Petrolifera Petroleum Limited Announces Third Quarter Results

03.11.2010 | CNW

CALGARY, Nov. 3 /CNW/ - Petrolifera Petroleum Limited (PDP - TSX) today announced its financial and operating results for the three months ("Q3") and the nine months ended September 30, 2010.

Highlights:

- A process to assess strategic alternatives for the company was initiated

- Debt renegotiations were implemented and debt was reduced by approximately $16 million

- Long term test results at Brillante were encouraging

- Commodity pricing improved in Argentina

- Seismic at Turpial and over La Pinta structure in Colombia encouraging

As the company is engaged in an ongoing process to evaluate strategic alternatives, under the direction of a Special Committee comprised of independent directors and with the advice of independent counsel and financial advisors, we will not be holding a conference call to discuss the results of the reporting periods.

Summary Results

Three months ended Nine months ended
Sept. 30 Sept. 30

% %
2010 2009 Change 2010 2009 Change

FINANCIAL ($000, except
per share amounts)

Total revenue $15,694 $17,229 (9) $50,396 $65,891 (24)
Cash flow from
operations before
non-cash working
capital(1) 4,339 5,503 (21) 16,786 26,540 (37)
Per share, basic 0.03 0.07 (57) 0.12 0.41 (71)
Per share, diluted 0.03 0.07 (57) 0.12 0.40 (70)
Net loss (2,702) (11,359) 76 (5,552) (6,744) 18
Per share, basic
and diluted(4) (0.02) (0.14) 86 (0.04) (0.11) 64
Net capital spending 7,530 13,389 (44) 40,968 59,478 (31)
Cash 11,477 55,953 (79) 11,477 55,953 (79)
Working capital 10,354 724 1,330 10,354 724 1,330
Long-term
investments(2) 18,689 19,873 (6) 18,689 19,873 (6)
Long-term debt(2) 40,693 27,464 48 40,693 27,464 48
Shareholders' equity 246,050 238,475 3 246,050 238,475 3
Total assets $339,575 $368,288 (8) $339,575 $368,288 (8)

OPERATING

Daily sales volumes
Crude oil and

natural gas
liquids - bbl/d 2,885 3,653 (21) 3,313 4,511 (27)
Natural gas - mcf/d 4,077 4,252 (4) 3,708 5,633 (34)
Barrels of oil
equivalent -
boe/d(3) 3,564 4,362 (18) 3,931 5,450 (28)
Average selling prices
Crude oil and natural
gas liquids
- $/bbl $55.14 $48.07 15 $52.47 $49.87 5
Natural gas - $/mcf $2.72 $2.74 (1) $2.64 $2.89 (9)
Barrels of oil
equivalent
- $/boe(3) $47.79 $42.93 11 $46.72 $44.26 6

COMMON SHARES
OUTSTANDING (000s)

Weighted average
Basic 145,478 82,418 77 136,454 64,205 113
Diluted(4) 145,478 82,539 76 136,455 65,619 108
End of period 145,478 121,759 19 145,478 121,759 19
----
(1) Cash flow from operations before non-cash working capital changes ("cash flow") and cash flow per share do not have standardized meanings prescribed by Canadian generally accepted accounting principles ("GAAP") and therefore may not be comparable to similar measures used by other companies. Cash flow includes all cash flow from operating activities and is calculated before changes in non-cash working capital. The most comparable measure calculated in accordance with GAAP would be the net loss. Cash flow is reconciled with the net loss in the accompanying Management's Discussion & Analysis ("MD&A"). Management uses these non-GAAP measurements for its own performance measures and to provide its shareholders and investors with a measurement of the company's efficiency and its ability to fund a portion of its future growth expenditures.

(2) Long-term investments includes the carrying value of notes received for Asset Backed Commercial Paper ("ABCP") with a face value of $30.9 million and $34.6 million as at September 30, 2010 and September 30, 2009, respectively. Long-term bank debt in the amount of $22.5 million and $27.5 million as at September 30, 2010 and September 30, 2009, respectively, is primarily secured on a limited recourse basis by the underlying notes formerly known as ABCP.

(3) All references to barrels of oil equivalent (boe) are calculated on the basis of 6 mcf : 1 bbl. Boes may be misleading, particularly if used in isolation. This conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(4) As the company has net losses during the nine months ended September 30, 2010, and the three months and nine months ended September 30, 2009, the dilutive effect of stock options and share purchase warrants became anti-dilutive, causing the basic weighted average common shares outstanding to be used as the denominator in the dilutive per share net loss calculations. There were no "in-the-money" stock options and share purchase warrants for the three months ended September 30, 2010.

On September 7, 2010 we announced that our Board of Directors had initiated a process to review Petrolifera's business plan and to identify, examine and consider a range of strategic alternatives available to the company for enhancing shareholders' value. Among other things, this may include exploring potential asset divestments and joint ventures, a corporate sale or business combination, evaluation of financing and recapitalization opportunities or other alternatives to increase shareholders' value. The Board of Directors determined that it was an appropriate time to assess strategic options following a thorough review of current operations, the exploration opportunities, contractual obligations and capital requirements to exploit the company's lands in Argentina, Colombia and Peru and an evaluation of the company's current financial position.

The process of reviewing strategic alternatives is being overseen by a Special Committee of three independent directors: K. Andrew Gustajtis, Gordon H. Johnston and Christopher J. Smith. Mr. Smith, who is also Chairman of the Audit Committee of the Petrolifera Board, is serving as Chair of the Special Committee. The Special Committee has a mandate to solicit, review and consider strategic alternatives and to consider and recommend to the Board of Directors whether any proposed transaction is in the best interests of the Company and its security holders. In connection with its mandate, the Special Committee retained RBC Capital Markets for the purpose of assisting the Special Committee in the performance of its mandate.

No decision on any particular alternative has been reached at this time and there can be no assurance that the process will result in a transaction or, if a transaction is entered into, as to its terms or timing. Petrolifera does not intend to make any further announcements regarding the process, unless and until its Board of Directors has approved a specific transaction or other course of action, or otherwise deems disclosure of developments is appropriate.

During the reporting period, Petrolifera concluded the flowing phase of a long term test of its Brillante SE-1X well in its 100%-owned Sierra Nevada License, Colombia. The 21-day extended flow test of the upper portion of the Cienaga de Oro ("CDO") reservoir was completed at 0630 hrs on Saturday, September 18th. Total recovery during the test equaled the government-permitted volumes of 66 mmscf of natural gas, 284 barrels of 57.3o degree API gravity condensate, and 28 barrels of water. Government-permitted production rates during the final 24-hours of the flow period were 3.1 mmscf of natural gas, 19.0 barrels of condensate, and 1.1 barrels of water.

Final analysis of the bottom hole pressure data is pending acquisition and recovery of bottom hole gauges. That analysis will provide the technical basis for all future conclusions and estimates of reserves and resources. Nevertheless, it is appropriate to point out at this time that no flowing wellhead pressure loss was experienced during the flow test. The flowing wellhead pressure increased from 1,016 psi to 1,055 psi, while the daily natural gas production increased slightly from 3.0 mmscf to 3.1 mmscf per day. Readers should be cautioned that the measured flow rates from the long term test may not be indicative of stabilized production rates for the Brillante SE 1X well.

No reduction in wellhead flowing pressure or natural gas rate indicates that no limits to the CDO reservoir were encountered during the 21-day flow period. Management is extremely pleased with the results to date and on this basis, plans to implement an early production scheme that will allow for the production and sale of modest amounts of natural gas until a full development is completed.

In this regard, Petrolifera has been in discussions with Colombian companies which supply smaller scale volumes of natural gas to local markets and is evaluating an opportunity to proceed with a small scale commercial project at Brillante and possibly at La Pinta. Proceeding would allow Petrolifera to secure a modest source of Colombian cash flow. The application of this interim solution for marketing natural gas could also be important to Petrolifera, as the company may then be able to commence production of crude oil from the Porquero Formation at the La Pinta well, by conserving and producing associated natural gas indicated to be present with the light gravity crude oil tested from this formation.

Petrolifera is also engaged in discussions with regional pipeline aggregators about medium term solutions to move Brillante and other regional natural gas to the available markets in Colombia.

The company's technical staff is currently interpreting 3D seismic which was shot over the La Pinta structure. Preliminary analysis is encouraging, as additional well-defined structures have been mapped in various prospective horizons.

The company is also evaluating its Turpial License in the Lower Magdalena Basin. These lands are prospective for medium to heavy oil accumulations and it is anticipated drilling could occur on the 50 percent-owned and operated block in 2011.

In Peru, Petrolifera has conducted negotiations with several large international oil companies including two companies which recommended a farmin based on their technical appraisals but neither secured final approval at their corporate level. Accordingly, discussion were concluded without a farmout agreement for the company's Blocks 107 and 133 in the Ucayali Basin, Peru. Various parties continue to assess both the Ucayali acreage and the company's Block 106 in the Maranon Basin of northern Peru.

In Argentina, the company's overall production volumes have remained relatively stable after experiencing a minor downturn during a pump replacement on the 1012 well in the Puesto Morales Norte Field. During Q3 2010, crude oil sales realized an improved selling price of $55.14/bbl, marking sustained improvement in crude prices this year. Crude oil sales prices for the balance of 2010 are expected to be favorable.

Forward Looking Information

Information in this press release contains forward-looking information including but not limited to the evaluation of strategic alternatives for enhancing shareholder value including asset divestments and joint ventures, a corporate sale or business combination, evaluation of financing and recapitalization opportunities or other alternatives, the planned sale of natural gas from the Colombian Brillante SE-1X well, potential production of crude oil from the Porquero formation from the Colombian La Pinta IX well and longer term field development plans for the Sierra Nevada license and anticipated improvements in commodity prices in Argentina for the balance of 2010. Forward-looking information is not based on historical facts but rather on Management's expectations regarding the company's future growth, results of operations, production, future capital and other expenditures (including the amount, nature and sources of funding thereof), competitive advantages, plans for and results of drilling activity, environmental matters, business prospects and opportunities and expectations with respect to general economic and capital market conditions. In addition, such forward-looking information is based upon certain expectations regarding the outcome of the strategic alternatives process. Such forward-looking information reflects Management's current beliefs and assumptions and is based on information currently available to Management. Forward-looking information involves significant known and unknown risks and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking information, including but not limited to, risks associated with the oil and gas industry (e.g. operational risks in development, exploration and production, delays or changes to plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve estimates; the uncertainty of geological interpretations; the uncertainty of estimates and projections in relation to production, costs and expenses and health, safety and environment risks), the risk of commodity price and foreign exchange rate fluctuations, the uncertainty associated with negotiating with foreign governments and third parties located in foreign jurisdictions and the risk associated with international activity. Readers are cautioned that measured flow rates may not be indicative of sustainable production rates. Additional risks and uncertainties associated with Petrolifera's future plans are described elsewhere in this press release, in the accompanying Management's Discussion and Analysis and in Petrolifera's Annual Information Form for the year ended December 31, 2009. Although the forward-looking information contained herein is based upon assumptions which Management believes to be reasonable, the company cannot assure investors that actual results will be consistent with this forward-looking information. This forward-looking information is made as of the date hereof and the company assumes no obligation to update or revise this information to reflect new events or circumstances, except as required by law. Because of the risks, uncertainties and assumptions inherent in forward-looking information, prospective investors in the company's securities should not place undue reliance on this forward-looking information.

Management's Discussion and Analysis ("MD&A")

The following is dated as of November 3, 2010 and should be read in conjunction with the unaudited Consolidated Financial Statements of Petrolifera Petroleum Limited ("Petrolifera" or the "company") for the three months and nine months ended September 30, 2010, as contained in this interim report (the "Interim Report") and the audited Consolidated Financial Statements for the years ended December 31, 2009 and December 31, 2008, as contained in the company's annual report. Additional information relating to Petrolifera, including its Annual Information Form for the year ended December 31, 2009, is on SEDAR at www.sedar.com. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and are presented in Canadian dollars. This MD&A provides management's view of the financial condition of the company and the results of its operations for the reporting periods indicated.

Information in this report, including the letter to shareholders, contains forward-looking information including but not limited to the evaluation of strategic alternatives for enhancing shareholders' value including possible farmout and/or joint ventures arrangements, future exploration and development opportunities in Argentina, Colombia and Peru including the planned sales of natural gas from the Colombian Brillante SE-1X well and longer term field development plans for the Sierra Nevada license, future drilling plans in Argentina, Colombia and Peru and the anticipated timing associated therewith, planned capital expenditures (including sources of funding and timing thereof), anticipated improvements in natural gas prices in Argentina, the anticipated impact of the proposed conversion to International Financial Reporting Standards ("IFRS") on the company's Consolidated Financial Statements and the company's ability to continue to comply with financial covenants imposed pursuant to its reserve-backed credit facility. See "Forward-Looking Information" for a discussion of the forward-looking information contained in this report and the risks and uncertainties associated therewith. Additional risks and uncertainties relating to Petrolifera and its business and affairs are also described in detail in its Annual Information Form for the year ended December 31, 2009. Throughout this MD&A, per barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil (6:1). The conversion is based on an energy equivalency conversion method primarily applicable to the burner tip and does not represent a value equivalency at the wellhead. Boe may be misleading, particularly if used in isolation.

STRATEGIC ALTERNATIVES

Petrolifera announced on September 7, 2010 that it had initiated a process to review its business plan and to identify, examine and consider a range of strategic alternatives available to it for enhancing shareholders' value. Among the strategic options being considered are exploring potential asset divestments and joint ventures, a corporate sale or business combination, evaluation of financing and recapitalization opportunities, or other alternatives to increase shareholders' value. The company determined that it was an appropriate time to assess strategic options following a thorough review of current operations, its exploration opportunities, contractual obligations and capital requirements to exploit the company's lands in Argentina, Colombia and Peru, in combination with an evaluation of its current financial position. No decision on any particular alternative has been reached (at this time) and there can be no assurance that the process will result in a transaction or, if a transaction is entered into, as to its terms or timing.

The process of reviewing strategic alternatives is being overseen by a special committee of the Petrolifera Board ("Special Committee"). The Special Committee, comprised of three independent directors, has a mandate to solicit, review and consider strategic alternatives and to consider and recommend to the Board of Directors whether in the opinion of the Special Committee, any proposed transaction is in the best interests of the company and its shareholders. In connection with the performance of its mandate, the Special Committee has retained third party expertise.

2009 COMPARATIVE INFORMATION

Petrolifera announced on March 2, 2009, that its Board of Directors had authorized the company to initiate a process to dispose of its Argentinean interests. Petrolifera's Argentinean interests represented all of its current production, related revenues and substantially all of its reserves. During early July 2009, several bids for the company's Argentinean interests were received from third parties. After careful consideration, on July 15, 2009 the company announced that the process to dispose of its interests did not result in any acceptable bids and accordingly management decided to retain the company's Argentinean operations. As required per Canadian GAAP, because of the decision to retain the Argentinean operations, these operations are presented within the comparative periods' unaudited Consolidated Financial Statements and MD&A for the three months and nine months ended September 30, 2010 as "held for use", given the decision, made on July 15, 2009, to retain these operations, despite the classification in each of the 2009 first and second quarter's Interim Reports as discontinued operations.

For the three months ended September 30, 2010, the comparative period's presentation of the Argentinean interests as continuing operations gives effect to depletion and depreciation expense related to the period from March 2, 2009 to June 30, 2009, which had not been previously recognized as a result of the prior classification of the Argentinean interests as "discontinued operations", in addition to depletion, depreciation and accretion expense ("DD&A") for the third quarter of 2009. Because the Argentinean operation's depletion and depreciation for the period from March 2, 2009 to June 30, 2009 was recognized in the unaudited Consolidated Financial Statements for the three months ended September 30, 2009, which partially contributed to the company's reported net loss during the third quarter of 2009, DD&A and the net loss recognized for the three months ended September 30, 2009 is not comparable to the DD&A and the net loss recognized for the three months ended September 30, 2010.

FINANCIAL AND OPERATING REVIEW

SALES VOLUMES, PRICING AND REVENUE

	Three months ended Sept. 30			Nine months ended Sept. 30		
	2010	2009	% Change	2010	2009	% Change
Daily sales volumes:						
Crude oil and natural gas liquids - bbl/d	2,885	3,653	(21)	3,313	4,511	(27)
Natural gas - mcf/d	4,077	4,252	(4)	3,708	5,633	(34)
Equivalent - boe/d	3,564	4,362	(18)	3,931	5,450	(28)

Average selling prices:
Crude oil and natural
gas liquids - $/bbl $55.14 $48.07 15 $52.47 $49.87 5
Natural gas - $/mcf $2.72 $2.74 (1) $2.64 $2.89 (9)
Weighted average
selling price -
$/boe $47.79 $42.93 11 $46.72 $44.26 6

Petroleum and natural
gas sales ($000) $15,671 $17,229 (9) $50,138 $65,854 (24)
Interest and other
income ($000) 23 - - 258 37 597

Total revenue ($000) $15,694 $17,229 (9) $50,396 $65,891 (24)

Petroleum and natural gas revenues for the nine months ended September 30, 2010 were $50.1 million on average sales volumes of 3,931 boe per day, compared to $65.9 million on average sales volumes of 5,450 boe per day during the same period in 2009, decreases of 24 percent and 28 percent, respectively. Petroleum and natural gas revenues for the third quarter of 2010 were $15.7 million on average sales volumes of 3,564 boe per day, compared to $17.2 million on average sales volumes of 4,362 boe per day during the third quarter of 2009, decreases of nine percent and 18 percent, respectively. For the three months and nine months ended September 30, 2010, sales of crude oil and natural gas liquids represented 81 percent and 84 percent of the company's sales volumes, respectively, which is comparable to 84 percent and 83 percent for the same periods in 2009.

The reduction in petroleum and natural gas revenues for the three months and nine months ended September 30, 2010, compared to the same periods in 2009, reflect lower sales volume, partially offset by higher average selling prices. The lower sales volume for the third quarter of 2010 compared to the same period in 2009 was mainly attributable to natural production declines and a temporary shut in of a key producing well, PMN - 1012, caused by a pump failure. Also, as commonly happens on a high water-cut well after a pump replacement, crude oil production from this well took some time to recover to its previous level. The sales volumes for the nine months ended September 30, 2010 were lower compared to the same period in 2009 for the same reasons, in addition to operational downtime that included scheduled equipment maintenance on well PMN - 1061; workovers on key producing wells PMN - 1082 and PMN - 1111; a temporary shut-in of another key producing well, PMN - 1002, also caused by a pump failure; and production anomalies from less significant wells such as well PMN - 1113. Natural gas sale volumes were impacted for the nine months ended September 30, 2010 by scheduled maintenance work programs on the company's natural gas pipeline.

Upon receipt of all required production permits, the company anticipates initial natural gas sales volumes from the Colombian Brillante SE-1X exploratory well during 2011. Subsequent to September 30, 2010, the company has sold modest volumes of natural gas liquids produced during the long term test at Brillante SE-1X. These new sales will provide the company its initial Colombian revenue, while it formulates longer term field development plans to more fully exploit the discovery of natural gas reserves and related liquids made in this region. All of Petrolifera's sales during 2010 were from the Puesto Morales/Rinconada, Puesto Morales Este and, to a lesser extent, Vaca Mahuida Concessions in Argentina and the majority (90 percent) of its crude oil sales were made to the Argentinean operation of a large multinational company.

Relative to the second quarter of 2010, when petroleum and natural gas revenues were $16.7 million on sales volumes of 3,887 boe per day, lower revenues due to lower sales volumes were experienced during the third quarter of 2010. During June 2010, the company completed an expansion of its produced water treatment capacity, which provides flexibility to handle increased fluid volumes with higher water cuts.

Prices realized for the company's crude oil and natural gas liquids sales increased 15 percent and 5 percent, respectively, to average $55.14 per barrel and $52.47 per barrel for the three months and nine months ended September 30, 2010, compared to $48.07 per barrel and $49.87 per barrel realized during the same periods in 2009. Higher realized US dollar crude oil pricing, respectively averaging US$53.70 per barrel and US$51.76 per barrel during the three months and nine months ended September 30, 2010, compared favorably to the average US$44.70 per barrel and US$43.26 per barrel, respectively received during the same periods in 2009. This favorable US dollar pricing was offset by an average six percent and 13 percent strengthening, respectively, of the Canadian dollar relative to the US dollar for the three months and nine months ended September 30, 2010, compared to the same periods in 2009, which reduced the company's reported average selling prices.

The company's third quarter 2010 realized crude oil and natural gas liquids prices increased six percent relative to the price of $52.13 per barrel realized during the second quarter in 2010. Petrolifera negotiated a new crude oil sales agreement with a well-established multinational purchaser during the second quarter of 2010 and secured a higher US dollar crude oil price than received during the first quarter of 2010 and throughout 2009. During the three months and nine months ended September 30, 2010, the crude oil price realized by Petrolifera averaged approximately 71 percent and 67 percent of the WTI average of US$76.02 per barrel and US$77.48 per barrel, respectively, compared to the 66 percent and 76 percent of the WTI averages of US$67.26 per barrel and US$56.59 per barrel, respectively, received in the same periods in 2009. Lower crude oil pricing relative to WTI prices is due to price controls in Argentina.

The company successfully negotiated a price increase for 2010 South American winter sales volumes of natural gas to US$2.61 per mcf. This was a four percent improvement relative to the US$2.51 per mcf realized on sales volumes during the South American winter of 2009. However, during the three months and nine months ended September 30, 2010, natural gas prices decreased one percent and nine percent, respectively, over the levels realized during the same periods in 2009 to average $2.72 per mcf and $2.64 per mcf. The lower realized natural gas pricing during the three months and nine months ended September 30, 2010 relative to the same periods in 2009, as expressed in Canadian dollars, resulted from an average six percent and 13 percent strengthening of the Canadian dollar as compared to the US dollar, respectively. The realized natural gas price was two percent higher on the improved South American winter pricing during the third quarter of 2010, compared to the second quarter of 2010 when it averaged $2.66 per mcf. Natural gas prices are believed to have the potential of further improvement in the longer term, due to market conditions and new Argentinean policy initiatives.

Interest and other income was minimal during the three months and nine months ended September 30, 2010 and 2009 and primarily reflected interest earned on short-term cash and restricted cash deposits. Interest on the investment in notes, formerly known as Asset Backed Commercial Paper ("ABCP"), with a face value of $30.9 million as at September 30, 2010 (Dec. 31, 2009 - $ 34.6 million) has not been recognized since August 2007, due to the lack of market liquidity for these notes. During the three months and nine months ended September 30, 2010, the company did not receive any interest payments on its investment formerly known as ABCP, as the specified short term interest rate approximated the 50 basis points required to be paid out on this investment. See "RESTRICTED CASH, DEBT AGREEMENT OPTION AND LONG-TERM INVESTMENTS" for additional details including estimates of valuation and the reduction in the face value of these longer-term notes.

ROYALTIES, OPERATING EXPENSES AND CORPORATE NETBACKS

CORPORATE NETBACKS(1)

Three months ended Sept. 30				
	2010		2009	
($000, except per unit amounts)	Total	Per boe	Total	Per boe
Average daily sales (boe/d)	3,564		4,362	
Petroleum and natural gas sales	$15,671	$47.79	$17,229	$42.93
Interest and other income	23	0.07	-	-
Royalties	(2,221)	(6.77)	(2,445)	(6.09)
Net revenue	13,473	41.09	14,784	36.84
Operating costs	(5,410)	(16.50)	(5,763)	(14.36)
Corporate netback	$8,063	$24.59	$9,021	$22.48

Nine months ended Sept. 30				
	2010		2009	
($000, except per unit amounts)	Total	Per boe	Total	Per boe
Average daily sales (boe/d)	3,931		5,450	

Petroleum and natural
gas sales $50,138 $46.72 $65,854 $44.26
Interest and other income 258 0.24 37 0.02
Royalties (7,156) (6.67) (9,362) (6.29)

Net revenue 43,240 40.29 56,529 37.99
Operating costs (15,871) (14.79) (17,362) (11.67)

Corporate netback $27,369 $25.50 $39,167 $26.32
----

(1) Calculated by dividing related revenue and costs by total boe sold, resulting in a corporate netback. Netback does not have a standardized meaning prescribed by GAAP and therefore is unlikely to be comparable to similar measures used by other companies. The most comparable measure calculated in accordance with GAAP would be net losses. Nevertheless, Petrolifera's management uses netbacks as a performance measurement of operating efficiency and the prevailing royalty regime. A high ratio of netback to selling price is a positive indicator. A reconciliation of corporate netback to the net loss can be found in the Net Loss table.

Compared to the three months ended September 30, 2009, Petrolifera's corporate netbacks of $24.59 per boe increased nine percent for the third quarter of 2010, whereas the corporate netback of $26.32 per boe for the nine months ended September 30, 2009, resulted in a decrease of three percent during the same period in 2010. The company realized higher commodity pricing during the three months and nine months ended September 30, 2010, compared to the same periods in 2009. However, for the nine months ended September 30, 2010, the higher realized commodity pricing was more than offset by higher operating costs per boe. Petrolifera's calculated unit netbacks of $24.59 per boe and $25.50 per boe for the three months and nine months ended September 30, 2010, were respectively, 51 percent and 55 percent of the average selling prices per boe, which were slight reductions from the 52 percent and 59 percent achieved during the same periods in 2009.

The corporate netback of $24.59 per boe in the third quarter of 2010 was five percent lower than the $25.80 per boe realized in the second quarter of 2010. Improved average realized selling prices were more than offset by higher operating costs per boe during the third quarter of 2010 compared to these items in the second quarter 2010.

ROYALTIES

Royalties represent charges levied by governments and landowners against production or revenue. Included in royalties are revenue taxes imposed by provincial jurisdictions. Royalties during the nine months ended September 30, 2010 were $7.2 million ($6.67 per boe), or 14 percent of oil and natural gas revenue, compared to $9.4 million ($6.29 per boe), or 14 percent of oil and natural gas revenue, in the same period in 2009. Royalties in the third quarter of 2010 were $2.2 million ($6.77 per boe), or 14 percent of oil and natural gas revenue, compared to $2.4 million ($6.09 per boe), or 14 percent of oil and natural gas revenue in the same period in 2009 and $2.4 million ($6.76 per boe), or 14 percent of oil and natural gas revenue in the second quarter of 2010. On a boe basis, the royalty increases were primarily attributable to the higher realized commodity pricing during the three months and nine months of 2010, compared to the same periods in 2009. Total royalty costs decreased during the three months and nine months ended September 30, 2010, compared to the same periods in 2009, primarily from lower sales volumes and a strengthening of the Canadian dollar relative to the US dollar.

OPERATING COSTS

Total operating costs during the three months and nine months ended September 30, 2010, decreased by approximately six percent and nine percent, respectively, compared to the same periods in 2009, largely due to lower petroleum sales volumes and the benefit of proceeds from third party oil treatment, which reduced the company's operating costs while allowing the company to better utilize its crude oil processing facility and a strengthening of the Canadian dollar relative to the US dollar.

On a per boe basis, however, operating costs increased 15 percent and 27 percent for the three months and nine months ended September 30, 2010, respectively, to $16.50 per boe and $14.36 per boe, compared to $14.79 per boe and $11.67 per boe for the same periods in 2009. This resulted from lower petroleum sales volumes, combined with increased costs for contract operator salaries and payments to surface owners both prescribed by Argentinean law alongside increased repair and maintenance costs of the company's natural gas pipeline, water injection and pumping well engines and pumps during the three months and nine months ended September 30, 2010 as compared to the same periods in 2009. Total fluid throughput increased during the current periods, partially due to the late 2009 infill well drilling program, although the average amount of crude oil produced decreased due to higher water cuts and a maturing waterflood. Accordingly, the additional fluid handling costs contributed to additional increases in the operating costs per boe for the three months and nine months ended September 30, 2010, relative to the same periods in 2009.

Total operating costs in the third quarter of 2010 of $5.4 million were modestly higher than the $5.3 million reported during the second quarter of 2010, primarily the result of a slight strengthening of the US dollar relative to the Canadian dollar, which increased the third quarter's reported operating costs.

NET LOSS AND SHARES OUTSTANDING

NET LOSS

Three months ended Sept. 30				
	2010		2009	
($000, except per unit amounts)	Total	Per boe	Total	Per boe
Corporate netback	$8,063	$24.59	$9,021	$22.48
General and administrative	(1,909)	(5.82)	(2,278)	(5.68)
Stock-based compensation	(537)	(1.64)	(1,561)	(3.89)
Finance charges	(1,041)	(3.17)	(1,132)	(2.82)
Foreign exchange gain (loss)	(577)	(1.76)	1,102	2.75
Depletion, depreciation and accretion	(7,171)	(21.87)	(17,568)	(43.78)
Fair value recovery (loss)	-	-	(2,104)	(5.24)
Income tax recovery (provision)	831	2.53	3,428	8.54
Taxes other than income taxes	(361)	(1.10)	(267)	(0.67)
Net loss	$(2,702)	$(8.24)	$(11,359)	$(28.31)

Nine months ended Sept. 30				
	2010		2009	
($000, except per unit amounts)	Total	Per boe	Total	Per boe
Corporate netback	$27,369	$25.50	$39,167	$26.32
General and administrative	(5,508)	(5.13)	(6,370)	(4.28)
Stock-based compensation	(2,318)	(2.16)	(3,999)	(2.69)
Finance charges	(3,133)	(2.92)	(4,057)	(2.73)
Foreign exchange gain (loss)	(1,379)	(1.28)	110	0.07
Depletion, depreciation and accretion	(22,712)	(21.16)	(24,610)	(16.54)
Fair value recovery (loss)	4,800	4.47	(2,104)	(1.41)
Income tax recovery (provision)	(1,465)	(1.37)	(3,250)	(2.18)
Taxes other than income taxes	(1,206)	(1.12)	(1,631)	(1.10)
Net loss	$(5,552)	$(5.17)	$(6,744)	$(4.53)

In the third quarter of 2010, the company reported a net loss of $2.7 million ($0.02 per weighted average basic and diluted share) compared to a net loss of $11.4 million ($0.14 per weighted average basic and diluted share) for the same period in 2009. The reduction in the net loss during the third quarter of 2010, relative to the same period in 2009, was primarily attributable to a higher weighed average selling price per boe and reduced expenses (including lower operating, royalty, general and administrative, stock-based compensation, finance charges and DD&A expenses). Due to the 2009 sales process relating to the company's Argentinean interests, DD&A is not comparable on a quarter-over-quarter basis. See "Depletion, Depreciation and Accretion Expense ("DD&A")" for further details on the comparability of DD&A and the net loss for the three months ended September 2010 compared to the same period in 2009.

For the nine months ended September 30, 2010, the company reported a lower net loss of $5.6 million ($0.04 per weighted average basic and diluted share), compared to a net loss of $6.7 million ($0.11 per weighted average basic and diluted share) for the same period in 2009. The reduction in the net loss during the nine months ended September 30, 2010, relative to the same period in 2009, was due to the same factors as those which impacted results for the third quarter of 2010 relative to the same period in 2009, in addition to lower income taxes, lower taxes other than income taxes and the recognition of the fair value of a debt agreement option in the amount of $4.8 million. See "RESTRICTED CASH, DEBT AGREEMENT OPTION AND LONG TERM INVESTMENTS" for further details on the debt agreement option and the calculation of its fair value.

The company's Argentinean operation is considered self-sustaining. Accordingly, changes in this operation's reported net assets, expressed in Canadian dollars resulting from foreign exchange differences between the US dollar and Canadian dollar, is recognized as other comprehensive income (loss). For the three months and nine months ended September 30, 2010, the company's other comprehensive losses were $3.0 million and $1.7 million, respectively, compared to other comprehensive losses of $9.2 million and $16.8 million for the same periods in 2009, respectively. The other comprehensive losses for the three months and nine months ended September 30, 2010 were respectively due to a three percent and two percent strengthening of the Canadian dollar as at September 30, 2010, compared to the US/Canadian dollar relationship at June 30, 2010 and December 31, 2009. This resulted in a decrease in the carrying value of the net assets of the company's Argentinean operations, which are denominated in US dollars and reported in Canadian dollars. Similarly, the other comprehensive losses during the three months and nine months ended September 30, 2009, were due to an eight percent and 14 percent strengthening of the Canadian dollar at September 30, 2009, compared to the US/Canadian dollar relationship as at June 30, 2009 and December 31, 2008, respectively.

SHARES OUTSTANDING

During the three months and nine months ended September 30, 2010, the weighted average number of common shares outstanding was 145.5 million and 136.5 million, respectively, compared to 82.4 million and 64.2 million for the same periods in 2009. The increase in the weighted average number of common shares for the three months and nine months ended September 30, 2010, relative to the same periods in 2009, reflected the weighed average inclusion of the April 2010 issuance of 23.7 million common shares from treasury for gross proceeds of $20.1 million; the August 2009 issuance and September 2009 private placement issuance of 65.3 million and 1.1 million common shares from treasury, respectively, for gross proceeds of $57.5 million and $1.0 million; and 0.4 million options that were exercised during the second half of 2009 and the first half of 2010, resulting in the issuance of a like number of common shares. As the company had net losses for the nine months ended September 30, 2010 and the three months and nine months ended September 30, 2009, the effect of "in-the-money" stock options and share purchase warrants became anti-dilutive, resulting in the exclusion of the effect of these equity instruments on the diluted net loss per common share calculations. There were no "in-the-money" stock options and share purchase warrants for the three months ended September 30, 2010.

As at the close of business on November 2, 2010, the company had the following securities issued and outstanding:

- 145,477,660 common shares; and

- 9,051,454 stock options; and

- 33,239,600 warrants, exercisable at $1.20 per warrant until
August 28, 2011.

GENERAL & ADMINISTRATIVE ("G&A") AND STOCK-BASED COMPENSATION

G&A expenses were $1.9 million and $5.5 million for the three months and nine months ended September 30, 2010, respectively, compared to $2.3 million and $6.4 million for the same periods in 2009 which included one-time expenses related to the company's process to dispose of its Argentinean interests (see

"2009 COMPARATIVE INFORMATION"). The G&A expense primarily consist of management and administrative salaries, legal and professional fees, insurance, travel, other administrative costs including increased professional fees related to the company's strategic alternatives process. See "STRATEGIC ALTERNATIVES" for further details. G&A expenses of $3.9 million and $3.6 million primarily related to further exploration and evaluation of prospects in Colombia, Peru and Argentina were also capitalized during the nine months ended September 30, 2010 and 2009, respectively.

On a per boe basis, expensed G&A was $5.13 per boe of sales during the nine months ended September 30, 2010, compared to $4.28 per boe in the same period in 2009. The increase in G&A per boe for the nine months ended September 30, 2010, relative to the same period in 2009, was primarily due to lower sales volumes.

For the nine months ended September 30, 2010, a non-cash expense of $2.3 million ($2.9 million in 2009) was recorded as stock-based compensation, reflecting the amortization of the fair value of stock options over the vesting period. The decrease in stock-based compensation during the nine months ended September 30, 2010, as compared to the same period of 2009, primarily reflects a decrease in the weighted average fair value assigned to each granted option combined with a reduction in the number of granted options.

During the nine months ended September 30, 2009, certain employees, officers and non-managerial directors of the company voluntarily surrendered 1.8 million options with a weighted average exercise price of $13.79 per option. In accordance with Canadian GAAP, any unvested options that were voluntarily surrendered were deemed to have become vested, resulting in the recognition of additional non-cash stock-based compensation expense of $1.1 million during the nine months ended September 30, 2009.

FINANCE CHARGES

Included in the finance charges of $3.1 million and $4.1 million for the nine months ended September 30, 2010 and nine months ended September 30, 2009, respectively, was interest paid and accrued on the company's outstanding current and long-term bank debt and deferred financing charges that are being amortized over the term of the revised reserve-backed credit agreement. The decrease in finance charges during the nine months ended September 30, 2010, compared to the same period in 2009, reflected lower average company borrowings and a lower effective interest rate of 3.6 percent as compared to 4.4 percent for the respective periods. Finance charges in the third quarter of 2010 of $1.0 million was comparable to the $1.1 million reported in the same quarter of 2009 as lower average company borrowings were offset by a higher effective interest rate of 4.6 percent, compared to 3.0 percent for the respective period.

During the nine months ended September 30, 2010, the company expensed $0.7 million of deferred financing costs related to a previous credit facility agreement, as the terms of this agreement were modified in a revised credit facility agreement. See "CREDIT FACILITIES" for further details.

FOREIGN EXCHANGE

For the three months and nine months ended September 30, 2010, the weakening of the US dollar relative to the Canadian dollar resulted in a foreign exchange gain on lower reported US dollar denominated debt, as expressed in Canadian dollars. This foreign exchange gain was offset by foreign exchange losses on Argentinean and corporate working capital, as partially denominated in Argentinean pesos and US dollars, respectively. As the Canadian dollar strengthened relative to both aforementioned foreign currencies, the company reported a corresponding reduction in working capital, as expressed in Canadian dollars. Combined, this resulted in a net foreign exchange loss of $0.6 million and $1.4 million for the three months and nine months ended September 30, 2010, compared to gains of $1.1 million and $0.1 million during the same periods in 2009, respectively.

DEPLETION, DEPRECIATION & ACCRETION ("DD&A")

In accordance with Canadian GAAP, depletion and depreciation on the company's Argentinean interests, previously disclosed as "discontinued operations", were not recognized in the June 30, 2009 unaudited Consolidated Financial Statements during the period from March 2, 2009 to June 30, 2009 when these interests were for sale. As a result of management's decision, on July 15, 2009, to terminate the sales process, the company's Argentinean interests were again classified as "held for use" for the three months ended September 30, 2009, resulting in the recognition of depletion and depreciation on the company's Argentinean interests from March 2, 2009 to June 30, 2009 in addition to the appropriate DD&A for the third quarter of 2009, in the financial results for the three months ended September 30, 2009. As a result of recognizing the Argentinean operation's depletion and depreciation expense from previous periods in the financial results for the third quarter of 2009, total DD&A, DD&A per boe and the net loss for the three months ended September 30, 2009 is not comparable to the same measures from previous or subsequent quarters. Had the company not recognized the Argentinean operation's depletion and depreciation expense from prior periods, as included in DD&A for the three months ended September 30, 2009, the normalized DD&A for the three months ended September 30, 2009, would have approximated $9.2 million, which would have resulted in a normalized net loss of approximately $3.8 million for the same period.

DD&A for the nine months ending September 30, 2009 was not affected by the classification of the company's Argentinean interests from discontinued operations to "held for use" as during the course of the nine months ended September 30, 2009 it had been fully recognized.

DD&A is calculated using the unit-of-production method relative to total estimated proved reserves. DD&A for the nine months ended September 30, 2010 totaled $22.7 million, a decrease compared to $24.6 million in the same period in 2009, largely due to lower petroleum sales volumes and the strengthening of the Canadian dollar relative to the US dollar, which reduced the reported DD&A. On a per boe basis, however, DD&A increased 28 percent for the nine months ended September 30, 2010 to $21.16 per boe as compared to $16.54 per boe for the same period in 2009. The increase in DD&A on a per boe basis during the nine months ended September 30, 2010 compared to the same period in 2009 was primarily due to the higher estimated costs of future capital expenditures and a 2009 year-end reserve adjustment.

Capital costs of $10.4 million (Dec. 31, 2009 - $14.0 million) incurred for unevaluated properties and other assets in Argentina and $57.4 million (Dec. 31, 2009 - $56.1 million) and $83.0 million (Dec. 31, 2009 - $47.5 million) for major development projects and other assets in the pre-production stage located in Peru and Colombia, respectively, have been excluded from the cost pool subject to depletion and depreciation. As at September 30, 2010, proceeds received from the company's partners on its Vaca Mahuida Concession resulted in a decrease in Argentinean capital costs for unevaluated properties relative to prior reported periods. See "Capital spending" for further details.

Accretion expense, which is included in DD&A, was $0.1 million and $0.4 million for the three months and nine months ended September 30, 2010 and 2009. Accretion expense will continue to be recorded at appropriate levels in the future to accrete the discounted liability of $9.8 million (Dec. 31, 2009 - $9.6 million) over the estimated timing of reclamation expenditures on the company's oil and gas properties.

FAIR VALUE OF DEBT AGREEMENT OPTION

As at September 30, 2010, the company estimated the fair value of a debt agreement option in the amount of $4.8 million, upon the company's April 2010 decision to not extend the term of a credit facility agreement that gives the company the option to settle a portion of its debt in consideration for a portion of its investment in notes formerly known as ABCP. See "RESTRICTED CASH, DEBT AGREEMENT OPTION AND LONG-TERM INVESTMENTS" for further details.

TAXES

The current income tax provision of $1.3 million and $2.9 million in the nine months ended September 30, 2010 and 2009, respectively, related primarily to income taxes payable in Argentina. Additionally, future income tax expenses of $0.2 million and $0.3 million for the nine months ended September 30, 2010 and for the nine months ended September 30, 2009, respectively, was recorded at the statutory rate, to recognize the differences between the remaining tax pools and accounting carrying values. The implied effective tax rate of the income tax provision is not indicative of the company's jurisdictional tax rates for the three and nine months ended September 30, 2010 and September 30, 2009. Taxes other than income taxes of $1.2 million and $1.6 million for the nine months ended September 30, 2010 and September 30, 2009, respectively, primarily represent taxes charged on all banking transactions in Argentina.

CAPITAL RESOURCES, CAPITAL EXPENDITURES AND LIQUIDITY

In April 2010, the company improved its liquidity and strengthened its balance sheet with a successful bought deal public offering of common shares from treasury (the "2010 Public Offering") for gross proceeds of $20.1 million. The proceeds funded a portion of the company's exploration capital spending program, including exploration activity on the company's Sierra Nevada and Magdalena licenses, located onshore Colombia; the repayment of a portion of the company's reserve-backed debt; and for working capital.

During the third quarter of 2010, the company initiated a process to review its business plan and to identify, examine and consider a range of strategic alternatives available to it for enhancing shareholders' value. Although the company continues to pursue farmout arrangements aimed at enhancing shareholders' value, at lower risk, from its strong ownership positions and early stage geological and geophysical activity in Peru and Colombia, other than for its Turpial License in Colombia, these efforts have not materialized in any other concluded agreements to date. The company therefore determined that it was an appropriate time to assess strategic options following a thorough review of current operations, its exploration opportunities, contractual obligations and capital requirements to exploit the company's lands in Argentina, Colombia and Peru, in combination with an evaluation of its current financial position. In addition to joint ventures, the strategic options being considered to increase shareholders' value include exploring potential asset divestments, a corporate sale or business combination, evaluation of financing and recapitalization opportunities and other alternatives. No decision on any particular alternative has been reached (at this time) and there can be no assurance that the process will result in a transaction or, if a transaction is entered into, as to its terms or timing.

The April 2010 Public Offering, in combination with the company's cash balances, non-cash working capital, cash flows and potential arrangements pursuant to the company's strategic alternatives review, are anticipated to provide the company with the required liquidity to meet existing work commitments and reduce outstanding debt in accordance with the terms of a revised reserve-backed credit agreement. Should farmout arrangements or any other potential arrangements pursuant to the company's strategic alternatives review not proceed as planned, the company has the ability to defer budgeted capital expenditures on certain licenses.

During the nine months ended September 30, 2010, the company entered into farmout agreements on its Puesto Guevara and Vaca Mahuida Concessions, both located in Rio Negro Province, Argentina and on the northern portion of the Rinconada Block, located in La Pampa Province, Argentina. Under each farmout agreement, the farmee agreed to incur all of the remaining capital spending requirements to fulfill the respective concession's work program, or to drill wells at no cash cost to the company, in the case of the northern portion of the Rinconada Block. In addition, the company was reimbursed $3.8 million for recent drilling activity on its Vaca Mahuida Concession. Under the Rinconada Block farmout agreement, the farmee agreed to finance a three well drilling program or to reimburse the company with a cash payment of $1.0 million for each well not drilled by November 30, 2011 in addition to any fines or penalties imposed by the governmental authority. With the signing of the 2010 Argentinean farmout agreements, the company eliminated all remaining net work commitments in Argentina while maintaining meaningful working interests in its Argentinean properties after its venturers' work obligations are fulfilled. With the Argentinean farmout agreements now in place, existing cash reserves and cash flows can be primarily directed to debt reduction or to evaluating more prospective land holdings in Peru and Colombia.

For the remainder of 2010, following the recent completion of the company's seismic programs on the Sierra Nevada and Turpial Licenses, respectively located in the Lower and Middle Magdalena Basins onshore Colombia, the company's only remaining significant work obligation is the drilling of an exploratory well on the Magdalena License, located in the lower Magdalena Basin onshore Colombia. See "COMMITMENTS, CONTRACTUAL OBLIGATIONS, GUARANTEES & OFF-BALANCE SHEET FINANCING" for a detailed discussion of the status of the company's various work commitments.

In August 2010, the company signed a revised credit facility agreement with scheduled repayments until expiry on June 30, 2012. The company made a one-time payment of US$11.7 million prior to signing the revised credit facility agreement and, subsequent thereto, made a quarterly permanent debt repayment of US$3.8 million to reduce the availability under the facility from US$50.0 million to US$34.5 million. Pursuant to the terms of the revised agreement, the company will make regular quarterly permanent debt repayments through to expiry, at which time all borrowings will be repaid, with a final payment of US$12.0 million at maturity. The revised reserve-backed credit facility improved the company's working capital position, as a portion of its reserve-backed debt, previously recorded as a current liability, is now classified as long-term. The company anticipates repayment of its reserve-backed debt from cash flows, cash balances, non-cash working capital and prospective potential cash proceeds from farmout arrangements or from any other arrangements pursuant to the company's strategic alternatives review.

CASH FLOW

Cash flow and cash flow per share do not have standardized meanings prescribed by GAAP and therefore may not be comparable to similar measures used by other companies. Cash flow includes all cash flow from operating activities and is calculated before changes in non-cash working capital. The most comparable measure calculated in accordance with GAAP would be net loss. Cash flow is reconciled with net loss below. Cash flow per share is calculated by dividing cash flow by the weighted average shares outstanding. Management uses these non-GAAP measurements for its own performance measures and to provide its shareholders and investors with a measurement of the company's efficiency and its ability to fund a portion of its future growth expenditures and to reduce outstanding debt in accordance with the terms of the revised reserve-backed credit agreement.

Three months ended Nine months ended
Sept. 30 Sept. 30

($000) 2010 2009 2010 2009

Net loss $(2,702) $(11,359) $(5,552) $(6,744)
Add (deduct) non-cash
charges:
Depletion, depreciation
and accretion 7,171 17,568 22,712 24,610
Fair value loss (recovery) - 2,104 (4,800) 2,104
Future income tax provision
(recovery) (1,151) (3,944) 199 344
Stock-based compensation 537 1,561 2,318 3,999
Unrealized foreign exchange
loss (gain) 311 (640) 1,034 1,571
Amortization of deferred
charges 173 213 875 656

Cash flow $4,339 $5,503 $16,786 $26,540

Per share, basic $0.03 $0.07 $0.12 $0.41
Per share, diluted $0.03 $0.07 $0.12 $0.40

Cash flow in the first nine months of 2010 was $16.8 million, or $0.12 per weighted average basic and diluted share, compared to $26.5 million, or $0.41 per weighted average basic share and $0.40 per diluted share in the same period of 2009. The 37 percent decrease in cash flow during the first nine months of 2010, relative to the same period in 2009, primarily resulted from lower sales volumes, the impact of a strengthening Canadian dollar relative to the US dollar thereby lowering the company's Canadian dollar reported cash flows and realized foreign exchange losses on the company's working capital. The company implemented a waterflood program at PMN in order to mitigate natural reservoir pressure declines, but in a portion of the field the program has been less effective than anticipated. The company is considering a drilling campaign which will target proved, non-producing reserves from within the PMN Field. Successful drilling of new wells and the company's recent expansion of its water treatment capacity, are anticipated to extend the ability to sustain production and recover increased volumes of crude oil. A restricted level of continuing capital expenditures on Puesto Morales has also contributed to lower production and related sales volumes as funds were redirected to more expensive but higher potential projects, primarily in Colombia.

Cash flow in the third quarter of 2010 was $4.3 million or $0.03 per weighted average basic and diluted share, compared to $5.5 million or $0.07 per weighted average basic and diluted per share for the same period of 2009. The 21 percent decrease in cash flow during the third quarter of 2010, relative to the same period in 2009, reflects the same factors as those which impacted results for the first nine months of 2010 relative to the same period in 2009, in addition to a modest increase in taxes other than income taxes. Cash flow per share for the three months and nine months ended September 30, 2010 also decreased relative to the same periods in 2009 for the aforementioned reasons and from the impact of an increase in the number of shares outstanding.

During the third quarter of 2010, cash flow was 18 percent lower, compared to the second quarter of 2010 cash flow of $5.3 million or $0.04 per weighted average basic and diluted share, primarily due to lower sales volumes and higher operating, finance and general and administrative expenses.

EQUITY FINANCING & PRIVATE PLACEMENT FROM TREASURY

In March 2010, the company announced that it entered into an underwriting agreement with a syndicate of underwriters to issue 20,590,000 common shares at a price of $0.85 per common share on a "bought deal" basis for gross proceeds of approximately $17.5 million. The underwriters were granted an over-allotment option (the "Over-Allotment Option"), which included the right to purchase up to an additional 15 percent of the offering of common shares, exercisable in whole or in part up to 30 days following closing of the 2010 Public Offering. The Over-Allotment Option was exercised in whole by the underwriters on April 14, 2010 (the closing date of the 2010 Public Offering) and accordingly resulted in a total issuance of 23,678,500 common shares with gross proceeds of approximately $20.1 million.

The net proceeds of the 2010 Public Offering in the amount of $18.8 million were added to working capital, to fund a portion of the company's exploration capital expenditure program, primarily in Colombia and to reduce indebtedness relating to the company's reserve-backed credit facility. As at September 30, 2010, the net proceeds of the 2010 Public Offering had been fully deployed to fund approximately $11.7 million of capital expenditures in Colombia, repayment of US$5.0 million of the reserve-backed credit facility and to fund $2.0 million of working capital, mostly held as cash, pending further expenditures, primarily anticipated to be in

Colombia.

The proposed use of net proceeds per the 2010 Public Offering relative to actual use of net proceeds as at September 30, 2010, are as follows:

($000)	Use of Net Proceeds Per 2010 Public Offering	Use of Net Proceeds as at Sept. 30, 2010
Capital expenditure program, primarily in Colombia	$ 10,520	$ 11,651
Reduction of reserve-backed credit facility	Up to US$5,000	US$5,000
Working capital	3,300	1,962
	$ 18,820	$ 18,820

During August 2009, the company issued 65,343,000 units (each, a "Unit") at a price of $0.88 per Unit, with each Unit consisting of one common share and one-half of one common share purchase warrant of the company (each whole common share purchase warrant, a "Warrant", exercisable at $1.20 per Warrant until September 30, 2011), for gross proceeds of approximately $57.5 million (the "2009 Public Offering") and during September 2009, a non-brokered private placement was completed with certain directors and officers of the company to issue 1,137,500 Units on identical terms to the 2009 Public Offering for gross proceeds of approximately $1.0 million (the "Private Placement"). Each Warrant entitles the holder thereof to purchase one common share at an exercise price of $1.20 per Warrant until August 28, 2011.

The net proceeds in the amount of $55.4 million of the 2009 Public Offering and Private Placement were initially added to working capital, to augment cash balances, to be used to fund a portion of the company's exploration capital expenditure program, primarily in Colombia and to reduce indebtedness relating to the company's reserve-backed credit facility. As at September 30, 2010, the net proceeds of the 2009 Public Offering and Private Placement had been fully deployed to repay US$15.0 million of the company's reserve-backed credit facility, to fund approximately $35.3 million of capital expenditures in Colombia and to fund a US$4.1 million trust account for a portion of the company's Colombian work commitments.

CAPITAL SPENDING

	Three months ended Sept. 30		Nine months ended Sept. 30	
($000)	2010	2009	2010	2009
Colombia	$4,698	$8,203	$36,763	$32,478
Argentina	2,433	4,863	6,635	19,989
Peru	534	309	1,293	6,977
Corporate	60	14	72	34
Capital spending	$7,725	$13,389	$44,763	$59,478
Proceeds from farmout arrangements	(195)	-	(3,795)	-
Net capital spending	$7,530	$13,389	$40,968	$59,478

Net capital spending in the three months and nine months ended September 30, 2010 was $7.5 million and $41.0 million, respectively, compared to $13.4 million and $59.5 million for the same periods in 2009. Net capital spending during the three months ended September 30, 2010 was financed from available cash, cash flow and proceeds from the 2010 Public Offering. Net capital spending during the nine months ended September 30, 2010 was financed from the same sources as described for the third quarter of 2010, in addition to funds from the 2009 Public Offering. Expenditures in Colombia were primarily for the drilling and long term testing of the Brillante SE-1X well and the La Pinta 1X well remedial work, both on the Sierra Nevada License.

Colombia

During mid-February 2010, the company spudded its 100 percent-owned Brillante SE-1X exploratory well, located on the Sierra Nevada License in the Lower Magdalena Basin, onshore Colombia. During the third quarter of 2010, the company concluded a 21-day extended flow term test of its Brillante SE-1X well on the upper portion of the Cienago de Oro ("CDO") reservoir. The total recovery during the test equaled the government permitted volumes of 66 mmcf of natural gas, 284 barrels of 57.6 degrees API gravity condensate and 28 barrels of water. Government permitted production rates during the final 24 hours of the flow period were 3.1 mmcf of natural gas, 19.0 barrels of condensate and 1.1 barrels of water. No flowing wellhead pressure loss or reduction in the natural gas rate was experienced during the 21-day flow period. The flowing wellhead pressure increased from 1,016 psi to 1,055 psi, while the daily natural gas production increased slightly from 3.0 mmcf per day to 3.1 mmcf per day. Evaluations of deeper pay intervals drilled in the Brillante SE-1X exploratory well may be conducted in subsequent appraisal wells.

Final analysis of the Brillante SE-1X pressure data is pending acquisition and recovery of bottom hole gauges. Based on the preliminary long-term test results, the company anticipates commencement of production of natural gas and associated natural gas liquids in 2011, provided it can successfully negotiate a natural gas off take agreement and receives the required production permits. Medium to long-term solutions are also being evaluated to transport Brillante and other regional natural gas to available markets in Colombia.

In January 2010, a snubbing unit was mobilized from the United States to the 100 percent-owned La Pinta 1X exploration well, drilled during 2009 on the company's Sierra Nevada License, situated onshore the Lower Magdalena Basin. Previously, the well had been suspended following evidence of sand plugging in the production tubing, which precluded further testing. The La Pinta 1X well bore was reentered with an objective of cleaning out the tubing string blockage to enable a test of the well. Unfortunately, on test the tubing again plugged and a decision was made to plug off the CDO and to move up hole to attempt to test a zone in the Upper Porquero Formation. During May 2010, a drill stem test was conducted in the Upper Porquero Formation at subsurface depths between 7,804 feet and 7,834 feet that flowed 47 degrees light gravity crude oil and natural gas at an average measured rate of 139 barrels of crude oil per day and 739 mcf of natural gas per day, through a 32/64" choke with a surface pressure of 238 psi. Only the upper portion of the Porquero reservoir was perforated. The company is studying the feasibility of various productivity stimulation, appraisal and production methods to place the La Pinta 1X well onstream.

Readers are cautioned that measured flow rates may not be indicative of stabilized production rates for the Brillante SE-1X or La Pinta 1X exploratory wells. Also, further evaluation, testing and appraisal of the La Pinta 1X well is required before an assessment of commerciality can be made and evaluation of the Brillante SE-1X well long-term test is also required. The company has a right to appraise its oil and gas rights in Colombia but it does not have a right to produce same until such time as the reserves are determined to be commercial.

During the third quarter of 2010, the company's technical staff interpreted 3D seismic which was shot over the La Pinta structure in the first half of 2010. This interpretation has resulted in additional well-defined structures being mapped over the La Pinta structure in various prospective horizons.

The company commenced and completed a 144 km(2) 2D seismic program in the first nine months of 2010 on its Turpial License in the Middle Magdalena Basin, onshore Colombia where multiple prospects have been defined. The company was carried through the first US$1.9 million of costs related to this work program by its joint venturer who earned an undivided 50 percent working interest in the Turpial License. The company retained a 50 percent working interest and operatorship of the Turpial License.

Argentina

Included in the first nine months of 2010 were expenditures incurred to increase to 33,000 barrels per day the capacity of the company's water treatment and water handling facilities at PMN, Argentina. The expanded water treatment capacity was installed to enable the company to handle increased fluid volumes from new drilling. Included in the first nine months of 2010, the company also capitalized certain workover costs related to perforation of additional intervals in the Centenario Formation and adjustments to water injection rates to sustain crude oil production on certain PMN wells, including PMN 1111.

In January 2010, the company announced that it had entered into a farmout agreement of the Vaca Mahuida ("VM") Concession, situated southeast of Puesto Morales, Argentina, whereby the company would continue as operator and retain a 25 percent carried interest in exchange for a $1.0 million recovery of back costs incurred on the VM X-2014 exploratory well, subsequently completed as a shut-in natural gas well and the completion of the company's remaining committed work program for the Concession. Four exploratory wells ranging in depth from 1,000 to 1,500 meters were drilled by the company during the second quarter of 2010 under the terms of the agreement. The 2010 VM drilling campaign fulfilled this Concession's work commitment and the terms of the farmout agreement, subject to confirmation that the company's work commitments have been met by the Province of Rio Negro, Argentina. All five of the VM exploratory wells encountered hydrocarbons in at least one of the Centenario, Loma Montosa, Sierras Blancas, Punta Rosada or Pre-Cuyo Formations. This validated the geological model through the confirmation of both hydrocarbon migration and trapping in the VM Concession. Results to date for these wells were as follows:

- VM X-2014 well was completed as a natural gas well and tested dry natural gas at approximately 1.0 mmcf per day from the Centenario Formation;

- LFe.X-1 well tested 80 barrels per day of crude oil and 1.5 mmcf per day of dry natural gas from the Centenario Formation with the Sierra Blancas Formation to be further evaluated at a later date;

- LG.x-1 well tested dry natural gas at rates of 1.5 mmcf per day from the Centenario Formation, 2.2 mmcf per day from the Loma Montosa and 1.5 mmcf per day from the Sierra Blancas Formation; and

- Pa. x-1 and YA.x-1 wells encountered hydrocarbons during drilling in at least one of several formations, but during completion all tested intervals produced water or negligible amounts of crude oil.

During the first quarter of 2010, the company successfully farmed out a working interest in its Puesto Guevara Concession, also situated southeast of Puesto Morales in the Province of Rio Negro, Argentina. Upon completion by the farmee of the committed work program, which requires the drilling of one exploratory well, the company's ownership in this Concession will be reduced to 44 percent, with Petrolifera continuing as the operator. The farmee has also agreed to the drilling of a second exploratory well at its cost. The two exploratory well program is anticipated during 2011 with each well ranging in depth from 1,000 meters to 1,700 meters.

During the second quarter of 2010, the company completed an agreement to farmout the northern portion of its Rinconada Block, located in La Pampa Province, Argentina, in exchange for a 35 percent carried working interest in three wells. The company retains operatorship of the southern portion of Rinconada.

Peru

Minimal capital expenditures were incurred for pre-drilling activities for the first nine months of 2010 on the company's three Peruvian blocks. The company has met, or surpassed, all of its current work commitments for Block 106, in the Maranon Basin, Peru and for Block 107, located in the Ucayali Basin, Peru, in a timely manner. The first phase work commitment for Block 133 is minimal.

The company continues the process of pursuing farmout agreements with respect to Blocks 107 and 133 with several large international companies, in an attempt to secure recovery of a portion of its sunk costs incurred on these Blocks and to secure work commitments for new drilling and/or seismic activity. Management had extensive discussions with several large companies, including two companies which based on their technical appraisals recommended the farmout but neither secured final approval at their corporate level. On Block 106, further discussions are also underway or anticipated with a number of qualified, interested third parties, also with a view to farming out an interest in this License.

CREDIT FACILITIES

During 2009, the company negotiated an expansion of a line-of-credit to a maximum of $23.2 million with a Canadian chartered bank. This line-of-credit was primarily secured by the eligible master asset vehicles Classes A1 through C received by the company in exchange for a portion of the ABCP (the "First ABCP line-of-credit"). Any of the borrowings from the expanded First ABCP line-of-credit are categorized as long-term, as the facility's initial maturity is April 2012 and the company can make up to four extension requests with each extension representing an additional one-year period. The First ABCP line-of-credit bears interest at a floating rate. As at September 30, 2010 and December 31, 2009 the outstanding draws on the First ABCP line-of-credit facility was $22.5 million.

The company has a second line-of-credit agreement to a maximum of $5.0 million which was fully drawn as at September 30, 2010 and December 31, 2009. This second line-of-credit, which has an initial expiry in April 2011, is solely secured by the ineligible master asset vehicles Classes 1 & 2 ("MAV IA 1 & 2") notes as received by the company in 2009 in exchange for a portion of the ABCP (the "Second ABCP line-of-credit"). During April 2010, the company advised its lender it would not renew this facility beyond its expiry date, at which time it will exercise its option to deliver to the lender the MAV IA 1 & 2 notes, which at the time of acquisition in 2007 had a face value of $6.6 million but through subsequent impairment provisions had no carrying value on the company's accounts as at December 31, 2009. As the company has the option to settle its $5.0 million in borrowings as drawn on the Second ABCP line-of-credit agreement through delivery to its lender of the MAV IA 1 & 2 notes, the company advised its lender that it intends to settle such borrowings with the MAV IA 1 & 2 notes and accordingly, as at September 30, 2010 the company has classified the $5.0 million in borrowings made under this facility as a current liability (Dec. 31, 2009 - $5.0 million was classified as a long-term liability).

In August 2010, the company signed a revised credit facility agreement with a syndicate of banks with scheduled repayments over the term, expiring on June 30, 2012. The company made a one-time payment of US$11.7 million prior to signing the revised credit facility agreement and subsequent thereto, made a quarterly permanent debt repayment of US$3.8 million. These had the effect of reducing the availability under the facility from US$50.0 million to US$34.5 million. The company's remaining quarterly permanent debt repayments through to expiry of the agreement, in June 2012 at which time all borrowings under this credit facility will be due and payable, is as follows:

As at	(US$000)
December 31, 2010	$3,750
March 31, 2011	3,750
June 30, 2011	3,750
September 30, 2011	3,750
December 31, 2011	3,750
March 31, 2012	3,750
June 30, 2012	$12,000

Under the terms of the revised reserve-backed credit facility, one-half of any potential farmout proceeds received by the company up to a maximum of US$5.0 million are to be first allocated to reduce the final US$12.0 million permanent debt repayment due and payable upon expiry of the revised agreement in June 2012.

The extension of the expiry date of the revised credit facility agreement over the expiry date of the previous agreement immediately improved the company's working capital position, as a portion of its reserve-backed debt previously held as a current liability was classified as long-term. The company intends to finance the permanent debt repayments from existing cash balances, cash flows, non-cash working capital and a portion of proceeds, if any, from any arrangements pursuant to the company's strategic alternatives review.

The revised reserve-backed credit facility bears interest at LIBOR plus a margin, is partially secured by the pledge of the shares of Petrolifera's subsidiaries and parent company guarantees and has a provision for a borrowing base adjustment every six months, with the next adjustment to be calculated based on information as at June 30, 2010.

As at September 30, 2010, the outstanding reserve-backed facility was US$34.5 million (Dec. 31, 2009 - US$50.0M) with $15.4 million recognized as a current liability (Dec. 31, 2009 - $52.3 million) and $20.1 million as long-term (Dec. 31, 2009 - $-). As at September 30, 2010, the outstanding First and Second ABCP line-of-credit facilities was $27.5 million (Dec. 31, 2009 - $27.5 million) with $5.0 million recognized as a current liability (Dec. 31, 2009 - $-) and $22.5 million as a long-term liability (Dec. 31, 2009 - $27.5 million).

The company is subject to external restrictions on its revised reserve-backed credit facility. Under this facility's agreement, the company is required to maintain certain operating conditions in addition to the financial covenants where certain outstanding draws cannot exceed two and half times the 12 month trailing EBITDA and a minimum working capital ratio, where working capital is defined by the terms of the revised credit facility agreement to exclude bank debt primarily secured by the longer term notes previously known as ABCP, of 1.25: 1.00. EBITDA is a non-GAAP measure and is defined by the revised credit facility agreement as net loss prior to deduction of finance charges, income taxes, depletion, depreciation and accretion expense, stock-based compensation, unrealized foreign exchange losses (gains) and any other non-cash expenses. As at September 30, 2010, outstanding draws on the revised reserve-backed credit facility and a portion of long-term bank debt were $44.1 million and EBITDA was $27.5 million, for a ratio of debt-to-EBITDA of 1.6, which is in compliance with the imposed limit. With existing realized commodity pricing, the company's cost structure and a scheduled permanent debt repayment program, Petrolifera anticipates that it will continue to be in compliance with this financial covenant.

Reconciliation of net loss to EBITDA is as follows:

	Three Months Ended				12 Months Ended
($000)	Dec. 31, 2009	Mar. 31, 2010	June 30, 2010	Sept. 30, 2010	Sept. 30, 2010
Net loss	$(4,081)	$(2,553)	$(297)	$(2,702)	$(9,633)
Add (deduct) interest, income taxes, depletion, depreciation and accretion expense and other non-cash expenses:					
Depletion, depreciation and accretion	8,936	8,087	7,454	7,171	31,648
Fair value of option on debt agreement	-	-	(4,800)	-	(4,800)
Finance charges	1,040	1,060	1,032	1,041	4,173
Stock-based compensation	675	677	1,104	537	2,993
Income tax provision (recovery)	724	542	1,754	(831)	2,189
Unrealized foreign exchange loss (gain)	(143)	618	105	311	891
EBITDA	$7,151	$8,431	$6,352	$5,527	$27,461

RESTRICTED CASH, DEBT AGREEMENT OPTION AND LONG-TERM INVESTMENTS

As at September 30, 2010, the debt agreement option represented the company's option to settle $5.0 million in borrowings solely through the delivery of its MAV IA 1 & 2 notes, whereas long-term investments included notes received in exchange for ABCP, with a face value of $30.9 million (Dec. 31, 2009 - $34.6 million) and a carrying value of $18.7 million (Dec. 31, 2009 - $18.7 million). As at December 31, 2009, long-term investments also includes collateral to support issued letters of credit of $0.7 million. As at September 30, 2010, restricted cash included collateral to support issued letters of credit of $1.5 million, with terms to maturity of less than one year (Dec. 31, 2009 - $3.2 million). These investments were classified as held for trading and were carried at fair value, which is assessed each reporting date. The fair value of the debt agreement option and notes received in exchange for ABCP is explained herein.

As discussed under "CREDIT FACILITIES", during April 2010, the company advised its lender that upon expiry of the $5.0 million Second ABCP line-of-credit agreement, the company will deliver to the lender the MAV IA 1 & 2 notes that were issued to the company in 2009 in replacement for a portion of its investment in ABCP. The lender's recourse on the company's borrowings of $5.0 million is solely limited to the MAV IA 1 & 2 notes, which at the time of acquisition in 2007 had a face value of approximately $6.6 million but through subsequent years' impairment provisions had no carrying value in the company's accounts as at December 31, 2009. As the company has the option to settle its $5.0 million in borrowings solely through delivery to its lender of the MAV IA 1 & 2 notes and advised its lender, during the second quarter of 2010, that it will settle the $5.0 million in borrowings through delivery of the MAV IA 1 & 2 notes, the company has recognized the fair value of the debt agreement option of $4.8 million as at September 30, 2010 using a probabilistic valuation model.

In the first nine months of 2010, the company did not receive any cash interest receipts on any class of notes formerly known as ABCP that it holds, as the specified short term interest rate approximated the 50 basis points required to be paid out from this investment. Current interest rates are marginally above the 50 basis points threshold, so the company does not anticipate any significant cash interest receipts during the foreseeable future.

During the third quarter of 2010, the company was advised the ineligible master asset vehicle asset tracking Class 1 ("MAV IA 1") notes, with total pledged market collateral of $500.0 million, incurred several credit events within its market portfolio resulting in losses greater than the pledged market collateral. The company had an investment in the MAV IA 1 notes with an original face value of $3.7 million and a carrying value as at December 31, 2009 of nil. The company has removed the MAV IA 1 notes from its reported portfolio of longer-term notes previously known as ABCP, thereby reducing the outstanding principal amount of its portfolio by $3.7 million for the three months and nine months ended September 30, 2010.

For the three months and nine months ended September 30, 2009, the company reported a $2.1 million fair value impairment on its MAV IA 1 and ineligible master asset vehicle asset tracking Class 2 ("MAV IA 2") notes, which when combined forms the MAV IA 1 & 2 notes as previously defined, thereby reducing the September 30, 2009 carrying value of its MAV IA 1 & 2 notes to nil. The recognition of the fair value impairment for the three months and nine months ended September 30, 2009 was accompanied by the removal of the MAV IA 2 notes from the company's reported portfolio of longer-term notes previously known as ABCP.

Despite the permanent impairment in the MAV IA 1 & 2 notes as at September 30, 2010, the company still retains the right to exercise its debt agreement option in April 2011 to settle $5.0 million in borrowings solely through the delivery of its MAV IA 1 & 2 notes.

Although management understands there have been some third party transactions during the first nine months of 2010, no active market quotations have developed for the eligible master asset vehicle longer term notes. As a result, management has estimated the fair value of the company's investment in the eligible master asset vehicle longer term notes at September 30, 2010 based on a probabilistic recovery of principal and interest, after taking into account all available information. Under this valuation method, several different outcomes of the recovery of the principal and interest are estimated, considering the information available as at September 30, 2010. A weighted average recovery is then calculated. This weighted average recovery is used to determine the discounted cash flows that are expected from these investments. The discount rate used to discount the expected cash flows from the eligible master asset vehicle longer term notes approximates the risk-free rate over the expected life of the eligible master asset vehicle longer term notes. As the rate used for discounting was an approximation of the risk-free rate, all other risks have been incorporated in the estimated probability-adjusted expected outcomes. This methodology applied all risking information into the various scenarios and discounted the fully-risked cash flow stream only for the time value of money. The recovery factors used were as follows:

Class of Note	Face Value of Notes ($000s)	Capital Recovery Range	Interest Recovery Range	Risk-adjusted Capital Weighted Average Recovery	Risk-adjusted Interest Weighted Average Recovery	Term (yrs)	Risk-free Discount Rate
A-1	$13,978	0 - 80%	0 - 60%	75%	54%	3 - 7	3%
A-2	13,543	0 - 70%	0 - 30%	64%	27%	7	3%
B	2,459	0 - 30%	0%	27%	0%	7	3%
C	928	0%	0%	0%	0%	7	3%
Total	$30,908						

Based on the above approach the fair value of the investment in the eligible master asset vehicle longer term notes was $18.7 million as at September 30, 2010 and December 31, 2009. Since 2007, the total recognized impairment on the eligible and ineligible master asset vehicle longer term notes is approximately 46 percent of the original cost of the investment, including impairments recognized on the ABCP.

The theoretical fair value of the company's eligible master asset vehicle longer-term notes could range from $14.0 million to $25.0 million, using the valuation methodology described above, with reasonably possible alternative assumptions. The outcome of the actual timing and amount ultimately recoverable from these notes may differ materially from this estimate, which would impact the company's losses. To date, no active market for the eligible master asset vehicle longer term notes has developed to permit liquidation of the company's investment for proceeds equal to or greater than the collateral value pursuant to the First ABCP line-of credit agreement.

IMPACT OF NEW AND PROPOSED ACCOUNTING PRONOUNCEMENTS

In December 2008, the CICA issued Section 1582, Business Combinations, which will replace CICA Section 1581 of the same name. Section 1582 establishes principles and requirements of the acquisition method for business combinations and related disclosures. This statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 2011 with earlier application permitted. The company is currently evaluating the impact of adopting this standard to any business combination entered on or after January 1, 2011 on its

Consolidated Financial Statements.

In December 2008, the CICA issued Sections 1601, Consolidated Financial Statements, and 1602, Non-Controlling Interests, which replaces existing Section 1600. Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 provides guidance on accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. These standards are effective on or after the beginning of the first annual reporting period beginning on or after January 2011 with earlier application permitted. The company is currently evaluating the impact of adopting Section 1601 and on the accounting of non-controlling interests resulting from any business combinations entered on or after January 1, 2011 on its Consolidated Financial Statements.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

In October 2009, the Canadian Accounting Standards Board issued a third and final International Financial Reporting Standards ("IFRS") Omnibus Exposure Draft confirming that publicly accountable enterprises will be required to adopt IFRS in place of Canadian GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. The company's IFRS adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by the company for the year ended December 31, 2010, including the opening balance sheet as at January 1, 2010.

During 2008, the company commenced the transition process to IFRS and has been progressing towards completion throughout 2009 and into 2010. The company's IFRS transition project consists of three key phases: the preliminary phase, the impact and evaluation phase and the implementation phase. A fulsome description of the company's IFRS transition project phases and the company's progress to the end of 2009 is contained within the company's MD&A for the year ended December 31, 2009.

Management has presented its preliminary recommendations to the Audit Committee regarding the IFRS policies (and specifically IFRS 1, First Time Adoption of IFRS) to be adopted by the company in connection with the transition process to IFRS. These preliminary recommendations were accepted by the Audit Committee and are subject to such changes as may be required by new developments in IFRS and continued evaluation by management of the impact of these policy selections during the implementation phase of the transition process. Management is in the process of preparing an opening balance sheet as at January 1, 2010 and comparative interim financial statements for 2010 based upon the preliminary accounting policies recommended and as such quantified information regarding the impact of IFRS on key line items in the company's financial statements has not yet been completed.

IFRS 1, First Time Adoption of IFRS provides companies adopting IFRS with a number of optional exemptions and mandatory exceptions in certain areas to the general requirement for full retrospective application of IFRS. Most adjustments required on transition to IFRS will be made retrospectively against retained earnings as of the date of the first comparative balance sheet presented upon IFRS adoption, based on standards applicable at that time. Management has analyzed the various accounting policy choices available under IFRS 1 and has begun to implement those determined to be the most appropriate for the company. The following is a summary of the proposed application of the IFRS 1 exemptions:

- Property, Plant & Equipment ("PP&E") - IFRS 1 provides an exemption allowing companies who follow the full cost accounting guideline under Canadian GAAP, such as Petrolifera, to value the PP&E assets at their deemed cost being the Canadian GAAP net book value assigned to these assets as at the date of the transition, January 1, 2010. The net book value of the PP&E assets will be allocated to new cost centres on the basis of the company's reserve volumes or values on the date of transition.

- Cumulative Translation Adjustments ("CTA") - IFRS 1 provides an exemption allowing the company to not comply with IAS 21 - The Effects of Changes in Foreign Exchange Rates that existed at the date of transition to IFRS. Instead, the company will elect to deem the CTA for its foreign operations to be zero at the date of transition. The company will then recognize directly in retained earnings at the date of transition its CTA as measured in accordance with Canadian GAAP.

- Asset Retirement Obligation ("ARO") - IFRS 1 provides another exemption for full cost accounting companies under Canadian GAAP, such as Petrolifera, to measure its ARO liability at the date of transition in accordance with IAS 37 - Provisions, Contingent Liabilities and Contingent Assets. The company will then recognize directly in retained earnings at the date of transition any difference in the measures between IFRS and the company's previous measure in accordance with Canadian GAAP.

The transition from Canadian GAAP to IFRS is a significant undertaking that may materially affect the company's reported financial position and results of operations. However, this does not reflect a change in the underlying economics of Petrolifera's business. At this time, the company has identified key differences that may impact the financial statements as follows:

- Classification of Exploration and Evaluation ("E&E") expenditures from PP&E - Upon transition to IFRS, the company will separately classify all E&E expenditures on the Consolidated Balance Sheet. Under Canadian GAAP, E&E expenditures are included in PP&E. E&E expenditures consist of the book value for the company's undeveloped land that relate to exploration properties primarily in Colombia and Peru. E&E expenditures will not be depleted and must be assessed for impairment when indicators suggest the possibility of impairment.

- Calculation of depletion expense for PP&E assets - Upon transition to IFRS, the company has the option to calculate depletion using a reserve-base of proved reserves or proved and probable reserves, as compared to the Canadian GAAP method of calculating depletion using only proved reserves. The company has not concluded at this time which method for calculating depletion will be used.

- Impairment of PP&E assets - Under IFRS, impairment of PP&E must be calculated at a more granular level than under the Canadian GAAP Full Cost Accounting Guideline where all the company's oil and gas assets are accumulated into one of three geographic costs centres. Impairment calculations will be performed at a "Cash Generating Unit" level ("CGUs") by comparing the CGUs carrying value to a corresponding risk adjusted recovery of either proved or proved and probable reserves. The deemed cost of the company's oil and gas PP&E has been allocated to two proposed CGUs based on the company's proved plus probable reserve values at January 1, 2010. The company's proposed CGUs could change in the future as a result of dispositions pursuant to the strategic alternatives review process. The first impairment calculations will be performed on the company's two proposed CGUs as at the date of IFRS transition, January 1, 2010, which could result in a material difference in the total PP&E balance as determined under IFRS versus Canadian GAAP.

- The effects of foreign changes in foreign exchange rates - Under IFRS, the translations of the company's US dollar functional currency (see "Change in functional currency") Colombian, Peruvian and certain Corporate operations (the "Integrated Operations") to the company's Canadian dollar presentation currency is performed by applying the closing and average US dollar relative to Canadian dollar rates at the date and period of the Consolidated Balance Sheet and Statement of Operations, respectively, with the resulting exchange difference recognized in other comprehensive loss. Under Canadian GAAP, the Integrated Operations' monetary assets and liabilities and associated income and expenses are translated using the aforementioned technique with the exception that the exchange difference is recognized in net loss, while the Integrated Operations' non-monetary assets and liabilities and associated income and expenses are translated at the historical average US dollar relative to Canadian dollar rates.

- Change in functional currency - Under Canadian GAAP, the company's measurement of its Integrated Operations has been based on the Canadian dollar whereas under IFRS this basis will change to the US dollar. As there is a change in the company's basis of measuring its Integrated Operations, the company is currently measuring this retroactive restatement as at the time of transition to IFRS on January 1, 2010. The company anticipates that any such change will be recognized as other comprehensive income (loss) upon the transition to IFRS. The company will then apply the IFRS 1 exemption allowing it to elect to deem other comprehensive income (loss) for its foreign operations to be zero at the date of transition, as previously discussed, with a corresponding adjustment directly in retained earnings.

- Provisions for asset retirement costs - Under IFRS, the company is required to revalue its entire liability for asset retirement costs at each balance sheet date using a current liability - specific discount rate. Under Canadian GAAP, once recorded, asset retirement obligations are not adjusted for future changes in discount rates.

In addition to accounting policy differences, the company's transition to IFRS is expected to impact its internal controls over financial reporting, disclosure controls and procedures, certain of the company's business activities and IT systems as follows:

- Internal controls over financial reporting ("ICFR") - the company is currently in the process of reviewing its ICFR documentation and is identifying instances where controls must be amended or added in order to address the accounting policy changes required under IFRS. It is anticipated that any documentation changes will be substantively completed and that testing of the amended controls will commence in the fourth quarter of 2010. No material changes in control procedures are expected as a result of transition to IFRS.

- Disclosure controls and procedures ("DC&P") - The company has assessed the impact of transition to IFRS on its DC&P and has not identified any material changes required in its control environment. Management has currently drafted its IFRS financial statements and notes thereto while also monitoring requirements put forth by the IASB in discussion papers and exposure drafts for future disclosure requirements.

- Business activities - Management has been cognizant of the upcoming transition to IFRS and as such has worked with its counterparties and lenders to ensure that any agreements that contain references to Canadian GAAP financial statements are modified to allow for IFRS statements. Based on the expected changes to the company's accounting policies at this time, no issues are anticipated with the existing wording of debt covenants and related agreements as a result of the transition to IFRS.

- IT systems - the company is currently updating its accounting system in order to ready the company for IFRS reporting. The modifications are not significant, however, deemed critical in order to allow for reporting of both Canadian GAAP and IFRS statements in 2010 as well as the modifications required to track PP&E and E&E expenditures at a more granular level of detail for IFRS reporting. Additional system modifications may be required based on final policy choices.

Management's timeframe to complete the third and final implementation phase of its IFRS adoption efforts is scheduled during the fourth quarter of 2010, which will allow the company to adopt IFRS in place of Canadian GAAP, effective January 1, 2011.

COMMITMENTS, CONTRACTUAL OBLIGATIONS, GUARANTEES & OFF-BALANCE SHEET ARRANGEMENTS

WORK COMMITMENTS

In 2005, Petrolifera acquired two significant oil and gas exploration licenses onshore Peru for Blocks 106 and 107, respectively, located in the Maranon and Ucayali Basins. During April 2009, Petrolifera was awarded a license over Block 133, offsetting and contiguous with Block 107. During 2009 and 2010, Petrolifera relinquished approximately one-third and one half and of Block 106 and 107, respectively. Based on its interpretation of the Block 106 476 km and Block 107 950 km 2D seismic programs acquired over the acreages by the company in 2007 and 2008, Petrolifera believes it has retained the most prospective acreages under Block 106 and 107.

The Peruvian licenses have negotiated work programs through 2016, unless extended. Each work program has a specified minimum financial commitment that must be met for the company to maintain its rights to these licenses. Specifically, the immediate minimum work commitments of US$0.3 million for Block 133 are primarily comprised of geological field studies and as such are not capital intensive. The company has met, or surpassed, all of its current work commitments for Blocks 106 and 107 in a timely manner. The company has received approval of its Block 107 Environmental Impact Assessment ("EIA") for several potential drilling sites and is awaiting approval of its recently filed EIA amendment. The ability to defer drilling activity until 2013 positions the company to maintain these properties in good standing at low cost. The company has the right to withdraw from the licenses at the end of each period associated with the term of the licenses.

In 2007, the company was granted three Colombian concessions comprised of one license, Sierra Nevada, and two Technical Evaluation Assessments ("TEAs"). Petrolifera converted the Turpial and Sierra Nevada II TEAs into exploration licenses with the latter renamed Magdalena. The company recently completed the second phase of its Sierra Nevada License work program, which required the drilling of one exploratory well and acquiring additional seismic, with the completion of this phase still to be acknowledged by the Agencia Nacional de Hidrocarburos ("ANH"). The company completed drilling the Sierra Nevada License's second phase exploratory well, Brillante SE-1X during March 2010 to a total depth of 9,500 feet. During the second quarter of 2010, the company completed a 3D seismic program over the La Pinta structure which, when combined with the Brillante SE-1X exploratory well, is anticipated to complete the Sierra Nevada's second phase work program. The company has notified ANH that it will commence with phase 3 of the Sierra Nevada License work program, which requires the drilling of one exploration well and a modest seismic program prior to June 2011. Whilst still to be acknowledged by ANH, the company recently completed the second phase 2D seismic acquisition and interpretation work program on its Turpial License. This was disproportionately financed by the company's joint venturer. The company is in the first phase of its Magdalena License, which requires an exploration well to be completed prior to the end of December 2010. The company anticipates the drilling of an exploratory well on its San Angel prospect during the fourth quarter of 2010 to meet this requirement.

The company's aforementioned remaining Colombian and Peruvian work commitments are anticipated to be financed from existing cash reserves, cash flows, the 2010 Public Offering and any other potential arrangements reached pursuant to the company's strategic alternatives review. Should any potential arrangements pursuant to the strategic alternatives review not proceed, the company has the ability to defer capital expenditures on certain licenses.

In Argentina, the company has farmed out its Vaca Mahuida and Puesto Guevara Concessions work commitments of US$2.9 million and US$0.6 million, respectively, through agreements reached in the first quarter of 2010. At Vaca Mahuida, a total of five exploratory wells have been drilled by the company, financed by the company's joint venturers. The company's working interest in the Vaca Mahuida Concession will reduce to 25 percent upon the Province of Rio Negro, Argentina, acknowledging that the company's existing work commitment has been met. Once the company's joint venturer has funded the work commitment for the Puesto Guevara Concession, the company's working interests will be 44 percent in this Concession. The company has no net remaining work commitments in Argentina given its Vaca Mahuida Concession's work commitment is anticipated to have been met and its Puesto Guevara Concession's work commitment is to be solely funded by its joint venturer.

CONTRACTUAL OBLIGATIONS

The company's gross contractual obligations for drilling, leases for office premises and other equipment and an administrative services agreement for the remaining three months ended December 31, 2010 and annually thereafter are as follows:

($000)	2010	2011	Subsequent to 2011	Total
Drilling contract and other leases	$3,524	$774	$238	$4,536

GUARANTEES

As at September 30, 2010 the company has issued letters of credit in the total amount of US$1.4 million and US$0.1 million, respectively, to secure the capital expenditure requirements associated with the Colombian and Peruvian work commitments (Dec. 31, 2009 - US$2.1 million and US$1.7 million, respectively). As at September 30, 2010, a deposit of US$0.2 million (Dec. 31, 2009 - US$4.1 million) is held in a trust account in Colombia to meet certain work obligations on the Magdalena License as they occur.

OFF-BALANCE SHEET ARRANGEMENTS

The company does not have any off-balance sheet arrangements.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of the company is also responsible for designing internal controls over the company's financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. There have been no changes in the company's systems of internal controls over financial reporting during the three and nine months ended September 30, 2010 that would materially affect, or are reasonably likely to materially affect, the company's internal controls over financial reporting.

BUSINESS RISKS

Petrolifera is exposed to certain risks and uncertainties inherent in the oil and gas business. Furthermore, being a smaller independent company, it is exposed to financing and other risks which may impair its ability to realize on its assets or to capitalize on opportunities which might become available to it. Additionally, Petrolifera operates in various foreign jurisdictions and is exposed to other risks including currency fluctuations, political and economic risk, price controls and varying forms of fiscal regimes and government policies or changes thereto which may impair Petrolifera's ability to conduct profitable operations.

The risks arising in the oil and gas industry include price fluctuations for both crude oil and natural gas over which the company has limited control; risks arising from exploration and development activities; production risks associated with the depletion of reservoirs and the ability to market production. Additional risks include environmental and health and safety concerns.

Virtually all of the company's total revenue in its nine months ended September 30, 2010 was derived from crude oil, natural gas and natural gas liquids production from the Puesto Morales/Rinconada Concession in Argentina. The occurrence of any event that would prevent the production of crude oil and natural gas by the company from the Puesto Morales/Rinconada Concession, including physical problems or infrastructure facilities (howsoever arising) supporting the producing region or negative actions on the part of any government or regulatory authority in Argentina, would have a significant adverse effect on the company's cash flows and revenue until such time as such problem is remedied. Additionally, there is a risk of premature decline of the reservoirs that may impact recoverability of the reserves associated with significant wells.

Petrolifera is in the process of identifying, examining and considering a range of strategic alternatives available for enhancing shareholders' value. No decision on a particular alternative has been reached and there can be no assurance that the process will result in a transaction or, if a transaction is entered into, as to its terms or timing. In this regard, farmout (and joint venture) efforts continue with respect to much of the company's prospect inventory. Current capital market conditions may make this process more challenging and time consuming than under more buoyant and stable economic conditions, resulting in the company having to bring participants into its acreage holdings and planned activities on less attractive terms than might otherwise have been negotiated. There can be no assurances as to the timing or completion of possible farmout (and/or joint venture) arrangements.

Farmout or joint venture arrangements can expose Petrolifera to additional risks and uncertainties where the concurrence of co-venturers is required to pursue various actions or the co-venturer is required to fund expenditures on behalf of Petrolifera to meet contractual work commitments. Other parties influencing the timing of events may have priorities that differ from Petrolifera's, even if they generally share Petrolifera's objectives. Additionally, Petrolifera is exposed to the credit risk of its co-venturers and possible default if its co-venturer fails to meet contractual work commitments initially undertaken by Petrolifera under its Licenses.

The success of the company's capital programs as embodied in its productivity and reserve base, could also impact its prospective liquidity and pace of future activities. Control of finding, development, operating and overhead costs per boe is an important long-term criterion in determining company growth, success and access to new capital sources.

To date, the company has utilized debt and equity financing and has had a bias towards conservatively financing its operations under normal industry conditions to offset the inherent risks of international oil and gas exploration, development and production activities. The company may be required to raise additional capital to fund its activities in light of overall industry conditions, the remaining work commitments associated with the company's exploratory lands and the slow pace at which farmout negotiations are preceding. Capital markets may not be receptive to offerings of new equity from treasury, whether by way of private placement or public offerings. Additionally, there can be no assurance that the outstanding Warrants will be exercised to provide the company with additional liquidity.

Access to financing has been impacted by sub-prime mortgage defaults, the liquidity crisis affecting the ABCP and collateralized debt obligation markets and deterioration in the global economy. Banks have been adversely affected by the worldwide economic crisis and have severely curtailed existing liquidity lines, increased pricing and introduced new and tighter borrowing restrictions to corporate borrowers, with extremely limited access to new facilities or for new borrowers. These factors may impact Petrolifera's ability to obtain equity, debt or bank financing on terms that are commercially reasonable, or at all, and could negatively impact its ability to access liquidity needed for its operations in the longer term. This may be further complicated by the limited market liquidity for shares of smaller companies, restricting access to some institutional investors.

Periodic fluctuations in energy prices and changes in economic, political and social conditions in jurisdictions in which the company operates may also affect lending policies of the company's banker for new borrowings in addition to the semi-annual review of reserves which may reduce the existing availability of indebtedness. This in turn could limit growth prospects over the short run or may even require the company to dedicate cash flow, dispose of properties or raise new equity to reduce bank borrowings under circumstances of declining energy prices or disappointing drilling results.

While hedging activities may have opportunity costs when realized prices exceed hedged pricing, such transactions are not meant to be speculative and are considered within the broader framework of financial stability and flexibility. Management continuously reviews the need to utilize such financing techniques.

The company attempts to mitigate its business and operational risk exposures by maintaining comprehensive insurance coverage on its assets and operations, by employing or contracting competent technicians and professionals, by instituting and maintaining operational health, safety and environmental standards and procedures and by maintaining a prudent approach to exploration and development activities. The company also addresses and regularly reports on the impact of risks to its shareholders, writing down the carrying values of assets that may not be recoverable.

OUTLOOK

The Board of Directors has initiated a process to review Petrolifera's business plan and to identify, examine and consider a range of strategic alternatives available to the company for enhancing shareholders' value. Among other things, this may include exploring potential asset divestments and joint ventures, a corporate sale or business combination, evaluation of financing and recapitalization opportunities or other alternatives to increase shareholders' value. The Board of Directors determined that it was an appropriate time to assess strategic options following a thorough review of current operations, the exploration opportunities, contractual obligations and capital requirements to exploit the company's lands in Argentina, Colombia and Peru and an evaluation of the company's current financial position.

No decision on any particular alternative has been reached at this time and there can be no assurance that the process will result in a transaction or, if a transaction is entered into, as to its terms or timing.

FORWARD-LOOKING INFORMATION

This interim report, including the Letter to Shareholders, contains forward-looking information including, but not limited to, the evaluation of strategic alternatives for enhancing shareholder value including possible farmout and/or joint ventures arrangements, continued exploration activities in respect of the Sierra Nevada and Magdalena Licenses in Colombia, the anticipated drilling of an exploratory well on the San Angel prospect within the Magdalena License onshore Colombia during 2010, the planned production and sale of natural gas from the Brillante SE-1X well in the Sierra Nevada License, planned drilling in Argentina, anticipated improvements in natural gas prices in Argentina, planned capital expenditures (including sources of funding and timing thereof), expectations regarding the company's ability to continue to comply with financial covenants imposed pursuant to its reserve-backed credit facility and otherwise meet its existing work commitments and the anticipated impact of the proposed conversion to IFRS on the company's consolidated financial statements. Forward-looking information is not based on historical facts but rather on Management's expectations regarding the company's future growth, results of operations, production, future capital and other expenditures (including the amount, nature and sources of funding thereof), competitive advantages, plans for and results of drilling activity, environmental matters, business prospects and opportunities and expectations with respect to general economic and capital market conditions. Such forward-looking information reflects Management's current beliefs and assumptions and is based on information currently available to Management. Forward-looking information involves significant known and unknown risks and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking information, including but not limited to, risks associated with the oil and gas industry (e.g. operational risks in development, exploration and production, delays or changes to plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve estimates; the uncertainty of geological interpretations; the uncertainty of estimates and projections in relation to production, costs and expenses and health, safety and environment risks), the risk of commodity price and foreign exchange rate fluctuations, the uncertainty associated with negotiating with foreign governments and third parties located in foreign jurisdictions and the risk associated with international activity. While the board of directors of the company has engaged in a process to identify, examine and consider a range of strategic alternatives available to it for enhancing shareholder value, no decision has been reached and there can be no assurance that the process will result in a transaction or, if a transaction is entered into, as to its term or timing. There can be no assurance that further exploration or approval of the company's Colombian licenses will lead to commercial discoveries or, if there are commercial discoveries, that the company will be able to realize such resources as intended. Few properties that are explored are ultimately developed into new reserves. Readers are cautioned that measured flow rates may not be indicative of sustainable production rates. Petrolifera has the right to appraise its oil and gas rights in Colombia but it does not have a right to produce same until such time as the reserves are determined to be commercial. The company's ability to complete its capital program and repay outstanding indebtedness is dependent upon completion of planned farmout arrangements and recovery of sunk costs, maintenance of stable production in Argentina, stabilized or improved commodity prices and the satisfaction of all commitments by joint venturers in connection with the properties that have been farmed out. Petrolifera may have to bring participants into its acreage holdings and planned evaluation activities on less attractive terms than might otherwise have been the case due to the combination of tighter economic conditions and the influence of contractual commitments and deadlines on the terms of trade. There can be no assurance that the company will be successful in its efforts to secure planned farmouts and/or joint venture arrangements. There can be no assurance that the company will be successful in its efforts to secure cash payments, if any, or any planned farmouts and/or joint venture arrangements in Peru or Colombia and thereby reduce its indebtedness under the reserve-backed credit facility. Additionally, the company's ability to pay quarterly principal repayments when due is dependent on cash balances and cash flow from operations. Cash flow from operations is dependent on future production levels, commodity prices and foreign exchange rates. Additional risks and uncertainties associated with Petrolifera's future plans are described elsewhere in this interim report and in Petrolifera's Annual Information Form for the year ended December 31, 2009. Although the forward-looking information contained herein is based upon assumptions which Management believes to be reasonable, the company cannot assure investors that actual results will be consistent with this forward-looking information. This forward-looking information is made as of the date hereof and the company assumes no obligation to update or revise this information to reflect new events or circumstances, except as required by law. Because of the risks, uncertainties and assumptions inherent in forward-looking information, prospective investors in the company's securities should not place undue reliance on this forward-looking information. Additionally, readers are reminded that cash flow from operations and EBITDA do not have standardized meanings prescribed by GAAP and therefore may not be comparable to similar measures used by other companies. Cash flow from operations and EBITDA are reconciled to net earnings (loss) in the MD&A.

QUARTERLY RESULTS(4)

	2008	2009		
For the Three Months Ended or As At	Dec 31	Mar 31	June 30	Sept 30
FINANCIAL RESULTS ($000, EXCEPT PER SHARE AMOUNTS) - UNAUDITED				
Total revenue	37,411	26,407	22,255	17,229
Cash flow(1)	21,689	10,804	10,233	5,503
Basic, per share(1)	0.39	0.20	0.19	0.07
Diluted, per share(1)	0.39	0.20	0.18	0.07
Net earnings (loss)	2,662	1,188	3,427	(11,359)
Basic and diluted, per share(5)	0.05	0.02	0.06	(0.14)
Net capital spending	35,539	25,612	20,477	13,389
Cash	30,701	30,994	14,803	55,953
Working capital (deficit)	19,956	33,768	22,895	724
Long-term investments(6)	25,428	21,501	21,172	19,873
Long-term bank debt(6)	77,150	104,649	102,104	27,464
Shareholders' equity	202,347	209,240	201,749	238,475
Total assets	355,658	371,054	353,424	368,288
OPERATING RESULTS				

Sales volumes:
Crude oil and natural
gas liquids - bbl/d 6,877 5,245 4,652 3,653
Natural gas - mcf/d 5,451 6,500 6,232 4,252
Equivalent - boe/d(2) 7,786 6,328 5,691 4,362
Pricing:
Crude oil and natural
gas liquids - $/bbl 56.76 52.17 48.72 48.07
Natural gas - $/mcf 2.88 2.98 2.87 2.74
Selected highlights - $/boe:(2)
Weighted average
selling price 52.15 46.30 42.97 42.93
Interest and other income 0.08 0.06 - -
Royalties 7.66 6.02 6.74 6.09
Operating costs 10.28 10.33 11.04 14.36
Corporate netback(3) 34.29 30.01 25.20 22.48

COMMON SHARE INFORMATION
(000, EXCEPT SHARE PRICE)

Shares outstanding at end
of period 54,948 54,948 54,948 121,759
Weighted average shares
outstanding for the period:
Basic 54,948 54,948 54,948 82,418
Diluted(5) 55,043 55,195 55,600 82,539
Volume traded during quarter 8,826 10,053 13,268 55,032
Common share price ($):
High 3.99 1.60 3.47 2.85
Low 0.75 0.80 1.49 0.76
Close (end of period) 1.05 1.60 2.85 1.08

2009 2010

For the Three Months Ended
or As At Dec 31 Mar 31 June 30 Sept 30

FINANCIAL RESULTS
($000, EXCEPT PER SHARE
AMOUNTS) - UNAUDITED

Total revenue 17,900 17,908 16,794 15,694
Cash flow(1) 5,867 7,177 5,270 4,339
Basic, per share(1) 0.05 0.06 0.04 0.03
Diluted, per share(1) 0.05 0.06 0.04 0.03
Net earnings (loss) (4,081) (2,553) (297) (2,702)
Basic and diluted,
per share(5) (0.03) (0.02) 0.00 (0.02)
Net capital spending 9,378 15,742 17,696 7,530
Cash 35,732 32,207 41,179 11,477
Working capital (deficit) (2,508) (10,659) 17,156 10,354
Long-term investments(6) 19,395 19,202 19,210 18,689
Long-term bank debt(6) 27,464 27,456 45,373 40,693
Shareholders' equity 232,126 227,097 251,260 246,050
Total assets 349,065 345,509 376,233 339,575

OPERATING RESULTS

Sales volumes:
Crude oil and natural
gas liquids - bbl/d 3,833 3,706 3,356 2,885
Natural gas - mcf/d 4,056 3,862 3,184 4,077
Equivalent - boe/d(2) 4,509 4,349 3,887 3,564
Pricing:

Crude oil and natural
gas liquids - $/bbl 48.08 50.65 52.13 55.14
Natural gas - $/mcf 2.53 2.54 2.66 2.72
Selected highlights - $/boe:(2)
Weighted average
selling price 43.15 45.41 47.19 47.79
Interest and other income - 0.34 0.29 0.07
Royalties 6.40 6.50 6.76 6.77
Operating costs 13.42 13.24 14.92 16.50
Corporate netback(3) 23.33 26.01 25.80 24.59

COMMON SHARE INFORMATION
(000, EXCEPT SHARE PRICE)

Shares outstanding at end
of period 121,759 121,798 145,478 145,478
Weighted average shares
outstanding for the period:
Basic 121,759 121,789 141,835 145,478
Diluted(5) 121,777 121,812 141,835 145,478
Volume traded during quarter 35,921 47,157 15,295 13,739
Common share price ($):
High 1.09 1.31 1.01 0.81
Low 0.79 0.84 0.64 0.55
Close (end of period) 0.97 0.96 0.65 0.79
----

(1) Cash flow from operations before non-cash working capital changes ("cash flow") and cash flow per share do not have standardized meanings prescribed by Canadian generally accepted accounting principles ("GAAP") and therefore may not be comparable to similar measures used by other companies. Cash flow includes all cash flow from operating activities and is calculated before changes in non-cash working capital. The most comparable measure calculated in accordance with GAAP would be net earnings (loss). Cash flow is reconciled with net earnings (loss) in this Management's Discussion & Analysis ("MD&A") and MD&A for prior periods. Management uses these non-GAAP measurements for its own performance measures and to provide its shareholders and investors with a measurement of the company's efficiency and its ability to fund a portion of its future growth expenditures.

(2) All references to barrels of oil equivalent (boe) are calculated on the basis of 6 Mcf : 1 bbl. Boe may be misleading particularly if used in isolation. This conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(3) Corporate netback is a non-GAAP measure used by management as a measure of operating efficiency and profitability. It is calculated as petroleum and natural gas revenue and other income less royalties and operating costs. For a reconciliation of netbacks to net earnings (loss) see this MD&A and MD&A for prior periods.

(4) Fluctuations in results over the previous quarters are due principally to variations in oil and gas prices (including variations in foreign exchange rates), production mix and production volumes. In addition, the net loss for the quarter ended September 30, 2009 was adversely affected by the inclusion of depletion and depreciation from March 2, 2009 to June 30, 2009. Depletion and depreciation was initially not recognized from March 2, 2009 to June 30, 2009 due to the decision, at that time, to sell the company's Argentinean interests. Attributing to fluctuations in working capital is the classification of debt as either current or long-term.

(5) As the company has net losses during the three months ended September 30 and December 31, 2009 and March 31 and June 30, 2010,

the dilutive effect of stock options and share purchase warrants became anti-dilutive, causing the basic weighted average common shares outstanding to be used as the denominator in the dilutive per share net loss calculation. There were no "in-the-money" stock options and share purchase warrants for the three months ended September 30, 2010.

(6) Includes carrying value of notes received for ABCP with a face value of $30.9 million and $34.6 million as at September 30, 2010 and December 31, 2009, respectively. Long-term debt in the amount of $22.5 million and $27.5 million as at September 30, 2010 and December 31, 2009, respectively, is primarily secured on a limited recourse basis by the underlying notes formerly known as ABCP.

PETROLIFERA PETROLEUM LIMITED

CONSOLIDATED BALANCE SHEETS

(UNAUDITED)

As at	Sept. 30, 2010	Dec. 31, 2009
	($000)	
ASSETS		
Current		
Cash	$ 11,477	$ 35,732
Accounts receivable	21,570	20,871
Restricted cash	1,536	3,247
Inventory (Note 3)	583	958
Financial instrument - debt agreement option (Note 5)	4,800	-
Income taxes receivable	2,215	4,636
Prepaid expenses	399	464
Deferred financing costs (Note 4)	-	706
	42,580	66,614
Long-term investments (Note 5)	18,689	19,395
Property and equipment	278,306	263,056
	$ 339,575	$ 349,065
LIABILITIES		
Current		
Accounts payable and accrued liabilities	$ 10,910	$ 15,850
Income taxes payable	861	913
Bank debt (Note 4)	20,407	52,330
Due to a related company	48	29
	32,226	69,122
Long-term bank debt (Note 4)	40,693	27,464
Asset retirement obligations (Note 6)	9,815	9,552
Future income taxes	10,791	10,801
	93,525	116,939
SHAREHOLDERS' EQUITY		
Share capital and warrants (Note 7(a))	167,156	148,264
Contributed surplus (Note 7(e))	22,769	20,453
Accumulated other comprehensive loss	(5,485)	(3,753)
Retained earnings	61,610	67,162
	246,050	232,126

$ 339,575 $ 349,065

Commitments and guarantees (Note 10)

PETROLIFERA PETROLEUM LIMITED

CONSOLIDATED STATEMENTS OF OPERATIONS AND RETAINED EARNINGS (UNAUDITED)

(UNAUDITED)

Three Months Ended Nine Months Ended
Sept. 30 Sept. 30

$000 (except per
share amounts) 2010 2009 2010 2009

REVENUE
Petroleum and natural gas $15,671 $17,229 $50,138 $65,854
Interest and other income 23 - 258 37

15,694 17,229 50,396 65,891
Royalties (2,221) (2,445) (7,156) (9,362)

13,473 14,784 43,240 56,529

EXPENSES
Operating 5,410 5,763 15,871 17,362
General and administrative 1,909 2,278 5,508 6,370
Finance charges (Note 4) 1,041 1,132 3,133 4,057
Taxes other than income taxes 361 267 1,206 1,631
Foreign exchange loss (gain) 577 (1,102) 1,379 (110)
Depletion, depreciation and
accretion (Note 11) 7,171 17,568 22,712 24,610
Fair value loss (recovery)
(Note 5) - 2,104 (4,800) 2,104
Stock-based compensation
(Note 7(c)) 537 1,561 2,318 3,999

17,006 29,571 47,327 60,023

Loss before income taxes (3,533) (14,787) (4,087) (3,494)

Current income tax provision 320 516 1,266 2,906
Future income tax provision
(recovery) (1,151) (3,944) 199 344
----
(831) (3,428) 1,465 3,250

NET LOSS (2,702) (11,359) (5,552) (6,744)

RETAINED EARNINGS,
BEGINNING OF PERIOD 64,312 82,602 67,162 77,987

RETAINED EARNINGS,
END OF PERIOD $61,610 $71,243 $61,610 $71,243

NET LOSS PER SHARE
(Note 9(a))

Basic and diluted $(0.02) $(0.14) $(0.04) $(0.11)

PETROLIFERA PETROLEUM LIMITED

CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

(UNAUDITED)

Three Months Ended Nine Months Ended
Sept. 30 Sept. 30

($000) 2010 2009 2010 2009

Net loss $(2,702) $(11,359) $(5,552) $(6,744)
Foreign currency
translation adjustment (3,045) (9,173) (1,732) (16,824)

Comprehensive loss $(5,747) $(20,532) $(7,284) $(23,568)

CONSOLIDATED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

(UNAUDITED)

Three Months Ended Nine Months Ended
Sept. 30 Sept. 30

($000) 2010 2009 2010 2009

Accumulated other
comprehensive income
(loss), beginning of
period $(2,440) $8,455 $(3,753) $16,106
Foreign currency
translation adjustment (3,045) (9,173) (1,732) (16,824)

Accumulated other
comprehensive loss,
end of period $(5,485) $(718) $(5,485) $(718)

PETROLIFERA PETROLEUM LIMITED

CONSOLIDATED STATEMENTS OF CASH FLOWS

(UNAUDITED)

Three Months Ended Nine Months Ended
Sept. 30 Sept. 30

($000) 2010 2009 2010 2009

Cash provided by (used in)
the following activities:
OPERATING
Net loss $(2,702) $(11,359) $(5,552) $(6,744)
Items not involving cash:
Depletion, depreciation and
accretion 7,171 17,568 22,712 24,610

Fair value loss (recovery)
(Note 5) - 2,104 (4,800) 2,104
Stock-based compensation
(Note 7(c)) 537 1,561 2,318 3,999
Unrealized foreign exchange
loss (gain) 311 (640) 1,034 1,571
Amortization of deferred
charges (Note 4) 173 213 875 656
Future income tax provision
(recovery) (1,151) (3,944) 199 344

Cash flow from operations
before non-cash working
capital changes 4,339 5,503 16,786 26,540
Changes in non-cash working
capital (Note 9(b)) 4,170 2,859 1,047 14,414

8,509 8,362 17,833 40,954

FINANCING
Issue of common shares or
common share purchase
warrants (Note 7(a)) - 58,768 20,148 58,768
Repayment of bank debt or
long-term bank debt (16,111) (4,973) (16,119) (11,394)
Deferred financing costs
and other (296) (218) (2,078) -
Share issue costs (Note 7(b)) - (3,155) (1,306) (3,155)
Proceeds of bank debt or
long-term bank debt - 924 - 19,896
Changes in non-cash working
capital (Note 9(b)) (1,782) - 54 -

(18,189) 51,346 699 64,115

INVESTING
Exploration and development
of oil and gas properties (7,725) (13,389) (44,763) (59,478)
Proceeds from farmout
agreements (Note 10) 195 - 3,795 -
Proceeds from restricted cash 5 - 2,480 -
Investment in restricted cash - (1,482) (144) (1,188)
Receipt of interest on
long-term investments - 97 - 1,623
Changes in non-cash working
capital (Note 9(b)) (12,142) (2,577) (4,454) (14,839)

(19,667) (17,351) (43,086) (73,882)

INCREASE (DECREASE) IN CASH (29,347) 42,357 (24,554) 31,187
Effect of foreign exchange
on foreign currency
denominated cash balances (355) (1,207) 299 (5,935)
CASH, BEGINNING OF PERIOD 41,179 14,803 35,732 30,701

CASH, END OF PERIOD $11,477 $55,953 $11,477 $55,953

Supplementary cash flow information (Note 9(c))

PETROLIFERA PETROLEUM LIMITED

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

PERIOD ENDED SEPTEMBER 30, 2010

(UNAUDITED)

1. FINANCIAL STATEMENT PRESENTATION

The interim unaudited Consolidated Financial Statements as at and for the three and nine months ended September 30, 2010 include the accounts of Petrolifera Petroleum Limited and its wholly-owned subsidiaries and foreign branches (collectively, "Petrolifera" or the "company") and are presented in accordance with Canadian generally accepted accounting principles in Canadian dollars, unless otherwise noted. Petrolifera is engaged in petroleum and natural gas exploration, development and production activities in South America.

The interim unaudited Consolidated Financial Statements have been prepared following the same accounting policies and methods of computation as the annual audited Consolidated Financial Statements for the year ended December 31, 2009. The disclosures provided below do not conform in all respects to those included with the annual audited Consolidated Financial Statements. The interim unaudited Consolidated Financial Statements should be read in conjunction with the annual audited Consolidated Financial Statements and the notes thereto.

2. NEW ACCOUNTING PRONOUNCEMENTS AND STANDARDS

In December 2008, the CICA issued Section 1582, Business Combinations, which will replace CICA Section 1581 of the same name. Section 1582 establishes principles and requirements of the acquisition method for business combinations and related disclosures. This statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 2011 with earlier application permitted. The company is currently evaluating the impact of adopting this standard to any business combination entered on or after January 1, 2011 on its Consolidated Financial Statements.

In December 2008, the CICA issued Sections 1601, Consolidated Financial Statements, and 1602, Non-Controlling Interests, which replaces existing Section 1600. Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 provides guidance on accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. These standards are effective on or after the beginning of the first annual reporting period beginning on or after January 2011 with earlier application permitted. The company is currently evaluating the impact of adopting Section 1601 and on the accounting of non-controlling interests resulting from any business combinations entered on or after January 1, 2011 on its Consolidated Financial Statements.

3. INVENTORY

As at	Sept. 30, 2010	Dec. 31, 2009
	($000)	
Crude oil	$ 583	$ 958

The company maintains inventory as a consequence of the sales process for crude oil which has been produced and not delivered to customers for periods of up to several days, during which time it must be held in storage at the company's facilities and in transportation pipelines. Crude oil inventory was measured at September 30, 2010 and December 31, 2009 using a weighted average cost basis and is carried at the lower of cost and net realizable value.

4. BANK DEBT

	As at Sept. 30, 2010	Dec. 31, 2009
($000)		
Current bank debt		
Reserve-backed credit facility	$15,447	$52,330
ABCP line-of-credit	4,960	-
	$20,407	$52,330
Long-term bank debt		
Reserve-backed credit facility	$20,081	$-
ABCP line-of-credit	22,496	27,464
Deferred financing costs	(1,884)	-
	$40,693	$27,464
Total bank debt		
Reserve-backed credit facility	$35,528	$52,330
ABCP line-of-credit	27,456	27,464
Deferred financing costs	(1,884)	-
	$61,100	$79,794

In 2007, the company entered into a US$100.0 million reserve-backed credit facility with availability as at September 30, 2010 of US$34.5 million. In August 2010, the company signed a revised reserve-backed credit facility ("Revised Credit Facility") agreement with a syndicate of banks which expires on June 30, 2012. In August 2010, the company made a one-time payment of US$11.7 million prior to signing the Revised Credit Facility agreement and subsequent thereto, made a quarterly permanent debt repayment of US$3.8 million. These payments had the effect of reducing the availability under the facility from US$50.0 million as at December 31, 2009 to US$34.5 million as at September 30, 2010. The company agreed to make scheduled permanent debt repayments of US$3.8 million per quarter through to expiry of the Revised Credit Facility agreement in June 2012, at which time all borrowings under this Revised Credit Facility will be due and payable. Under the terms of the Revised Credit Facility agreement, one-half of any potential farmout proceeds received by the company up to a maximum of US$5.0 million are to be first allocated to reduce the final US$12.0 million permanent debt repayment as due and payable upon expiry of the revised agreement in June 2012. The Revised Credit Facility bears interest at LIBOR plus a margin, is partially secured by the pledge of the shares of Petrolifera's subsidiaries and has a provision for a borrowing base adjustment every six months, with the next adjustment to be calculated based on information as at June 30, 2010.

As at September 30, 2010, the outstanding Revised Credit Facility was $35.5 million (US$34.5 million) less approximately $1.9 million in deferred financing costs, which were recognized on the Revised Credit Facility agreement and are being amortized through to expiry of the facility in June 2012. As the terms of the Revised Credit Facility agreement were substantially changed, $0.7 million of deferred financing costs related to the previous agreement were fully amortized during the six months ended June 30, 2010. Total deferred financing costs amortization is $0.2 million and $0.9 million for the three and nine months ended September 30, 2010, respectively (2009 - $0.2 million and $0.7 million, respectively).

During 2009, the company negotiated with a Canadian chartered bank an expansion of its line-of-credit to a maximum of $23.2 million, with an initial expiry in April 2012 where the company can make up to four extension requests with each extension representing an additional one-year period. The line-of-credit as primarily secured by the eligible master asset vehicles Classes A1 through C as received by the company in exchange for a portion of the long term notes formerly known as Asset Backed Commercial Paper ("ABCP") bears interest at a floating rate. The company has classified the $22.5 million in borrowings as at September 30, 2010 and December 31, 2009 made under this facility as long-term bank debt.

The company has a second line-of-credit agreement with the same Canadian chartered bank previously mentioned to a maximum of $5.0 million which was fully drawn as at September 30, 2010 and December 31, 2009. This second line-of-credit, which has an initial expiry in April 2011, is solely secured by the ineligible master asset vehicle Classes 1 & 2 ("MAV IA 1 & 2") notes received by the company in 2009 in exchange for a portion of the ABCP (where the combined lines-of-credit facilities availability was $28.2 million as at September 30, 2010 and December 31, 2009 (the "ABCP line-of-credit")). During the second quarter of 2010, the company advised its lender it would not renew this facility beyond its expiry date of April 2011, at which time it will exercise its option to deliver to the lender the MAV IA 1 & 2 notes, which at the time of acquisition in 2007 had a face value of $6.6 million but through subsequent impairment provisions had no carrying value in the company's accounts as at December 31, 2009. As the company has the option to settle its $5.0 million in borrowings as drawn on this ABCP line-of-credit agreement through delivery to its lender of the MAV IA 1 & 2 notes, the company advised its lender that it intends to settle such borrowings with the MAV IA 1 & 2 notes and accordingly, the company has classified the $5.0 million in borrowings as at September 30, 2010 made under this facility as a current liability (December 31, 2009 - $5.0 million was classified as long-term bank debt).

Interest expense on the facilities for the three and nine months ended September 30, 2010 was $0.9 million and $2.1 million, respectively (2009 - $0.9 million and $3.4 million, respectively). These amounts were disclosed on the interim unaudited Consolidated Statements of Operations and Retained Earnings as finance charges which also include the amortization of deferred finance charges, debt facilities administration fees and vendor interest charges. The combined effective interest rate on the company's facilities was 4.6 and 3.6 percent for the three and nine months ended September 30, 2010, respectively (2009 - 3.0 percent and 4.4 percent, respectively). The unused credit on the ABCP line-of-credit facilities as primarily secured by the ABCP was $0.7 million as at September 30, 2010 and December 31, 2009.

5. FINANCIAL INSTRUMENTS

Capital management

The company is subject to external restrictions on its Revised Credit Facility. As at December 31, 2009 the previous facility had an overall limit of US$100.0 million, with an established availability of US$50.0 million. During August 2010, the company agreed to the terms of a Revised Credit Facility agreement, which included a reduced availability of US $34.5 million, based on producing crude oil and natural gas reserves as at December 31, 2009. The company repaid US$11.7 million against its reserve-backed credit facility at the signing of the Revised Credit Facility agreement and subsequent thereto, made a quarterly permanent debt repayment of US$3.8 million thereby reducing the total draws against this facility to the revised availability of US$34.5 million. The Revised Credit Facility has a provision for a borrowing base adjustment every six months, with the next adjustment to be calculated based on information as at June 30, 2010. The company's financial covenants include a debt-to-EBITDA ratio where outstanding bank debt and long-term debt, as defined by the terms of the Revised Credit Facility to exclude amounts primarily secured by the long term notes formerly known as ABCP, cannot exceed two and a half times ("2.5X") the 12 month trailing EBITDA in addition to a minimum working capital ratio of 1.25 : 1.00. EBITDA is defined by the Revised Credit Facility agreement as net loss prior to deduction of interest, income taxes, depletion, depreciation and accretion expense, stock-based compensation, unrealized foreign exchange losses (gains) and any other non-cash expenses and is reconciled to the net loss as follows:

($000)	Three Months Ended Dec. 31, 2009	Three Months Ended Mar. 31, 2010	Three Months Ended June 30, 2010	Three Months Ended Sept. 30, 2010	12 Months Ended Sept. 30, 2010
Net loss	$(4,081)	$(2,553)	$(297)	$(2,702)	$(9,633)
Add (deduct) interest, income taxes, depletion, depreciation and accretion expense and other non-cash expenses:					
Depletion, depreciation and accretion	8,936	8,087	7,454	7,171	31,648
Fair value of option on debt agreement	-	-	(4,800)	-	(4,800)
Finance charges	1,040	1,060	1,032	1,041	4,173
Stock-based compensation	675	677	1,104	537	2,993
Income tax provision (recovery)	724	542	1,754	(831)	2,189
Unrealized foreign exchange loss (gain)	(143)	618	105	311	891
EBITDA	$7,151	$8,431	$6,352	$5,527	$27,461

As at September 30, 2010, outstanding draws on portions of bank debt and long-term bank debt were $44.1 million and EBITDA was $27.5 million, for a debt-to-EBITDA financial covenant ratio of 1.6 : 1.0, which is in compliance with the 2.5X imposed limit.

Fair values of financial instruments

Financial instruments are recognized initially at fair value on the balance sheet and include cash, accounts receivable, restricted cash, debt agreement option, long-term investments, accounts payable and accrued liabilities, bank debt, due to a related company and long-term bank debt. The company has classified all of its financial instruments as held for trading, with the exception of the bank debt and long-term bank debt, which are classified as other liabilities. Held for trading instruments continue to be measured at fair value, while other liabilities are subsequently measured at amortized cost.

The fair value measurement of each of the company's significant held for trading financial assets is summarized in the following fair value hierarchy table that reflects the lowest level input of significance as used in the measurement as the basis of the assigned level:

($000)	Per Balance Sheet	Fair Value Hierarchy Level 1	Fair Value Hierarchy Level 2	Fair Value Hierarchy Level 3
Held for trading financial assets:				

Cash $11,477 $11,477 $- $-
Accounts receivable 21,570 - 21,570 -
Restricted cash 1,536 - 1,536 -
Debt agreement option 4,800 - - 4,800
Long-term investments 18,689 - - 18,689

Total held for trading
financial assets $58,072 $11,477 $23,106 $23,489

As no active market exists for the company's accounts receivable and restricted cash, these financial assets have been classified as Level 2. As at September 30, 2010, long-term investments is comprised of notes received in exchange for ABCP with a face value of $30.9 million (Dec. 31, 2009 - $34.6 million) and a carrying value of $18.7 million (Dec. 31, 2009 - $18.7 million). As at September 30, 2010, the debt agreement option represents the company's option to settle $5.0 million in borrowings solely through the delivery of its MAV IA 1 & 2 notes. The fair and face values for the Level 3 financial assets is explained below.

During the nine months ended September 30, 2010, the company advised its lender that upon the expiry of the $5.0 million ABCP line-of credit agreement, the company will deliver to the lender the MAV IA 1 & 2 notes that were issued to the company in 2009 in replacement for a portion of its investment in ABCP. The lender's recourse on the company's borrowings of $5.0 million is solely limited to the MAV IA 1 & 2 notes. As the company has the option to settle its $5.0 million in borrowings solely through delivery to its lender of the MAV IA 1 & 2 notes and has advised its lender during the nine months ended September 30, 2010 that it will settle the $5.0 million in borrowings through delivery of the MAV IA 1 & 2 notes, the company has recognized the fair value of the debt agreement option of $4.8 million as at September 30, 2010 using a probabilistic valuation model.

In January 2009, the Pan-Canadian Investors Committee for Third-Party Structured ABCP announced that the Superior Court of Ontario granted the Plan Implementation Order and that, accordingly, the plan for restructuring ABCP had been fully implemented. In exchange for the shorter-term ABCP, the company has now received the longer term notes with maturities that generally approximate those of the assets previously contained in the underlying conduits.

During the third quarter of 2010, the company was advised the ineligible master asset vehicle asset tracking Class 1 ("MAV IA 1") notes, with total pledged market collateral of $500.0 million, incurred several credit events within its market portfolio resulting in losses greater than the pledged market collateral. The company had an investment in the MAV IA 1 notes with an original face value of $3.7 million and a carrying value as at December 31, 2009 of nil. The company has removed the MAV IA 1 notes from its reported portfolio of longer-term notes previously known as ABCP, thereby reducing the outstanding principal amount of its portfolio by $3.7 million for the three and nine months ended September 30, 2010.

For the three and nine months ended September 30, 2009, the company reported a $2.1 million fair value impairment on its MAV IA 1 and ineligible master asset vehicle asset tracking Class 2 ("MAV IA 2") notes, which when combined forms the MAV IA 1 & 2 notes as previously defined, thereby reducing the September 30, 2009 carrying value of its MAV IA 1 & 2 notes to nil. The recognition of the fair value impairment for the three and nine months ended September 30, 2009 was accompanied by the removal of the original face value of the MAV IA 2 notes of $2.9 million from the company's reported portfolio of longer-term notes previously known as ABCP.

Despite the permanent impairment in the MAV IA 1 & 2 notes as at September 30, 2010, the company still retains the right to exercise its debt agreement option in April 2011 to settle $5.0 million in borrowings solely through the delivery of its MAV IA 1 & 2 notes.

Although there have been some isolated third party transactions during the nine months ended September 30, 2010, no active market quotations have developed for the eligible master asset vehicle longer term notes. As a result, management has estimated the fair value of the company's investment in the eligible master asset vehicle longer term notes at September 30, 2010, based on a probabilistic recovery of principal and interest, after taking into account all available information. Under this valuation method, several different outcomes of the recovery of the principal and interest are estimated, considering the information available as at September 30, 2010. A weighted average recovery is then calculated. This weighted average recovery is used to determine the discounted cash flows that are expected from these investments. The discount rate used to discount the expected cash flows from the eligible master asset vehicle longer term notes approximates the risk-free rate over the expected life of the eligible master asset vehicle longer term notes. As the rate used for discounting was an approximation of the risk-free rate, all other risks have been incorporated in the estimated probability-adjusted expected outcomes. This methodology applied all risking information into the various scenarios and discounted the fully-risked cash flow stream only for the time value of money. The recovery factors used were as follows:

Face Risk- Risk-
Value adjusted adjusted Capital Interest
Class of Capital Interest Weighted Weighted Risk-free
of Notes Recovery Recovery Average Average Term Discount
Note ($000s) Range Range Recovery Recovery (yrs) Rate

A-1 $13,978 0 - 80% 0 - 60% 75% 54% 3 - 7 3%
A-2 13,543 0 - 70% 0 - 30% 64% 27% 7 3%
B 2,459 0 - 30% 0% 27% 0% 7 3%
C 928 0% 0% 0% 0% 7 3%

Total $30,908

Based on the above approach the fair value of the investment in the eligible master asset vehicle longer term notes was $18.7 million as at September 30, 2010 and December 31, 2009. Since 2007, the total recognized impairment on the eligible and ineligible master asset vehicle longer term notes is approximately 46 percent of the original cost of the investment, including impairments recognized on the ABCP.

The theoretical fair value of the company's eligible master asset vehicle longer-term notes could range from $14.0 million to $25.0 million, using the valuation methodology described above, with reasonably possible alternative assumptions. The outcome of the actual timing and amount ultimately recoverable from these notes may differ materially from this estimate, which would impact the company's losses.

Credit risk

The company's maximum credit exposure on cash, accounts receivable, restricted cash, debt agreement option and long-term investments is equal to each financial asset's carrying value as at September 30, 2010.

Cash, restricted cash and the debt agreement option are held with highly rated international banks and therefore the company considers these assets to have negligible credit risk.

The company's accounts receivable are primarily with multinational purchasers, oil and gas marketers and local government agencies. The credit risk from joint venturers is considered to be low as generally the company requires that funding from joint venture partners is received prior to the company incurring the related work commitment expenditure. The company's production base is entirely located in Argentina and is heavily weighted to crude oil. The company has a concentration of credit risk as it sold US$13.0 million and US$41.1 million of crude oil production to one multinational purchaser and US$1.0 million and US$2.6 million in natural gas production to a reputable local gas marketing company during the three and nine months ended September 30, 2010, respectively. Receivables with local government agencies mainly pertain to excise taxes paid on certain expenditures. The company has not experienced any collection problems with its counterparties and does not currently have any overdue amounts. The company does not have an allowance for doubtful accounts and did not write off any receivables during the three and nine months ended September 30, 2010.

Refer to the fair values of financial instruments contained herein for further discussion regarding the credit risk of the longer term notes formerly known as ABCP as recognized as at September 30, 2010 on the Consolidated Balance Sheet as long-term investments.

Liquidity risk

The company manages the risk of not meeting its financial obligations through management of its capital structure, annual budgeting of its revenues, expenditures and cash flows, cash flow forecasting and maintaining an unused credit facility where practicable.

Accounts payable, as disclosed on the Consolidated Balance Sheet, fall due within the next year and are anticipated to be funded through the company's cash and collections of accounts receivable.

During August 2010, the company agreed to the terms of a revised reserve-backed credit facility resulting in a reduction in the facility's availability from US$50.0 million to the current available limit of US$34.5 million, all of which is drawn at September 30, 2010. The company also agreed to the following quarterly permanent debt repayments through to expiry of the agreement in June 2012 at which time all borrowings under this credit facility will be due and payable:

As at	(US$000)
December 31, 2010	3,750
March 31, 2011	3,750
June 30, 2011	3,750
September 30, 2011	3,750
December 31, 2011	3,750
March 31, 2012	3,750
June 30, 2012	$12,000

The quarterly repayments hereafter are anticipated to be funded from existing cash balances, cash flow from operations and proceeds, if any, from farmout agreements.

The company holds a combined ABCP line-of-credit availability of $28.2 million, of which $27.5 million is drawn at September 30, 2010. Of the $27.5 million drawn against the ABCP line-of-credit facilities, $5.0 million expires in April 2011 as solely secured by the MAV IA 1 & 2 notes and $22.5 million expires in April 2012 as primarily secured on a recourse basis by the eligible master asset vehicles Classes A1 through C notes received in exchange for the ABCP.

Market risk

Changes in commodity prices, interest rates and foreign currency exchange rates can expose the company to fluctuations in its net loss and in the fair value of its financial assets and liabilities.

Commodity price risk

Price fluctuations for crude oil, natural gas liquids and natural gas are a risk to the company over which it has little influence. Due to pricing controls present in Argentina and a domestic crude oil sales agreement with a multinational purchaser, crude oil selling prices reflect both current market conditions in Argentina and the movement of crude oil prices in international markets. Natural gas prices are impacted by the Argentine government and local demand with historic prices at low levels compared to world prices.

Interest rate risk

Floating rate debt exposes the company to fluctuations in cash flows and net losses due to changes in market interest rates. Based on the existing debt balance, a one percent increase (decrease) in the underlying market interest rates would have increased (decreased) the net loss by approximately $0.6 million on an annual basis.

Foreign currency exchange rate risk

Substantially all of the company's operations are conducted in foreign jurisdictions, so the company is exposed to foreign currency exchange rate risk on most of its activities as reported in Canadian dollars ("CAD"). Oil and natural gas sales contracts are denominated in US dollars ("USD") and settled in Argentine pesos ("ARS"). Operating and capital expenditures are incurred in USD, ARS and Colombian pesos ("COP"), and to a lesser extent in Peruvian nuevos soles ("PEN"). The revised reserve-backed credit facility is denominated in USD, which partially limits the company's foreign currency exposure as cash outflows (interest expense) are of the same denomination to cash inflows (oil and gas revenues). The table below details the company's financial instruments exposure to foreign currencies:

As at Sept. 30, 2010

($000)	Per Balance Sheet	CAD	USD	ARS	PEN	COP
		CAD equivalent amounts				
Cash	$11,477	$3,426	$5,423	$1,807	$9	$812
Accounts receivable	21,570	32	7,186	4,891	1,302	8,159
Restricted cash	1,536	-	1,536	-	-	-
Debt agreement option	4,800	4,800	-	-	-	-
Long-term investments	18,689	18,689	-	-	-	-
Accounts payable and accrued liabilities	(10,910)	(567)	(2,900)	(5,476)	(12)	(1,955)
Bank debt	(20,407)	(4,960)	(15,447)	-	-	-
Long-term bank debt	(40,693)	(22,496)	(18,197)	-	-	-
Net financial assets (liabilities)	$(13,938)	$(1,076)	$(22,399)	$1,222	$1,299	$7,016

The company estimates a 20 percent change in the CAD against the above listed foreign currencies could be reasonably possible over a twelve month period. A 20 percent strengthening in the CAD would result in a change to loss before taxes and other comprehensive loss as follows (an equal but opposite impact to loss before taxes and other comprehensive loss would result if the CAD weakened by 20 percent):

USD ARS PEN COP

($000) CAD equivalent amounts

Increase in loss before taxes $(702) $- $(217) $(1,169)
Decrease in other comprehensive loss $4,232 $- $- $-
----

6. ASSET RETIREMENT OBLIGATIONS

At September 30, 2010 the estimated total undiscounted amount required to settle the asset retirement obligations was $17.0 million (2009 - $17.3 million). These obligations are expected to be settled over the useful lives of the underlying assets, which currently extend up to 18 years into the future. This amount has been discounted using a credit-adjusted risk-free interest rate of six percent and an annual inflation rate of two percent. Changes to asset retirement obligations were as follows:

Nine Months Ended Sept. 30 2010

($000)

Asset retirement obligations, beginning of period $9,552
Liabilities incurred 21
Change in estimate (22)
Cumulative translation adjustment (154)
Accretion expense 418

Asset retirement obligations, end of period $9,815
----

7. SHARE CAPITAL, WARRANTS AND CONTRIBUTED SURPLUS

(a) Authorized:

The authorized capital is comprised of an unlimited number of common shares and 33,239,600 warrants, respectively.

Issued common shares:

Number of Amount
Nine Months Ended Sept. 30, 2010 Common Shares ($000)

Common shares, beginning of period 121,758,510 $143,610
Issuance of common shares through
public offering (b) 23,678,500 20,127
Issued common shares upon exercise
of options (c) 40,000 20
Issued common shares upon exercise
of warrants (d) 650 1
Assigned value of options exercised (e) - 2
Issue costs net of tax-effect (b) (1,258)

Common shares, end of period 145,477,660 $162,502

Issued warrants:

Number of Amount
Nine Months Ended Sept. 30, 2010 Warrants ($000)

Warrants, beginning of period 33,240,250 $4,654
Exercised warrants (d) (650) -

Warrants, end of period 33,239,600 $4,654

Share capital and warrants:

Sept. 30, Dec. 31,
As at 2010 2009

($000)

Share capital and warrants $167,156 $148,264

(b) Equity Financing:

In March 2010, the company announced that it entered into an underwriting agreement with a syndicate of underwriters to issue 20,590,000 common shares at a price of $0.85 per common share on a "bought deal" basis for gross proceeds of approximately $17.5 million ("Public Offering"). The underwriters were granted an over-allotment option (the "Over-Allotment Option"), which included the right to purchase up to an additional 15 percent of the common shares, exercisable in whole or in part up to 30 days following closing of the Public Offering. The Over-Allotment Option was exercised in whole by the underwriters on April 14, 2010, the closing date of the Public Offering and resulted in a total issuance of 23,678,500 common shares, raising gross proceeds to approximately $20.1 million. Issue costs of $1.3 million were incurred with respect to the equity financing.

(c) Stock Options:

As at September 30, 2010 and 2009, the company had outstanding stock options to acquire common shares, as follows:

Nine Months Ended Sept. 30 2010 2009

Weighted Weighted
Average Average
Number of Exercise Number of Exercise
Options Price Options Price

Outstanding,
beginning of
period 7,683,067 $1.60 4,576,327 $6.85
Granted 2,229,454 0.91 5,280,900 1.31
Exercised (40,000) (0.50) (330,000) (0.80)
Forfeited or
cancelled (391,000) (3.10) (1,891,160) (13.14)
Expired (427,667) (1.00) - -

Outstanding,
end of period 9,053,854 $1.40 7,636,067 $1.72

Exercisable,
end of period 5,157,421 $1.42 3,101,467 $1.86

Options granted under the plan are generally fully exercisable after two

or three years and expire five years after the date granted. The table
below summarizes outstanding stock options and the weighted average
remaining contractual life, in years, by ranges of exercise prices as at
September 30, 2010 and 2009:

As at Sept. 30 2010 2009

Weighted Weighted
Average Average
Remaining Remaining
Number Contractual Number Contractual
Outstanding Life (yrs) Outstanding Life (yrs)

$0.50 - - 40,000 0.3
$0.86 - $1.09 6,520,354 4.2 4,764,567 4.6
$1.70 - $1.75 313,000 0.1 368,000 1.1
$2.00 932,000 3.1 1,007,000 4.1
$2.64 - $3.37 1,209,000 3.5 1,209,000 4.5
$5.40 - $19.20 79,500 2.2 247,500 2.0

Total 9,053,854 3.8 7,636,067 4.2

During the three and nine months ended September 30, 2010, a non-cash
expense of $0.5 million and $2.3 million, respectively, (2009 -
$1.6 million and $2.9 million) was recorded as stock-based compensation,
reflecting the amortization of the fair value of stock options over the
vesting period. Additionally, during the nine months ended September 30,
2009, certain employees, officers and non-managerial directors of the
company voluntarily surrendered 1,786,660 options with a weighted average
exercise price of $13.79 per option. Any unvested options that were
voluntarily surrendered were deemed to have become vested, resulting in
the recognition of an additional non-cash stock-based compensation
expense for the nine months ended September 30, 2009 of $1.1 million.

The fair value of each option granted for 2010 is estimated on the date
of grant using the Black-Scholes option-pricing model with assumptions
for grants as follows:

Dividend Risk-free Expected Expected
yield interest rate life volatility

2010 -% 2.0% to 2.8% 4 years 81% to 82%
2009 -% 2.0% to 2.7% 4 years 89% to 90%

The weighted average fair value at the date of grant of all options
granted for the nine months ended September 30, 2010 was $0.56 per option
(for the three and nine months ended September 30, 2009 - $0.65 and $0.84
per option, respectively).

(d) Warrants:

Each warrant entitles the holder thereof to purchase one common share at
an exercise price of $1.20 per warrant until August 28, 2011. At the time
of issuance, the weighted average fair value of all issued warrants was
$0.14 per warrant.

(e) Contributed Surplus:

Nine Months Ended Sept. 30 2010

($000)

Contributed surplus, beginning of period $20,453
Stock-based compensation (c) 2,318
Assigned value of options exercised (2)

Contributed surplus, end of period $22,769
----

8. SEGMENTED INFORMATION

The company has corporate offices in Canada, the US and Barbados (combined to comprise the "Corporate" segment), petroleum and natural gas operations in Argentina and exploration activities in Peru and Colombia. Financial information pertaining to these segments is presented below.

Corporate Argentina Peru Colombia Total

($000)

Three months ended
Sept. 30, 2010

Revenue, gross $- $15,680 $- $14 $15,694
Net loss (2,030) (637) (8) (27) (2,702)
Property and equipment 73 137,339 57,446 83,448 278,306
Capital expenditures 60 2,433 534 4,698 7,725
Total assets $29,264 $159,113 $58,778 $92,420 $339,575

Three months ended
Sept. 30, 2009

Revenue, gross $- $17,229 $- $- $17,229
Net loss (4,738) (6,488) (110) (23) (11,359)
Property and equipment 302 164,521 55,655 44,820 265,298
Capital expenditures 14 4,863 309 8,203 13,389
Total assets $63,227 $190,488 $60,314 $54,259 $368,288

Nine months ended
Sept. 30, 2010

Revenue, gross $3 $50,286 $- $107 $50,396
Net earnings (loss) (1,240) (4,318) (28) 34 (5,552)
Property and equipment 73 137,339 57,446 83,448 278,306
Capital expenditures 72 6,635 1,293 36,763 44,763
Total assets $29,264 $159,113 $58,778 $92,420 $339,575

Nine months ended
Sept. 30, 2009

Revenue, gross $9 $65,860 $22 $- $65,891
Net earnings (loss) (10,564) 3,877 (13) (44) (6,744)
Property and equipment 302 164,521 55,655 44,820 265,298
Capital expenditures 34 19,989 6,977 32,478 59,478
Total assets $63,227 $190,488 $60,314 $54,259 $368,288

Crude oil sales totaling US$13.0 million and US$41.1 million (2009 - US $14.6 million and US$51.9 million) were made to a large international oil company and natural gas sales totaling US$1.0 million and US$2.6 million (2009 - US$1.0 million and US$3.8 million) were made to a local gas marketing company during the three and nine months ended September 30, 2010, respectively.

9. SUPPLEMENTARY INFORMATION

(a) Per share amounts

The following table summarizes the calculation of basic and diluted common shares:

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2010	2009	2010	2009
Weighted average common shares outstanding - basic	145,477,660	82,417,689	136,453,825	64,205,191
Dilutive effect of stock options and share purchase warrants	-	121,139	1,432	1,414,008
Weighted average common shares outstanding - diluted	145,477,660	82,538,828	136,455,257	65,619,199

As the company has net losses for the nine months ended September 30, 2010 and the three and nine months ended September 30, 2009, the dilutive effect of stock options and share purchase warrants became anti-dilutive, resulting in the exclusion of the dilutive effect of stock options and share purchase warrants on the diluted net loss per common share calculation.

(b) Net change in non-cash working capital

	Three months ended Sept. 30		Nine months ended Sept. 30	
($000)	2010	2009	2010	2009
Accounts receivable	$(154)	$5,259	$(986)	$17,588
Inventory	33	10	224	(13)
Income taxes receivable	1,900	(332)	2,369	(640)
Prepaid expenses	261	284	64	211
Accounts payable and accrued liabilities	(11,827)	(5,184)	(4,997)	(17,112)
Income taxes payable	13	272	(46)	(465)
Due to a related company	20	(27)	19	6
	$(9,754)	$282	$(3,353)	$(425)
Operating	$4,170	$2,859	$1,047	$14,414
Financing	(1,782)	-	54	-
Investing	(12,142)	(2,577)	(4,454)	(14,839)
	$(9,754)	$282	$(3,353)	$(425)

(c) Supplementary cash flow information

	Three months ended Sept. 30		Nine months ended Sept. 30	
($000)	2010	2009	2010	2009
Interest paid	$826	$886	$2,062	$3,341
Income taxes paid	$-	$748	$1,943	$3,051

10. COMMITMENTS AND GUARANTEES

Work commitments

The Peruvian licenses have negotiated work programs through 2016, unless extended. Each work program has a specified minimum financial commitment that must be met for the company to maintain its rights to these licenses. Specifically, the immediate minimum work commitments of US$0.3 million for Block 133 are primarily comprised of geological field studies and as such are not capital intensive. The company has met, or surpassed, all of its current work commitments for Blocks 106 and 107 in a timely manner. The company has received approval of its Block 107 Environmental Impact Assessment ("EIA") for several potential drilling sites and is awaiting approval of its recently filed EIA amendment, at which time it can commence with the fourth period's work commitment requiring one well to be completed by 2013. The company has the right to withdraw from the licenses at the end of each period associated with the term of the licenses.

In 2007, the company was granted three Colombian concessions comprised of one license, Sierra Nevada, and two Technical Evaluation Assessments ("TEAs"). Petrolifera converted the Turpial and Sierra Nevada II TEAs into exploration licenses with the latter renamed Magdalena. The company has completed the second phase of its Sierra Nevada License work program, which required the drilling of one exploratory well and acquiring additional seismic, with the completion of this phase still to be acknowledged by the Colombian authority, Agencia Nacional de Hidrocarburos ("ANH"). The company completed drilling the Sierra Nevada License's second phase exploratory well, Brillante SE-1X, during March 2010, to a total depth of 9,500 feet. During the second quarter of 2010, the company completed a 3D seismic program over the La Pinta structure which, when combined with the Brillante SE-1X exploratory well, is anticipated to complete the Sierra Nevada's second phase work program. The company has notified the ANH that it will commence with phase 3 of the Sierra Nevada License work program, which requires the drilling of one exploration well and a modest seismic program prior to June 2011. Whilst still to be acknowledged by ANH, the company recently completed the second phase 2D seismic acquisition and interpretation work program on its Turpial License. This was disproportionately financed by the company's joint venturer. The company is in the first phase of its Magdalena License, which requires an exploration well to be completed prior to December 2010. The company anticipates the drilling of an exploratory well on its San Angel prospect during the fourth quarter of 2010 to meet this requirement.

In Argentina, the company has farmed out its Vaca Mahuida and Puesto Guevara Concessions work commitments of US$2.9 million and US$0.6 million, respectively, through agreements reached in the first quarter of 2010. At Vaca Mahuida, a total of five exploratory wells have been drilled by the company, financed by the company's joint venturers. The Vaca Mahuida farmout agreement also provided for the reimbursement to the company of $3.8 million for the costs of drilled wells during the nine months ended September 30, 2010. The company's working interest in the Vaca Mahuida Concession will reduce to 25 percent upon acknowledgement by the Province of Rio Negro, Argentina, that the existing work commitment has been met. Once the company's joint venturer has funded the work commitment for the Puesto Guevara Concession, the company's working interests will be reduced to 44 percent in this Concession. The company has no net remaining work commitments in Argentina given its Vaca Mahuida Concession's work commitment is anticipated to have been met and its Puesto Guevara Concession's work commitment is to be solely funded by its joint venturer.

Contractual commitments

The company's gross contractual commitments under service contracts for drilling, leases for office premises and other equipment and an

administrative services agreement for the remaining three months ended
December 31, 2010 and annually thereafter are as follows:

($000)	2010	2011	Subsequent to 2011	Total
Drilling service contract and other leases	$3,524	$774	$238	$4,536

Guarantees

As at September 30, 2010 the company has issued letters of credit in the total amount of US$1.4 million and US$0.1 million, respectively, to secure the capital expenditure requirements associated with the Colombian and Peruvian work commitments (Dec. 31, 2009 - US$2.1 million and US$1.7 million, respectively). As at September 30, 2010, a deposit of US$0.2 million (Dec. 31, 2009 - US$4.1 million) is held in a trust account in Colombia to meet certain work obligations on the Magdalena License as they occur.

11. COMPARATIVE INFORMATION

The company announced on March 2, 2009 that its Board of Directors had authorized the company to initiate a process to dispose of its Argentinean interests. During early July 2009, several bids for the company's Argentinean interests were received from third parties and, after careful consideration, on July 15, 2009 the company announced that the process to dispose of its interests did not result in any acceptable bids. This resulted in the company's Argentinean interests being reported within the unaudited Consolidated Financial Statements from the beginning of each period for the three and nine months ended September 30, 2009 as though the operations were part of continuing operations, resulting in the recognition of depletion and depreciation expense, as disclosed on the Consolidated Statement of Operations and Retained Earnings as depletion, depreciation and accretion ("DD&A") expense, from March 2, 2009, the date that management had initially ceased recognition. Accordingly, the comparative information within these unaudited Consolidated Financial Statements for the three months ended September 30, 2009 includes the Argentinean interest's depletion and depreciation expense, as included in DD&A expense, for the period March 2, 2009 to June 30, 2009.

For further information:

Petrolifera Petroleum Limited, R. A. Gusella, Executive Chairman, (403) 538-6201; Or Gary D. Wine, President and Chief Operating Officer, (403) 539-8450; Or Kristen J. Bibby, Vice President Finance and Chief Financial Officer, (403) 539-8450, Inquiries@petrolifera.ca, www.petrolifera.ca