based Compensation Expenses

Stock-based compensation expenses totalled $0.2 million in the third quarter of 2006 relating to stock options granted. The calculation of this non-cash expense is determined based on the fair value of stock options granted amortized over the vesting period of the option. The exercise price of each option is not less than the market price of the Company's stock on the date of the grant.

Foreign Exchange Loss (Gain)

The Company recorded a foreign exchange loss of $0.6 million in the third quarter of 2006. The loss was generated mainly due to Colombian Peso denominated working capital balances combined with a decrease in the value of the United States dollar relative to the Colombian Peso.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion expense increased to $3.8 million ($16.85 per barrel) in the third quarter of 2006 from $1.5 million ($15.05 per barrel) in the third quarter of 2005 and in the first nine months of 2006 increased to $9.6 million ($16.46 per barrel) from $4.2 million ($14.52 per barrel) in the first nine months of 2005.

Taxes

The Company recorded a $0.5 million income tax expense in the third quarter of 2006 compared to $0.3 million in the same period in 2005, and a $1.5 million expense in the first nine months of 2006 compared to $1.0 million in the first nine months of 2005. Taxes consist of presumptive income taxes in Colombia that are based on equity capitalization levels.

Net Income

Net income in the third quarter increased by 260 percent to $4.3 million ($0.04 per basic and diluted share) compared to $1.2 million ($0.01 per basic and diluted share) in the third quarter of 2005. Net income in the first nine months of 2006 increased by 507 percent to $12.1 million ($0.14 per basic and diluted share) compared to $2.0 million ($0.03 per basic and diluted share) in the first nine months of 2005. These increases were due to substantially higher production and crude oil sales prices, partially offset by higher royalties, production expenses and depletion, depreciation and accretion expense.

Funds Flow from Operations

The Company's funds flow from operations increased by 207 percent to $8.2 million in the third quarter of 2006 from $2.7 million in the third quarter of 2005. On a basic and diluted per share basis, funds flow from operations increased by 200 percent to $0.09 from $0.03 in the same period in 2005. Funds flow from operations increased by 257 percent to $22.0 million in the first nine months of 2006 compared to $6.2 million in the first nine months of 2005. On a basic and per diluted share basis, funds flow from operations increased by 225 percent to $0.26 in the first nine months of 2006 from $0.08 in the first nine months of 2005. These increases in the 2006 periods are primarily a result of higher production and realized oil sales prices.

Capital Expenditures

Capital expenditures totalled $21.7 million in the third quarter of 2006 compared to $4.2 million in the third quarter of 2005. On a year to date basis, capital expenditures totalled $49.7 million in the first nine months of 2006 compared to $12.6 million in the first nine months of 2005. In the three and nine month periods ended September 30, 2006 the expenditures related to drilling and workovers at Orito, first phase work commitments including acquiring and evaluating seismic data on the Company's exploration blocks, and workovers at Neiva.

SUMMARY OF QUARTERLY RESULTS

	2006 (1)			2005 (1)				2004 (1)
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Financial (US$000s except where noted)								
Crude oil revenue	**12,818**	13,581	6,239	3,932	4,953	3,921	3,865	4,045
Funds flow from operations (2)	**8,202**	10,479	3,363	1,838	2,668	1,728	1,786	2,281
Per share – basic and diluted ($) (3)	**0.09**	0.13	0.04	0.02	0.03	0.02	0.02	0.03
Net income	**4,252**	6,462	1,407	257	1,182	386	428	823
Per share – basic and diluted ($) (3)	**0.04**	0.08	0.02	0.00	0.01	0.00	0.01	0.01
Capital expenditures	**21,696**	9,110	18,942	19,605	4,216	4,389	3,996	3,311
Operations								
Operating netback (US$/bbl)								
Crude oil sales price	**57.57**	57.14	51.12	44.75	50.17	42.08	40.06	38.07
Royalties	**4.60**	4.61	4.09	3.59	4.01	3.37	3.21	3.05
Production expenses	**6.97**	5.59	8.36	8.59	7.84	8.11	6.89	5.81
Operating netback	**46.00**	46.94	38.67	32.57	38.32	30.60	29.96	29.21
Average daily crude oil production (bbls)	**2,420**	2,612	1,356	955	1,073	1,024	1,072	1,155

(1) Amounts in the periods ending on or before June 30, 2006 have been translated and restated in US$ from the previously reported Canadian dollar amounts. See "Change in Accounting Policy".

(2) Calculated based on cash flow from operations before changes in non-cash working capital.

(3) Assumed weighted average number of basic and diluted shares totalled 78,999,900 prior to incorporation on April 20, 2006. See "Formation of the Company".

Significant factors influencing quarterly results are:

- Late in the first quarter of 2006, the Company completed the Orito-117 and 118 wells, resulting in a significant increase in production.
- Production increases have resulted in a significant decrease in per barrel operating and general and administrative costs in 2006.
- Historically high world crude oil prices over the past two years.

Outstanding Share Data

The number of outstanding shares of Petrominerales as at November 10, 2006 remains unchanged from September 30, 2006 at 95.0 million.

Commitments

The Company has committed to various work programs pursuant to its exploration contracts. These commitments are expected to total approximately $22.6 million before June 30, 2008 and represent normal course exploration expenditures including acquiring and evaluating seismic data and drilling exploration wells. The Company has also secured two drilling rigs for 18 and 16-month terms (starting June 2006 and December 2006, respectively), which are expected to cost $22.0 million over their combined contract terms. Securing these rigs provides the Company with guaranteed access to the equipment required to implement the planned exploration program during the winter dry season in the Llanos Basin and also facilitates the Company's Orito development drilling program.

The following is a summary of the Company's remaining contractual commitments at September 30, 2006:

Type of Obligation ($000s)	Total	< 1 Year	1-3 Years
Exploration contracts and TEAs	22,600	16,600	6,000
Drilling rigs [(1)]	22,000	17,000	5,000
Total	44,600	33,600	11,000

(1) The contracted drilling rigs will be used to satisfy a portion of the commitments on the exploration contracts.

Liquidity and Capital Resources

At September 30, 2006 the Company had no debt and net working capital of $28.3 million, including cash and cash equivalents of $38.7 million.

The Company has an operating line of credit with a borrowing capacity of seven billion Colombian Pesos (approximately $3.1 million) less letters of credit outstanding resulting in available borrowing capacity of approximately $0.3 million. The Company can borrow at the fixed term deposit rate set by the Central Bank of Colombia plus six percent per annum.

The Company obtained a commitment letter in April 2006 from an international bank for a $50 million revolving credit facility with an initial $25 million borrowing base. The facility bears interest at a rate equal to the LIBOR (London Interbank Offered Rate) plus three percent per annum and is subject to standard closing conditions.

Transactions with Related Parties

Petrominerales Colombia Ltd. maintains a Technical Services Agreement with the Company's indirect parent company, Petrobank, for items such as geological, geophysical, and engineering services provided. All charges are based on cost plus a marginal administrative fee, no more than five percent. These costs totalled $0.7 million for the three-month period (2005 – $0.5 million) and $1.6 million for the nine-month period ended September 30, 2006 (2005 – $1.0 million). Of these costs, $0.5 million for the three-month period and $1.3 million for the nine-month period ended September 30, 2006 (2005 – $0.3 million and $0.4 million, respectively) were capitalized while the remainder was recorded as general and administrative expense.

The Company pays Petrobank a monthly fee of $75,000 pursuant to a Management Services Agreement made effective May 1, 2006. Costs under this agreement totalled $0.2 million for the three-month period and $0.5 million for the nine-month period ended September 30, 2006, and was recorded as general and administrative expense.

Change in Accounting Policy

Change in Reporting Currency

On July 1, 2006, the Company changed its reporting currency from Canadian dollars to United States dollars, as the United States dollar is more appropriate for the Company's investors and other users of the financial statements. In making this change in reporting currency, the Company has followed recommendations of the Emerging Issues Committee ("EIC") of the Canadian Institute of Chartered Accountants ("CICA"), set out in EIC-130, *"Translation Method When Reporting Currency Differs From The Measurement Currency Or There Is A Change In The Reporting Currency"*.

Financial Statements for all periods presented have been translated from Canadian dollars into United States dollars using the current rate method, based on EIC-130 recommendations. Using this method, all consolidated assets and liabilities have been translated using the exchange rate at the balance sheet dates, while shareholders' equity has been translated using the historical rates of exchange in effect on the dates of the corresponding transactions. The consolidated statements of operations and retained earnings and consolidated statements of cash flow have been translated using the prevailing average exchange rates for the period, except for financing transactions which have been translated using the historical rates of exchange. Any resulting exchange differences due to this translation are included in shareholders' equity as cumulative translation adjustment. The consolidated financial statements reflect a cumulative translation adjustment and a corresponding increase in capital assets of $16.0 million as at September 30, 2006. All comparative financial information being presented has been restated to reflect the Company's financial statements as if they have been historically reported in United States dollars.

Outlook

In addition to the plans discussed in this MD&A, please see the third quarter 2006 Report to Shareholders.

CONSOLIDATED BALANCE SHEETS

(Unaudited, thousands of United States dollars)

As at	September 30, 2006	December 31, 2005
		(Restated – Note 3)
Assets		
Current assets		
Cash and cash equivalents	**$ 38,679**	$ 113
Accounts receivable and other current assets	**9,156**	2,274
	47,835	2,387
Capital assets	**130,735**	85,930
	$ 178,570	$ 88,317
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	**$ 19,494**	$ 17,612
	19,494	17,612
Asset retirement obligations	**644**	539
Shareholders' equity		
Common shares (Note 4)	**138,906**	67,308
Contributed surplus (Note 4)	**337**	-
Cumulative translation adjustment (Note 3)	**16,024**	11,814
Retained earnings (deficit)	**3,165**	(8,956)
	158,432	70,166
	$ 178,570	$ 88,317

Commitments and contingencies (Note 6)

See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF OPERATIONS AND RETAINED EARNINGS

(Unaudited, thousands of United States dollars, except per share amounts)

	Three months ended September 30, 2006	Three months ended September 30, 2005	Nine months ended September 30, 2006	Nine months ended September 30, 2005
		(Restated-Note 3)	(Restated-Note 3)	(Restated-Note 3)
Revenues				
Oil	**$ 12,818**	$ 4,953	**$ 32,638**	$ 12,739
Interest income	**312**	-	**197**	-
Royalties	**(1,025)**	(396)	**(2,620)**	(1,019)
	12,105	4,557	**30,215**	11,720
Expenses				
Production	**1,551**	774	**3,899**	2,195
General and administrative	**1,210**	713	**2,968**	2,164
Foreign exchange loss (gain)	**614**	76	**(155)**	202
Stock-based compensation	**198**	-	**337**	-
Depletion, depreciation and accretion	**3,752**	1,486	**9,586**	4,186
	7,325	3,049	**16,635**	8,747
Income before taxes	**4,780**	1,508	**13,580**	2,973
Taxes	**(528)**	(326)	**(1,459)**	(977)
Net income	**4,252**	1,182	**12,121**	1,996
Deficit, beginning of period (Restated – Note 3)	**(1,087)**	(10,395)	**(8,956)**	(11,209)
Retained earnings (deficit), end of period	**$ 3,165**	$ (9,213)	**$ 3,165**	$ (9,213)
Basic and diluted earnings per share (Note 4)	**$ 0.04**	$ 0.01	**$ 0.14**	$ 0.03

See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOW

(Unaudited, thousands of United States dollars)

	Three months ended September 30, **2006**	Three months ended September 30, 2005 (Restated-Note 3)	Nine months ended September 30, **2006** (Restated-Note 3)	Nine months ended September 30, 2005 (Restated-Note 3)
Operating Activities				
Net income	**$ 4,252**	$ 1,182	**$ 12,121**	$ 1,996
Depletion, depreciation and accretion	**3,752**	1,486	**9,586**	4,186
Stock-based compensation	**198**	-	**337**	-
	8,202	2,668	**22,044**	6,182
Changes in non-cash working capital	**(59)**	182	**(6,398)**	(989)
	8,143	2,850	**15,646**	5,193
Financing Activities				
Issuance of common shares (Note 4)	**(199)**	-	**49,782**	-
Equity received from majority shareholder (Note 4)	**-**	2,175	**21,816**	7,747
	(199)	2,175	**71,598**	7,747
Investing Activities				
Expenditures on capital assets	**(21,696)**	(4,216)	**(49,748)**	(12,601)
Changes in non-cash working capital	**9,059**	(750)	**967**	(241)
	(12,637)	(4,966)	**(48,781)**	(12,842)
Net effect of foreign exchange on cash held in foreign currencies	**-**	9	**103**	5
Net change in cash position	**(4,693)**	68	**38,566**	103
Cash and cash equivalents, beginning of period	**43,372**	109	**113**	74
Cash and cash equivalents, end of period	**$ 38,679**	$ 177	**$ 38,679**	$ 177
Cash and cash equivalents consist of:				
Cash	**$ 892**	$ 177	**$ 892**	$ 177
Cash equivalents	**$ 37,787**	$ -	**$ 37,787**	$ -

Commitments and contingencies (Note 6)

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, 2006
(Unaudited, all tabular amounts are expressed in thousands of United States dollars, except share amounts)

Note 1 – Formation of the Company and Basis of Presentation

Petrominerales Ltd. ("Petrominerales" or the "Company") was incorporated in the Bahamas on April 20, 2006 as a wholly-owned subsidiary of Petro International Ltd., which in turn is a wholly-owned subsidiary of Petrobank Energy and Resources Ltd. ("Petrobank"), for the purpose of acquiring all of the issued and outstanding common shares of Petrominerales Colombia Ltd., a wholly owned subsidiary of Petro International Ltd., in connection with the initial public offering of the common shares of the Company (the "IPO").

On June 29, 2006, the Company completed the IPO of 16 million common shares for total gross proceeds of Cdn$60 million (Cdn$55.6 million net of costs).

In conjunction with the completion of the IPO, the Company acquired all of the issued and outstanding common shares of Petrominerales Colombia Ltd. from Petro International Ltd. in exchange for 78,999,900 common shares of the Company. The acquisition of Petrominerales Colombia Ltd. by the Company is a non-arms length transaction and as such has been recorded by the Company at carrying value. The Company's financial statements presented for comparative purposes reflect the financial position, results of operations and cash flows as if the Company had been combined with Petrominerales Colombia Ltd. since inception.

Note 2 – Significant Accounting Policies

These interim consolidated financial statements include the accounts of the company and its subsidiaries as at and for the three and nine month periods ended September 30, 2006 and should be read in conjunction with the audited financial statements of Petrominerales Colombia Ltd. as at and for the year ended December 31, 2005 (which can be found on SEDAR at www.sedar.com in the Company's Final Long Form Prospectus dated June 13, 2006). 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 financial statements of Petrominerales Colombia Ltd., except for the change in reporting currency as described in Note 3.

Note 3 – Change in Accounting Policy

Change in Reporting Currency

On July 1, 2006, the Company changed its reporting currency from Canadian dollars (Cdn$) to United States dollars ($), as this currency is more appropriate for the Company's investors and other users of the financial statements. In making this change, the Company has followed recommendations of the Emerging Issues Committee ("EIC") of the Canadian Institute of Chartered Accountants ("CICA"), set out in EIC-130, "Translation Method When The Reporting Currency Differs From The Measurement Currency Or There Is A Change In The Reporting Currency."

Financial statements for all periods presented have been translated from Canadian dollars into United States dollars using the current rate method, based on EIC-130 recommendations. Using this method, all consolidated assets and liabilities have been translated using the exchange rate at the balance-sheet dates, while shareholders' equity has been translated using the historical rates of exchange in effect on the dates of the corresponding transactions. The consolidated statements of operations and deficit and consolidated statements of cash flow have been translated using the prevailing average exchange rates for the period, except for financing transactions which have been translated using the historical rates of exchange. Any resulting exchange rate differences due to this translation are included in shareholders' equity as cumulative translation adjustment. All comparative financial information being presented has been restated to reflect the Company's financial statements as if they have been historically reported in United States dollars and the effect on the consolidated financial statements resulted in a cumulative translation adjustment and corresponding increase in capital assets of $16.0 million as at September 30, 2006.

Note 4 – Share Capital

Authorized

The Company has authorized capital of 200,000,000 common shares, with a par value of $1.00 per common share.

Common Shares

Common Share Continuity	Number	Amount
		(Restated – Note 3)
December 31, 2005 [1]	78,999,900	$ 67,308
Contributed from Petrobank before March 31, 2006	-	21,816
Incorporation on April 20, 2006	100	-
Issued pursuant to IPO	16,000,000	53,766
Share issue costs	-	(3,984)
Balance at September 30, 2006	**95,000,000**	**$ 138,906**

(1) In connection with the IPO, the Company issued 78,999,900 common shares in exchange for all of the issued and outstanding common shares of Petrominerales Colombia Ltd. and includes common shares and contributed surplus of Petrominerales Colombia Ltd. representing the historical equity contributed indirectly by Petrobank as if the Company and Petrominerales Colombia Ltd. had been combined since inception.

Stock Options

The Company has established a stock option plan for directors, officers and employees. The plan allows for the issuance of up to 10 percent of the outstanding shares of the Company. The exercise price is no less than the market price of the Company's stock on the date of the grant. Stock option terms are determined by the Company's Board of Directors but typically, options vest evenly over a period of four years from the date of grant and expire between five and 10 years after the date of grant. As at September 30, 2006, the Company had 3,090,126 stock options outstanding, with a weighted average exercise price of Cdn$3.77 per share. The remaining contractual life is between five and ten years and no options are currently available for exercise.

Stock-Based Compensation

The Company uses the fair value-based method of accounting for its stock-based compensation plan whereby the fair value of stock options is recognized as stock-based compensation expense and contributed surplus. Stock-based compensation expense for the three and nine-month periods ended September 30, 2006 totalled $0.2 million and $0.3 million respectively (2005 – nil).

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

Nine months ended September 30, 2006	
Risk free interest rate	**4.5%**
Dividend rate	**0%**
Expected life (years)	**3.3**
Expected volatility	**30%**

The average fair value per stock option granted during the three and nine-month periods ended September 30, 2006 was $1.19 (2005 – nil) and $1.04 (2005 – nil) respectively, as at the date of grant.

Earnings Per Share

Basic and diluted earnings per share have been calculated based on net income divided by the weighted average number of common shares outstanding for the three month period ended September 30, 2006 of 95,000,000 (2005 – 78,999,900) and for the nine month period ended September 30, 2006 of 84,509,118 (2005 – 78,999,900). The diluted calculations include nil additional shares for the potential impact of stock options and stock-based compensation, as the impact is anti-dilutive.

Note 5 – Related Party Transactions

Petrominerales Colombia Ltd. maintains a Technical Services Agreement with the Company's indirect parent company, Petrobank, for items such as geological, geophysical, and engineering services provided. All charges are based on cost plus a marginal administrative fee, no more than five percent. These costs totalled $0.7 million for the three-month period (2005 – $0.5 million) and $1.6 million for the nine-month period ended September 30, 2006 (2005 – $1.0 million). Of these costs, $0.5 million for the three-month period and $1.3 million for the nine-month period ended September 30, 2006 (2005 – $0.3 million and $0.4 million, respectively) were capitalized while the remainder was recorded as general and administrative expense.

The Company pays Petrobank a monthly fee of $75,000 pursuant to a Management Services Agreement made effective May 1, 2006. Costs under this agreement totalled $0.2 million for the three-month period and $0.5 million for the nine-month period ended September 30, 2006, and was recorded as general and administrative expense.

Note 6 – Commitments and Contingencies

The Company has committed to various work programs pursuant to its exploration contracts. These commitments are expected to total approximately $22.6 million before June 30, 2008 and represent normal course exploration expenditures including acquiring and evaluating seismic data and drilling exploration wells. The Company has also secured two drilling rigs for 18 and 16-month terms (starting June 2006 and December 2006, respectively), which are expected to cost $22.0 million over their combined contract terms. The contracted drilling rigs will be used to satisfy a portion of the commitments on the exploration contracts. Petrominerales plans to fund these commitments with existing cash balances, funds flow from operations, and available credit facilities. The Company has issued letters of credit totalling $2.8 million outstanding in connection with the obligations on these exploration contracts.

PETROBANK ENERGY AND RESOURCES LTD.

STRENGTH in our resources Q3·06

FINANCIAL & OPERATING HIGHLIGHTS

	Three months ended September 30, 2006	2005	% change	Nine months ended September 30, 2006	2005	% change
Financial						
($000s, except where noted)						
Oil and natural gas revenue	**24,639**	17,983	37	**73,499**	42,571	73
Funds flow from operations [1]	**14,788**	8,877	67	**45,368**	16,848	169
Per share – basic ($)	**0.22**	0.15	47	**0.68**	0.29	134
– diluted ($)	**0.21**	0.15	40	**0.66**	0.29	128
Net income	**5,169**	3,170	63	**20,486**	7,624	169
Per share – basic ($)	**0.08**	0.05	60	**0.31**	0.13	138
– diluted ($)	**0.07**	0.05	40	**0.30**	0.13	131
Capital expenditures	**57,904**	32,094	80	**158,356**	59,716	165
Total assets	**395,654**	215,829	83	**395,654**	215,829	83
Net debt [2]	**70,366**	54,526	29	**70,366**	54,526	29
Common shares outstanding, end of period (000s)						
Basic	**67,293**	59,148	14	**67,293**	59,148	14
Diluted	**71,346**	64,333	11	**71,346**	64,333	11
Operations [3]						
Canadian operating netback ($/boe except where noted)						
Natural gas revenue ($/mcf) [4]	**5.39**	8.25	(35)	**6.23**	7.03	(11)
Oil and NGL revenue ($/bbl)	**72.13**	65.50	10	**64.52**	60.16	7
Oil and natural gas revenue [4]	**44.28**	53.07	(17)	**44.61**	45.34	(2)
Royalties	**6.00**	10.41	(42)	**6.94**	9.24	(25)
Production expenses	**8.63**	5.81	49	**6.47**	6.52	(1)
Transportation expenses	**0.42**	1.08	(61)	**0.43**	1.20	(64)
Operating netback	**29.23**	35.77	(18)	**30.77**	28.38	8
Colombian operating netback ($/bbl)						
Oil revenue	**64.58**	60.24	7	**63.20**	53.97	17
Royalties	**5.16**	4.82	7	**5.07**	4.32	17
Production expenses	**7.80**	9.41	(17)	**7.56**	9.31	(19)
Operating netback	**51.62**	46.01	12	**50.57**	40.34	25
Average daily production						
Canada – natural gas (mcf)	**10,578**	11,485	(8)	**13,267**	10,805	23
Canada – oil and NGL (bbls)	**756**	551	37	**802**	381	110
Total Canada (boe)	**2,519**	2,465	2	**3,013**	2,182	38
Colombia – oil (bbls)	**2,420**	1,073	126	**2,133**	1,056	102
Total Company (boe)	**4,939**	3,538	40	**5,146**	3,238	59

(1) Calculated based on cash flow before changes in non-cash working capital and asset retirement obligations settled.
(2) Includes working capital (deficiency) and subordinated notes. The subordinated notes were repaid on July 31, 2006.
(3) 6 mcf of natural gas is equivalent to 1 barrel of oil equivalent ("boe").
(4) Canadian sales prices are shown after forward gas sales contracts.

REPORT TO SHAREHOLDERS

HIGHLIGHTS

The third quarter results are highlighted as follows:

- At our WHITESANDS project we began combustion operations and produced first oil from the world's first THAI™ well pair, initiated the Pre-Ignition Heating Cycle ("PIHC") on the second of three well pair and drilled five successful exploration wells on our oil sands leases.
- The Company drilled 46 (40.5 net) conventional oil and gas wells in Canada.
- Conventional production averaged 4,939 boepd in the third quarter of 2006, a 40 percent increase over the comparative 2005 period.
- Funds flow from operations increased 67 percent to $14.8 million.
- Net income increased by 63 percent to $5.2 million.
- In July 2006, the Company closed a new $120 million credit facility and used a portion of the proceeds to repay the remaining $50 million of 9% subordinated notes that were outstanding.

OPERATIONAL UPDATE

Heavy Oil Business Unit

THAI™ combustion operations at WHITESANDS during the third quarter of 2006 continued to confirm the effectiveness of the THAI™ technology in our first well pair. Two additional key operational milestones were achieved in the third quarter with the initiation of the Pre-Ignition Heating Cycle ("PIHC") on the second well pair and the shipment of the first produced oil from the project.

Air injection and combustion was initiated on the first of the three project wells on July 20, 2006, and we have been continually injecting air into the vertical well of this center well pair. During the first three weeks of air injection, in-situ combustion ignition was confirmed as we measured various indicators of the combustion reaction, including significantly rising temperatures in the reservoir zone, production of combustion gases and rising horizontal well bore temperatures. This trend continued through the third quarter with recorded reservoir temperatures reaching as high as 800 degrees Centigrade. Combustion gas analysis consistently demonstrated a high ratio of carbon dioxide to carbon monoxide, indicating a very high level of conversion of oxygen, hydrocarbon gases indicative of thermocracking of oil in-situ, and free hydrogen generated from high temperature reactions, all indicators of efficient high temperature combustion. These data also suggest that we are upgrading the oil in-situ. We are very early in the process of building out the combustion front in the first THAI™ well pair and estimate that only approximately 7,000 m^3 of the reservoir has been affected by combustion at the toe of the horizontal well, which is less than one percent to total reservoir volume expected to be affected by combustion over the life of each THAI™ well pair.

Since initiating THAI™ production operations, the gross production capability from the first horizontal well has consistently exceeded 1,000 barrels of fluid per day with the potential production capability double our initial forecast rate. High productive capacity has meant that we have had to manage operations to match well flow with current plant capability. The composition of produced fluids continues to be variable, consisting of a combination of condensed steam from the Pre-Ignition Heating Cycle ("PIHC"), reservoir water, bitumen, and sand. Bitumen production rates, while variable, increased over the quarter. During October we saw a significant rise in bitumen production and we produced approximately 4,000 barrels of bitumen. This production was not rateable on a daily basis since the plant facilities were not on stream for the entire period. However, during this period, when producing at high gross fluid rates, we experienced an average 30 percent bitumen cut. While facility bottlenecks and well and plant maintenance operations during the quarter reduced the ability to produce continuously and at the higher rates, air injection operations were not curtailed and have increased over the quarter, indicating an expanding area of combustion.

Surface facilities have been able to handle a wide range of fluid rates and temperatures, however we have experienced facilities downtime and reduced production due to equipment commissioning issues, adjustments to manage higher than design well production capability, and sand production. These facilities issues necessitate ongoing operational adjustments and sand clean-out procedures in the surface facilities and the horizontal well. As reported previously, the produced sand is very fine-grained, indicating that a sand-bridging structure within the reservoir has yet to be fully established. This is most likely a result of our transition from the earlier steam injection operations to combustion operations, and may have been impacted by earlier horizontal well procedures at the beginning of the THAI™ production phase. While we expect the produced sand to be minimized as the combustion front expands and a consistent rateable flow regime is established, we are also enhancing our sand handling capability to minimize plant down time. These facilities modifications are underway and are expected to be in place by the end of November.

Modified PIHC operations began late in the third quarter for the second well pair and we expect to initiate the PIHC for the third well pair in November. The modified PIHC operations are designed to reduce the amount of steam and time required to create reservoir mobility before initiating air injection and combustion.

We are still in the very early stages of the THAI™ process and in a state of continual adjustment of our operations. This continuous improvement process is consistent with starting up the first field scale demonstration of a new technology, allowing us to modify certain aspects of our surface facilities and operating procedures. We foresee an ongoing process of technical improvement and innovation as we enhance our ability to produce significant volumes of oil using the THAI™ process.

Additional Resource Delineation

During the second quarter of 2006, we reported that the estimated gross bitumen-in-place on a portion of the 62 sections of oil sands leases owned by our 84 percent subsidiary, WHITESANDS Insitu Ltd. had increased to 1.6 billion barrels, based on a May 2006 Fekete Associates Ltd. resource evaluation. In addition, a recoverable reserve and resource assessment by McDaniel Associates Ltd. ("McDaniel") effective May 1, 2006 estimated an initial gross recoverable bitumen volume, based on Steam Assisted Gravity Drainage ("SAGD") technology, of up to 537 million barrels, which includes 25 million barrels of gross probable reserves and 70 million barrels of gross probable plus possible reserves.

During the third quarter of 2006 we drilled five oil sands exploration wells on areas of the leases we believed to contain considerable additional recoverable resources. Weather and ground conditions prevented us from drilling an additional four planned wells, which will now be incorporated into our winter drilling program. The five new wells all intersected significant McMurray channel of a quality equal to or better than previous wells. All of these wells were cored and logged and will be incorporated into an updated McDaniel recoverable resource report. The initial McDaniel report included only 13 sections of our lands, those with at least one drill hole per section, and excluded a number of sections with McMurray channel indicated by our 3-D seismic and/or areas on trend with known McMurray channel. The additional ten well winter drilling program is also expected to delineate significant new recoverable bitumen resources. We have requested an update to the McDaniel report to reflect the impact of the most recent drilling program, and we anticipate a further update will follow our winter drilling program. We also plan to update the reserve evaluation based on the THAI™ recovery process which we believe will have a higher recovery rate, and hence greater recoverable reserves than the SAGD-based estimates.

Project Development

In addition to the ongoing delineation of the recoverable resource potential of our lands we are also evaluating a potential project site for a THAI™ expansion project of approximately 10,000 barrels per day. We have been in the early stages of evaluating a new project area proximal to the current pilot site, to optimize infrastructure, and have selected a preliminary project area. Project scoping and preliminary engineering are expected to commence early in 2007.

A CAPRI™ test is anticipated by mid 2007, this will either be through a modification of one of the three current horizontal wells, or in a well drilled specifically for CAPRI™.

The THAI™ Process

THAI™ is an evolutionary in-situ gravity assisted 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.

THAI™ has many potential benefits over other in-situ recovery methods, such as SAGD. These potential 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.

THAI™ can also be applied to other heavy oil deposits and it is our strategy to initiate projects in mobile oil reservoirs in Canada and/or internationally. Our 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, Petrobank's 80.7 percent owned subsidiary, Petrominerales Ltd. (TSX: PMG), is evaluating two heavy oil Technical Evaluation Areas in Colombia covering 0.8 million acres for the potential application of THAI™.

Canadian Business Unit

Canadian Business Unit production averaged 2,519 boe per day ("boepd") in the third quarter of 2006, compared to 2,465 boepd in the third quarter of 2005 and 3,017 boepd in the second quarter of 2006. Our 2006 program has, to date, experienced delays due to weather conditions, regulatory approval and equipment availability. At the end of the third quarter we began to bring on initial production additions from our successful 2006 projects that allowed us to exit the quarter producing approximately 3,000 boepd. During the third quarter, activity increased dramatically with the drilling of 46 (40.5 net) wells, compared to only 17 (14.1 net) wells in the second quarter and 12 (8.7 net) in the first quarter of the year. The majority of the impact of this 2006 program will be realized through production additions during the fourth quarter. The first new production in 2006 from our Jumpbush drilling program was tied-in to our facility at the end of the third quarter. We currently have approximately nine million cubic feet of natural gas per day ("mmcfpd") of behind-pipe capacity awaiting tie-in. The recent drop in natural gas prices had encouraged Petrobank to accelerate our low risk light oil drilling program and defer our gas drilling programs. Results to date on the light oil plays in both the Bakken and the Torquay zones of southeast

Saskatchewan and southwest Manitoba are very encouraging and will result in significant new oil production being added during the fourth quarter.

Canadian Business Unit Drilling Results

	Q1		Q2		Q3		Q4 To Date		Year to date		
Property	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Success %
Jumpbush/Milo	4.0	2.8	14.0	11.6	29.0	25.1	1.0	1.0	48.0	40.5	100%
Red Willow	2.0	2.0	1.0	1.0	4.0	4.0	1.0	1.0	8.0	8.0	75%
Innes - Bakken	-	-	-	-	3.0	3.0	2.0	2.0	5.0	5.0	80%
Sinclair - Torquay	-	-	-	-	6.0	6.0	5.0	5.0	11.0	11.0	100%
Other operated	3.0	3.0	1.0	1.0	2.0	2.0	-	-	6.0	6.0	67%
Non-operated	3.0	0.9	1.0	0.5	2.0	0.4	-	-	6.0	1.8	72%
Total	12.0	8.7	17.0	14.1	46.0	40.5	9.0	9.0	84.0	72.3	92%
% gas	42%	44%	88%	86%	72%	72%	22%	22%	65%	65%	

Jumpbush

The majority of our 2006 Jumpbush wells were drilled in the third quarter. To date, we have drilled 44 (37.0 net) wells, 31 (23.9 net) of which have been tied-in and another 13 (13 net) wells are currently awaiting tie-in. Prior to year-end, additional compression will also be added to increase production from all of the wells drilled and tied-in this year. The 13 remaining wells to be tied-in have been tested at 3.6 mmcfpd but we expect the first month's contribution will be approximately 2.0 mmcfpd. We have one additional well planned to be drilled and tied-in this year. We continue to work on planning and regulatory approvals for a 50 to 100 well program next year.

Milo

Milo is just south and east of the Jumpbush property, where we have been extending our Jumpbush exploration model, pursuing Belly River zones with high initial production rates. In 2006, four (3.5 net) wells have been drilled, three (2.5 net) wells during the third quarter. This gas is more complicated to tie-in as we need to utilize third party pipelines and facilities. Currently the four wells have tested at aggregate rates of 2.25 mmcfpd, and we anticipate aggregate initial production from the wells of approximately 1.1 mmcfpd. Through the balance of 2006 we plan to tie-in the four wells and drill a fifth well. We continue to expand our inventory of opportunities on this trend and are confident in the exploration model we are employing to identify lands of interest and add to our inventory of drilling locations.

Red Willow

High deliverability Mannville zones that can be either oil or gas bearing characterize the Red Willow property. To date in 2006, eight wells (8.0 net) have been drilled, with four of those drilled in the third quarter and one more drilled in the fourth quarter. Our drilling resulted in one oil well and five gas wells. The best results have come from the last four gas wells drilled with three of these wells testing at combined rates of 5.3 mmcfpd. We anticipate the first month contribution from all four wells to be approximately 5.5 mmcfpd. Through the balance of 2006 we plan to tie-in these four wells and drill a horizontal well into an existing Glauconite zone oil pool.

Innes area – Bakken Resource Play

The Bakken resource play of southeast Saskatchewan generally requires horizontal wells with specialized fracture stimulations to create economic production of light oil. Petrobank initially participated in this play as a partner in wells operated by other companies testing the initial viability of extracting light oil from this geographically extensive, low permeability reservoir. In 2006 we have participated in four (0.81 net) joint interest wells to date. Furthermore, we expect to participate in an additional three (0.75 net) non-operated wells to be drilled by year-end. We have utilized the experience gained from these early joint ventures to high-grade and expand our 100 percent working interest acreage, further increasing our strong land position in the Bakken play. In the third quarter we began drilling our own 100 percent working interest wells. So far five horizontal wells have been drilled and the rig is currently drilling the horizontal section of our sixth well. The first two of these wells have been fracture stimulated and we expect to have production from our stimulated wells on-stream during the month of November, and we expect to have another five horizontal wells drilled by year-end. We have a large inventory of opportunities in this area and our success to date means we have added many more development locations to this inventory. Petrobank will monitor performance from this relatively new play before providing comments on additions to our production.

Sinclair / Ryerson area – Torquay play

The Torquay play, like the Bakken play, is a relatively new light oil play in southeast Saskatchewan and southwestern Manitoba. Petrobank was able to monitor this play through farm-out agreements on a small part of our fee-simple lands located in Manitoba. Through late 2005 and 2006 Petrobank continued to assess this new opportunity and expand our land position in Saskatchewan and Manitoba on the trend. Starting in the third quarter, we have now drilled 11, 100 percent working interest wells, all of which are cased as potential oil wells. In the Ryerson area, a new pool has been discovered and to date we have drilled seven development wells, four of which are producing with all seven expected to be on-line within two weeks. Our remaining exploration wells are being evaluated and we anticipate drilling a minimum of five more exploration or development wells by year-end. Our inventory of development locations has expanded rapidly as a result of our success in the area to-date. Again, we will be monitoring the performance from this relatively new play before providing comments on additions to our production.

Exploration

Petrobank is further positioning itself in new exploration areas with higher impact plays to compliment our large inventory of low-risk gas and light oil opportunities. This program is growing and we have acquired 5,120 acres of exploration lands on new prospects during 2006. We will continue to add to our land position and mature our exploration ideas in these new areas with seismic and technical work in preparation for drilling in 2007.

Latin American Business Unit - Petrominerales Ltd. ("Petrominerales")

During the third quarter the activities of Petrominerales, Petrobank's 80.7 percent owned subsidiary, were focused on continuing development in Orito, implementing our pilot fracture stimulation program in Neiva and preparing for a significant exploration drilling program in the Llanos and Putumayo Basins which will begin during the first quarter of 2007.

Third quarter 2006 production averaged 2,420 bpd compared to 2,612 bpd in the second quarter of 2006 and 1,073 bpd in the third quarter of 2005. The significant increase from the prior year period is mainly due to the success of the Orito-117 and 118 completions at the end of the first quarter of 2006 which proved-up a significant southwest extension to the Orito field. The decrease from the prior quarter is mainly a result of certain wells being taken off production during the period for the re-work and recompletion programs outlined below, and due to natural declines.

Orito

We have now completed drilling three wells in the Orito field since June 2006, the Orito-119 well, the redrill of the Orito-116 location and the Orito-124 well.

The Orito-119 well was completed in the upper Caballos sands using a slim hole drilling design. Due to a lack of pressure integrity behind the production liner, a remedial cement job was attempted on the well. With this poor cement job, we were unable to apply our revised fracture stimulation program to the productive intervals in this well and initial oil production from the well has been limited to approximately 60 bpd. If this well exhibits improving productive capability as it cleans up following completion, we plan to install an electrical submersible pump to optimize the productive capability of the well.

Following the Orito-119 well, the rig drilled the sidetrack of the Orito-116 well, also incorporating our slim-hole drilling design, which reached total depth of 6,525 feet on July 4, 2006. As expected, the sidetrack well encountered a similar high quality series of Caballos sands as in the original 116 well which was our original confirmation of the southwest extension to the field, initially testing at rates of more than 1,000 bpd. Unfortunately, the sidetracked well appears to have experienced a casing collapse, similar to the one which occurred in the original 116 well and has now been abandoned. Based on these two well results and similar issues associated with the Orito-113 recompletion discussed below, Petrominerales will be eliminating slim-hole drilling design from our future development plans.

Following the Orito-116 sidetrack, the rig commenced drilling Orito-124, which reached total depth of 8,134 feet on October 3, 2006. We are in the process of completing the Orito-124 well, in the prolific southwest extension area of the field. Log analysis indicates significant hydrocarbon reserves in the Caballos B, C and D sands. Initial tests of the Caballos "B2" and "B3" reservoirs indicate oil productivity, and we are currently in the process of fracture stimulating these sands. Immediately thereafter we plan to fracture stimulate the C and D sands and put the well on test. The Orito-122 well is now drilling at a depth of 6,600 feet and we expect to reach total depth within the next week. The Orito-122 well is expected to prove the updip extension of the oil zone and more fully define the potential of this undrilled area. A successful well in this region of the field has the potential to further increase our inventory of development drilling locations.

In addition to this recent drilling, we also performed re-completions on the Orito-113 and Orito-115 wells. We re-entered the Orito-113 well in an attempt to recover lost production due to near wellbore damage and the well was also deepened to the Upper Caballos A sand. A slim hole liner was set in the previous open-hole productive interval to facilitate further fracture stimulation and zonal isolation. During our pre-stimulation operations, pressure communication behind the liner was observed, and the subsequent fracture stimulation was postponed. We installed a liner top packer to achieve annular isolation and performed a remedial cement job to allow for a successful fracture stimulation of the Caballos zone in that well. The well is currently cleaning up at rates of approximately 250 bpd. The Orito-115 well was also re-completed with a production liner and a fracture stimulation program. The well was placed back on-line recently, and is currently cleaning up with oil production rates of approximately 80 bpd, well in excess of the well's pre-stimulation potential.

Our second drilling rig, contracted for 16 months, has been further delayed and it is not expected to arrive in Orito before mid December. We are assessing the possibility of moving this rig directly to our Llanos exploration program to avoid high mobilization and demobilization costs associated with moving it into Orito where it would most likely only be capable of drilling one additional development well prior to returning to the Llanos Basin to commence our exploration program. Irrespective of our short-term plans, the rig will ultimately be moved to Orito to accelerate our development drilling program.

Neiva

At Neiva, we completed our initial phase of fracture stimulations involving five test wells in the Honda and Doima-Chicoral reservoirs. The DT-56 (Doima-Chicoral) stimulation was highly successful, increasing gross oil production rates from 86 to 170 bpd. The Honda formation fracture stimulations included the installations of progressive cavity pumps ("PCPs") and initially has resulted in significant increases in production. Based on positive initial results, we plan to drill at least three new Doima-Chicoral wells incorporating our fracture stimulation design into the completions. We will continue to monitor the Honda fracture stimulations and expect to be able to expand this program to more than 50 additional Honda locations at Neiva. We have also recently completed the conversion of two wells to water injectors as part of an initial pilot water flood program in the Honda reservoir. We commenced water injection on November 1st and expect response in the surrounding wells during the first half of 2007.

Exploration

Petrominerales has completed the first phase exploration commitments, which included acquiring 3-D seismic and interpretation of existing data on the first five of our exploration blocks, evaluating key, prospective portions of each block. Beginning in February 2007, we will begin a five-well drilling program to test the initial prospects on each of the Casanare Este, Casimena, Corcel and Las Aguilas blocks, as well as our second test on the Joropo block. In addition, Petrominerales has signed two exploration licenses (Mapache and Castor) covering a significant portion of the original Chicago Technical Evaluation Agreement ("TEA"). The recently signed Mapache block covers 107,705 acres and our proposal includes a first phase commitment to acquire 40 square kilometers of 3-D seismic and to drill two exploration wells, which are scheduled for the first quarter of 2008. The Castor block, which was just approved by the National Hydrocarbon Agency, covers 110,265 acres and our proposal includes the acquisition of an initial 30 square kilometer 3-D seismic survey and drilling one well. Petrominerales has also been evaluating the heavy oil potential of our two TEAs in the southern Llanos Basin, where there is evidence of an extensive heavy oil belt. We have begun negotiations to change the entire Rio Ariari TEA to an exploration block covering slightly more than 600,000 acres. Our proposal includes a first phase work commitment of 100 kilometers of 2-D seismic. We hope to complete negotiations on the Rio Ariari exploration license by the end of the month. We have also submitted a proposal to convert approximately 177,500 acres of the original Chiguiro TEA into an exploration license and we are evaluating our first right of refusal on a third party proposal over another portion of the original TEA area covering approximately 125,000 acres. Petrominerales has a license to use Petrobank's THAI™ technology and is evaluating the technology's applicability to these Llanos Basin heavy oil deposits.

Upon acceptance of these most recent exploration proposals, Petrominerales' exploration land base will total 2.0 million acres in nine exploration blocks and two TEAs.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") is dated November 10, 2006 and should be read in conjunction with the unaudited consolidated financial statements of Petrobank Energy and Resources Ltd. ("Petrobank" or the "Company") as at and for the three and nine month periods ended September 30, 2006, MD&A for the year ended December 31, 2005, and the audited consolidated financial statements as at and for the year ended December 31, 2005. Petrobank consolidates the financial and operating results of Petrominerales Ltd. ("Petrominerales"), a company with operations in Colombia, and WHITESANDS Insitu Ltd., a company holding oil sands leases and completing a pilot project to field demonstrate Petrobank's patented THAI™ heavy oil recovery process. Petrobank's ownership in the two companies is 80.7 percent and 84 percent, respectively. Additional information for the Company, including the Company's Annual Information Form, can be found on SEDAR at www.sedar.com or at www.petrobank.com. In addition to historical information, the MD&A contains forward-looking statements that are generally identifiable as any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events of performance (often, but not always, through the use of words or phrases such as "will likely result," "expected," "is anticipated," "believes," "estimated," "intends," "plans," "projection" and "outlook") are not historical facts and may be forward-looking and may involve estimates, assumptions and uncertainties which could cause actual results or outcomes to differ materially from those expressed in such forward-looking statements. 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: 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. Accordingly, 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. Further, any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events, except as required by applicable securities laws.

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 not considered measures under Canadian generally accepted accounting principles ("GAAP"), such as funds flow from operations, funds 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, funds flow from operations and funds flow per share reflect cash generated from operating activities before changes in other non-cash working capital and asset retirement obligations settled. These measures are considered important as they demonstrate the Company's ability to generate sufficient cash to fund future growth opportunities and repay debt. All amounts are in Canadian dollars, unless otherwise stated.

Revenue

In the third quarter of 2006, oil and natural gas revenue increased by 37 percent to $24.6 million from $18.0 million in the third quarter of 2005. On a year to date basis, revenue increased by 73 percent to $73.5 million in 2006 from $42.6 million in the same period in 2005. These increases were a result of higher oil production and realized oil prices in both Canada and Colombia, offset somewhat by lower natural gas production and realized natural gas prices in Canada.

Average Daily Production

Total production for the Company increased by 40 percent to 4,939 boe per day ("boepd") in the third quarter of 2006 compared to 3,538 boepd in the third quarter of 2005, comprised of 2,519 boepd of conventional oil and gas production in Canada and 2,420 barrels per day ("bpd") of oil production in Colombia. On a year to date basis, production increased by 59 percent to 5,146 boepd in 2006 compared to 3,238 boepd in 2005, comprised of 3,013 boepd in Canada and 2,133 bpd in Colombia.

The Company's natural gas production decreased to an average 10.6 million cubic feet per day ("mmcfpd") in the third quarter of 2006 compared to 11.5 mmcfpd in the third quarter a year earlier, and increased to 13.3 mmcfpd in the first nine months of 2006 compared to 10.8 mmcfpd in the first nine months of 2005. The increase in the nine-month period is mainly a result of significant production additions at Jumpbush at the end of 2005, since then gas production has experienced natural declines. The Company has drilled 56 (48.5 net) wells in the greater Jumpbush area and at Red Willow during 2006. The majority of these wells are being brought on production during the fourth quarter, with significant production increases expected by year-end. Oil and NGL production in Canada during the third quarter averaged 756 bpd, an increase of 37 percent from the 551 bpd produced in the third quarter of 2005, and increased by 110 percent to 802 bpd in the first nine months of 2006 compared to 381 bpd in the first nine months of 2005. Total Canadian production averaged 2,519 boepd in the third quarter and 3,013 boepd in the first nine months of 2006, increases of two and 38 percent, respectively, over the comparable periods in 2005. Canadian production includes royalty income production from the Company's fee title lands of 363 boepd in the third quarter, an increase of 19 percent over the 304 boepd received in the third quarter of 2005, and 424 boepd in the first nine months of 2006, a 51 percent increase over the 281 boepd received in the first nine months of 2005. The increases relate primarily to new Bakken light oil production in southeast Saskatchewan. The Company has now commenced an extensive drilling program targeting the Bakken and Torquay formations in southeast Saskatchewan and southwest Manitoba which is expected to significantly increase working interest oil production over the near term and through 2007.

Oil production in Colombia increased by 126 percent to 2,420 bpd in the third quarter of 2006 from 1,073 bpd in the third quarter of 2005. Production in the first nine months of 2006 doubled from 1,056 bpd in the first nine months of 2005 to 2,133 bpd in the first nine months of 2006. These increases are due mainly to the completion of the Orito-117 and 118 wells late in the first quarter of 2006.

Average Benchmark Prices and US$ Exchange Rate

	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	**2006**	2005
WTI crude oil (US$/bbl)	**70.54**	63.19	**68.26**	55.61
WTI crude oil (Cdn$/bbl)	**79.11**	75.92	**77.24**	67.94
NYMEX natural gas (US$/mmbtu)	**6.18**	9.73	**6.89**	7.75
US$/Cdn$ exchange rate	**0.89**	0.83	**0.88**	0.82

Realized Prices

The average natural gas price received in the third quarter was $5.39 per mcf, a 35 percent decrease from the $8.25 per mcf received in the third quarter of 2005, and the average price received in the first nine months of 2006 also decreased to $6.23 per mcf from $7.03 per mcf in the first nine months of 2005. Approximately 20 percent of natural gas production in the third quarter and 16 percent in the first nine months was sold under the Company's long-term physical natural gas sales contract at a price of $3.72 per mcf.

The average Canadian oil and NGL price received in the third quarter was $72.13 per barrel, a 10 percent increase from the $65.50 per barrel received in the third quarter of 2005, and the price received in the first nine months of 2006 increased by seven percent to $64.52 per barrel compared to $60.16 per barrel in the first nine months of 2005. Canadian oil and NGL prices represented a US$6.36 (9% of WTI) per barrel discount to average WTI prices in the quarter compared to US$8.73 (14% of WTI) per barrel in the third quarter of 2005. The average discount decreased with the addition of more light oil production from the Company's fee title lands despite the addition of conventional heavy oil production from the Macklin area, which is subject to higher discounts.

Oil sales prices in Colombia averaged US$57.57 per barrel in the third quarter, representing a US$12.97 per barrel (18% of WTI) discount to WTI compared to a price of US$50.17 per barrel, representing a discount of US$13.02 per barrel (21% of WTI) in the third quarter of 2005. On a year to date basis, sales prices averaged US$56.05 per barrel in the first nine months of 2006, representing a US$12.21 per barrel discount (18% of WTI) compared to an average price of US$44.19 per barrel in the first nine months of 2005, representing a discount of US$11.42 per barrel (21% of WTI). The discount to WTI decreased as an increased percentage of production is coming from higher quality Orito oil.

Royalties

Royalties totalled $2.5 million in the third quarter of 2006, a decrease from $2.8 million in the third quarter of 2005, and increased to $8.7 million in the first nine months of 2006 compared to $6.7 million in the first nine months of 2005. Canadian royalties as a percentage of revenue fell to 14 percent in the current quarter from 20 percent in the third quarter of 2005 and similarly decreased to 16 percent in the first nine months of 2006 from 20 percent in the first nine months of 2005. The decreases are mainly a result of higher royalty income production from the Company's fee title lands which has no associated royalty expense. Colombian royalties remain constant at a rate of eight percent until the Company's net production per field exceeds 5,000 bpd.

Production Expenses

Consolidated production expenses increased to $3.7 million in the third quarter of 2006 compared to $2.2 million in the third quarter of 2005, and increased to $9.7 million in the first nine months of 2006 compared to $6.6 million in the first nine months of 2005. Production expenses per unit of production in Canada were $8.63 per boe in the third quarter, an increase of 49 percent from $5.81 per boe in the third quarter of 2005, and were $6.47 per boe in the first nine months of 2006, comparable with the $6.52 per boe incurred in the same period of 2005. The increase in the current quarter is mainly a result of increased water handling costs incurred at Red Willow, which are expected to decline following the completion of our water handling facilities.

Production expenses in Colombia averaged $7.80 per barrel during the quarter, a 17 percent decrease from the third quarter 2005 average of $9.41 per barrel, and averaged $7.56 per barrel in the first nine months of 2006, a 19 percent decrease from $9.31 per barrel in the same period of 2005. Ecopetrol, the state oil company and Petrominerales' partner, is responsible for primary production operations at Orito and Neiva at a cost (subject to annual inflation, currency, and other adjustments) of US$4.14 per barrel and US$2.25 per barrel, respectively. The Company's remaining production expenses in Colombia are primarily fixed which results in lower production costs per barrel as production increases.

General and Administrative Expenses

General and administrative expenses increased to $2.0 million during the quarter from $1.6 million in the third quarter of 2005, and increased to $6.3 million during the first nine months of 2006 from $5.6 million in the first nine months of 2005.

Stock-Based Compensation Expense

Stock-based compensation expense totalled $0.8 million in the third quarter of 2006, an increase from $0.3 million in the same period a year earlier, and $2.5 million in the first nine months compared to $0.8 million in the same period of 2005. The calculation of this non-cash expense is determined based on the fair value of stock options and deferred common shares granted, which are amortized over the related vesting period. At higher common share prices the calculated fair value of new grants increases along with the corresponding stock-based compensation expense. Starting in the second quarter of 2006, stock-based compensation expense also includes costs associated with stock options granted by the Company's 80.7 percent owned subsidiary, Petrominerales. In addition, the Company allowed the vesting of certain stock options held by employees of Petrominerales to be accelerated on a one-time basis to allow those employees to invest in the Petrominerales IPO, resulting in higher stock-based compensation in the second quarter of 2006.

Foreign Exchange Loss (Gain)

The Company recorded a foreign exchange loss of $0.7 million in the third quarter of 2006. The loss was generated mainly due to Colombian Peso denominated working capital balances in Colombia combined with a decrease in the value of the United States dollar relative to the Colombian Peso.

Interest Expense

The Company recorded $0.4 million of interest expense in the third quarter of 2006 compared to $2.0 million in the third quarter of 2005, and recorded $2.5 million in the first nine months of 2006 compared to $6.7 million in the first nine months of 2005. Effective April 1, 2006, the Company started to capitalize interest in relation to the WHITESANDS project in accordance with GAAP. Capitalized interest totalled $1.1 million during the third quarter and $2.4 million in the nine-month period. The Company will continue to capitalize interest until the project moves into a commercial phase. Interest expense also decreased in comparison to the first nine months of 2005 due to the early redemptions of $50.5 million face value of subordinated notes throughout 2005 and the final repayment on the July 31, 2006 maturity date.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion expense increased to $6.9 million in the third quarter compared to $4.0 million in the third quarter of 2005, and increased to $20.9 million in the first nine months of 2006 from $11.4 million in the first nine months of 2005. On a unit-of-production basis in Canada, the rate increased to $13.42 per boe compared to $9.87 per boe in the third quarter of 2005, and increased to $12.76 per boe in the first nine months of 2006 from $10.56 per boe in the first nine months of 2005. The increases are mainly due to significant capital expenditures incurred during 2006. In Colombia, the rate decreased to $17.20 per barrel in the third quarter compared to $18.07 per barrel in the same period a year earlier, and increased to $17.92 per barrel in the first nine months of 2006 from $17.76 per barrel in the first nine months of 2005.

Taxes

The Company's third quarter taxes remained consistent at $0.6 million year over year and increased to $1.9 million in the first nine months of 2006 from $1.5 million in the first nine months of 2005. Taxes include presumptive income and equity taxes in Colombia.

Future Income Taxes

The Company recorded a $0.8 million future income tax expense in the third quarter of 2006 comparable to an expense of $0.9 million in the third quarter of 2005. Despite a large increase in net income during the first nine months of 2006, the Company recorded a future income tax recovery of $0.4 million compared to a recovery of $0.3 million in the first nine months of 2005. The recovery during the first nine months relates to the reduction in future federal and provincial income tax rates enacted during the second quarter of 2006. The future income tax liability on the consolidated balance sheets is also reduced by investment tax credits earned on scientific research and development expenditures related to the WHITESANDS THAI™ project. The Company currently has an unrecognized future income tax asset in Colombia. Accordingly, no future income tax expense is recorded on Colombian income.

Net Income

Net income increased by 63 percent to $5.2 million ($0.07 on a per diluted share basis) in the third quarter and by 169 percent to $20.5 million ($0.30 per diluted share) in the first nine months of 2006 from $3.2 million ($0.05 per diluted share) and $7.6 million ($0.13 per diluted share) in the respective 2005 periods despite having recorded a one-time, $4.7 million, gain in the second quarter of 2005. The third quarter increase from the prior year period is due mainly to higher production and realized oil prices in Colombia, capitalized interest, lower interest expense, and lower royalties in Canada, partially offset by lower natural gas prices, higher production expenses, general and administrative expenses, stock-based compensation costs, and depletion, depreciation and accretion. The increase in the nine month period is due mainly to higher production in Canada and Colombia, higher realized oil prices in Colombia, lower royalties as a percentage of revenue in Canada, lower interest expense, and lower future income taxes, partially offset by higher production, general and administrative, stock-based compensation, and depletion, depreciation and accretion expenses.

Funds Flow from Operations

The Company's funds flow from operations increased by 67 percent to $14.8 million in the third quarter of 2006 from $8.9 million in the third quarter of 2005. On a per diluted share basis, funds flow increased by 40 percent to $0.21 from $0.15 in the same period in 2005. The increase in the 2006 period is due mainly to higher production, higher realized oil prices, and lower per barrel operating costs in Colombia, combined with lower interest expense. Funds flow from operations increased 169 percent to $45.4 million in the first nine months of 2006 compared to $16.8 million in the first nine months of 2005. On a per diluted share basis, funds flow from operations increased 128 percent to $0.66 in the first nine months of 2006 from $0.29 in the first nine months of 2005. This increase is mainly a result of higher production and realized oil prices combined with lower per unit operating costs and lower interest expense.

Capital Expenditures

Three months ended September 30,		**2006**		2005
Business Unit				
Canada	$	**29,170**	$	16,395
Latin America (Petrominerales)		**24,272**		5,063
Heavy Oil		**4,462**		10,636
Total	$	**57,904**	$	32,094

Nine months ended September 30,		**2006**		2005
Business Unit				
Canada	$	**55,106**	$	28,586
Latin America (Petrominerales)		**56,356**		15,423
Heavy Oil		**46,894**		15,707
Total	$	**158,356**	$	59,716

Canadian Business Unit expenditures were spread amongst drilling, completions, workovers, and land acquisitions primarily at the Company's Jumpbush, Red Willow and southeast Saskatchewan light oil properties during the third quarter and first nine months of 2006. A total of 46 (40.5 net) wells were drilled in the third quarter and 84 (72.3 net) wells drilled year to date, of which 26 (25.5 net) wells remain to be tied in before the end of the year. The Company's Latin American expenditures related to drilling and workovers at Orito, first phase work commitments including acquiring and evaluating seismic data on the Company's exploration blocks, and workovers at Neiva. The Heavy Oil Business Unit expenditures in the third quarter were focused on start-up operations at the WHITESANDS THAI™ project, including air injection on the first well pair. Heavy Oil Business Unit expenditures in the nine-month period also include expenditures on oil sands land acquisitions, and the construction of the project including facilities and drilling well pairs.

Outstanding Share Data

The number of outstanding shares of Petrobank as at November 10, 2006 remains unchanged from September 30, 2006 at 67,292,874.

Commitments

The Company's 80.7 percent owned subsidiary, Petrominerales, has committed to various work programs pursuant to exploration contracts in Colombia. These commitments are expected to total approximately US$22.6 million before June 30, 2008 and represent normal course exploration expenditures including acquiring and evaluating seismic data and drilling exploration wells. Petrominerales has also secured two drilling rigs for 18 and 16-month terms (starting in June 2006 and December 2006, respectively), which are expected to cost US$22.0 million over their combined contract terms. Securing these rigs provides Petrominerales with guaranteed access to the equipment required to implement the planned exploration program during the winter dry season in the Llanos Basin and also facilitates the Orito development-drilling program.

The Company has secured a drilling rig until September 30, 2008 to facilitate the drilling program targeting the Bakken formation in southeast Saskatchewan. The Company had commitments of $3.7 million remaining under the terms of this contract as at September 30, 2006.

The following is a summary of the Company's remaining contractual commitments at September 30, 2006:

Type of Obligation ($000s)	Total	< 1 Year	1-3 Years	4-5 Years	> 5 Years
Exploration contracts and TEAs in Colombia (US$)	22,600	16,600	6,000	-	-
Drilling rigs in Colombia (US$) [(1)]	22,000	17,000	5,000	-	-
WHITESANDS compressor lease (US$)	2,055	411	822	822	-
Total (US$)	**46,655**	**34,011**	**11,822**	**822**	**-**
Drilling rigs in Canada	3,669	2,364	1,305	-	-
Office operating leases	2,155	801	956	398	-
Total (Cdn$)	**5,824**	**3,165**	**2,261**	**398**	**-**

(1) The contracted drilling rigs will be used to satisfy a portion of the commitments on the exploration contracts.

Liquidity and Capital Resources

At September 30, 2006, net debt totalled $70.4 million and was offset by $45.4 million in cash resulting mainly from the initial public offering of the Company's previously wholly owned subsidiary, Petrominerales, on June 29, 2006 for gross proceeds of $68.6 million ($63.5 million net). Petrobank retains an 80.7 percent interest in Petrominerales.

At September 30, 2006, the Company had drawn $85.4 million on its $120 million secured Canadian credit facility. The facility consists of a $40 million committed reserve-based revolver with an initial term ending on July 27, 2007 that is extendable at Petrobank's option for an additional year, a $10 million revolving demand loan, and a $70 million bridge loan which matures on April 28, 2007. The facility bears interest at rates between LIBOR (London InterBank Offered Rate) plus 110 and 215 basis points depending on debt-to-EBITDA (earnings before interest, taxes, depreciation, and amortization) levels. Advances under the facility are secured by a $300 million demand debenture. The facility is being used to fund ongoing development and exploration expenditures in Canada, drilling additional delineation wells on 62 sections of oil sands leases owned by Petrobank's 84 percent subsidiary, WHITESANDS Insitu Ltd., and replaced previous debt, including the Company's subordinated notes, which matured and was repaid on July 31, 2006. The Company is evaluating alternative financing arrangements to repay the $70 million bridge loan on or before its April 28, 2007 maturity date.

Petrominerales has obtained a commitment from an international bank for a US$50 million revolving credit facility with an initial US$25 million borrowing base. The facility bears interest at a rate equal to LIBOR plus 300 basis points per annum and is subject to standard closing conditions.

The Company intends to fund working capital requirements and commitments through available debt, cash flows, and also possibly through equity and / or debt issuances.

Change in Accounting Policy

Change in Currency Translation

Following completion of the initial public offering of 19.3 percent of the Company's previously wholly owned subsidiary, Petrominerales Ltd., the Company determined that there was a significant change its operations in Colombia, and determined that these operations are now self-sustaining. The accounts of the self-sustaining Colombian operations are translated using the current rate method, whereby assets and liabilities are translated at period-end exchange rates, while revenues and expenses are translated using average monthly rates for the period. Translation gains and losses are deferred and included as a separate component of shareholders' equity.

Previously, operations in Colombia were considered to be integrated and were translated using the temporal method. Under the temporal method, monetary assets and liabilities were translated at the period end exchange rate, other assets and liabilities at the historical rates and revenues and expenses at the average monthly rates except depletion, depreciation and accretion, which were translated on the same basis as the related assets, and gains or losses on translation were recognized in income.

As a self-sustaining foreign operation, the Colombian assets and liabilities are now translated into Canadian dollars at the rate of exchange in effect at the balance sheet date, revenues and expenses are translated at the average monthly rates of exchange during the period and gains or losses on translation are included in a currency translation adjustment account in shareholders' equity.

This change was adopted prospectively on July 1, 2006 and resulted in a currency translation adjustment of $17,859,000 with a corresponding decrease in capital assets. In the third quarter of 2006, an $18,000 translation gain was recorded to the currency translation adjustment account.

Outlook

In addition to the plans discussed in this MD&A, please see the third quarter 2006 Report to Shareholders.

SUMMARY OF QUARTERLY RESULTS

	2006			2005				2004
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Financial ($000s except where noted) [1]								
Oil and natural gas revenue	24,639	27,267	21,593	22,510	17,983	13,206	11,382	17,028
Funds flow from operations [2]	14,788	19,032	11,548	12,304	8,877	4,575	3,396	4,388
Per share – basic ($)	0.22	0.28	0.18	0.20	0.15	0.08	0.06	0.08
– diluted ($)	0.21	0.27	0.17	0.19	0.15	0.08	0.06	0.08
Net income (loss)	5,169	12,075	3,242	5,184	3,170	4,702	(248)	6,630
Per share – basic ($)	0.08	0.18	0.05	0.08	0.05	0.08	-	0.12
– diluted ($)	0.07	0.17	0.05	0.08	0.05	0.08	-	0.12
Capital expenditures	57,904	32,935	67,517	58,436	32,094	16,842	10,780	14,272
Property dispositions	-	-	-	-	-	-	-	100,166
Operations								
Canadian operating netbacks by product [3]								
Natural gas sales price ($/mcf)	5.39	5.84	7.13	10.36	8.25	6.60	6.08	5.80
Royalties	0.71	0.80	1.33	2.15	1.60	1.45	1.19	1.18
Production expenses	1.02	0.84	0.74	0.70	0.91	1.10	1.02	1.18
Transportation expenses	0.10	0.10	0.10	0.11	0.23	0.21	0.29	0.23
Operating netback	3.56	4.10	4.96	7.40	5.51	3.84	3.58	3.21
Light/medium oil and NGL sales price ($/bbl)	73.88	71.55	60.76	63.46	66.45	63.60	47.59	21.05
Royalties	10.92	11.34	11.56	13.82	14.12	13.94	9.76	10.18
Production expenses	13.08	9.15	5.41	7.92	7.05	10.82	9.99	9.11
Operating netback	49.88	51.06	43.79	41.72	45.28	38.84	27.84	1.76
Heavy oil sales price ($/bbl)	53.87	50.53	25.37	31.10	52.14	-	-	15.96
Royalties	1.32	1.22	0.68	0.72	0.91	-	-	4.36
Production expenses	29.14	17.25	9.60	15.28	5.95	-	-	9.89
Operating netback	23.41	32.06	15.09	15.10	45.28	-	-	1.71
Oil equivalent sales price ($/boe)	44.28	43.86	45.51	62.21	53.07	42.63	38.30	29.90
Royalties	6.00	6.13	8.32	13.00	10.41	9.35	7.59	7.53
Production expenses	8.63	6.46	4.89	5.07	5.81	7.12	6.76	7.81
Transportation expenses	0.42	0.43	0.46	0.53	1.08	1.13	1.43	0.93
Operating netback	29.23	30.84	31.84	43.61	35.77	25.03	22.52	13.63
Colombian operating netback ($/bbl)								
Oil sales price	64.58	64.05	59.03	52.50	60.24	52.34	49.13	46.45
Royalties	5.16	5.17	4.72	4.20	4.82	4.19	3.93	3.71
Production expenses	7.80	6.26	9.66	10.08	9.41	10.09	8.46	7.08
Operating netback	51.62	52.62	44.65	38.22	46.01	38.06	36.74	35.66
Average daily production								
Canada – natural gas (mcf)	10,578	13,322	15,960	14,792	11,485	11,245	9,662	17,880
Canada – light/medium oil and NGL (bbls)	690	678	689	639	514	273	317	993
Canada – heavy oil (bbls)	66	119	164	23	37	-	-	424
Total Canada (boe)	2,519	3,017	3,513	3,127	2,465	2,147	1,927	4,397
Colombia – oil (bbls)	2,420	2,612	1,356	955	1,073	1,024	1,072	1,155
Total Company (boe)	4,939	5,629	4,869	4,082	3,538	3,171	2,999	5,552

(1) 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 bpd 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. The only remaining contract is a forward gas sales contract.

CONSOLIDATED BALANCE SHEETS

(Unaudited, thousands of Canadian dollars)

As at	September 30, 2006	December 31, 2005
Assets		
Current assets		
Cash and cash equivalents	$ 45,406	$ 25,343
Accounts receivable and other current assets	22,120	21,727
	67,526	47,070
Capital assets	328,128	213,912
	$ 395,654	$ 260,982
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 52,502	$ 58,834
Bank debt (Note 11)	70,000	-
Subordinated notes (Note 6)	-	49,044
	122,502	107,878
Bank debt (Note 11)	15,390	-
Obligations under gas sale and transportation contracts	5,032	5,650
Asset retirement obligations (Note 5)	9,025	7,931
Future income tax	5,433	10,358
	157,382	131,817
Non-controlling interests (Note 3)	78,687	8,406
Shareholders' equity		
Common shares (Note 4)	158,191	123,262
Contributed surplus (Note 4)	2,825	1,573
Cumulative translation adjustment (Note 2)	(17,841)	-
Retained earnings (deficit)	16,410	(4,076)
	159,585	120,759
	$ 395,654	$ 260,982

Commitments and contingencies (Note 9)

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, 2006	Three months ended September 30, 2005	Nine months ended September 30, 2006	Nine months ended September 30, 2005
Revenues				
Oil and natural gas	$ **24,639**	$ 17,983	$ **73,499**	$ 42,571
Royalties	**(2,540)**	(2,836)	**(8,661)**	(6,747)
	22,099	15,147	**64,838**	35,824
Expenses				
Production	**3,735**	2,248	**9,723**	6,569
Transportation	**97**	246	**358**	714
General and administrative	**2,043**	1,619	**6,260**	5,556
Stock-based compensation	**799**	348	**2,536**	782
Interest (Note 7)	**379**	2,047	**2,535**	6,720
Foreign exchange loss (gain)	**660**	(44)	**(106)**	(44)
Depletion, depreciation and accretion	**6,941**	4,023	**20,930**	11,411
	14,654	10,487	**42,236**	31,708
Income (loss) before other items, taxes and non-controlling interests	**7,445**	4,660	**22,602**	4,116
Other income (expense)	**90**	(70)	**300**	501
Gain	**-**	-	**-**	4,744
Loss on repurchase of subordinated notes	**-**	-	**-**	(542)
Income before taxes and non-controlling interests	**7,535**	4,590	**22,902**	8,819
Taxes	**(620)**	(567)	**(1,880)**	(1,512)
Future income tax (expense) recovery	**(826)**	(853)	**408**	317
Income before non-controlling interests	**6,089**	3,170	**21,430**	7,624
Income applicable to non-controlling interests (Note 3)	**(920)**	-	**(944)**	-
Net income	**5,169**	3,170	**20,486**	7,624
Retained earnings (deficit), beginning of period	**11,241**	(12,430)	**(4,076)**	(16,884)
Retained earnings (deficit), end of period	$ **16,410**	$ (9,260)	$ **16,410**	$ (9,260)
Earnings per share (Note 4)				
Basic	$ **0.08**	$ 0.05	$ **0.31**	$ 0.13
Diluted	$ **0.07**	$ 0.05	$ **0.30**	$ 0.13

See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOW

(Unaudited, thousands of Canadian dollars)

	Three months ended September 30, **2006**	Three months ended September 30, 2005	Nine months ended September 30, **2006**	Nine months ended September 30, 2005
Operating Activities				
Net income	$ **5,169**	$ 3,170	$ **20,486**	$ 7,624
Depletion, depreciation and accretion	**6,941**	4,023	**20,930**	11,411
Stock-based compensation	**799**	348	**2,536**	782
Future income taxes	**826**	853	**(408)**	(317)
Amortization of discount on subordinated notes	**133**	483	**880**	1,550
Gain	**-**	-	**-**	(4,744)
Loss on repurchase of subordinated notes	**-**	-	**-**	542
Income applicable to non-controlling interests	**920**	-	**944**	-
	14,788	8,877	**45,368**	16,848
Asset retirement obligations settled	**(82)**	(170)	**(160)**	(207)
Changes in non-cash working capital (Note 10)	**2,810**	(4,132)	**(9,280)**	(9,084)
	17,516	4,575	**35,928**	7,557
Financing Activities				
Issuance of bank debt	**64,194**	-	**85,390**	-
Repayment of subordinated notes (Note 6)	**(49,924)**	-	**(49,924)**	-
Equity issued by subsidiaries – net of issuance costs (Note 3)	**(222)**	-	**61,033**	12,651
Issuance of common shares – net of issuance costs (Note 4)	**148**	2,385	**32,966**	12,236
Sale of interest in subsidiary – net of costs (Note 3)	**(39)**	-	**7,924**	-
Amortization of obligations under gas hedging contracts	**(208)**	(208)	**(618)**	(618)
Repurchase of subordinated notes	**-**	-	**-**	(30,767)
Changes in non-cash working capital (Note 10)	**2,650**	-	**6,921**	(3,800)
	16,599	2,177	**143,692**	(10,298)
Investing Activities				
Expenditures on capital assets	**(57,904)**	(32,094)	**(158,356)**	(59,716)
Changes in non-cash working capital (Note 10)	**12,780**	18,096	**(1,230)**	15,163
	(45,124)	(13,998)	**(159,586)**	(44,553)
Net effect of foreign exchange on cash held in foreign currencies	**29**	-	**29**	-
Net change in cash position	**(10,980)**	(7,246)	**20,063**	(47,294)
Cash and cash equivalents, beginning of period	**56,386**	35,461	**25,343**	75,509
Cash and cash equivalents, end of period	$ **45,406**	$ 28,215	$ **45,406**	$ 28,215
Cash and cash equivalents consist of:				
Cash	$ **3,217**	$ 18,348	$ **3,217**	$ 18,348
Cash equivalents	$ **42,189**	$ 9,867	$ **42,189**	$ 9,867

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, 2006
(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars, except share amounts)

Note 1 – Significant Accounting Policies

The interim consolidated financial statements for Petrobank Energy and Resources Ltd. ("Petrobank" or the "Company") as at and for the three and nine-month periods ended September 30, 2006 should be read in conjunction with the audited consolidated financial statements as at and for the year ended December 31, 2005. 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, 2005. Certain prior period amounts have been reclassified to conform to current presentation.

Note 2 – Change in Accounting Policy

Change in Currency Translation

Following completion of the initial public offering of 19.3 percent of the Company's previously indirect wholly owned subsidiary, Petrominerales Ltd. ("Petrominerales"), the Company determined that there was a significant change in its operations in Colombia, and determined that these operations are now self-sustaining. The accounts of the self-sustaining Colombian operations are translated using the current rate method, whereby assets and liabilities are translated at period-end exchange rates, while revenues and expenses are translated using average monthly rates for the period. Translation gains and losses are deferred and included as a separate component of shareholders' equity.

Previously, operations in Colombia were considered to be integrated and were translated using the temporal method. Under the temporal method, monetary assets and liabilities were translated at the period end exchange rate, other assets and liabilities at the historical rates and revenues and expenses at the average monthly rates except depletion, depreciation and accretion, which were translated on the same basis as the related assets, and gains or losses on translation were recognized in income.

As a self-sustaining foreign operation, the Colombian assets and liabilities are now translated into Canadian dollars at the rate of exchange in effect at the balance sheet date, revenues and expenses are translated at the average monthly rates of exchange during the period and gains or losses on translation are included in a currency translation adjustment account in shareholders' equity.

This change was adopted prospectively on July 1, 2006 and resulted in a currency translation adjustment of $17,859,000 with a corresponding decrease in capital assets. In the third quarter of 2006, an $18,000 translation gain was recorded to the currency translation adjustment account.

Note 3 – Non-Controlling Interests

On June 29, 2006 Petrobank completed an initial public offering of the common shares of its indirectly owned subsidiary, Petrominerales Ltd., which comprises Petrobank's Latin American Business Unit. The offering was comprised of a 16.0 million common share issuance from treasury of Petrominerales and a 2.3 million secondary offering of shares held by Petrobank for total gross proceeds of $68.6 million, ($63.5 million net of costs). After the transaction, Petrobank owns 80.7 percent of Petrominerales, the remaining 19.3 percent of which is reflected on the consolidated balance sheet within non-controlling interests. Petrominerales' earnings or losses are included in the Company's net income and adjusted to reflect the portion attributable to the non-controlling interests. In addition, non-controlling interests also represent a 16 percent interest owned by a third party in the Company's WHITESANDS Insitu Ltd. subsidiary, which owns the Company's oil sands leases and the WHITESANDS THAI™ project.

Note 4 – Share Capital

As at September 30, 2006 the Company had outstanding 67,292,874 common shares, 3,902,663 stock options, and 150,500 deferred common shares.

Common Share Continuity	Number	Amount
Balance at December 31, 2005	63,219,721	$ 123,262
Exercise of stock options	530,050	1,706
Exercise of warrants	945,700	3,783
Issued through secondary listing [(1)]	2,597,403	33,377
Share issue costs	-	(3,135)
Tax effect of share issue costs	-	1,058
Options settled for cash [(2)]	-	(2,765)
Transfer from contributed surplus related to stock options exercised	-	905
Balance at September 30, 2006	**67,292,874**	**$ 158,191**

(1) On February 6, 2006, the Company closed an issuance of 2.6 million common shares through a secondary listing on the Oslo Stock Exchange for net proceeds of $30.2 million.

(2) The Company approved the exercise of certain Petrobank stock options, which were settled with cash for Petrominerales employees who invested in the initial public offering of Petrominerales.

Changes in Contributed Surplus	Amount
Balance at December 31, 2005	$ 1,573
Transfer to common shares related to stock options exercised	(905)
Stock-based compensation related to Petrobank stock options	2,157
Balance at September 30, 2006	**$ 2,825**

Stock Option Continuity	Number	Weighted - Average Exercise Price
Balance at December 31, 2005	4,138,526	$ 3.83
Granted	801,250	13.99
Exercised	(530,050)	(3.22)
Cancelled	(240,375)	(12.07)
Settled for cash	(266,688)	(4.51)
Balance at September 30, 2006	**3,902,663**	**$ 5.44**

Share Purchase Warrants

In the first six months of the year share purchase warrants totalling 945,700 were exercised before they expired on May 6, 2006 resulting in total cash proceeds of $3.8 million.

Deferred Common Shares

As at September 30, 2006, there were 150,500 deferred common shares outstanding under the Company's deferred share compensation plan, which allows holders to receive one common share upon payment of $0.05 per share. The deferred common shares vest after three years and expire after 10 years. Up to 0.5 million deferred common shares have been approved for issuance under this plan.

Stock-Based Compensation

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

Nine months ended September 30,	**2006**	2005
Risk free interest rate	**4.5 – 5.0%**	4.25%
Dividend rate	**0%**	0%
Expected life – options (years)	**3.5 – 4**	4
Expected life – deferred common shares (years)	**8**	8
Expected volatility	**40%**	30 – 50%

The average fair value per stock option and deferred common shares granted during the three and nine month periods ended September 30, 2006 was $5.05 (2005 – $3.61) and $5.00 (2005 – $1.98) respectively, as at the date of grant.

Earnings Per Share

Basic and diluted earnings per share have been calculated based on net income divided by the weighted average number of common shares outstanding for the three month period ended September 30, 2006 of 67,267,227 (2005 – 58,817,874) and for the nine month period ended September 30, 2006 of 66,345,730 (2005 – 57,252,574). The diluted calculations for the three month period ended September 30, 2006 include 2,299,965 (2005 – 1,691,709) additional shares and for the nine month period ended September 30, 2006 include 2,472,060 (2005 – 748,401) additional shares for the potential impact of stock options and deferred common shares.

Note 5 – Asset Retirement Obligations

Changes to asset retirement obligations were as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	**2006**	2005
Asset retirement obligations, beginning of period	**$ 8,533**	$ 2,870	**$ 7,931**	$ 2,870
Obligations incurred	**407**	796	**658**	1,015
Obligations settled	**(82)**	(170)	**(160)**	(207)
Accretion expense	**167**	65	**477**	185
Changes in estimated future cash flows and other	**-**	271	**119**	(31)
Asset retirement obligations, end of period	**$ 9,025**	$ 3,832	**$ 9,025**	$ 3,832

The obligations have been calculated using an inflation rate of two percent and discounted using a credit-adjusted risk free rate of eight percent per annum. Most of these obligations are not expected to be paid for several years extending up to 40 years in the future, and are expected to be funded from the Company's general resources available at the time of settlement. The total undiscounted amount of estimated cash flows required to settle the obligations is $33.6 million (2005 – $18.1 million).

Note 6 – Subordinated Notes

Petrobank's nine percent, unsecured subordinated notes were repaid on July 31, 2006. The notes were recorded at fair value on issuance and the discount to face value was being amortized to interest expense over the term of the notes.

	Carrying Value	Face Value
Balance at December 31, 2005	$ 49,044	$ 49,924
Amortization of discount	880	-
Repaid upon maturity	(49,924)	(49,924)
Balance at September 30, 2006	**$ -**	**$ -**

Note 7 – Interest

Effective April 1, 2006 the Company capitalized interest in relation to its WHITESANDS major development project and totalling of $1.1 million and $2.4 million in the three and nine-month periods ended September 30, 2006, respectively.

Note 8 – Technology Partnerships Canada Financing

Technology Partnerships Canada ("TPC") has committed to invest up to $9.0 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 $9.0 million. Benefits of nil and $3.1 million were incurred in the three and nine month periods ending September 30, 2006, respectively. No further benefits will be recognized as the total accrued to date has reached the maximum benefit of $9.0 million, all of which have been recorded as a reduction of capital assets. 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.

Note 9 – Commitments and Contingencies

The Company's 80.7 percent owned subsidiary, Petrominerales, has committed to various work programs pursuant to exploration contracts in Colombia. These commitments are expected to total approximately US$22.6 million before June 30, 2008 and represent normal course exploration expenditures including acquiring and evaluating seismic data and drilling exploration wells. Petrominerales has also secured two drilling rigs for 18 and 16-month terms (starting June 2006 and December 2006, respectively), which are expected to cost US$22.0 million over their combined contract terms. The contracted drilling rigs will be used to satisfy a portion of the commitments on the exploration contracts. Securing these rigs provides Petrominerales with guaranteed access to the equipment required to implement the planned exploration program during the winter dry season in the Llanos Basin and also facilitates the Orito development-drilling program.

The Company has secured a drilling rig until September 30, 2008 to facilitate the drilling program targeting the Bakken formation in southeast Saskatchewan. The Company had commitments of $3.7 million remaining under the terms of the contract as at September 30, 2006.

The development of certain of the Company's assets and the success of its operations are dependent on obtaining sufficient financing to fund its working capital requirements, future capital expenditure commitments, and the repayment its $70 million bridge loan due on April 28, 2007. The Company plans to meet these funding requirements through either the issuance of equity and/or through additional debt financing.

Note 10 – Changes in Non-Cash Working Capital

	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	**2006**	2005
Change in:				
Accounts receivable and other current assets	**$ 1,732**	$ (5,061)	**$ (393)**	$ (9,812)
Less: accrued financing items (Note 8)	**-**	1,555	**3,136**	1,555
	$ 1,732	$ (3,506)	**$ 2,743**	$ (8,257)
Accounts payable and accrued liabilities	**16,508**	17,470	**(6,332)**	10,536
	$ 18,240	$ 13,964	**$ (3,589)**	$ 2,279
Changes relating to:				
Attributable to operating activities	**$ 2,810**	$ (4,132)	**$ (9,280)**	$ (9,084)
Attributable to financing activities [1]	**$ 2,650**	$ -	**$ 6,921**	$ (3,800)
Attributable to investing activities	**$ 12,780**	$ 18,096	**$ (1,230)**	$ 15,163

(1) Cash flow generated from financing activities in 2006 relate to TPC funding received (Note 8).

Note 11 – Bank Debt

At September 30, 2006, the Company had drawn $85.4 million on its $120 million secured Canadian credit facility. The facility consists of a $40 million committed reserve-based revolver with an initial term ending July 27, 2007 extendable at Petrobank's option for an additional year, a $10 million revolving demand loan, and a $70 million bridge loan that matures on April 28, 2007. The Company is evaluating alternative financing arrangements to repay the $70 million bridge loan on or before its April 28, 2007 maturity date. The facility bears interest at rates between LIBOR (London InterBank Offered Rate) plus 110 and 215 basis points depending on debt-to-EBITDA (earnings before interest, taxes, depreciation, and amortization) levels. Advances under the facility are secured by a $300 million demand debenture.

Note 12 – Segmented Information

Three months ended September 30,	2006			2005		
	Canada and Other	Colombia	Total	Canada and Other	Colombia	Total
Revenues						
Oil and natural gas	$ 10,262	$ 14,377	$ 24,639	$ 12,036	$ 5,947	$ 17,983
Royalties	(1,391)	(1,149)	(2,540)	(2,360)	(476)	(2,836)
	8,871	13,228	22,099	9,676	5,471	15,147
Expenses						
Production	1,999	1,736	3,735	1,319	929	2,248
Transportation	97	-	97	246	-	246
General and administrative	698	1,345	2,043	763	856	1,619
Depletion, depreciation and accretion	3,111	3,830	6,941	2,239	1,784	4,023
Segmented income	$ 2,966	$ 6,317	$ 9,283	$ 5,109	$ 1,902	$ 7,011
Non-segmented items						
Stock-based compensation			(799)			(348)
Interest			(379)			(2,047)
Foreign exchange gain (loss)			(660)			44
Other income (expense)			90			(70)
Taxes			(620)			(567)
Future income tax expense			(826)			(853)
Income applicable to non-controlling interests			(920)			-
Net income			$ 5,169			$ 3,170
Identifiable assets [1]	$ 214,536	$ 181,118	$ 395,654	$ 130,983	$ 84,846	$ 215,829
Capital expenditures [1]	$ 33,632	$ 24,272	$ 57,904	$ 27,031	$ 5,063	$ 32,094

[1] Canada and Other includes Heavy Oil Business Unit expenditures of $4.5 million in 2006 (2005 – $10.6 million), identifiable assets at September 30, 2006 of $76.3 million (2005 – $43.3 million), and negligible revenue and expenses.

Nine months ended September 30,	2006			2005		
	Canada and Other	Colombia	Total	Canada and Other	Colombia	Total
Revenues						
Oil and natural gas	$ 36,693	$ 36,806	$ 73,499	$ 27,007	$ 15,564	$ 42,571
Royalties	(5,707)	(2,954)	(8,661)	(5,502)	(1,245)	(6,747)
	30,986	33,852	64,838	21,505	14,319	35,824
Expenses						
Production	5,320	4,403	9,723	3,884	2,685	6,569
Transportation	358	-	358	714	-	714
General and administrative	2,904	3,356	6,260	2,905	2,651	5,556
Depletion, depreciation and accretion	10,495	10,435	20,930	6,292	5,119	11,411
Segmented income	$ 11,909	$ 15,658	$ 27,567	$ 7,710	$ 3,864	$ 11,574
Non-segmented items						
Stock-based compensation			(2,536)			(782)
Interest			(2,535)			(6,720)
Foreign exchange gain			106			44
Other income			300			501
Gain			-			4,744
Loss on repurchase of subordinated notes			-			(542)
Taxes			(1,880)			(1,512)
Future income tax recovery			408			317
Income applicable to non-controlling interests			(944)			-
Net income			$ 20,486			$ 7,624
Identifiable assets [1]	$ 214,536	$ 181,118	$ 395,654	$ 130,983	$ 84,846	$ 215,829
Capital expenditures [1]	$ 102,000	$ 56,356	$ 158,356	$ 44,293	$ 15,423	$ 59,716

[1] Canada and Other includes Heavy Oil Business Unit expenditures of $46.9 million in 2006 (2005 — $15.7 million), identifiable assets at September 30, 2006 of $76.3 million (2005 — $43.3 million), and negligible revenue and expenses.

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