

Management's Discussion and Analysis

Petro Uno Resources Ltd. ("Petro Uno" or the "Company") is a public company engaged in the exploration for, and the development and production of, petroleum and natural gas in Western Canada, and has a fiscal year end of December 31.

This Management's Discussion and Analysis ("MD&A") is a review of Petro Uno's performance during the period covered by the financial statements, and of Petro Uno's financial condition and future prospects. This MD&A should be read in conjunction with the audited, financial statements of the Company for the year ended December 31, 2009 and 2008 with the notes related thereto. The consolidated financial statements for the year ended December 31, 2009 and December 31, 2008 have been prepared in accordance with generally accepted accounting principles ("GAAP") in Canada. Petro Uno's Board of Directors has reviewed and approved the consolidated financial statements and MD&A. This MD&A is effective April 26, 2010.

Additional information on the financial statements, this MD&A and other factors that could affect the company's operations and financial results are included in reports, on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com).

READER ADVISORIES

Forward Looking Statements

In the interest of providing Petro Uno shareholders and potential investors with information regarding the Company, including management's assessment of Petro Uno's future plans and operation, certain statements contained in this MD&A constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of the "safe harbor" provisions of applicable securities legislation. Forward-looking statements are typically identified by words such as "anticipate", "believe", "plan", "intend", "forecast", "target", "project" or similar words suggesting future outcomes or statements regarding an outlook.

Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statement will not occur, which may cause Petro Uno's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements.

These risks and uncertainties include, among other things: volatility of and assumptions regarding oil and gas prices; fluctuations in currency and interest rates; product supply and demand; market competitions; risks inherent in Petro Uno's marketing operations, including credit risks; imprecision of reserve estimates and estimates of recoverable quantities of oil, natural gas and liquids; Petro Uno's ability to replace and expand oil and gas reserves; risks associated with technology; its ability to generate sufficient cash from operations to meet its current and future obligations; Petro Uno's ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; Petro Uno's ability to secure adequate product transportation; changes in environmental and other regulations or the interpretations of such regulations; political and economic conditions; terrorist threats; risks associated with potential future lawsuits and regulatory actions made against Petro Uno; Petro Uno's ability to utilize all of its tax pools and investment tax credits; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by Petro Uno.

Statements relating to “reserves” are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. Although Petro Uno believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this MD&A are made as of the date of this MD&A, and Petro Uno does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement.

Non-GAAP Measures

This MD&A uses the terms “funds flow from operations”, “netbacks” and “net debt”, which are terms not recognized under GAAP. The Company uses these measures to help evaluate its performance, leverage, and liquidity as well as to assess potential acquisitions.

The Company considers funds flow from operations as a key performance measure as it demonstrates the Company’s ability to generate funds necessary to repay debt and to fund future growth through capital investment. Funds flow from operations and funds flow from operations per share should not be considered as an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with Canadian GAAP as an indicator of Petro Uno’s performance. Petro Uno’s determination of funds flow from operations may not be comparable to that reported by other companies. The reconciliation between net earnings and funds flow from operations can be found in the statement of cash flows in the financial statements. Petro Uno also presents funds flow from operations per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of net earnings per share, which per share amount is calculated under GAAP and is more fully described in the notes to the financial statements.

The Company considers corporate netbacks as a key measure as it demonstrates its profitability relative to current commodity prices. Corporate netbacks are comprised of operating, funds from operations and net earnings netbacks. Operating netback is calculated as the average sales price of its commodities (excluding financial instrument gains and losses) and then subtracts royalties, transportation costs and operating expenses. Funds flow netback starts with the operating netback and further deducts general and administrative costs, interest expense and adds interest income. To calculate the net earnings netback, Petro Uno takes the funds flow netback and deducts unrealized gains/losses on hedges, stock-based compensation expense, depletion, depreciation and amortization charges and future income taxes. There is no GAAP measure that is reasonably comparable to netbacks. See the section below entitled “Operating Netbacks by Product” for calculations of operating netbacks for each commodity type.

Net debt and working capital deficiency, which terms represent current assets less current liabilities and bank debt is used to assess efficiency, liquidity and the general financial strength of the company. Mark-to-market financial contracts are excluded from the net debt calculation. There is no GAAP measure that is reasonably comparable to net debt and working capital.

The Company reconciles funds flow from operations to cash flow from operating activities, which is the most directly comparable measure calculated in accordance with GAAP as follows:

	2009	2008
Cash inflow (outflow) provided by operating activities	\$ (462,161)	\$ 188,595
Change in non-cash working capital	231,236	(338,402)
Funds flow from operations	\$ (230,925)	\$ (149,807)

Barrel of Oil Equivalent

Where amounts are expressed in a barrel of oil equivalent ("boe"), or barrel of oil equivalent per day ("boe/d"), natural gas volumes have been converted to barrels of oil equivalent at 6 thousand cubic feet ("mcf") to one barrel. Use of the term boe may be misleading particularly if used in isolation. The boe conversion ratio of 6 mcf to 1 barrel ("bbl") of oil or natural gas liquids is based on an energy equivalency conversion methodology primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion conforms to the Canadian Securities Regulators' National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities.

Business Strategy

The Company operates in two geographical areas – West Central Alberta and West Central Saskatchewan. Its main core producing and development assets are located near Red Earth, Alberta and Kindersley, Saskatchewan. Petro Uno's goal for its shareholders is to create repeatable production and reserve growth per share. This growth occurs mainly through development drilling on its ever-expanding Saskatchewan land base, but also through strategic acquisitions of either producing assets or corporate entities. The Company's growth strategy is highly dependent on its ability to bring behind-pipe volumes into production in a timely manner. Petro Uno has been very successful in keeping the elapsed time between when the well is completed to when it commences producing to a minimum. The Company therefore converts its capital spent into cash flow in an expeditious manner.

Company Overview

During the third quarter of 2009, the Company took a strategic shift in direction when the management team was augmented with experience in an emerging Viking oil resource play in the Kindersley area of West Central Saskatchewan. Currently, the Company's main business focus is to build a large development land base of opportunities on the Dodsland Viking pool.

In early October, Petro Uno entered into a Farm-in Agreement ("Agreement") with a privately owned oil company located in the Kindersley area of Saskatchewan encompassing 1,000 net acres of land prospective for horizontal well development targeting the Viking Light Oil formation. The Company committed to drill two horizontal wells within 180 days on the land block. Petro Uno will earn a 100% working interest in said wells in exchange for a gross overriding royalty. The Company is to drill a minimum of one horizontal well on the lands every six months. The Company has also been granted a right of first refusal on an additional 640 net acres adjacent to the above referenced lands providing for additional potential horizontal well development opportunities.

On October 15 and 29, 2009 the Company closed an equity financing ("the Financing"), issuing 14,285,714 Units at a price of \$0.35 per unit for gross proceeds of \$5,000,000. Each Unit was comprised of one common share and one-half of one common share purchase warrant, with each whole common share purchase warrant entitling the holder thereof to acquire one common share of the company at a price of \$0.40 per share, expiring 12 months from the date of grant. All securities issued pursuant to the Financing were subject to a four month hold period which expired on February 16, 2010 and March 2, 2010 respectively for the first and second tranche of the Financing.

On December 1, 2009 the Company closed a private placement, issuing 4,000,000 flow-through shares at a price of \$0.50 per flow-through share for gross proceeds of \$2,000,000.

Operations Update

The Company continues to operate its Alberta properties, acquired in 2008, in a cost effective manner. The properties continue to produce as expected, with regular operational challenges being dealt with as they arise in a manner which reflects the nature of the wells, being long-life wells with relatively consistent declines and minimal upside. Strengthening of world oil prices has help solidify cash flow from this production.

In December 2009, the Company fulfilled its farm-in commitment by drilling 2 (2.0 net) successful Viking horizontal development wells with multi-stage fracs. In Alberta, the Company re-completed 2 (1.45 net) wells, one in the Red Earth area and the other in Loon. Upon drilling and completion of the two Dodsland development wells, Petro Uno altered various completion techniques. Results were very encouraging in the area to commit to a 14 (7.0 net) well development program on these high-growth lands for 2010. The Company continued to generate internal development drilling prospects and acquire land to ensure continued growth in 2010.

In March, 2010, Petro Uno completed an acquisition of a private company with assets based in the Dodsland Viking pool (“the Privateco acquisition”). The Privateco acquisition expanded the high-growth core area in Saskatchewan for the Company.

During the first quarter 2010, the Company worked on completion and equipping operations to bring on new production from the successful drilling in the fourth quarter of 2009. The two wells drilled in the fourth quarter 2009 were brought on production January 10, 2010 and are currently each producing at a stabilized rate of approximately 30 bbls/d of light (38 degree API) oil. The Company drilled and completed 2 (1.5 net) Viking horizontal development wells in Saskatchewan in mid March 2010.

Petro Uno’s capital budget for 2010 is estimated to be \$8.2 million allowing for commodity price and production fluctuations. The program will be funded from remaining cash raised in 2009, cash flow, the possible sale of Alberta properties and debt.

As part of Petro Uno’s growth strategy and business plan, accretive property or corporate acquisitions are continually evaluated by the Company.

Summary of Results

(\$ thousands, except per share data)	2009	2008
FINANCIAL		
Revenue	763	892
Funds flow from operations ⁽¹⁾	(231)	(150)
Per share – basic and diluted	(0.02)	(0.01)
Net Loss	(494)	(136)
Per share – basic and diluted	(0.04)	(0.01)
Capital expenditures, net	1,731	3,060
Net working capital surplus (deficiency) ⁽²⁾	3,229	(1,079)
Total Assets	10,672	4,202
Shares outstanding	28,121	9,836
Weighted average shares	13,018	9,136
OPERATIONAL		
Daily production		
Natural gas (mcf/d)	11	11
Natural gas liquids (bbl/d)	1	1
Oil (bbl/d)	31	22
Total (boe/d @ 6:1)	33	25
Average pricing ⁽³⁾		
Natural gas (\$/mcf)	4.36	8.50
Natural gas liquids (\$/bbl)	32.15	66.50
Light oil (\$/bbl)	65.78	103.02
Total (\$/boe)	63.04	98.20

⁽¹⁾ Funds flow from operations is calculated as cash provided by operating activities and adding changes in non-cash working capital and asset retirement expenditures, if any. Funds from operations is used to analyze the Company's operating performance and leverage. Funds from operations does not have a standardized measure prescribed by GAAP and therefore may not be comparable with calculations of similar measures for other companies.

⁽²⁾ Net working capital deficiency includes accounts receivable, prepaid expenses and deposits, accounts payable, accrued liabilities and bank debt

⁽³⁾ Average prices are before the deduction of transportation costs.

Detailed Financial Review

Sales Volumes

Volumes		Three months ended December 31,		Year ended December 31,	
		2009	2008	2009	2008
		(unaudited)	(unaudited)		
Natural gas	mcf/d	9	12	11	11
Oil	bbls/d	28	32	31	22
Liquids	bbls/d	1	1	1	1
Barrels of oil equivalent	BOE/D (6:1)	30	34	33	25

Volumes have decreased during the fourth quarter of 2009 compared to the same period of 2008 as a result of normal production declines.

Volumes for the year ended December 31, 2009 and 2008, Petro Uno's sales volume averaged 33 boe/d and 25 boe/d respectively. Daily sales volumes increased 33% in 2009 compared to the prior period, the result of a milder winter not having an adverse affect on the production of wells in

the Red Earth and Loon areas. Natural gas and liquids sales coming from the Lanaway area averaged 2.5 boe per day for the fourth quarter or 8% of the total sales volumes.

Revenue

		Three months ended December 31,		Year ended December 31,	
		2009	2008	2009	2008
		<i>(unaudited)</i>	<i>(unaudited)</i>		
Revenue					
Natural gas sales	\$m	4	8	18	35
Liquids sales	\$m	2	2	6	15
Oil sales	\$m	214	196	740	842
Total	\$m	220	207	763	892

		Three months ended December 31,		Year ended December 31,	
		2009	2008	2009	2008
		<i>(unaudited)</i>	<i>(unaudited)</i>		
Company Prices					
Natural gas price	\$/mcf	5.14	7.45	4.36	8.50
Liquids price	\$/bbl	32.67	37.66	32.15	66.50
Oil price	\$/bbl	83.51	67.53	65.78	103.02

Crude oil prices continued to recover as Petro Uno received on average \$83.51/bbl in the fourth quarter of 2009 which represents an increase 24% increase from the prices received during the same period of 2008. The Company's average natural gas price of \$5.14/mcf received in 2009 declined 31% from the average price received during 2008.

Crude oil revenues in 2009 were \$739,652 compared to \$842,251 in 2008. The Company received an average oil price of \$65.78/bbl in 2009, a decrease of 36% from \$103.02/bbl for the year ending December 2008.

Revenues from natural gas and liquids sales totalled \$23,797 in 2009, compared to \$49,628 in 2008. The Company received an average gas price of \$4.36/mcf in 2009, a decrease of 49% from \$8.50 for the year ending December 2009.

To date, Petro Uno has not undertaken any hedging or commodity price contracts.

Royalties

		Three months ended December 31,		Year ended December 31,	
		2009	2008	2009	2008
		<i>(unaudited)</i>	<i>(unaudited)</i>		
Crown royalties expense	\$m	7	(10)	16	20
Crown royalties per boe	\$	2.57	(3.17)	1.33	2.18
Royalty rate		3%	-5%	2%	2%
Gross overriding royalties expense	\$m	5	6	17	26
Gross overriding royalties per boe	\$	1.99	1.76	1.37	2.86
Royalty rate		2%	3%	2%	3%

Royalties in the fourth quarter of 2009 averaged \$4.56/boe or 5.4% of total revenue. In the fourth quarter of 2008 a year-to-date adjustment on a non-operated property in the Loon area resulted in a net recovery of royalties.

For the year ended December 31, 2009, total royalties were \$32,680, or approximately 4% of total revenue, reflecting the combined impact of gross overriding and the Alberta crown royalties. The low royalty rate experienced to date is due to wells classified as low producers combined

with lower commodity prices. Royalty rates can vary based on a number of factors such as reference pricing, royalty holidays and production rates. Crown royalty holidays are generally available to certain production from new pool discoveries.

Transportation Expenses

		Three months ended December 31,		Year ended December 31,	
		2009	2008	2009	2008
		(unaudited)	(unaudited)		
Expense per financial statements	\$m	8	6	31	23
Expense (\$ per boe)	\$	2.82	1.86	2.57	2.59
Expense (% of revenue)	%	3.5%	2.8%	4.1%	2.6%

Transportation expenses were \$31,110 for the current year and amounted to 4.1% of production revenue as compared to \$23,479 and 2.6% for 2008. The increase in aggregate transportation expense in 2009 was mainly attributable to the increase in third party costs during the year. On a per boe basis, the rate was relatively flat with 2009 at \$2.57 and \$2.59 in 2008. Transportation costs are comprised of gas transportation, pipeline tariffs for oil and liquids transportation as well as trucking charges. The charges for the current period are not necessarily indicative of future costs and will depend on the type of production additions (oil and liquids versus natural gas). These costs are dependent on a variety of factors such as: the type of production facilities; the method of transportation; the distances covered; the rates charged by the carriers; quantities shipped; cost of the carrier's fuel; the type of service offered (interruptible versus firm service) as well as ownership of the transportation facilities. The cost per boe for 2010 is currently expected to be consistent with that of 2009 as the majority of these costs are variable in nature and there are currently no unutilized firm service contracts.

Operating Expenses

		Three months ended December 31,		Year ended December 31,	
		2009	2008	2009	2008
		(unaudited)	(unaudited)		
Operating expenses	\$m	88	127	316	318
Operating expenses per boe	\$	32.06	40.33	26.13	34.96

Operating expenses for the year ended December 31, 2009 were \$316,449 or \$26.13/boe compared to \$317,510 for the year ending December 31, 2008, when operating costs were \$34.96/boe. The decrease is due to lower costs of fuel and lease maintenance as a result of a milder winter in 2009. The Company expects total operating expenses per boe to decrease in 2010 as a result of additional production from planned drilling activity scheduled for 2010. Since different operating areas have variable cost structures such as processing and labour, the expenses are dependent upon the per unit basis of any new production developed or purchased.

Field netback

		Three months ended December 31,		Year ended December 31,	
		2009	2008	2009	2008
		(unaudited)	(unaudited)		
<i>\$ unless otherwise stated</i>					
Price		79.92	65.66	63.04	98.20
Transportation expenses		(2.82)	(1.86)	(2.57)	(2.59)
Crown royalties		(2.57)	3.17	(1.33)	(2.18)
Gross overriding royalties		(1.99)	(1.76)	(1.37)	(2.86)
Operating expenses		(32.06)	(40.33)	(26.13)	(34.96)
Field netback		40.48	24.88	31.64	55.61

Field netbacks in the fourth quarter of 2009 were \$40.48/boe, a 63% increase to \$24.88 in the comparable quarter of 2008. The improved field netback in the fourth quarter of 2009 over the year of 2009 is the result of the recovery of oil prices although they are still well below the same periods of 2008.

Field netbacks of \$31.64/boe for 2009 were lower by 43% as compared to the \$55.61/boe realized in 2008. The 36% decrease in average commodity prices in 2009 was the largest single contributor to the decline in field netbacks.

General and Administrative (“G&A”)

		Three months ended December 31,		Year ended December 31,	
		2009	2008	2009	2008
		<i>(unaudited)</i>	<i>(unaudited)</i>		
Gross G&A	\$m	274	220	599	553
Overhead recoveries	\$m	(11)	-	(29)	-
Net G&A expense		263	220	570	553

Net G&A expenses in 2009 were \$570,079 compared to \$553,030 in 2008. Total G&A costs in 2009 consist of salaries and consulting costs, office rent and parking, fees to professional service providers, credit facility charges and computer related software licenses. Gross G&A has increased slightly year over year primarily due to the associated expenditures related to company activity.

During the year ended December 31, 2009, capital expenditure levels were higher, resulting in higher capital recoveries, compared with the prior year which had no capital activity. During the 2009 year, the Company recovered \$29,269 of G&A costs from operated activities compared to nil during 2008.

The Company does not capitalize any G&A expenses.

Stock Based Compensation

		Three months ended December 31,		Year ended December 31,	
		2009	2008	2009	2008
		<i>(unaudited)</i>	<i>(unaudited)</i>		
SBC expense	\$m	44	6	72	11

Stock-based compensation expense represents the amortization of the expense associated with the notional fair value of stock options granted. The fair value of the options is determined by the price of the stock, its volatility, risk-free rates of return and the vesting periods. The fair value of all stock options is amortized over the options’ vesting period, which is three years for all options granted. Stock-based compensation expense was \$71,549 for 2009 compared to \$11,423 for 2008. The increase in the current year’s expense was due to 1,933,000 new stock options granted during the year at an average price of \$0.33 and average fair value of \$0.31 per share for purposes of the expense amortization.

Interest Expense

		Three months ended December 31,		Year ended December 31,	
		2009	2008	2009	2008
		<i>(unaudited)</i>	<i>(unaudited)</i>		
Interest	\$m	3	13	26	43
Interest per boe	\$	0.97	4.01	2.18	4.76

The Company raised money during the fourth quarter of 2009 and used some of the proceeds to eliminate the bank debt.

Interest expense for fiscal 2009 decreased to \$26,441 compared to \$43,260 in fiscal 2008 due to lower lending rates in 2009.

Depletion, Depreciation and Accretion (“DD&A”)

		Three months ended December 31,		Year ended December 31,	
		2009	2008	2009	2008
		<i>(unaudited)</i>	<i>(unaudited)</i>		
Depletion	\$m	84	94	378	243
Depreciation	\$m	-	-	-	1
Accretion	\$m	12	7	21	11
Total DD&A	\$m	96	101	399	255
DD&A per boe	\$m	34.79	31.96	32.98	28.11

DD&A expense is determined by a combination of Petro Uno’s spending on its own development program, drilling successes and the cost of any acquisitions. These factors caused the aggregate DD&A expense to increase from \$255,295 (\$28.11/boe) in 2008 to \$393,398 (\$32.49/boe) in 2009. The rate per boe increase of 15.6% is due to Petro Uno having a larger capital depletable base as compared to the increase in proved reserves, as well a higher percentage of reserves being assigned to probable versus proved at year end. Petro Uno’s year end reserves are based on new drilling completed in December 2009 which did not come on production until January 2010. Therefore, our independent reserve engineers assigned a significant portion of the new reserves to probable rather than proved reserve categories.

Accretion costs were \$20,906 in 2009, compared to \$11,220, reflecting the higher future retirement liabilities incurred from drilling activities.

Ceiling Test

The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test (the “ceiling or impairment test”). The ceiling test is a two-stage process which is performed at least annually or when events or conditions dictate. The first stage of the test is a recovery test which compares the undiscounted future cash flow from proved reserves at forecast prices and costs plus the cost less impairment of unproved properties to the net book value of the petroleum and natural gas assets to determine if the assets are impaired. A potential impairment loss exists when the net book value of the petroleum and natural gas assets exceeds such undiscounted cash flow. The second stage determines the amount of the impairment loss to be recorded.

The impairment is measured as the amount by which the net book value of the petroleum and natural gas assets exceeds the future discounted cash flow from proved plus probable reserves at forecast prices and costs. A risk-free interest rate is used to arrive at the net present value of the future cash flows. Any impairment is recorded as additional depletion and depreciation. No write-down was required at December 31, 2009, based on the independent, third party engineering consultant’s report.

Income Taxes

Petro Uno had an income tax recovery for 2009 of \$188,961 and was comprised entirely of future income taxes. This amount represented a 33% decrease from the tax provision booked in 2008. The tax recovery was mainly the result of the loss incurred in 2009.

Petro Uno entered into a flow-through share private placement financing in December 1, 2009 wherein it is required to renounce \$2.0 million in eligible exploration and development expenses before December 31, 2010. The tax effects of the renunciations are recorded when the documents relating to the renunciation are filed with the tax authorities. The Company renounced \$1.0 million on February 4, 2010 of the flow-through financing and therefore will recognize the tax effect in the first quarter of 2010. At the time the renunciation is made the estimated tax effect of the foregone tax benefits will be charged to share capital with a corresponding increase to the future income tax liability.

Pursuant to the terms of the flow-through arrangement, the Company spent the remaining flow-through commitment of \$1.0 million in March 2010 and will renounce, file and record the future tax adjustment associated with this renouncement in May 2010.

At December 31, 2009, the Company has approximately \$1,013,707 (2008 - \$530,572) in non-capital losses available for application against future taxable income expiring between 2027 and 2029.

Taking into account projected spending for 2010 as well as the anticipated production levels and commodity prices, it is anticipated that Petro Uno will not be cash taxable throughout 2010.

Cashflow and net earnings

	Year ended December 31,	
	2009	2008
Loss for the period	\$ (494,281)	\$ (135,979)
Items not affecting cash:		
Depletion, depreciation and accretion	399,398	255,295
Stock-based compensation	71,549	11,954
Future income taxes	(188,961)	(281,077)
Recapture of depreciation on sale of asset	(1,012)	-
Asset retirement obligations paid	(17,618)	-
Funds flow from operations	(230,925)	(149,807)

Funds flow from operations in 2009 was (\$230,925), representing a decrease of 54% from (\$149,807) realized in 2008. The decline was largely attributable to the 36% decline in the corporate average commodity prices. Likewise, Petro Uno had a net loss for 2009 of \$547,276 as compared to a net loss of \$135,979 in 2008.

	Year ended December 31,	
	2009	2008
Weighted average shares outstanding		
Basic	13,017,679	9,135,725
Diluted	13,183,903	9,635,725
Funds flow from operations	\$ (230,925)	\$ (149,807)
Basic and diluted per share	\$ (0.02)	\$ (0.01)
Net (Loss) earnings	\$ (494,281)	\$ (135,979)
Basic and diluted per share	\$ (0.04)	\$ (0.01)

On a per share basis, Petro Uno had a net loss of \$0.04 for both basic and diluted earnings per share for 2009 as compared to a net loss of \$0.01 basic and diluted earnings per share for 2008. Funds flow from operations per share in 2009 was (\$0.02) for basic and diluted as compared to (\$0.01) basic and diluted per share results from 2008.

Capital Expenditures

	Year ended December 31,	
	2009	2008
Land and lease retentions	4	-
Seismic	-	16
Drilling and completions	1,727	-
Production facilities, pipeline, plant and equipment	1	-
Acquisitions	-	3,040
Office	(1)	5
	<u>1,731</u>	<u>3,060</u>

The Company incurred non-acquisition capital expenditures of \$1,731,190 during 2009 compared to \$20,244 in 2008. During December 2009, the Company drilled 2 (2.0 net) wells in Saskatchewan and re-completed 2 (1.45 net) wells in Alberta.

The Company has built its land base through farm-in agreements, drilling to earn land, freehold leasing and acquisitions. At December 31, 2009, the Company had approximately 2,781 net acres of undeveloped land in Alberta and Saskatchewan.

Liquidity and Capital Resources

<i>(\$ thousands except per share data)</i>	2009	2008
Common shares outstanding	13,018	9,836
Closing share price at year end	0.60	0.11
	<u>\$ 7,811</u>	<u>\$ 1,082</u>
Total Market Capitalization		
Working capital (surplus) deficiency	(3,229)	104
Bank debt	-	975
Total Net debt (surplus)	<u>(3,229)</u>	<u>1,079</u>
Asset retirement obligation	251	172
Future income taxes	282	723
Total capitalization	<u>\$ 5,114</u>	<u>\$ 3,056</u>

Oil and gas exploration and development is a capital intensive business. Periodic infusions of additional capital may be required to accelerate the rate of the Company's growth. Petro Uno chooses to finance its ongoing capital expenditure program through a combination of reinvesting cash flow, bank borrowing and additional equity.

At December 31, 2009, the Company had a credit facility of \$1.25 million with a Canadian chartered bank. Petro Uno had \$4.9 million in cash and short term deposits, nil drawn against the credit facility (December 31, 2008, \$975,000) and a working capital surplus of \$3.23 million. The credit facility is subject to an annual review by May 2010. Once this process is completed Petro Uno expects an increase in the amount available.

During the fourth quarter, the Company successfully completed two equity financings. On October 15 and 29, 2009 the Company closed an equity financing ("the Financing"), issuing 14,285,714 Units at a price of \$0.35 per unit for gross proceeds of \$5,000,000. Each Unit was comprised of one common share and one-half of one common share purchase warrant, with each whole common share purchase warrant entitling the holder thereof to acquire one common share of the company at a price of \$0.40 per share, expiring 12 months from the date of grant. All securities issued pursuant to the Financing are also subject to a four month hold period expiring

on February 16, 2010 and March 2, 2010 respectively for the first and second tranche of the Financing.

On December 1, 2009 the Company closed a private placement, issuing 4,000,000 flow-through shares at a price of \$0.50 per flow-through share for gross proceeds of \$2,000,000. The net proceeds received were applied to the revolving credit facility and were used for general corporate purposes, including an increase in capital expenditures during the fourth quarter 2009.

On March 2, 2010, the Company announced that it, together with Renegade Petroleum Ltd. ("Renegade"), completed the acquisition of a private Saskatchewan company ("Privateco"), from Privateco's shareholders for cash consideration of approximately \$4.5 million (Renegade's contribution) and 2 million common shares of Petro Uno at a deemed value of \$1.2 million.

Share Capital

At December 31, 2009, the Company had 28,121,464 (2008 - 9,835,750) common shares, 2,433,000 (2008 - 700,000) options and 7,142,857 (2008 - 1,767,875) share purchase warrants issued and outstanding.

Issued and outstanding common shares

	Number of shares	Amount
Balance, at incorporation	-	\$ -
Issue of common shares for cash	3,000,000	300,000
Issue of common shares for cash	3,000,000	600,000
Exercise of options	150,000	30,000
Fair value of options on exercise		1,718
Share issue costs, net of future income taxes of	\$ 27,760	(96,955)
Balance, December 31, 2007	6,150,000	\$ 834,763
Issue of common shares for cash	3,535,750	1,226,553
Exercise of options	150,000	30,000
Fair value of options on exercise		1,717
Share issue costs, net of future income taxes of	\$ 47,668	(154,032)
Balance As at December 31, 2008	9,835,750	\$ 1,939,001
Issue of common shares for cash	14,285,714	3,638,311
Issue of flow-through common shares for cash	4,000,000	2,000,000
Share issue costs, net of future income taxes of	\$ 252,561	(710,676)
Balance As at December 31, 2009	28,121,464	\$ 6,866,636

Issued and outstanding share purchase warrants

Warrants	Number of warrants	Amount
Balance, at Incorporation	-	\$ -
Issue of share purchase warrants for cash	1,767,875	187,747
Balance As at December 31, 2008	1,767,875	\$ 187,747
Warrants expired	(1,767,875)	(187,747)
Issue of share purchase warrants for cash	7,142,857	1,361,689
Balance As at December 31, 2009	7,142,857	\$ 1,361,689

As at the date hereof the Company has 30,394,788 common shares, 2,333,000 options to purchase common shares and 7,066,607 share purchase warrants issued and outstanding.

Contractual Obligations

The Company's revolving credit facility is subject to annual review in May 2010. Petro Uno expects the revolving credit facility to be increased in May 2010 as the Company's reserves are currently sufficient to support a credit facility of this size.

In October 2009, Petro Uno entered into a Farm-in Agreement ("Agreement") with a privately owned oil company located in Saskatchewan encompassing 1,000 net acres of land prospective for horizontal well development targeting the Viking Light Oil formation. The Company is to drill a minimum of one horizontal well on the lands every six months.

On December 1, 2009, Petro Uno issued flow-through shares for gross proceeds of \$2.0 million. At that time, the Company committed to incur \$2.0 million of eligible expenditures under this flow-through arrangement by December 31, 2010. At December 31, 2009, Petro Uno had incurred \$1.0 million of eligible expenditures. The tax effect of the tax benefits renounced to subscribers will be recognized in the financial statements when the renouncement documents are filed in early 2010.

Pursuant to the terms of the flow-through arrangement, the Company spent the remaining flow-through commitment of \$1.0 million in March 2010 and will renounce and record the future tax adjustment associated with this renouncement in the second quarter of 2010.

As at April 26, 2010, the Company had expended all funds received pursuant to the 2009 flow-through agreements with renunciation of flow-through completed in April 2010.

The Company does not have any other off-balance sheet financing arrangements.

Related Party Transactions

At December 31, 2009, the Company owed \$43,000 to Renegade Oil & Gas Ltd., a former related party with common directors and officers. These fees relates to general and administrative expenses for the purposes of sharing the same office space and equipment.

A director of the Company is a partner at a law firm that provides legal services to the Company. For the year ended December 31, 2009, fees of \$179,382 (2008 - nil) were charged for fees and services provided from the firm. Included in accounts payable and accrued liabilities at December 31, 2009 is \$147,607 (2008 - nil) owing to the law firm.

The Company acquired a private Saskatchewan company (the "PrivateCo Acquisition") with Renegade Petroleum Ltd. ("Renegade") and agreed to enter into a joint venture agreement (the "Joint Venture") with Renegade in connection with multiple farm-ins in the Viking play in the Kindersley area of Saskatchewan. Three directors' of the Company are also directors' of Renegade. The Company has taken steps, including independent discussion, review and approval of the terms of the PrivateCo Acquisition and Joint Venture and significant decisions to be undertaken under the Joint Venture by management and directors who are not Renegade directors.

All related party transactions are conducted in the normal course of business operations and are measured at the exchange amount, which is established and agreed to based on standard rates, time spent and costs incurred.

Subsequent Events

On February 2, 2010 the Company agreed to enter into a joint venture (the "Joint Venture") with Renegade Petroleum Ltd. ("Renegade"). Under the Joint Venture, the Company will participate on a 50/50 basis with Renegade in the development of the Viking Pool in the Dodsland area of Saskatchewan with the object being to drill horizontal multi stage fractured wells into the Viking zone. The Company has entered into 8 farm-in agreements covering 10,560 acres in the area. In excess of 100 drilling locations have been identified on the associated acreage. Under the terms of the Joint Venture, Renegade will also have an option to participate in any further farm-in agreements that the Company may negotiate in the region on a 50/50 basis. The Joint Venture agreement, which has an effective date of January 1, 2010, was finalized and signed by both parties on April 26, 2010. Renegade will equalize into the first three wells drilled by Petro Uno and accounting adjustments will be completed in the second quarter.

On March 1, 2010, the Company announced that 7,142,857 warrants of the Company (the "Warrants") to purchase common shares of the Company ("Common Shares") commenced trading on the TSX Venture Exchange under the trading symbol "PUP.WT" at market open on March 2, 2010. The Warrants were issued in connection with the private placement (see Note 8 a) which closed in two tranches on October 15, 2009 (the "First Tranche") and October 29, 2009 (the "Second Tranche"). Each Warrant entitles the holder thereof to acquire one Common Share at a price of \$0.40 per share at any time prior to October 15, 2010 for Warrants issued under the First Tranche and October 29, 2010 for Warrants issued under the Second Tranche.

On March 1, 2010, the Company announced that it, together with Renegade Petroleum Ltd. ("Renegade"), completed a joint acquisition of a private Saskatchewan company (the "Privateco Acquisition"), from its shareholders for total consideration of \$5.7 million. Under the Privateco Acquisition, the Company issued 2,000,000 common shares at \$0.60 per share in the capital of Petro Uno and Renegade paid \$4.5 million in cash. The Company will "drill to equalize" on the first \$3.3 million in drilling, completion and equipping costs associated on the Privateco Acquisition or farm-in lands.

Certain directors of the Company also serve as directors of Renegade. The independent directors of Petro Uno independently considered and unanimously approved both the Privateco Acquisition and the entry into the Joint Venture.

During the month of March, 2010 and pre the signing of the Joint Venture agreement, the Company drilled 2 (1.5 net) successful horizontal wells in Saskatchewan. Pursuant to the terms of the flow-through arrangement (Note 8a), the Company will renounce \$1,000,000 of Canadian exploration and development expense deductions and record the future tax adjustment associated with this renouncement in the second quarter of 2010. As a result of the short spring breakup, the Company is currently working on completing and equipping the wells for production.

During the month of April, 2010, the Company drilled 2 (0.79 net) successful horizontal wells in Saskatchewan.

At April 26, 2010, the Company had expended all funds received pursuant to the 2009 flow-through agreements and will renounce, file and record the future tax adjustment associated with this renouncement in April 2010.

Selected Quarterly Information

The unaudited consolidated financial data presented below has been prepared in accordance with Canadian generally accepted accounting principles. The reporting and measurement currency is the Canadian dollar. The following table summarizes selected quarterly information.

Operational	Unit	2009			
		Q4	Q3	Q2	Q1
Production					
Natural gas	(mcf/d)	9	11	11	12
Natural gas liquids	(bbls/d)	1	1	1	1
Light oil	(bbls/d)	28	29	36	29
Total	(boe/d)	30	32	39	32
Pricing					
Natural gas	(\$Cdn/mcf)	\$ 5.14	\$ 3.29	\$ 3.98	\$ 5.38
Natural gas liquids	(\$/bbl)	\$ 32.67	\$ 36.86	\$ 31.53	\$ 28.65
Light oil	(\$Cdn/bbl)	\$ 83.51	\$ 68.37	\$ 63.76	\$ 48.54
Total	(\$/boe)	\$ 79.92	\$ 64.95	\$ 61.46	\$ 47.29
Financial					
Petroleum and natural gas sales	(\$m)	220	190	217	136
Funds from operations	(\$m)	(172)	(13)	7	(54)
Per share – basic and diluted	(\$)	(0.01)	-	-	(0.01)
Net earnings (loss)	(\$m)	(170)	(136)	(91)	(148)
Per share – basic and diluted	(\$)	(0.01)	(0.01)	(0.01)	(0.01)
Capital expenditures	(\$m)	1,712	9	14	-
Total assets	(\$m)	10,672	3,961	3,822	3,935
Working capital surplus(deficit)	(\$m)	3,229	(1,169)	(1,144)	(1,128)
Field Netback	(\$/boe)	\$ 40.48	\$ 38.73	\$ 32.98	\$ 14.50
Weighted average shares outstanding					
Basic	(m)	13,018	9,836	9,836	9,836
Diluted	(m)	13,184	10,436	10,336	10,336

Operational	Unit	2008			
		Q4	Q3	Q2	Q1
Production					
Natural gas	(mcf/d)	12	14	20	-
Natural gas liquids	(bbls/d)	1	1	1	-
Light oil	(bbls/d)	32	35	23	-
Total	(boe/d)	34	38	27	-
Pricing					
Natural gas	(\$Cdn/mcf)	\$ 7.37	\$ 8.78	\$ 8.85	\$ -
Natural gas liquids	(\$/bbl)	\$ 37.56	\$ 79.07	\$ 72.86	\$ -
Light oil	(\$Cdn/bbl)	\$ 67.41	\$ 119.69	\$ 126.02	\$ -
Total	(\$/boe)	\$ 65.46	\$ 115.01	\$ 114.94	\$ -
Financial					
Petroleum and natural gas sales	(\$m)	207	403	282	-
Funds from operations	(\$m)	(125)	89	(24)	(61)
Per share – basic and diluted	(\$)	(0.01)	0.01	-	(0.01)
Net earnings (loss)	(\$m)	(177)	55	46	(60)
Per share – basic and diluted	(\$)	(0.02)	0.01	-	(0.01)
Capital expenditures	(\$m)	-	-	20	3,040
Total assets	(\$m)	4,202	4,303	4,392	4,345
Working capital surplus(deficit)	(\$m)	(1,079)	(953)	(1,043)	(980)
Field Netback	(\$/boe)	\$ 24.80	\$ 82.27	\$ 56.42	\$ -
Weighted average shares outstanding					
Basic	(m)	9,836	9,836	8,428	7,121
Diluted	(m)	10,336	10,336	8,928	7,721

Business Conditions and Risks

The exploration for, and development and production of, crude oil and natural gas involves a wide range of business and financial risks, some of which are beyond the control of the Company. Included in these risks are the uncertainty of finding economically recoverable reserves, fluctuations in commodity prices, interest rate and foreign exchange rate volatility, and the possibility of changes to royalty, tax and environmental regulations. The oil and gas industry is also highly competitive and the Company competes with numerous other companies, many of which have greater financial and human resources.

The Company faces several key risks in its business, including possible commodity price downturns, emergence of superior competing technologies, reliance on relatively few key suppliers and customers, and adequacy of capital and/or cash flow to pursue its business plan objectives. This list is not intended to be exhaustive, but merely to communicate to shareholders certain key risks faced by the Company in its business operations. The Company, where it can employ strategies to mitigate and minimize some risks. But some risks and market conditions are outside of the Company's influence and control.

The business risks facing the Company are mitigated in a number of ways. Geological, geophysical, engineering, environmental and financial analyses are performed on new exploration prospects, development projects and potential acquisitions to ensure an acceptable balance between risk and reward. The Company's ability to increase its production, revenues and cash flows depends on its success in not only developing its existing properties, but also

acquiring, exploring for and developing new reserves and production and managing those assets in an efficient manner.

Despite best practice analysis being conducted on projects, there are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves, including future prices for crude oil and natural gas, engineering data, projected future rates of production and the timing of future expenditures. The process of estimating oil and gas reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. An independent engineering firm has evaluated the Company's properties for the year ended December 31, 2009 to determine a fair estimate of reserves.

The Company's financial results are also impacted by fluctuations in the exchange rate between the Canadian and U.S. dollars. Crude oil prices and, to some extent, natural gas prices are based on reference prices denominated in U.S. dollars, while the majority of the Company's expenses are denominated in Canadian dollars.

A substantial portion of the Company's accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal credit risks in that industry. The carrying amount of accounts receivable represents the maximum credit exposure. As at December 31, 2009 and 2008, the Company's receivables were aged as follows:

	December 31, 2009	December 31, 2008
Ageing		
Not past due (less than 90 days)	\$ 238,695	\$ 82,887
Past due (90 days to one year)	2,486	2,584
	\$ 241,181	\$ 85,471

Legal, Environmental, Remediation and other Contingent Matters

The Company reviews legal, environmental, remediation and other contingent matters to both determine whether a loss is probable based on judgment and interpretation of laws and regulations, and determine that the loss can reasonably be estimated. When the loss is determined, it is charged to earnings. The Company's management monitor known and potential contingent matters and make appropriate provisions by charges to earnings when warranted by circumstances.

Critical Accounting Policies and Estimates

Management is required to make judgments, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company. The following outlines the accounting policies and practices involving the use of estimates that are critical in determining Petro Uno's financial results:

Full cost accounting

The Company follows the full cost method of accounting for petroleum and natural gas operations, whereby all costs relating to the exploration and development of petroleum and natural gas reserves are capitalized on a country-by-country cost centre basis. Such costs include land acquisition costs, costs of drilling both productive and non-productive wells, well equipment, flow-line and facility costs, geological and geophysical expenses and overhead expenses directly related to exploration and development activities. Gains or losses on sales of properties are recognized only when crediting the proceeds to the recorded costs would result in a change of 20% or more in the depletion and depreciation rate. The aggregate of capitalized costs, net of certain costs related to unproved properties, and estimated future development costs are amortized using the unit-of-production method based on estimated proved reserves of

petroleum and natural gas before royalties as determined by independent petroleum engineers. Changes in estimated proven reserves or future development costs have a direct impact on depletion and depreciation expense.

Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly to determine if proved reserves should be assigned to them. If proved reserves are assigned to the properties, the costs are included in the depletion calculation.

Oil and natural gas reserves

Estimates of oil and natural gas reserves are projections based on geological and engineering data. There are uncertainties inherent in these projections including the interpretation of data and the projection of future rates or production and the timing of developmental expenditures. Reserve engineering is an analytical process of estimating below ground accumulations of oil and natural gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. The Company's proved oil and gas reserves are evaluated and reported on annually by an independent, qualified, petroleum-engineering consultant. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to a number of uncertainties and various interpretations. The Company expects that over time its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels. Reserve estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion. A revision to the reserves estimate could result in a higher or lower DD&A charge to net earnings. Downward revisions to reserve estimates could also result in a write-down of oil and natural gas property, plant and equipment under the ceiling test described below.

Ceiling test

The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test (the "ceiling or impairment test"). The ceiling test is a two-stage process which is performed at least annually or when events or conditions dictate. The first stage of the test is a recovery test which compares the undiscounted future cash flow from proved reserves at forecast prices and costs plus the cost less impairment of unproved properties to the net book value of the petroleum and natural gas assets to determine if the assets are impaired. A potential impairment loss exists when the net book value of the petroleum and natural gas assets exceeds such undiscounted cash flow. The second stage determines the amount of the impairment loss to be recorded.

The impairment is measured as the amount by which the net book value of the petroleum and natural gas assets exceeds the future discounted cash flow from proved plus probable reserves at forecast prices and costs. A risk-free interest rate is used to arrive at the net present value of the future cash flows. Any impairment is recorded as additional depletion and depreciation. No write-down was required at December 31, 2009.

Asset retirement obligations

The Company recognizes the fair value of an asset retirement obligation ("ARO") in the period in which it is incurred when a reasonable estimate of fair value can be made. The obligations recognized are estimates of statutory, contractual or legal obligations that the Company will reasonably be expected to incur to retire producing well sites and natural gas processing facilities. These estimates are then discounted to their present value using the Company's credit adjusted risk-free interest rate (Petro Uno used 7% for 2009). The fair value of the estimated ARO is recorded as a long-term liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on a unit-of-production basis over the life of the reserves. The liability amount is increased each reporting period due to the passage of time

and the amount of this accretion is charged to earnings in the period through charges to accretion expense. Actual costs incurred upon settlement of the retirement obligation are charged against the obligation to the extent of the liability recorded. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost would also result in an increase or decrease to the ARO and the related asset retirement cost. Any difference between the actual costs incurred upon settlement of the ARO and the recorded liability is recognized as a gain or loss in the Company's earnings in the period in which the settlement occurs. Determination of the original undiscounted costs is based on engineering estimates using current costs in accordance with existing legislation and industry practice. The estimation of these costs can be affected by factors such as the number of wells drilled, well depth, estimated future salvage values, location of the well and current environmental legislation. Actual payments to settle the obligations may differ from the estimated amounts.

Future income tax

The Company follows the liability method of accounting for income taxes. Under this method the Company records future income tax assets and liabilities based on "temporary differences" (differences between the accounting basis and the tax basis of the assets and liabilities) and are measured using the substantively enacted tax rates and laws expected to apply when these differences reverse. Timing of future revenue streams and future capital spending changes can affect the timing of any temporary differences, and accordingly affect the amount of the future income tax liability calculated at a point in time. These differences could materially impact earnings. The effect of a change in substantively enacted income tax rates on future income tax assets and liabilities is recognized in income in the period that the change occurs.

The determination of the Company's income tax liability requires interpretation of complex laws and regulations. As such, income taxes are subject to measurement uncertainty and the interpretations can impact net earnings through the income tax expense and the future income tax assets and liabilities. All tax filings are subject to audit and potential reassessment. The actual income tax liability may differ significantly from the liability estimated or recorded.

Stock-based compensation

The Company has a stock based compensation plan enabling officers, directors and employees to purchase common shares at exercise prices equal to the market price on the date the option is granted. The Company uses the fair value method for valuing stock option grants. Compensation costs attributable to share options granted are measured at their fair value at the grant date and expensed over the expected exercise time period with a corresponding increase to contributed surplus. Upon exercise of the stock options, the consideration paid by the option holder, together with the amount previously recognized in contributed surplus, is credited to share capital. The assumptions used in calculating its stock based compensation expense are: the volatility of the stock price, risk-free rates of return and the expected lives of the options given that some will be forfeited upon termination of employment.

Financial Instruments

The Company's financial instruments consist of financial assets, financial liabilities, and derivatives. All financial instruments are initially recognized at fair value on the balance sheet. Measurement of financial instruments subsequent to the initial recognition, as well as resulting gains and losses, are recorded based on how each financial instrument was initially classified. The Company has classified each identified financial instrument into the following categories: held for trading, loans and receivables, and other financial liabilities. Held for trading financial instruments are measured at fair value with gains and losses recognized in earnings immediately. The fair value of derivatives is estimated for the Company by a third party. Loans and receivables, held to maturity investments and other financial liabilities are recognized at amortized cost using the effective interest method and impairment losses are recorded in earnings when incurred. Only those financial assets and liabilities that must be classified as held for trading are classified as such by the Company.

In the future the Company may use derivative instruments to manage market risk associated with volatile commodity prices, such instruments must be classified as held for trading and recorded on the balance sheet at fair value as derivative assets and liabilities. Under the alternative hedge accounting treatment, gains and losses on derivatives classified as effective cash flow hedges would be included in other comprehensive income until the time at which the hedged item is realized. The Company does not utilize derivative instruments for speculative purposes and would elect not to apply hedge accounting. Therefore, gains and losses on these instruments would be recorded as unrealized gains and losses on derivatives in the consolidated statement of income, comprehensive income and retained earnings in the period they occur and as realized gains and losses on derivatives when the contracts are settled. Since unrealized gains and losses on derivatives are non-cash items, there would be no impact on cash provided by operating activities as a result of their recognition.

Other estimates

The accrual method of accounting will require management to incorporate certain estimates of revenues, royalties, and production costs as at a specific reporting date but for which actual revenue, royalties and other costs have not yet been received. In addition, the Company must estimate capital expenditures on capital projects that are in progress or recently completed where actual costs have not been received as of the reporting date.

New Accounting Policies

During 2009, amendments were made to Section 3862, Financial Instruments – Disclosures. The amendments include enhanced disclosures relating to the fair value of financial instruments and the liquidity risk associated with financial instruments. Section 3862 now requires that all financial instruments measured at fair value be categorized into one of three hierarchy levels. The amendments are consistent with recent amendments to financial instruments disclosure under International Financial Reporting Standards (“IFRS”).

Update On Financial Reporting Requirements

As of January 1, 2010, the Company will adopt the following CICA Handbook sections:

1. Section 1582 “*Business Combinations*”, which replaces Section 1581. Under this guidance, the purchase price used in business combination is based on the fair value of shares exchanged at their market price at the date of the exchange. Currently the purchase price used is based on the market price of the shares for a reasonable period before and after the date the acquisition is agreed upon and announced. This new guidance generally requires all transaction costs to be expensed, which currently are capitalized as part of the purchase price. Contingent liabilities are to be recognized at fair value at the acquisition date and re-measured at fair value through earnings of each reporting period until settled. Currently only contingent liabilities that are resolved and payable are included in the cost to acquire the business. In addition, negative goodwill is required to be recognized immediately in earnings, unlike the current requirement to eliminate it by deducting it from non-current assets in the purchase price allocation.
2. Section 1601, “*Consolidated Financial Statements*”, which together with Section 1602 below replaces the former guidance under section 1600, “*Consolidated Financial Statements*”. Section 1601 establishes standards for the preparation of consolidated financial statements.
3. Section 1602, “*Non-controlling Interests*”, provides guidance on accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. This standard requires a non-controlling interest in a subsidiary to be classified as a separate component of equity. In addition, net earnings and components of other comprehensive income are attributed to both the parent and non-controlling interest.

International Financial Reporting Standards

On January 1, 2011, International Financial Reporting Standards (“IFRS”) will become the generally accepted accounting principles in Canada. The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by Petro Uno for the year ended December 31, 2010, including the opening balance sheet as at January 1, 2010. During 2009 the Company has assessed the impact of adopting IFRS and is continuing to implement plans for transition. The project is being managed in-house by an accounting professional who has engaged in IFRS educational programs and continues to develop the Company’s adoption of IFRS. The Company’s auditors will be involved throughout the process to ensure the Company’s policies are in accordance with these new standards.

Management has not yet finalized its accounting policies and as such is unable to quantify the impact on the financial statements of adopting IFRS. In addition, due to anticipated changes to IFRS and International Accounting Standards prior to Petro Uno’s adoption of IFRS, management’s plan is subject to change based on new facts and circumstances that arise after the date of the MD&A.

In July 2009 an amendment to IFRS 1 First Time Adoption of International Reporting Standards was issued that applies to oil and gas assets under full cost. The amendment allow an entity that used full cost accounting under its previous GAAP to elect, at its time of adoption, to measure exploration and evaluation assets at the amount determined under the entity’s previous GAAP and to measure oil and gas assets in the development and production phases by allocating the amount determined under the entity’s previous GAAP for those assets to the underlying assets pro rata using reserve volumes or reserve values as of that date. Petro Uno currently anticipates that it will use this exemption. IFRS 1 also provides a number of other optional exemptions and mandatory exceptions in certain areas to the general requirement for full retrospective application. Management is analyzing the various accounting policy choices available and will implement those determined to be the most appropriate for the Company which other than the full cost accounting exemption noted above are:

Business Combinations - IFRS 1 would allow Petro Uno to use the IFRS rules for business combinations on a prospective basis rather than re-stating all business combinations.

Share-based payments - IFRS 1 allow Petro Uno an exemption on IFRS 2, “Share-based Payments” to equity instruments which vested before Petro Uno’s transition date to IFRS.

The transition from Canadian GAAP to IFRS is significant and may materially affect our reported financial position and results of operations. At this time, Petro Uno has identified key differences that will impact the financial statements as follows:

- Exploration and Evaluation (“E&E”) expenditures – On transition to IFRS, Petro Uno will re-classify all E&E expenditures that are currently included in the PP&E balance on the Consolidated Balance Sheet. This will consist of the book value of undeveloped land that relates to exploration properties. E&E assets will not be depleted and must be assessed for impairment when indicators of impairment exist.
- Depletion expense – On transition to IFRS, Petro Uno has the option to base the depletion calculation using either proved reserves or proved and probable reserves. Petro Uno has not concluded at this time which method it will use.
- Impairment of PP&E assets – Under IFRS, impairment tests of PP&E must be performed on specific portions of PP&E as opposed to the entire PP&E balance which is currently required under Canadian GAAP through the full cost ceiling test. Impairment calculations will be performed at the cash generating unit level using either total proved or proved plus probable reserves.
- Due to the recent withdrawal of the exposure draft on IAS 12 Income Taxes in November 2009 and the issuance of the exposure draft on IAS 37 Provisions, Contingent Liabilities

and Contingent Assets in January 2010, Management is still determining the impact of these revised standards on its IFRS transition.

The differences described above are those existing based on Canadian GAAP and IFRS pronouncements that currently exist. These differences should not be regarded as being complete as the intention is to highlight those areas believed to be the most significant to Petro Uno. Furthermore, the IASB has significant on-going projects that could affect the Company's financial statements in future years.