

**Argosy Energy Inc.**

**Management Discussion and Analysis**  
**And**  
**Unaudited Interim Condensed Consolidated Financial Statements**

**September 30, 2011**

## Management Discussion and Analysis

The following discussion and analysis (“MD&A”) reports on the financial condition and the results of operations of Argosy Energy Inc. (“Argosy” or the “Company”), was prepared on, and is dated November 14, 2011 and is to be read in conjunction with the accompanying unaudited interim consolidated financial statements and related notes for the three and nine month periods ended September 30, 2011 as well as the audited consolidated financial statements and related notes and MD&A for the year ended December 31, 2010.

### *Description of Business*

Argosy was formed pursuant to a Plan of Arrangement between Accrete Energy Inc. (“Accrete”), Pengrowth Energy Trust, Pengrowth Company, Pengrowth Energy Partnership and Argosy (“the Arrangement”) on December 31, 2008 and is a junior energy company focused on the acquisition, exploration, exploitation and development of oil and natural gas in Alberta in western Canada.

On May 14, 2010, Argosy acquired 100% of the issued and outstanding shares of its only subsidiary, Radius Resources Corp. (Radius), as part of a restructuring process undertaken by Radius. Radius has oil and gas operations primarily focused in the Ante Creek area of Alberta.

As at September 30, 2011, there were 22,243,622 (15,536,939 at December 31, 2010) common shares and 2,223,500 (1,433,000 at December 31, 2010) stock options outstanding. As at the date of this MD&A there are 22,243,622 common shares and 2,223,500 stock options outstanding. At December 31, 2010 there were 1,847,183 common share purchase warrants outstanding. During 2011, 706,683 common share purchase warrants were exercised and the remainder expired.

Additional information may be found on the Company’s web site at [www.argosyenergy.com](http://www.argosyenergy.com) and on the SEDAR web site at [www.sedar.com](http://www.sedar.com).

Argosy’s shares trade on the Toronto Stock Exchange (“TSX”) under the symbol GSY.

### *Basis of Presentation*

The interim consolidated financial statements have been prepared in accordance with International Accounting Standard 34 “Interim Financial Reporting” in accordance with International Financial Reporting Standards (“IFRS”). This is the second time that the Company has reported its financial statements under IFRS. The Company utilized standards and interpretations thereof that are expected to be effective as at December 31, 2011, the date of the Company’s first annual report under IFRS. The effective date of the Company’s transition to IFRS was January 1, 2011. Previously the Company prepared its interim and annual consolidated financial statements in accordance with Canadian generally accepted accounting principles (“Canadian GAAP or “CGAAP”). The adoption of IFRS did not have any effect on the Company’s operations, strategic decisions or cash flow from operations before changes in non-cash working capital.

The IFRS policies that have been adopted together with reconciliations between CGAAP and IFRS have been provided in the notes to the unaudited consolidated financial statements for the three and nine month periods ended September 30, 2011. Additional information in respect to the adoption of IFRS is provided in this MD&A.

The reporting and functional currency is the Canadian dollar.

The Company evaluates its performance based on net earnings, net backs and cash flow. The Company considers cash flow a key measure as it illustrates the Company’s ability to meet obligations necessary to

repay debt and fund future growth through capital investment. Cash flow per share is presented using the weighted average shares outstanding in a manner consistent with that used to calculate earnings per share.

In addition, the term “net debt” is used by the Company to describe one of the measures used by Company management to monitor the remaining availability of its credit facilities. Net debt is calculated by the Company by subtracting current assets values from the sum of current liabilities including bank debt without consideration of current values of derivative instruments.

The terms “cash flow” and “netbacks” should not be considered an alternative to, or more meaningful than cash flow from operating activities as prescribed by IFRS or CGAAP as an indicator of the Company’s performance. Argosy’s definition of cash flow and/or netbacks may not be comparable to that reported by other companies. The term “net debt” is not prescribed by IFRS.

The following reconciles cash flow provided by operating activities, the most comparable IFRS measure to cash flow used in this MD&A:

<b>\$ Thousands</b>	<b>Three Months Ended September 30,</b>		<b>Nine Months Ended September 30,</b>	
	<b>2011</b>	<b>2010</b>	<b>2011</b>	<b>2010</b>
Cash flow provided (used) by operating activities (IFRS)	(490)	(2,971)	341	(1,245)
Net changes in non-cash working capital	(169)	326	(707)	2,306
Cash flow (not prescribed - IFRS)	(659)	(2,645)	(366)	1,061

The following table reconciles field and corporate netback to income before taxes, the most comparable IFRS measure:

<b>\$ Thousands</b>	<b>Three Months Ended September 30,</b>		<b>Nine Months Ended September 30,</b>	
	<b>2011</b>	<b>2010</b>	<b>2011</b>	<b>2010</b>
Income (loss) and comprehensive income (loss) (IFRS)	(1,702)	(2,650)	(452)	(1,284)
Deferred income taxes	146	(1,540)	1,032	(951)
Depletion and depreciation	742	1,141	2,327	3,638
Financing expenses	260	255	557	766
Realized gain on derivative instruments	-	(183)	(22)	(256)
Unrealized gain on derivative instruments	-	(150)	-	(656)
Gain on acquisition – Radius resources Corp.	-	-	-	(2,228)
Gain on disposition	(107)	(6,174)	(4,082)	(6,174)
Impairment loss	-	10,050	-	10,050
Corporate netback (not prescribed - IFRS)	(661)	749	(640)	2,905
General and administrative expense	1,515	1,041	4,475	3,351
Field netback (not prescribed - IFRS)	854	1,790	3,835	6,256

### ***Barrel of Oil (“BOE”) Conversion***

In this MD&A production data is commonly stated in barrels of oil equivalent using a six (6) to one (1) conversion ratio when converting thousands of cubic feet of natural gas to barrels of oil and a one (1) to one (1) conversion ratio for natural gas liquids. An equivalency of six (6) thousand cubic feet of natural gas to one (1) barrel of oil is based on energy equivalent at the burner tip and does not represent a value equivalency at the well head.

### ***Forward-Looking Statements***

Certain statements included or incorporated herein constitute forward-looking statements. These statements relate to future events or the future performance of Argosy. All statements other than statements of historical fact are forward-looking.

Such forward-looking statements or information are provided for the purpose of providing information about management's current expectations and plans relating to the future. Readers are cautioned that reliance on such information may not be appropriate for other purposes, such as making investment decisions. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "continue", "might", "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "estimate", "budget", "forecast", "predict", "project", "potential", or the negative of these terms and similar expressions. In addition, these financial statements and accompanying management discussion may contain forward-looking statements attributed to third party industry sources. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements.

Forward-looking statements include, but are not limited to, statements with respect to:

The performance characteristics of Argosy's oil and natural gas properties; oil and natural gas production levels; the quantity of oil and natural gas reserves; the performance characteristics of oil and natural gas properties; projection of market prices; other trends of the capital markets; the size of and future net revenues from Argosy's oil and natural gas reserves; capital expenditure programs; supply and demand for oil and natural gas and commodity prices; financial conditions; industry conditions; capital expenditure programs; drilling plans; expectations regarding the Argosy's ability to raise capital and to continually add to reserves through acquisitions, exploration and development; treatment under governmental regulatory regimes and tax laws; estimated tax pool balances; future land expiries; governmental regulations; anticipated IFRS elections and the impact of the conversion to IFRS and realization of the anticipated benefits of acquisitions and dispositions.

In addition, statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves and resources described can be profitably produced in the future.

The forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond the Company's control and which would cause results to differ materially from those expressed in the forward-looking statements contained in these financial statements and accompanying management discussion. These risks and uncertainties may include, but are not limited to:

general economic conditions in Canada, the United States and globally; industry conditions, including fluctuations in the price of oil and natural gas; governmental regulation of the oil and gas industry, including environmental regulation; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry; volatility of commodity prices; environmental risks; fluctuation in foreign exchange or interest rates; liabilities inherent in oil and gas operations; geological, technical, drilling and processing problems; unanticipated operating events which can reduce production or cause production to be shut in or delayed; failure to obtain industry partner and other third party consents and approvals, when required; stock market volatility and market valuations; competition for, among other things, capital, acquisitions of reserves, undeveloped land, skilled personnel, and equipment and facilities; the need to obtain required consents, permits or approvals from regulatory authorities; competition for, among other things, capital, acquisition of reserves, undeveloped land, skilled personnel and equipment and facilities; the lack of availability of qualified personnel or management; uncertainties associated with estimating oil and natural gas reserves; aboriginal land claims; stock market volatility; the implementation of International Financial Reporting Standards and the other factors considered under "Risk Management" in the Management Discussion and Analysis for the year ended December 31, 2010.

Readers are cautioned that the foregoing lists should not be considered to be exhaustive. Readers are also cautioned that these factors and risks are difficult to predict and that the preparation of financial statements in accordance with Canadian GAAP requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Forward-looking statements and other information contained herein concerning the oil and gas industry and Argosy's general expectations concerning this industry are based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which Argosy believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While Argosy is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

The foregoing summary of assumptions and risks relating to forward-looking information is provided in this MD&A in order to provide readers with a more complete perspective on the Company's future operations and may not be appropriate for other purposes. Although the assumptions used in the preparation of such information and statements are considered reasonably accurate by the Company at the time of preparation, they may prove to be incorrect. Accordingly, readers are cautioned that the actual results achieved will vary from the information provided herein and the variations may be material.

Investors should not 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. These forward-looking statements are made as of the date of this date or as of the date specified in any documents that may be incorporated by reference into the financial statements and accompanying management discussion, as the case may be.

## *Operating Summary*

### **Average Daily Production**

	<b>Three Months Ended September 30,</b>		<b>Nine Months Ended September 30,</b>	
	<b>2011</b>	<b>2010</b>	<b>2011</b>	<b>2010</b>
Oil (bbl/d)	133	64	108	38
NGL (bbl/d)	50	84	58	90
Total Oil/NGL (bbl/d)	183	148	164	128
Gas (mcf/d)	2,992	4,656	3,239	5,080
Total (boe/d) <sup>(1)</sup>	682	924	706	974

(1) The reader is cautioned that the use of the term boe's ("barrels of oil equivalent") may be misleading particularly when used in isolation. A boe conversion of 6 mcf to 1 boe may not represent a value equivalency at the wellhead.

The production included in the table above includes the production from Radius' Ante Creek property for the period from the date of its acquisition on May 14, 2010. The Company sold its Saxon property effective August 1, 2010.

The Company is focused on developing its oil prospects. During the first three quarters of 2011 it Completed a well at Pouce Coupe that it had spudded in 2010, drilled and completed two 100% owned oil wells at Claresholm and has spudded a third 100% owned Claresholm oil well that is in the process of being completed in the 4<sup>th</sup> quarter 2011. Production from the 2011 drilling program has been intermittent during the testing period as the Company gathers information about the geological and production characteristics. The information obtained will assist the Company in planning its future oil drilling and land acquisition programs at Claresholm.

Production averaged 736 bbl/day for the 1<sup>st</sup> quarter and 701 bbl/day for the 2<sup>nd</sup> quarter of 2011. The decrease to 682 bbl/day for the 3<sup>rd</sup> quarter of 2011 occurred as a result of natural production declines and a 5 day shutdown for plant turn around at Claresholm.

The decrease in production for the period ended September 30, 2011 versus the period ended September 30, 2010 was due to the loss of the production that occurred on the sale of the Saxon property, the shut down for plant turn around at Claresholm and natural declines. The decrease was offset in part by production from Ante Creek, production from a well at Pouce Coupe that was put on stream in the first quarter of 2011 and test production from Claresholm oil wells that were on stream intermittently during the 3<sup>rd</sup> quarter 2011.

#### Natural Gas Sales Volumes (mcf/d)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Ante Creek	86	216	93	73
Atlee-Buffalo	35	32	29	32
Claresholm	2,628	3,718	2,868	4,005
Edson	243	316	248	343
Saxon	-	374	-	627
Total	2,992	4,656	3,239	5,080

The decrease in production for 2011 as compared to 2010 occurred because of natural declines, a shut down for plant turn around at the Claresholm natural gas processing plant and the sale of the Saxon property.

Natural gas production for the 1<sup>st</sup> quarter 2011 was 3,537 mcf/day and for the 2<sup>nd</sup> quarter was 3,194 mcf/day. The decrease to 2,992 mcf/day for the 3<sup>rd</sup> quarter of 2011 quarter was attributable to natural production declines and the shut down for plant turn around at the Claresholm natural gas processing plant.

#### Crude Oil Sales volumes (bbl/d)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Ante Creek	28	40	28	13
Claresholm	82	24	54	25
Pouce Coupe	22	-	26	-
Total	133	64	108	38

The increase in oil production for the 3<sup>rd</sup> quarter of 2011 versus the 3<sup>rd</sup> quarter of 2010 is due to the addition of the Pouce Coupe well that was drilled in 2010 and put on stream early in 2011 and intermittent test production from wells drilled at Claresholm during 2011.

Oil production for the 1<sup>st</sup> quarter was 83 bbl/day and 107 bbl/day for the 2<sup>nd</sup> quarter 2011. The increase is due to the addition intermittent test production from wells drilled in 2011 at Claresholm. The increase in oil production for the 9 month period ended September 30, 2011 versus the same period in 2010 was due to the addition of the Pouce Coupe well, a full 9 months of production from Ante Creek and sporadic test production from wells drilled in 2011 at Claresholm.

**Natural Gas Liquids Sales Volumes (bbl/d)**

	<b>Three Months Ended September 30,</b>		<b>Nine Months Ended September 30,</b>	
	<b>2011</b>	<b>2010</b>	<b>2011</b>	<b>2010</b>
Ante Creek	2	5	2	2
Claresholm	40	60	47	64
Edson	8	17	9	18
Saxon	-	2	1	6
<b>Total</b>	<b>50</b>	<b>84</b>	<b>58</b>	<b>90</b>

The decrease to 50 bbl/day for the 3<sup>rd</sup> quarter 2011 from the 84 bbl/day that was recorded for the 3<sup>rd</sup> quarter of 2010 was attributable to natural production declines, a shut in for plant turn around at Claresholm and some adjustments to prior period liquid volumes by the third party processor at Edson.

Natural gas liquids production for the 3<sup>rd</sup> quarter of 2011 was off slightly from the previous quarters in 2011 because of natural declines and the plant turn around at Claresholm.

The 9 month production volumes are down due to natural declines, the sale of the Saxon property and the plant turn around at Claresholm.

**Product Prices****Natural Gas Prices (\$/mcf)**

	<b>Three Months Ended September 30,</b>		<b>Nine Months Ended September 30,</b>	
	<b>2011</b>	<b>2010</b>	<b>2011</b>	<b>2010</b>
Ante Creek	4.12	4.32	4.26	4.32
Atlee-Buffalo	3.77	3.63	3.85	4.19
Claresholm	4.11	3.98	4.21	4.58
Edson	3.90	3.92	4.12	4.49
Saxon	-	4.69	-	4.63
<b>Average Price</b>	<b>4.09</b>	<b>4.04</b>	<b>4.20</b>	<b>4.58</b>

Benchmark AECO C spot prices averaged \$3.66/mcf for the quarter ended September 30, 2011 and \$3.77/mcf for the nine months ended September 30, 2011. This compares to \$3.53/mcf and \$4.11/mcf for the equivalent periods in 2010.

Certain liquids are recombined to Company production giving it a higher heating content resulting in a premium sales pricing over the benchmark price being received.

**Crude Oil Sales Prices (\$/bbl)**

	<b>Three Months Ended September 30,</b>		<b>Nine Months Ended September 30,</b>	
	<b>2011</b>	<b>2010</b>	<b>2011</b>	<b>2010</b>
Ante Creek	82.69	70.88	85.83	70.88
Claresholm	82.58	74.82	88.60	75.90
Pouce Coupe	85.17	-	90.33	-
Average Price	83.04	72.37	88.28	74.12

Benchmark Edmonton Par prices averaged \$91.97 for the quarter ended September 30, 2011 and \$94.34 for the 9 months ended September 30, 2011. This compares to \$74.59 and \$76.65 for the equivalent periods in 2010. The Company sells its oil at the battery and prices that the Company receives are adjusted for pipeline tariffs and quality. As Claresholm production, for the most part, was initial test production that included completion fluids therefore the quality was not what would be expected over the long term.

**Natural Gas Liquids (“NGL”) Sales Prices (\$/bbl)**

	<b>Three Months Ended September 30,</b>		<b>Nine Months Ended September 30,</b>	
	<b>2011</b>	<b>2010</b>	<b>2011</b>	<b>2010</b>
Ante Creek	73.29	45.87	65.52	45.87
Claresholm	74.47	59.79	77.06	64.27
Edson	62.05	51.11	67.12	69.43
Saxon	-	16.00	88.03	83.30
Average Price	72.52	56.68	75.34	65.04

NGL prices that were received moved in tandem with oil prices. The Company’s interests at Saxon were sold in August 2010. The amounts shown in the table above for that area are as a result of relatively small adjustments to prior period revenue invoices by the third party processor that were booked on receipt in 2011.

**Revenue****Total Sales**

<b>\$ Thousands</b>	<b>Three Months Ended September 30,</b>		<b>Nine Months Ended September 30,</b>	
	<b>2011</b>	<b>2010</b>	<b>2011</b>	<b>2010</b>
<b>Oil</b>	1,014	347	2,599	767
<b>NGL</b>	335	431	1,201	1,597
<b>Gas</b>	1,125	1,678	3,714	6,350
<b>Total</b>	2,475	2,456	7,514	8,714

Revenue increased slightly for the three months ended September 30, 2011 over that which was recorded in the equivalent period in 2010 because oil production and oil and natural gas prices were higher for the 3<sup>rd</sup> quarter of 2011 than they were for the 3<sup>rd</sup> quarter of 2010. This was offset in part by the decrease in natural gas production in 2011. Total sales for the 9 months ended September 30, 2011 declined when compared to

the equivalent period last year. This was primarily due to the decline in the average 9 month natural gas volumes and prices in 2011.

#### Natural Gas Sales Revenue

<b>\$ Thousands</b>	<b>Three Months Ended September 30,</b>		<b>Nine Months Ended September 30,</b>	
	<b>2011</b>	<b>2010</b>	<b>2011</b>	<b>2010</b>
Ante Creek	33	57	109	86
Atlee-Buffalo	12	10	31	36
Claresholm	993	1,361	3,295	5,014
Edson	87	114	279	420
Saxon	-	136	-	794
<b>Total</b>	<b>1,125</b>	<b>1,678</b>	<b>3,714</b>	<b>6,350</b>

Natural gas sales were \$1,355 for the 1<sup>st</sup> quarter and \$1,234 for the 2<sup>nd</sup> quarter of 2011.

Natural gas sales decreased primarily due to decreases in volumes as a result of natural declines at Claresholm, the plant turn around at Claresholm and the sale of the Saxon property.

#### Crude Oil Sales Revenue

<b>\$ Thousands</b>	<b>Three Months Ended September 30,</b>		<b>Nine Months Ended September 30,</b>	
	<b>2011</b>	<b>2010</b>	<b>2011</b>	<b>2010</b>
Ante Creek	216	178	665	261
Claresholm	625	169	1,296	506
Pouce Coupe	173	-	637	-
<b>Total</b>	<b>1,014</b>	<b>347</b>	<b>2,599</b>	<b>767</b>

Oil sales increased because of the inclusion of a full 9 months of production from Radius' Ante Creek property, test production from new wells in Claresholm and Pouce Coupe and an increase in oil prices.

Oil sales for the 1<sup>st</sup> quarter 2011 were \$641,000. The increase to \$944,000 in the 2<sup>nd</sup> quarter of 2011 occurred because of the addition of the Claresholm and Pouce Coupe production and an increase in oil prices.

Argosy's strategy going forward is to focus on the development of its oil prospects and thereby increase its oil sales relative to natural gas sales.

### Natural Gas Liquids (NGL) Sales Revenue

\$ Thousands	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Ante Creek	14	15	36	21
Claresholm	277	332	983	1,119
Edson	44	82	161	302
Saxon	-	2	21	155
	335	431	1,201	1,597

In general, natural gas liquids sales revenue decreased because of the sale of the Saxon property and declines at Claresholm which were offset in part by the addition of production from Radius' Ante Creek property and an increase in commodity pricing.

The Saxon property was sold effective August 1, 2010. The figures in the table above for Saxon are as a result of relatively small adjustments made to processing invoices related to past periods that were received and booked in 2011.

### Royalties

\$ Thousands except rates	Area	Rate	Three Months Ended September 30,		Nine Months Ended September 30,			
			2011	2010	2011	2010	Total	Rate
			Total \$	Total \$	Rate	Total \$	Rate	Total \$
	Ante Creek	12%	32	37	8%	65	10%	37
	Atlee-Buffalo	5%	1	1	4%	1	3%	1
	Claresholm	19%	368	94	15%	847	7%	448
	Edson	15%	20	70	18%	79	15%	211
	Pouce Coupe	6%	11	-	4%	26	-	-
	Saxon	-	-	(102)	67%	18	1%	322
	Total	17%	431	100	14%	1,036	7%	596

Royalty expense comprises royalties paid to the Province of Alberta, freehold land owners and overriding royalty owners for the right to produce the oil and natural gas owned by them.

Royalty rates increased at Claresholm because of a negative gas cost allowance applied in 2011 versus a positive one in 2010 and newer production at Claresholm is subject to overriding and freehold rates as opposed to those imposed by the Crown.

In March 2010 the Province of Alberta revised its deep drilling credit program. A Crown royalty credit of \$625 per meter is available for wells drilled that are deeper than 2000 meters (formerly 2,500 meters) to 3,500 meters. This credit is deducted from property, plant and equipment. In 2011, Argosy has received \$275,000 under this program.

The Province of Alberta reduced the royalty rates to 5% on the first year of production on new natural gas and conventional oil wells up to a maximum of 50,000 bbl of oil and 500,000 mcf of natural gas. The only well to which this program applies is the well drilled at Pouce Coupe.

For the nine month period ended September 30, 2011, Crown royalties were \$622,000 (\$183,000 in 2010), gross overriding royalties were \$181,000(\$181,000 in 2010), and freehold royalties were \$233,000(\$232,000 in 2010).

The figures for Saxon in the foregoing table for 2011 arise as a result of relatively small adjustments made to processing invoices related to past periods prior to the rationalization that were received and booked in the 2<sup>nd</sup> quarter 2011.

### Production and Operating Expenses

\$ Thousands except boe	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011	Total	2010	Total	2011	Total	2010	Total
Area	\$/boe	\$	\$/boe	\$	\$/boe	\$	\$/boe	\$
Ante Creek	23.13	95	10.67	80	18.63	234	10.67	80
Atlee-Buffalo	9.63	5	9.35	5	9.75	13	9.43	14
Claresholm	18.03	930	6.31	409	12.55	1,982	5.97	1,233
Edson	13.22	59	10.80	70	10.06	138	10.33	211
Pouce Coupe	49.27	100	-	-	38.77	274	-	-
Saxon	-	-	n/a	2	1.17	1	10.61	323
Total	18.97	1,190	7.32	566	13.71	2,643	7.00	1,861

On a year over year basis, production and transportation expenses increased on a per boe basis.

A plant turnaround was undertaken at Claresholm in the 3<sup>rd</sup> quarter 2011 and this accounted for the bulk of the increase from \$10.58 per barrel that was incurred during the 2<sup>nd</sup> quarter of 2011.

Claresholm operating costs have also increased in absolute terms because as the wells age, more work is required to maintain acceptable levels of production or at least partially offset normal declines. The decline in volumes also causes fixed costs to be spread over fewer production units which in turn lead to an increase in per unit costs.

A portion of Ante Creek production is not operated by the Company and therefore the Company cannot directly control costs. Furthermore, oil production at Ante Creek is trucked thus adding additional transportation costs.

Claresholm natural gas is processed in a Company operated processing plant. Edson and Ante Creek natural gas is processed by third party processors hence the cost of processing is higher. Edson is relatively remote leading to higher operating and transportation costs. To date in 2011, operations have been relatively trouble free.

Start up costs caused the Pouce Coupe operating costs to be high relative to such costs incurred at the Company's other areas.

The Saxon property was rationalized effective August 1, 2010. The figures in the table above for Saxon are as a result of relatively small adjustments made to processing invoices related to past periods prior to the rationalization that were received and booked in the 2<sup>nd</sup> quarter 2011.

Atlee Buffalo volumes are very low and even minor repair and maintenance items have a significant impact on the rate per boe. Overall though, Atlee Buffalo is not material.

Operating costs averaged \$11.18 per barrel for the 1<sup>st</sup> half of 2011. The increase to \$18.97 for the 3<sup>rd</sup> quarter 2011 is largely due to the plant turnaround and declining production at Claresholm and further startup costs at Pouce Coupe.

### ***Field and Corporate Netbacks***

#### **Field Netback**

	<b>Three Months Ended September 30,</b>		<b>Nine Months Ended September 30,</b>	
	<b>2011</b>	<b>2010</b>	<b>2011</b>	<b>2010</b>
	<b>\$/boe</b>			
Ante Creek	33.62	33.74	40.73	33.74
Atlee-Buffalo	11.86	11.40	12.43	14.87
Claresholm	15.04	21.93	17.39	24.03
Edson	11.88	15.03	16.32	19.62
Pouce Coupe	30.39	-	47.81	-
Saxon	-	26.02	28.08	20.12
<b>Field Netback</b>	<b>13.62</b>	<b>21.93</b>	<b>19.90</b>	<b>23.51</b>

Management has concluded that natural gas markets will remain weak for some time to come. On the other hand, it has concluded that the Company must take advantage of its inventory of oil prospects in order to improve profit margins even though the market for oil may be relatively volatile. To that end, the Company has focused its capital resources on the development of its oil opportunities at Claresholm and the completion of its oil well at Pouce Coupe during 2011. Production declines occurred due to no new natural gas wells being put on stream, the rationalization of the Saxon property and because the only intermittent production was realized from oil wells that were in a start up phase. Fixed operating costs then increased on a per barrel basis. Variable operating costs increased due to initial start up costs on new oil wells and because additional costs are required to maintain production from the older wells. In addition, a plant turnaround was undertaken at Claresholm. A negative gas cost allowance adjustment in respect to prior periods was received and booked in the 2<sup>nd</sup> quarter further exacerbating the decrease in field net backs. The increased margins that were realized from oil production from recent drilling as well as the acquisition of Radius' Ante Creek property had the effect of mollifying the decrease.

Field netbacks for the 2<sup>nd</sup> quarter of 2011 averaged \$21.43 per barrel reflecting the effect of the costs of the plant turnaround at Claresholm.

#### **Corporate Netback**

	<b>Three Months Ended September 30,</b>		<b>Nine Months Ended September 30,</b>	
	<b>2011</b>	<b>2010</b>	<b>2011</b>	<b>2011</b>
	<b>\$ Thousands</b>			
Field Netback	854	1,790	3,835	6,256
General and Administrative after acquisition and disposition costs	1,515	1,041	4,475	3,351
<b>Corporate Netback</b>	<b>(661)</b>	<b>749</b>	<b>(640)</b>	<b>2,905</b>

Corporate netback decreased because of decreased volumes increased operating costs and increased general and administrative costs.

General and administrative expenses represent costs which are relatively fixed except for acquisition and disposition costs. However, the Company incurred significant professional fees related to the additional

ongoing complexities related to the acquisition of Radius and related to transition to IFRS. In addition, it retroactively reinstated employee salaries that had been curtailed since 2009. No acquisition or disposition costs were incurred in 2011 while a total of \$721,000 of such costs was incurred in 2010. Acquisition and disposition costs are expensed in accordance with IFRS.

### ***General and Administrative Expense***

(\$ thousands)

<b>\$ Thousands</b>	<b>Three Months Ended September 30,</b>		<b>Nine Months Ended September 30,</b>	
	<b>2011</b>	<b>2010</b>	<b>2011</b>	<b>2010</b>
Salary & Benefits, net	686	503	2,712	1,492
Share Based Payments	270	122	434	255
General Office Expenses	661	309	1,640	1,056
Acquisition and disposition Related Costs	-	391	-	721
Total before recoveries	1,617	1,203	4,786	3,524
Recoveries	(102)	(284)	(311)	(173)
Total	1,515	1,041	4,475	3,351

The increase in salary & benefits arose because of the retroactive reinstatement in the 2<sup>nd</sup> quarter of salaries that had been curtailed. Share based payments increased because of the granting of stock options in 2011. General office expenses increased due to increases in professional fees caused by the increased complexities arising from the acquisition of Radius and the transition to IFRS and the recognition of additional obligations related to the Company's office leases

The adoption of IFRS on January 1, 2010 required that the Company account for acquisition and disposition related costs as expenses in the periods in which the costs were incurred and the services received. In 2010, \$330,000 of costs related to the Radius acquisition was expensed, \$40,000 in the 1<sup>st</sup> quarter and \$290,000 in the 2<sup>nd</sup> quarter. The Radius acquisition closed in May 2010.

General and administrative expense amounted to \$1,888,000 for the 2<sup>nd</sup> quarter 2011. The reduction to \$1,515,000 that was recorded for the 3<sup>rd</sup> quarter occurred because of the retroactive reinstatement in the 2<sup>nd</sup> quarter of salaries that had been curtailed.

Approximately \$223,000 (\$189,000 in 2010) of direct salary costs related to geological and geophysical personnel per quarter have been capitalized for the period ended September 30, 2011. Approximately \$31,000 of stock based compensation was capitalized in the 9 months ended December 31, 2011 (\$72,000 for the equivalent period in 2010). No other salary or overhead charges are capitalized.

### ***Finance Expenses***

Finance expenses under IFRS include accretion on decommissioning obligations and interest on the Company's credit facilities. Under CGAAP, finance expenses included only interest expense and the accretion on the decommissioning obligations was included in depreciation, depletion and accretion.

Finance expense is comprised of:

<b>\$ Thousands</b>	<b>Three Months Ended September 30,</b>		<b>Nine Months Ended September 30,</b>	
	<b>2011</b>	<b>2010</b>	<b>2011</b>	<b>2010</b>
Interest	229	213	463	687
Accretion	31	42	94	79
<b>Total</b>	<b>260</b>	<b>255</b>	<b>557</b>	<b>766</b>
Average bank indebtedness	19,334	16,015	16,157	15,117
Implied interest rate	4.7%	5.3%	4.5%	6.1%

Argosy utilized its operating line of credit, funds from share issuances and property divestitures to fund its capital program.

Average bank indebtedness increased primarily because capital expenditures exceeded financings and proceeds received from the sales of properties. The variations in rate relate to the application of the Bank's pricing grid which relies on prior period bank indebtedness balances.

The increase in accretion expense is primarily related to the Radius acquisition.

### ***Share-based Payments***

Stock-based compensation is accounted for using the fair value method using the Black-Scholes model to calculate the value at the date of the grants. Under IFRS, stock based compensation expense is recognized over the vesting periods on a graded basis which results in higher charges to stock based compensation in the early years of each grant. Forfeitures were estimated at 2% per year.

As at September 30, 2011 there were 2,223,500 options outstanding.

In the 1<sup>st</sup> quarter of 2011, 425,000 options with an exercise price of \$2.40 were granted. The fair value of these options was estimated to be \$556,000 (\$1.36 per option granted).

In the 3<sup>rd</sup> quarter of 2011, 365,500 options with an exercise price of \$2.33 were granted. The fair value of these options was estimated to be \$486,000 (\$1.33 per option granted).

### ***Depletion and Depreciation***

Under IFRS, depletion and depreciation expense is computed on a unit of production basis based on proved and probable reserves on an area basis. Depletion and depreciation on a boe basis varies from period by period primarily because of changes in proved plus probable reserves in the reserve base as well as changes in costs subject to depletion and depreciation, including future development costs.

### ***Impairment of Property and equipment***

The Company was required to perform impairment testing on the adoption of IFRS and subsequently if there are indicators of impairment in subsequent periods. Such impairment testing is done at the Cash Generating Unit ("CGU") level. Impairment is recorded if the CGU's carrying amount is greater than the value of the discounted cash flows expected to be derived from it. A CGU is the smallest identifiable grouping of assets that generates independent cash inflows.

The CGUs were tested for impairment at January 1, 2010 on adoption of IFRS and again at December 31, 2010 because there were indicators of impairment. The recoverable amount of the CGU's were estimated based on the higher of the value in use and the fair value less costs to sell. The estimate of fair value less costs to sell was determined using a discount rate of 12 percent and forecasted cash flows, with escalating prices and future development costs, as obtained from the reserve report prepared by the Company's independent industry reserve engineers. The prices used to estimate the fair value less cost to sell are those used by independent industry reserve engineers.

Management concluded that there were no indicators of impairment of its CGUs during the 9 month period ended September 30, 2011.

### ***Income Taxes***

Argosy has approximately \$53 million of income tax pools and \$8 million of operating loss carry-forwards at September 30, 2011 and does not anticipate being cash taxable in 2011.

### ***Cash Flow***

Cash flow for the nine month period ended September 30, 2011 was \$(366,000), ((\$0.02) per share) versus \$1,061,000 (\$0.07 per share) for the equivalent period last year.

Cash flow decreased because of decreased volumes and increased royalties, operating and general and administrative costs.

### ***Sensitivities***

The Company is in the process of exploiting its oil opportunities with a view to increasing oil production relative to natural gas. If the Company is successful, the impact of oil production and changes in oil prices are expected to have more impact whereas changes in natural gas volumes and prices are expected to have less impact on financial results. The following analysis was prepared by applying various pricing, volume and interest rate assumptions to the Company's 2011 forecast.

<b>\$ Thousands</b>	<b>Cash Flow and Pretax Earnings</b>
<hr/>	
Forecast of impact on Company estimates for the year ended December 31, 2011	
Change in Canadian crude oil of \$1/bbl	411
Change in natural gas price of \$0.10 / mcf	309
Change in natural gas liquids price of \$1 / bbl	208
Change in interest rate of 1%	160
Change in production of crude oil of 100 bbl/day	2,977
Change in production of natural gas liquids of 100 bbl/day	2,127
Change in production of natural gas production of 1,000 mcf/day	1,507

***Capital Expenditures***

<b>\$ Thousands</b>	<b>Three Months Ended September 30, 2011</b>	<b>Nine Months Ended September 30, 2011</b>
Drilling and completions	5,150	21,969
Geology and geophysical	380	987
Equipping and tie-ins	897	2,195
Land and producing property acquisitions, net	4,561	9,402
Office equipment	1	26
<b>Total expenditures</b>	<b>10,989</b>	<b>34,579</b>

The Company finished drilling and completed a 100% owned oil well at Pouce Coupe that was spudded in December of 2010 during 2011. The Company also drilled three 100% oil wells at Claresholm in 2011. One of these wells was put on stream on a test basis in June 2011 whilst another of the wells was put on stream on a test basis in August. The third well was completed late in September and shut in for pressure buildup. The Company also purchased over 17 sections of 100% owned land in the Claresholm area and 1 section of land in the Edson area during 2011. The Company also disposed of certain non-producing acreage in the Ante Creek area in response to an unsolicited offer for gross proceeds of \$4.6 million. The Company had concluded that the particular acreage that was disposed was surplus to its needs.

### *Quarterly Financial Information*

<b>Three Months Ended (\$000's) except per share data)</b>	<b>Sept. 30, 2011</b>	<b>June 30, 2011</b>	<b>Mar. 31, 2011</b>	<b>Dec. 31, 2010</b>	<b>Sept. 30, 2010</b>	<b>June 30, 2010</b>	<b>Mar. 31, 2010</b>	<b>Dec. 31, 2009<sup>(2)</sup></b>
Total assets	74,261	65,826	55,274	42,808	49,536	69,536	64,424	73,989
Total sales (boe/d)	682	701	736	770	924	1,098	954	724
Total sales \$	2,475	2,630	2,409	2,260	2,456	3,064	3,193	2,297
Cash flow <sup>(1)</sup>	(659)	560	515	397	597	1,037	1,092	(16)
Net income (loss)	(1,702)	1,689	(439)	(9,166)	(2,650)	1,493	(127)	(1,757)
Net income (loss) per share basic	(0.08)	0.08	(0.02)	(0.58)	(0.18)	0.10	(0.01)	(0.11)
Net income (loss) share diluted	(0.10)	0.08	(0.02)	(0.58)	(0.18)	0.10	(0.01)	(0.11)
Capital expenditures	34,579	26,967	13,327	5,056	2,222	1,009	5,375	3,685
Working capital; (deficiency)	(25,181)	(24,339)	(13,889)	(13,577)	(8,377)	(23,607)	(22,096)	(21,153)
Shareholders' equity	43,333	36,361	37,220	25,332	33,549	37,634	33,548	38,950

Notes:

<sup>(1)</sup>This financial information has been extracted from Argosy's unaudited quarterly and audited annual financial statements prepared in accordance with the accounting principles as outlined in the notes to the consolidated financial statements for 2011 and 2010 except for "cash flow" which is a non-prescribed measure under IFRS and previous to that, CGAAP.

<sup>(2)</sup>Argosy's IFRS transition date was January 1, 2010, therefore 2009 comparative information was calculated in accordance with CGAAP has not been restated.

### *Factors That Have Caused Variations Over the Quarters*

The variations in the Company's revenues, net earnings and cash flow are generally caused by fluctuations in realized market prices for oil and natural gas and in production volumes caused by drilling activity offset by production declines.

Total assets, total sales and net income increased between March 31, 2010 and September 30, 2010 because of the acquisition of Radius Resources Inc. for a cash consideration of \$2,629,588 and the issuance of 748,000 Argosy common shares at a deemed price of \$0.70 per share. A pretax gain of \$2,228,000 was recorded on the acquisition in the quarter ended September 30, 2010 because the assigned values of the assets acquired exceeded the sum of the cash consideration and the value of the shares issued. A portion of the cash required was offset by the issuance of 500,000 shares for gross proceeds of \$1,000,000 in the period.

Total assets, total sales, revenue and working capital deficiency decreased significantly between September 30, 2010 and September 30, 2011 because the Company sold its interests in the Saxon area for gross cash proceeds of \$16,710,000.

Total assets increased and working capital deficiency decreased in the first half of 2011 because the company issued 4,000,000 shares for gross proceeds of \$12,550,000 and it sold certain non-productive interests in the Ante Creek area for gross proceeds of \$4,555,000. The funds were used in part to reduce bank indebtedness and to fund the Company's drilling and land acquisition activities primarily in the Claresholm area.

During the 3<sup>rd</sup> quarter of 2011, the Company issued 2,000,000 common shares at a price of \$3.35 per share on a flow through basis for net proceeds of \$6,200,000. The funds were used to fund the Company's drilling activities primarily in the Claresholm area.

The Company focused its capital resources on the development of its oil opportunities at Claresholm and the completion of its oil well at Pouce Coupe during 2011. Because no new natural gas wells were drilled, because the Company rationalized its Saxon property and because test production from the new oil wells was intermittent, production on a boe basis declined. Fixed operating costs then increased on a per barrel basis. Variable operating costs increased due to initial start up costs on new oil wells and because additional costs are required to maintain production from the older wells. In addition, a plant turnaround was undertaken at Claresholm. A negative gas cost allowance adjustment in respect to prior periods was received and booked in the 2<sup>nd</sup> quarter further exacerbating the decrease in field net backs. The increased margins that were realized from oil production from recent drilling as well as the acquisition of Radius' Ante Creek property partially offset the decrease in production volumes.

### ***Liquidity and Capital Resources***

2011 Exploration and development program funding

	\$ (thousands)
Cash, Beginning of period	93
Cash flow	(366)
Change in non-cash working capital	3,534
Increase in Bank Debt	7,319
Issue of Capital Stock	19,444
Cash, end of period	-
<b>Net capital expenditures</b>	<b>30,024</b>

Argosy normally endeavors to fund its capital expenditure program from internally generated cash flow, debt, farm-ins, farm outs and additional equity or other funding if available on favorable terms. However the Company may, from time to time, rationalize assets that are deemed superfluous to its needs.

In January 2011, 255,949 warrants to purchase common shares were exercised for gross proceeds of \$575,885. In February 2011, the Company issued 4,000,000 common shares for gross proceeds of \$12,550,000. In March 2011, 250,000 warrants to purchase common shares were exercised for gross proceeds of \$562,500. In May 2011, 200,734 warrants to purchase common shares were exercised for gross proceeds of \$451,652. The Company closed the sale of certain lands in the Ante Creek area for proceeds of approximately \$4,500,000 in April 2011. In June 2011, the Company's Bank increased the credit limits from \$22 million to \$26 million on its Revolving Operating Demand Loan Facility as a result of a review of the Company's credit facilities. In July 2011, the Company issued 2,000,000 common shares for gross proceeds of \$6,700,000.

On November 14, 2011, the Company announced that it had agreed to a bought-deal financing under which it would issue 1,500,000 common shares at a price of \$2.00 per share and 3,404,256 common shares on a flow through basis at a price of \$2.35 per share for total gross proceeds of \$11 million. The Company has also agreed an overallotment option to its underwriters for an additional 225,000 common shares for additional gross proceeds of \$0.5 million if exercised.

The foregoing financing activities together with expected cash flow should provide sufficient funds to fund the Company's short term growth.

Funding for medium to long term growth will be dependent on future exploration success, commodity prices and capital markets.

Commodity prices and production volumes have a large impact on the ability of the Company to finance its capital program. Commodity prices and production volumes affect Argosy's ability to generate adequate cash flow. Moreover, bank financing is dependent on the value of the Company's reserves which are in turn affected by commodity prices, production volumes and drilling success.

It should be noted that a prolonged period of low commodity prices would negatively affect cash flow from operations and would likely result in a reduction in the amount of cash flow available for investment in drilling programs which would in turn negatively impact future production volumes and reserves. A prolonged period of low commodity prices may also negatively affect the availability of funds that might be available by way of bank financing because the bank financing is dependent on the value of the Company's reserves. The value of the Company's reserves would be negatively impacted by commodity pricing and lower production volumes.

A prolonged period of low commodity prices may also negatively affect the availability of funds that might be available in the equity markets as well. Future activities may require Argosy to alter its capitalization significantly through the issuance of additional capital stock.

At September 30, 2011 the Company's credit facilities comprised a Revolving Operating Demand Loan Facility with a credit limit of \$26,000,000 and an Acquisition/Development Demand Facility with a credit limit of \$4,000,000. At that date the Company had drawn \$19,883,000 against the Revolving Operating Demand Loan Facility and nil against the Acquisition/Development Demand Facility.

The Revolving Operating Demand Loan Facility bears interest at Bank prime plus a percentage determined quarterly ranging from .75% to 2.5% greater than the Bank's prime rate in accordance with the Bank's pricing grid. The Bank's pricing grid is dependent on the Company's debt to cash flow ratio where debt is defined by the Bank as working capital deficit, consolidated long-term debt including capital leases and retractable preferred shares which are retractable at the option of the holder and cash flow is defined by the Bank as net earnings, depletion, depletion and accretion, future income taxes and other charges to income not requiring a cash payment calculated for the most recently completed quarter and annualized. The application of the Bank's pricing grid resulted in a rate was approximately 1% over the Bank's prime rate. The Revolving Operating Demand Loan Facility bears a standby fee of between 0.2% and 0.45% on the undrawn portion of the loan facility.

The Revolving Operating Demand Loan Facility has no specific terms of repayment aside from the Bank's right of demand and periodic review. The Acquisition/Development Demand Loan requires unspecified monthly principal repayments over the engineering half life of the reserves being financed as determined by the Bank

The Acquisition/Development Demand Loan Facility is restricted to the acquisition of proved non-producing/undeveloped petroleum and natural gas reserves and/or development of proved producing/undeveloped petroleum and natural gas reserves, bears interest at a rate which is 0.5% higher than the Revolving Operating Demand Loan and bears a standby fee of between 0.2% and 0.45% on the undrawn portion of the loan facility.

Security for the facilities includes a general assignment of book debts, a \$75,000,000 debenture with a first floating charge over all assets with a negative pledge and an undertaking to provide fixed charges on the Company's major producing reserves at the request of the bank.

A covenant to the Revolving Operating Demand Loan Facility requires that the Company maintain a working capital ratio, exclusive of bank indebtedness, of at least 1 to 1. For purposes of this calculation, the undrawn availability under the Revolving Operating Demand Loan Facility is added to current assets. A covenant to the Revolving Operating Demand Loan facility requires that the Company limit hedging activities to 50% of actual production.

There is no similar working capital requirement for the Acquisition/Development Demand Loan.

There is no debt to equity requirements related to either of the facilities.

The Company was in compliance with all debt covenants at September 30, 2011.

The last review of the Company's borrowing limits occurred in June 2011. The next review is scheduled for November 2011. There can be no assurance that other amounts or terms will not change at the next scheduled bank review of the Company's borrowing limits.

### ***Contractual Obligations***

The Company's banking commitments are outlined in *Liquidity and Capital Resources*.

On February 11, 2011 the Company issued 1,000,000 common flow through shares at an issuance price of \$3.70 per share. The tax deductions related to these flow through shares will be renounced to flow through shareholders. The Company incurred the \$3,700,000 of qualifying Canadian Exploration Expenditures required to fulfill its flow through obligation in the first quarter of 2011.

On July 12, 2011 the Company issued 2,000,000 common shares pursuant to a bought deal private placement. These common shares were issued as flow through shares at a price of \$3.35 per flow through share for aggregate proceeds of \$6.7 million. The Company is committed to incur \$6.7 million of Canadian Exploration Expenses prior to December 31, 2012 in respect to this issuance. The Company incurred \$4.0 million of qualifying Canadian Exploration Expenditures required to fulfill its flow through obligation to the end of the third quarter of 2011.

On November 14, 2011, the Company announced that it had agreed to a bought-deal financing under which it would issue 1,500,000 common shares at a price of \$2.00 per share and 3,404,256 common shares on a flow through basis at a price of \$2.35 per share for total gross proceeds of \$11 million. The Company has also agreed an overallotment option to its underwriters for an additional 225,000 common shares for additional gross proceeds of \$0.5 million if exercised.

The Company has entered into various commitments related to the leasing of office premises. The payments due under such leases are as follows:

<b>Contractual obligations (\$ thousands)</b>	<b>2011</b>	<b>2012</b>	<b>2013</b>	<b>2014</b>	<b>2015</b>	<b>Thereafter</b>
Office Premises	174	808	879	609	-	-

### ***Risk Management***

There have been no changes in risk from those described in the Management's Discussion and Analysis for the year ended December 31, 2010.

## ***Outlook***

The Company is in the midst of a process that will result in the change of its focus from natural gas projects to those that can deliver quality, low cost oil production and reserve additions. Fortunately, Argosy is well positioned to take advantage of this situation.

At Claresholm Argosy has extended the Exshaw/Bakken resource play currently being developed just south of the US Canadian border in Northern Montana onto its lands., The Company drilled one vertical well in the 4<sup>th</sup> quarter of 2010 that established oil in two horizons. The upper Banff horizon was completed for vertical production late in 2010. However, the Company is of the opinion that the oil bearing reservoirs found are more ideally suited to horizontal development. A lower Big Valley horizontal well, a Banff horizontal well and a Baron's horizontal well were drilled in 2011. The Company is still evaluating the results of this drilling. It will direct additional capital spending to oil well drilling in the Claresholm area if the proposed multistage fracking technology proves to be economic for these reservoirs.

At Pouce Coupe, the Company has drilled a horizontal oil well to the Boundary Lake formation. The well was spudded in December 2010, completed in January 2011 and was put on stream in February 2011. This well promises to be an important contributor to the Company's cash flow once its production rate stabilizes.

At Ante Creek, recent industry drilling directly offsetting the Company's lands has validated the potential of production from the Montene formation of which 70% is light oil. The Company has identified 11 horizontal locations on its 100% working interest lands. It has also identified a deeper horizontal target.

In order to rationalize its asset base and focus on opportunities in the Alberta Bakken at Claresholm, the Company began actively marketing the sale of its Edson and Ante Creek CGU's in October 2011. The closing date for bids on such CGU's is scheduled for late November 2011. The Company expects that such bids will be substantial and that the proceeds from such sales will provide additional funding for its exploration efforts at Claresholm.

## ***Critical Estimates***

The Company's unaudited interim condensed consolidated financial statements have been prepared in accordance with IFRS.

Management is required to make appropriate decisions in respect to assumptions and estimates that impact the reported amounts balance sheet and income statement items. As the determination of accounts receivable, accounts payable, revenues and expenses is dependent upon future events, the preparation of these financial statements requires the use of estimates and assumptions which have been made using careful judgment. Areas requiring the use of management estimates include estimates of revenues, royalties and production costs at a specific reporting date but for which actual revenues and costs have not yet been received, estimates on capital projects which are in progress or recently been completed where actual costs have not been received at a specific reporting date, collectability of accounts receivable, recoverability of petroleum and natural gas interests, rates of depletion and depreciation, accrued liabilities, determination of decommissioning liabilities, the assessment of impairment of oil and gas assets, assumptions used in the calculation of stock-based compensation, allocation of proceeds for units between common shares and warrants, the classification of the Company's derivative contracts and the determination of the valuation allowance for future tax assets.

Amounts recorded for depreciation and depletion, and amounts used for impairment test calculations are based on estimates of oil and natural gas reserves. The company's credit facilities are also based on such estimates. The Company's reserve estimates are reviewed annually by an independent engineering firm. By their nature, these estimates of reserves and future cash flows are subject to measurement uncertainty, and the impact on the financial statements of future periods could be material.

The Company ensures that the individuals with the most knowledge of the activity are responsible for the estimate. Estimates and assumptions used in this regard are reviewed by management for reasonableness on a regular basis and past estimates are compared to actual results in order to make informed decisions on future estimates.

As time passes, new information may be gleaned or circumstances may change and this may cause the estimates to change materially from the current estimates.

Management believes the estimates that have been made in conjunction with the preparation of the Company's unaudited interim condensed consolidated financial statements are reasonable within reasonable limits of materiality and within the framework of the significant accounting policies adopted by the Company; however, actual results could differ from those estimates and could impact future results of operations and cash flows.

### ***Disclosure Controls and Internal Controls over Financial Reporting***

Argosy's Chief Executive Officer and Chief Financial Officer have designed or caused to be designed under their supervision, disclosure controls and procedures ("DC&P") to provide reasonable assurance that (i) material information relating to the Company and its consolidated subsidiaries is made known to Argosy's Chief Executive Officer and Chief Financial Officer by others; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

Argosy's Chief Executive Officer and Chief Financial Officer have designed or caused to be designed under their supervision, Internal Controls over Financial Reporting ("ICFR") to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with IFRS.

The control framework that Argosy's officers used to design the ICFR is the *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations.

No material changes in Argosy's ICFR were identified during the three months ended September 30, 2011 that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting. There were no material changes to ICFR as a result of the transition to IFRS.

It should be noted that while the Company's Chief Executive Officer and Chief Financial Officer believe that the Company's DC&P and ICFR provide a reasonable level of assurance that they are effective, such controls and procedures cannot provide absolute assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud. Furthermore, ICFR has inherent limitations no matter how well designed such controls may be. Control systems can provide reasonable, not absolute, assurance that the objectives of the control system are met.

The Company's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of September 30, 2011, that the Company's disclosure controls and procedures as at such date are effective to provide reasonable assurance that material information related to the Company, including its consolidated subsidiary, is made known to them by others within those entities.

***IFRS***

The Company adopted IFRS effective January 1, 2011. The Company's financial results for the first quarter of 2011 together with the results of the comparative periods in 2010 are reported using the IFRS principles. Certain selected comparative historical data for periods prior to 2010 is reported using CGAAP principles. Refer to the notes to the unaudited interim consolidated financial statements for further reconciliations of the impact of the transition to IFRS from CGAAP as well as a listing of the significant accounting policies adopted by the Company.

Refer to note 15 of the unaudited interim condensed consolidated financial statements for the reconciliations to Canadian GAAP for the consolidated statement of financial position as at September 30, 2010 and the consolidated statement of operations for the nine and three months ended September 30, 2010.

**Argosy Energy Inc.**  
**Condensed Consolidated Statements of Financial Position**  
**Unaudited**

(\$ Thousands)	September 30, 2011	December 31, 2010 (Note 15)
<b>ASSETS</b>		
Current assets		
Cash	-	93
Accounts receivable and accruals	1,662	1,411
Prepaid expenses and deposits	765	1,041
Fair value derivative contracts (note 13)	-	134
	2,427	2,679
Deferred taxes	-	639
Exploration and evaluation assets (note 8)	33,073	3,367
Property, plant and equipment (note 7)	38,761	36,762
	74,261	43,447
<b>LIABILITIES</b>		
Current liabilities		
Accounts payable and accruals	7,045	3,537
Onerous contracts	319	155
Premium liability (note 12)	361	-
Bank indebtedness (note 11)	19,883	12,564
	27,608	16,256
Onerous contracts	545	427
Deferred taxes	1,194	-
Decommissioning obligations (note 9)	1,581	1,432
	30,928	18,115
<b>SHAREHOLDERS' EQUITY</b>		
Share capital (note 12)	67,403	49,737
Contributed surplus	2,489	1,702
Deficit	(26,559)	(26,107)
	43,333	25,332
	74,261	43,447

Subsequent events –Note 14.

See accompanying notes to unaudited interim condensed consolidated financial statements.

**Argosy Energy Inc.**  
**Condensed Consolidated Statements of Operations and Comprehensive Income**  
**Unaudited**

	Three months ended September 30,		Nine months Ended September 30,	
	2011	2010 (note 15)	2011	2010 (note 15)
<b>(\$ Thousands except for per share information)</b>				
Revenue:				
Oil and gas sales	2,475	2,456	7,514	8,713
Royalties	(431)	(100)	(1,036)	(596)
Revenue, net of royalties	2,044	2,356	6,478	8,117
Realized gain on derivative contracts (note 13)	-	183	22	256
Unrealized gain (loss) on derivative contracts (note 13)	-	150	-	656
	2,044	2,689	6,500	9,029
Operating expenses	1,190	566	2,643	1,861
Depletion and depreciation	742	1,141	2,327	3,638
General and administrative	1,515	1,041	4,475	3,351
Impairment loss (note 10)	-	10,050	-	10,050
Gain on disposition	(107)	(6,174)	(4,082)	(6,174)
Income (loss) from operating activities	(1,296)	(3,935)	1,137	(3,697)
Finance expenses	260	255	557	766
Income (loss) before taxes	(1,556)	(4,190)	580	(4,463)
Gain on acquisition – Radius Resources Corp.	-	-	-	2,228
Deferred income taxes (recovery)	146	(1,540)	1,032	(951)
Loss and comprehensive loss for the period	(1,702)	(2,650)	(452)	(1,284)
Basic and diluted loss per share	(0.08)	(0.17)	(0.03)	(0.09)

Subsequent events – Note 14.

See accompanying notes to unaudited interim condensed consolidated financial statements.

**Argosy Energy Inc.**  
**Condensed Consolidated Statements of Changes in Shareholders' Equity**  
**Unaudited**

(\$ Thousands except number of common shares)	<b>Number Of Common Shares</b>	<b>Share Capital</b>	<b>Contributed Surplus</b>	<b>Deficit</b>	<b>Total Shareholder's Equity</b>
Balance at January 1, 2010 (notes 12 and 15)	12,853,197	45,837	1,292	(16,263)	30,866
Issued pursuant to private placement	2,000,004	3,600	-	-	3,600
Share based payments	-	-	392	-	392
Income for the period	-	-	-	(1,759)	(1,759)
Issued – Radius acquisition	748,000	524	-	-	524
Share issuance costs, net of tax	-	(27)	-	-	(27)
<b>Balance at September 30, 2010 ( notes 12and 15)</b>	<b>15,601,201</b>	<b>49,934</b>	<b>1,684</b>	<b>(18,022)</b>	<b>33,596</b>
Balance at January 1, 2011 (notes 12 and 15)	15,536,939	49,204	1,702	(26,107)	24,799
Issued pursuant to prospectus	4,000,000	11,800	-	-	11,800
Issued pursuant to private placement – exercise of warrants	706,683	1,794	-	-	1,794
Issued pursuant to private placement	2,000,000	5,800	-	-	5,800
Share issuance costs, net of tax	-	(1,195)	-	-	(1,195)
Share Based Payments	-	-	458	-	458
Loss for the period	-	-	-	(452)	(452)
Warrants expired	-	-	329	-	329
<b>Balance at September 30, 2011 (notes 12 and 15)</b>	<b>22,243,622</b>	<b>67,403</b>	<b>2,489</b>	<b>(26,559)</b>	<b>43,333</b>

Subsequent events –Note 14.

See accompanying notes to unaudited interim condensed consolidated financial statements

**Argosy Energy Inc.**  
**Condensed Consolidated Statements of Cash Flows**  
**Unaudited**

(\$ Thousands)	Nine months ended September 30	
	2011	2010 (note 15)
<hr/>		
Cash provided by (used in):		
<b>Cash provided by (used in) Operations</b>		
Income (loss) for the period	(452)	(1,284)
Adjustments for:		
Share based payments	434	282
Onerous contracts	281	(28)
Deferred income tax	1,032	(951)
Unrealized (gain) on derivative contracts	-	(656)
Gain on sale on E&E assets	(4,082)	-
Depletion and depreciation	2,327	3,638
Accretion	94	60
Changes in non-cash working capital (note 6)	707	(2,306)
	<hr/> 341	<hr/> (1,245)
<b>Investing</b>		
Capital expenditures	(34,579)	7,252
Proceeds from disposition	4,555	-
Changes in non-cash working capital (note 6)	2,827	(472)
	<hr/> (27,197)	<hr/> 6,780
<b>Financing</b>		
Increase (decrease in) Bank indebtedness	7,319	(13,225)
Proceeds from issue of share capital, net of issue costs	19,444	3,991
	<hr/> 26,763	<hr/> (9,234)
<b>Increase (decrease) in cash</b>		
Cash – beginning of period	93	4,300
Cash – end of period	<hr/> -	<hr/> 601
<hr/>		
Supplemental Information :		
Interest paid in cash	463	687
<hr/>		

Subsequent events –Note 14.

See accompanying notes to unaudited interim condensed consolidated financial statements

**Argosy Energy Inc.**  
**Notes to the Unaudited Interim Condensed Consolidated Financial Statements**  
**For the Three and Nine Months Ended September 30, 2011 and 2010**

**Reporting entity**

Argosy Energy Inc. (“Argosy” or the “Company”) is an independent public Company engaged in the acquisition, exploration, exploitation, development and production of crude oil and natural gas from its principal producing properties at Claresholm and Edson in Alberta, Canada.

On May 14, 2010, Argosy acquired 100% of the issued and outstanding shares of Radius Resources Corp. (Radius) which became and remains the Company’s only subsidiary. Radius has oil and gas operations primarily focused in the Ante Creek area of Alberta, Canada.

**1. Basis of preparation**

Statement of compliance

The unaudited interim condensed consolidated financial statements (the “financial statements”) have been prepared in accordance with International Accounting Standard 34 *Interim Financial Reporting*. These are the Company’s third unaudited consolidated condensed interim financial statements prepared under International Financial Reporting Standards (“IFRS”) for part of the period covered by the first IFRS annual financial statements and IFRS 1 *First-time Adoption of International Accounting Reporting Standards* has been applied. The unaudited interim condensed consolidated financial statements do not include all of the information required for full annual financial statements.

The Company’s significant accounting policies under IFRS are presented in note 2. These policies have been retrospectively and consistently applied except where specific exemptions permitted an alternative treatment on transition to IFRS in accordance with IFRS 1. The impact of the adoption of the new standards on the reported financial position, financial performance and cash flow is presented in note 15.

These unaudited interim condensed consolidated financial statements were approved for issue by the Company’s Board of Directors on November 14, 2011.

Basis of measurement

The unaudited interim condensed consolidated financial statements have been prepared on the historical cost basis except for derivative financial instruments, which are measured at fair value. The methods used to measure fair values are disclosed in note 3.

Functional and presentation currency

The unaudited interim condensed consolidated financial statements are presented in Canadian dollars which is the Company and its subsidiary’s functional currency.

Use of Estimates and judgments

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Significant areas where estimation uncertainty and critical judgments are applied include valuation of financial instruments, valuation of property, plant and equipment, impairment losses, depletion and depreciation, decommissioning obligations, onerous contracts, deferred taxes and measurement of stock-based compensation.

Reserve estimates impact a number of the areas referred to above, in particular, the valuation of property, plant and equipment and the calculation of depletion and depreciation.

## **2. Significant accounting policies**

The accounting policies set out below have been applied consistently to all periods presented in these unaudited interim condensed consolidated financial statements, and have been applied consistently by the Company and its subsidiary.

### **a. Basis of consolidation:**

#### **Subsidiaries**

Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, potential voting rights that currently are exercisable are taken into account. The financial statements of subsidiaries are included in the interim condensed unaudited consolidated financial statements from the date that control commences until the date that control ceases.

The purchase method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their recognized amounts (generally fair value) at the acquisition date. The excess of the cost of acquisition over the recognized amounts of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of acquisition is less than the fair values of the net assets of the subsidiary acquired, a bargain purchase gain is recognized immediately in the consolidated statement of income.

#### **Jointly controlled operations and jointly controlled assets**

Many of the Company's oil and natural gas activities involve jointly controlled assets. The unaudited interim condensed consolidated financial statements include the Company's share of these jointly controlled assets and the proportionate share of the relevant revenue and related costs.

#### **Transactions eliminated on consolidation**

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the unaudited interim condensed consolidated financial statements.

b. Financial instruments:

Non-derivative financial instruments.

Non-derivative financial instruments comprise cash, accounts receivable and accruals, accounts payables and accruals and bank indebtedness. Non-derivative financial instruments are recognized initially at fair value, plus, for instruments not classified as “fair value through profit or loss”, any directly attributable transaction costs. Subsequent to initial recognition, non-derivative financial instruments are measured as described below.

Cash

Cash comprise cash on hand, term deposits and other short-term highly liquid investments with original maturities of three months or less and is measured similar to other non-derivative financial instruments.

Other

Other non-derivative financial instruments, comprising accounts receivable and accruals, accounts payable and accruals and bank indebtedness are measured at amortized cost using the effective interest method, less any impairment losses. The Company nets all transaction costs incurred in relation to the acquisition of a financial asset or liability, against the related financial asset or liability. Bank indebtedness is recorded net of issue costs and are presented net of deferred interest payments, with interest recognized in earnings on an effective interest basis.

Derivative financial instruments.

The Company has entered into certain financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices. These instruments are not used for trading or speculative purposes. The Company has not designated its financial derivative contracts as effective accounting hedges, and thus has not applied hedge accounting, even though the Company considers all commodity contracts to be economic hedges. As a result, all financial derivative contracts are classified as “fair value through profit or loss” and are recorded on the statement of financial position at fair value. Transaction costs are recognized in profit or loss when incurred.

The Company accounts for forward physical delivery sales contracts, which are entered into and held for the purpose of delivery or receipt of non-financial items in accordance with expected sale or usage requirements as executory contracts. As such, these contracts are not considered to be derivative financial instruments and have not been recorded at fair value on the statement of financial position. Settlements on these physical sales contracts are recognized in oil and natural gas revenue.

Embedded derivatives are separated from the host contract and accounted for separately if the economic characteristics and risks of the host contract and the embedded derivative are not closely related, a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative, and the combined instrument is not measured at “fair value through profit or loss”. Changes in the fair value of separable embedded derivatives are recognized immediately in profit or loss.

### Share capital.

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares and stock options are recognized as a deduction from equity, net of any tax effects.

### c. Property, plant and equipment:

#### i. Recognition and measurement

##### Exploration and evaluation expenditures

Pre-license costs are recognized in the statement of operations and comprehensive income as incurred. The Company has not incurred any such costs.

Exploration and evaluation costs, including the costs of acquiring undeveloped land and drilling costs are initially capitalized until the drilling of the well is complete and the results have been evaluated. The costs are accumulated in cost centres by well, field or exploration area pending determination of technical feasibility and commercial viability. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved reserves are determined to exist. If proved and or probable reserves are found, the drilling costs and associated undeveloped land are tested for impairment and transferred to property, plant and equipment. The cost of undeveloped land that expires or any impairment recognized during a period, is charged as additional depletion and depreciation expense unless it is related to a viable Cash Generating Unit ("CGU") in which case such costs will transferred to the applicable CGU.

Exploration and evaluation assets are assessed for impairment if sufficient data exists to determine technical feasibility and commercial viability, and if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

##### Development and production costs.

Items of property, plant and equipment, which include oil and gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Development and production assets are grouped into CGU's for impairment testing.

The Company has grouped its development and production assets into the Claresholm, Edson, Saxon, Ante Creek and Pouce Coupe CGU's.

The cost of property, plant and equipment at January 1, 2010, the date of transition to IFRS, was determined using the IFRS 1 deemed cost election, whereby the costs at transition were allocated to CGU's based on reserve volumes and tested for impairment. The Company chose to allocate its costs based on proved plus probable reserves volumes. When significant parts of an item of property, plant and equipment, including oil and natural gas interests, have different useful lives, they are accounted for as separate items (components).

Gains and losses on disposal of an item of property, plant and equipment, including oil and natural gas interests, are determined by comparing the proceeds from disposal with the carrying amount of property, plant and equipment and are recognized as separate line items in profit or loss.

ii Subsequent costs.

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as oil and natural gas interests only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in profit or loss as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in profit or loss as incurred.

ii. Depletion and depreciation.

The net carrying value of development or production assets is depleted using the unit of production method by reference to the ratio of production in the quarter to the related proved and probable reserves, taking into account estimated future development and decommissioning costs necessary to bring those reserves into production and potential salvage values. These estimates are reviewed by independent reserves engineers at least annually. Proved and probable reserves are estimated using independent reserves evaluator reports and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. There should be a 50 percent statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as proved and probable and a 50 percent statistical probability that it will be less. The equivalent statistical probabilities for the proved component of proved and probable reserves are 90 percent and 10 percent, respectively. Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon:

- a reasonable assessment of the future economics of such production;
- a reasonable expectation that there is a market for all or substantially all the expected oil and natural gas production; and
- evidence that the necessary production, transmission and transportation facilities are available or can be made available.

Reserves may only be considered proved and probable if producibility is supported by either actual production or a conclusive formation test. The area of reservoir considered proved includes (a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, or both, and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geophysical, geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of oil and natural gas controls the lower proved limit of the reservoir. Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are only included in the proved and probable classification when successful testing by a pilot project, the operation of an installed program in the reservoir, or other reasonable evidence (such as, experience of the same techniques on similar reservoirs or reservoir simulation studies) provides support for the engineering analysis on which the project or program was based.

For other assets, depreciation is recognized in profit or loss over the estimated useful lives of each part of an item of property, plant and equipment using the declining balance method at rates between 20% and 30% per annum. Leased assets are depreciated over the shorter of the lease term and their useful lives unless it is reasonably certain that the Company will obtain ownership by the end of the lease term.

Depreciation methods, useful lives and residual values are reviewed at each reporting date.

d. Leased assets:

Operating leases are not recognized on the Company's statement of financial position. Payments made under operating leases are recognized in profit or loss on a straight-line basis over the term of the lease. Onerous leases are recognized in the accounts over the terms of the respective leases by reference to forecast cash outlays net of projected recoveries.

e. Impairment:

i. Financial assets

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset. An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate. Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics. All impairment losses are recognized in profit or loss. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in profit or loss.

ii. Non-financial assets.

The carrying amounts of the Company's non-financial assets, other than deferred tax assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or the CGU. The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves.

Fair value less cost to sell is determined as the amount that would be obtained from the sale of a CGU in an arm's length transaction between knowledgeable and willing parties. The fair value less cost to sell of oil and gas assets is generally determined as the net present value of the estimated future cash flows expected to arise from the continued use of the CGU, including any expansion prospects, and its eventual disposal, using assumptions that an independent market participant may take into account.

These cash flows are discounted by an appropriate discount rate which would be applied by such a market participant to arrive at a net present value of the CGU.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss. Impairment losses recognized in respect of CGU's are allocated first to reduce the carrying amount of any goodwill allocated to the units and then to reduce the carrying amounts of the other assets in the unit on a pro

rata basis. Impairment losses recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists.

An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

f. Share-based payments

The grant date fair value of equity-settled options granted to employees is recognized as stock-based compensation expense, within general and administrative expenses, with a corresponding increase in contributed surplus over the vesting period. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest.

g. Provisions – onerous contracts

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

h. Decommissioning obligations

The Company's activities give rise to dismantling, decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning obligations are measured at the present value of management's best estimate of the expenditures required to settle the present obligation at the date of the statement of financial position. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The credit adjusted interest rate is used in connection with the calculation of such future cash flows. The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the asset retirement obligations are charged against the provision to the extent the provision were established.

i. Revenue

Revenue from the sale of oil and natural gas is recorded when the significant risks and rewards of ownership of the product is transferred to the buyer which is usually when legal title passes to the external party and collection is reasonably assured. This is generally at the time product enters the pipeline. Revenue is presented both before and after royalties payable to the Crown and others. Transportation costs are netted from revenue where title transfers prior to transport on applicable sales pipelines and the transportation is held by and charged by the purchaser. Other transportation and processing fees and included in operating expenses. Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

j. Finance expense

Finance expense comprises interest expense on borrowings and accretion of the discount on decommissioning obligations.

k. Income tax

Income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity. Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes.

Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill.

Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

l. Earnings per share

Basic earnings per share is calculated by dividing the profit or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted earnings per share is determined by adjusting the profit or loss attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as options granted to employees.

m. New standards and interpretations not yet adopted:

The Company is currently reviewing the following new and revised accounting pronouncements that have been issued but are not yet effective to determine if they may have an impact on the Company:

*FRS 9 – Financial Instruments* – IFRS 9 was issued in November 2009 effective for annual reporting periods beginning on or after January 1, 2015, with earlier adoption permitted. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value through profit and loss.

*IFRS 10 Consolidated Financial Statements* – in May 2011, the IASB issued IFRS 10 which provides additional guidance to determine whether an investee should be consolidated. The guidance applies to all investees, including special purpose entities. The standard is required to be adopted for periods beginning January 1, 2013.

*IFRS 11 Joint Arrangements* – in May 2011, the IASB issued IFRS 11 which presents a new model for determining whether an entity should account for joint arrangements using proportionate consolidation or the equity method. An entity will have to follow the substance rather than legal form of a joint arrangement and will no longer have a choice of accounting method. The standard is required to be adopted for periods beginning January 1, 2013.

*IFRS 12 – Income Taxes.* IAS 12 “Income Taxes” was amended on December 20, 2010 to remove subjectivity in determining on which basis an entity measures the deferred tax relating to an asset. The amendment introduces a presumption that an entity will assess whether the carrying value of an asset will be recovered through the sale of the asset. The amendment to IAS 12 is effective for reporting periods beginning on or after January 1, 2012. the Company is currently evaluating the impact of this amendment to its financial statements.

*IFRS 13 Fair Value Measurement* is a new standard meant to clarify the definition of fair value, provide guidance on measuring fair value and improve disclosure requirements related to fair value measurement.

*IAS 27 Separate Financial Statements* has been amended to focus solely on accounting and disclosure requirements when an entity presents separate financial statements, due to the issuance of the new IFRS 10 which is specific to consolidated financial statements.

*IAS 28 Investments in Associates and Joint Ventures* has been amended as a result of the issuance of IFRS 11 and the withdrawal of IAS 31. The amended standard sets out the requirements for the application of the equity method when accounting for interest in joint ventures, in addition to interests in associates.

n. Flow through shares

Periodically, the Company finances a portion of its exploration and development activities through the issuance of flow-through shares. The resource expenditure deductions for income tax purposes related to exploratory development activities are renounced to investors in accordance with tax legislation. Flow-through shares issued are recorded in share capital at the fair value of common shares on the date of issue. The premium received on issuing flow-through shares is initially recorded as a premium liability. As qualifying expenditures are incurred, the premium is reversed and a deferred income tax liability is recorded. The net amount is then recognized as deferred income tax expense.

### 3. Determination of Fair Value

A number of the Company’s accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

(i) Property, plant and equipment and E&E assets

The fair value of property, plant and equipment is the estimated amount for which property, plant and equipment could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm’s length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The fair value of oil and natural gas interests (included in property, plant and equipment) is estimated with reference to the discounted cash flows expected to be derived from oil and natural gas production based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions, being 12% for 2011 (2010 – 12%). The market value of other items of property, plant and equipment is based on the quoted market prices

for similar items. Similarly, property, plant and equipment are recognized at fair value in a business combination.

- (ii) Cash and cash equivalents, accounts receivable and accruals and accounts payable and accruals

The fair value of cash and cash equivalents, accounts receivable and accruals and accounts payable and accruals is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At September 30, 2011 and December 31, 2010, the fair value of these balances approximated their carrying value due to their short term to maturity.

- (ii) Bank indebtedness

The fair value of bank loans approximates their carrying value, as they bear interest at floating rates and the premium charged at September 30, 2011 and December 31, 2010 was indicative of the Company's current credit spreads.

- (iii) Derivatives

The fair value of forward contracts and swaps is derived from quoted prices received from financial institutions and is based on published forward price curves as at the measurement date, using the remaining notional contracted oil and natural gas volumes.

- (iv) Stock options

The fair value of employee stock options is measured using a Black Scholes option pricing model. Measurement inputs include share price on measurement date, exercise price of the instrument, expected volatility (based on weighted average historic volatility adjusted for changes expected due to publicly available information), weighted average expected life of the instruments (based on historical experience and general option holder behavior), expected dividends, and the risk-free interest rate (based on government bonds).

The Company classified the fair value of its financial instruments measured at fair value according to the following hierarchy based on the amount of observable inputs used to value the instrument:

- Level 1 – observable inputs such as quoted prices in active markets;
- Level 2 – inputs, other than the quoted market prices in active markets, which are observable, either directly and/or indirectly; and
- Level 3 – unobservable inputs for the asset or liability in which little or no market data exists, therefore requiring an entity to develop its own assumptions.

The fair value of the derivative contracts used for risk management as shown in the consolidated statements of financial position as at September 30, 2011 and December 31, 2010 is measured using level 2. During the periods ended September 30, 2011 and 2010, there were no transfers between level 1, level 2 and level 3 classified assets and liabilities.

- (v) Flow through shares

The fair value of flow through shares is equal to the issue price of common shares that had no tax attributes that are issued at the same time or, if no such common shares are issued, the closing price of the common shares on the TSX immediately preceding the date that the agreement with the underwriters is consummated.

#### 4. Financial Risk Management

The Board of Directors oversees managements' establishment and execution of the Company's risk management framework. Management has implemented and monitors compliance with risk management policies. The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities.

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production, and financing activities such as credit risk, liquidity risk and market risk.

##### Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations. All of the Company's operations are conducted in Canada. The Company's exposure to credit risk is influenced mainly by the individual characteristics of each purchaser or joint venture partner.

All of the Company's petroleum and natural gas production is marketed under standard industry terms. The industry has a pre-arranged monthly settlement day for payment of revenues from all buyers of crude oil and natural gas. This occurs on the 25th day following the month in which the production is sold. As a result, the Company collects sales revenues in a predetermined and organized manner. Management monitors purchaser credit positions to mitigate any potential credit losses. To the extent the Company has joint interest activities with industry partners, the Company must collect, on a monthly basis, partners' share of capital and operating expenses. These collections are subject to normal industry credit risk. The Company attempts to mitigate risk from joint venture receivables by obtaining partner approval of capital projects prior to expenditure and collects in advance for significant amounts related to partners' share of capital expenditures in accordance with the industry operating procedures. The Company does not typically obtain collateral from petroleum and natural gas marketers or joint venture partners, however, the Company does have the ability to withhold production from joint venture partners in the event of non-payment. The Company's credit risk is limited to the carrying amount of its accounts receivable, which are due primarily from other entities involved in the oil and gas industry. These amounts are subject to the same risks as the industry as a whole. The Company had no material trade accounts receivable deemed uncollectible. The carrying amount of cash and accounts receivable represent the maximum credit exposure.

The maximum exposure to credit risk at the dates captioned below is as follows:

(\$000's)	Carrying amount	
	September 30, 2011	December 31, 2010
Cash and cash equivalents	0	93
Accounts receivable and accruals	1,662	1,411
	1,662	1,504

The maximum exposure to credit risk for accounts receivable and accruals at the reporting date by type of customer was:

(\$000's)	Carrying amount	
	September 30, 2011	December 31, 2010
Oil and natural gas marketers	907	1,249
Joint venture partners	397	153
Other	358	9
	1,662	1,411

As at September 30, 2011 and December 31, 2010 the Company's accounts receivable and accruals was aged as follows:

\$ 000's	Carrying amount	
	September 30, 2011	December 31, 2010
Not past due by less than 90 days	1,589	1,343
Past due by less than 120 days	25	68
Past due by more than 120 days	48	-
Total	1,662	1,411

These amounts are before offsetting amounts owing to joint venture partners that are included in accounts payable and accruals.

#### Liquidity risk

Liquidity risk relates to the risk the Company will encounter should it have difficulty in meeting obligations associated with the financial liabilities as they fall due.

The financial liabilities on the statement of financial position consist of accounts payable, accrued liabilities, and bank indebtedness. Accounts payable consists of invoices payable to trade suppliers relating to the office and field operating activities and its capital spending program. The Company processes invoices within a normal payment period. The Company also attempts to match its payment cycle with collection of oil and natural gas revenue on the 25th of each month. The Company prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. The Company uses authorizations for expenditures on both operated and non operated projects to further manage capital expenditures.

The Company anticipates it will continue to have adequate liquidity to fund its financial liabilities and its commitments through its future funds from operations, financings and available bank debt. The Company has revolving reserves-based credit facilities which are reviewed regularly by its lenders. These facilities are described in note 11.

The Company was not in default on its bank debt or any of its other financial liabilities.

All financial liabilities are due within one year.

#### Market risk

Market risk is the risk that changes in market prices, such as commodity prices, foreign exchange rates and interest rates will affect the Company's income or the value of the financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimizing the return. The Company may use both financial

derivatives and physical delivery sales contracts to manage market risks. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors and those limitations set by lenders in credit agreements.

#### Currency risk

Prices for oil are determined in global markets and generally denominated in United States dollars. Natural gas prices obtained by the Company are influenced by both U.S. and Canadian demand and the corresponding North American supply, and recently, by imports of liquefied natural gas. The exchange rate effect cannot be quantified but generally an increase in the value of the Canadian dollar as compared to the U.S. dollar will reduce the prices received by the Company for its petroleum and natural gas sales.

There were no financial instruments denominated in U.S. dollars at September 30, 2011 or December 31, 2010.

#### Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The interest charged on the outstanding bank loans fluctuates with the interest rates posted by the lenders. The Company has not entered into any mitigating interest rate hedges or swaps.

#### Commodity price risk

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by both the relationship between the Canadian and U.S. dollar and world economic events that dictate the levels of supply and demand. From time to time, the Company has entered into financial derivative contracts to mitigate such risks. The Company has no such contracts outstanding at September 30, 2011 nor did it enter into such contracts in 2011.

#### Capital management

The Company's objective in the course of the management of the Company's capital structure is to maintain a flexible capital structure that will allow it to execute on its capital expenditure program, which includes expenditures on oil and gas activities that may or may not be successful, optimize the cost of capital and maintains investor, creditor and market confidence.

The Company considers that its capital structure comprises share capital of \$67,403,000.

The Company monitors its capital structure and makes adjustments when possible. Business conditions including current economic trends, the underlying risk characteristics of the Company's assets, the depth and breadth of its exploration and development portfolio, the desired pace of investment, the availability of farm ins and farm outs, current and forecasted energy prices, the potential bank credit that could be obtained as a result of reserve growth and forecasted debt levels are all factors that the Company uses as inputs to its capital management process.

In order to maintain or adjust its capital structure, the Company may issue new common voting shares if available on favorable terms and/or renegotiate the terms of its banking facilities. The Company may also consider other sources of debt with different characteristics than existing bank indebtedness, adjust exploration and development capital expenditures and acquire or dispose of assets. Equity financing may not be readily available to junior oil and gas producers given current market conditions. The availability of bank credit is generally reducing and related costs are increasing. A covenant to the Revolving Operating Demand Loan facility requires that the Company maintain a working capital ratio, exclusive of bank indebtedness, of at least 1 to 1. For purposes of this calculation, the undrawn availability under the facility

is added to current assets. The Company was in compliance with this debt covenant at September 30, 2011 and at December 31, 2010. There is no similar working capital requirement for the acquisition/Development Demand Loan. There is no debt to equity requirements related to either of the facilities. The credit facilities are subject to regular reviews by the Company's Bank. The last such review was held in September 2011 with the next scheduled for November 2011.

A covenant to the Revolving Operating Demand Loan Facility requires that the Company limit hedging activities to 50% of actual production.

There were no changes in the Company's approach to capital management during the period.

Neither the Company nor its subsidiary is subject to externally imposed capital requirements.

## 5. Finance Expenses

Finance expenses are comprised of:

(\$000's)	Nine months Ended September 30,	
	2011	2010
Interest and financing costs on bank indebtedness	463	687
Accretion on decommissioning obligations	94	79
<b>Total</b>	<b>557</b>	<b>766</b>

## 6. Supplemental Cash Flow Information

Changes in non-cash working capital are comprised of:

(\$000's)	Nine months Ended September 30,	
	2011	2010
Source (Use) of cash or cash equivalents		
Accounts receivable and accruals	(251)	990
Prepaid expenses and deposits	277	(460)
Accounts payable and accruals	3,508	(3,308)
<b>Total</b>	<b>3,534</b>	<b>(2,778)</b>
Related to:		
Operations	707	(2,306)
Financing	-	-
Investing	2,827	(472)
<b>Total</b>	<b>3,534</b>	<b>(2,778)</b>

## 7. Property, Plant and Equipment

Depletion and depreciation, impairment of property plant and equipment and any eventual reversal thereof are recognized as separate line items in the unaudited consolidated statement of operations.

Property, plant and equipment  
(\$ 000's)

	At cost or deemed cost		
	Oil and Gas		Total
	Assets	Other	
January 1, 2010	87,547	187	87,734
Additions	23,057	84	23,141
Disposals	(15,724)	-	(15,734)
December 31, 2010	94,880	271	95,151
Additions	4,231	95	4,326
September 30, 2011	99,111	366	99,477

Accumulated depletion and depreciation and  
impairment losses  
(\$ 000's)

	Oil and Gas		
	Assets		Total
	Assets	Other	
January 1, 2010	30,098	7	30,105
Impairment loss at January 1, 2010 (note 10)	9,704	-	9,704
January 1, 2010	39,802	7	39,809
Disposal	(6,283)	-	(6,283)
Depletion and depreciation	4,756	7	4,763
Impairment loss during the period (note 10)	20,100	-	20,100
December 31, 2010	58,375	14	58,389
Depletion and depreciation	2,318	9	2,327
September 30, 2011	60,693	23	60,716

Carrying amounts  
(\$ 000's)

	Oil and Gas		
	Assets		Total
	Assets	Other	
January 1, 2010	47,745	180	47,925
December 31, 2010	36,505	257	36,762
September 30, 2011	38,418	343	38,761

## 8. Exploration and evaluation assets

Exploration and evaluation assets consist of the Company's exploration projects which are pending the determination of proved or probable reserves. Costs primarily consist of undeveloped land and drilling costs until the drilling of the well is complete and the results have been evaluated. The cost of undeveloped land that expires or any impairment recognized during a period, is charged as additional depletion and depreciation expense unless it is related to a viable Cash Generating Unit ("CGU") in which case such costs will be transferred to the applicable CGU and assessed for impairment. Exploration and evaluation assets

are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

(\$ 000's)	
Balance January 1, 2010	8,177
Additions	1,378
Disposals	(4,994)
Transfers to property, plant and equipment	(1,194)
Lease expiries	-
Balance December 31, 2010	3,367
Additions	30,840
Transfers to property, plant and equipment	(375)
Disposals	(580)
Lease expiries	(179)
Balance September 30, 2011	33,073

## 9. Decommissioning Obligations

The Company's decommissioning obligations result from its ownership interest in oil and natural gas assets including well sites and gathering systems.

The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future years. The Company has estimated the net present value of the decommissioning obligations to be \$1,581,000 as at September 30, 2011 (December 31, 2010 - \$1,432,000) based on an undiscounted inflation-adjusted total future liability of \$3,716,000 (December 31, 2010 - \$3,457,000). These payments are expected to be made over the next 25 years with the majority of costs to be incurred between 2012 and 2030. The discount factor, being the credit adjusted rate related to the liability, ranged from 7.0% to 8.5% (December 31, 2010 - 7.0% to 8.5%) depending on the estimated timing of the future obligation.

## 10. Impairment

As a result of applying the IFRS 1 exemption for deemed cost at January 1, 2010, the Company was required to test all of its cash generating units for impairment. The Company tested the Claresholm, Edson, Saxon, Ante Creek and Pouce Coupe CGUs for impairment.

In addition, as a result of continued weakness in natural gas pricing during the second half of 2010, the Company tested the same CGUs for impairment and recognized impairments totaling \$20,100,000 over that period in the Claresholm and Edson CGU's. Of this amount, \$10,050,000 of the impairment related to the three months ended September 30, 2010.

The recoverable amount of the CGUs was estimated based on the value in use. The estimate of fair value in use was determined using a discount rate of 12 percent and forecasted cash flows, with escalating prices and future development costs, as obtained from the reserve report. The prices used in such calculations were those used by independent industry reserve engineers for the respective periods.

Management has concluded that there were no indicators of impairment of its CGUs for the period from January 1, 2011 to September 30, 2011.

The impairment losses recognized in each CGU were as follows:

(\$ 000's)	Claresholm	Edson	Saxon	Ante Creek	Pouce Coupe	Other	Total
Impairment loss:							
January 1, 2010	7,461	1,561	677	-	-	5	9,704
Year ended December 31, 2010	18,090	1,981	-	-	-	29	20,100
	25,551	3,542	677	-	-	34	29,804

Carrying values:

(\$ 000's)	Claresholm	Edson (Note 14)	Saxon	Ante Creek (Note 14)	Pouce Coupe	Other	Office equipment	Decommissioning liabilities	Total
January 1, 2010	38,801	7,218	1,584	-	-	142	23	157	47,925
December 31, 2010	25,608	5,023	-	4,384	1,401	89	23	234	36,762
September 30, 2011	25,068	4,876	-	4,685	3,710	79	39	304	38,761

## 11. Bank Indebtedness

Amounts outstanding:

(\$000's)	September 30, 2011	December 31, 2010
Revolving operating demand loan	19,883	12,564
Acquisition/development demand loan	-	-
	19,883	12,564

At September 30, 2011 the Company's credit facilities comprised a Revolving Operating Demand Loan Facility with a credit limit of \$26,000,000 and an Acquisition/Development Demand Facility with a credit limit of \$4,000,000.

The Revolving Operating Demand Loan Facility bears interest at Bank prime plus a percentage determined quarterly ranging from .5% to 2.5% greater than the Bank's prime rate in accordance with the Bank's pricing grid. The Bank's pricing grid is dependent on the Company's debt to cash flow ratio where debt is defined by the Bank as working capital deficit, consolidated long term debt including capital leases and retractable preferred shares which are retractable at the option of the holder and cash flow is defined by the Bank as net earnings, adjusted for depletion, depreciation and accretion, future income taxes and other charges to income not requiring a cash payment calculated for the most recently completed quarter and annualized.

The application of the Bank's pricing grid resulted in a rate which is 1% greater than the Bank's prime rate.

The Revolving Operating Demand Loan Facility has no specific terms of repayment aside from the Bank's right of demand and periodic review. The Acquisition/Development Demand Loan Facility requires unspecified monthly principal repayments over the engineering half life of the reserves being financed as determined by the Bank. The Revolving Operating Demand Loan Facility bears a standby fee of between 0.2% and 0.45% on the undrawn portion of the loan facility.

The Acquisition/Development Demand Loan Facility is restricted to the acquisition of proved non-producing/undeveloped petroleum and natural gas reserves and/or development of proved

producing/undeveloped petroleum and natural gas reserves, bears interest at a rate which is 0.25% higher than the Revolving Operating Demand Loan Facility and bears a standby fee of 0.5% on the undrawn portion of the loan facility.

Security for the facilities includes a general assignment of book debts, a \$75,000,000 debenture with a first floating charge over all assets with a negative pledge and an undertaking to provide fixed charges on the Company's major producing reserves at the request of the bank.

A covenant to the Revolving Operating Demand Loan Facility requires that the Company limit hedging activities to 50% of actual production.

A covenant to the Revolving Operating Demand Loan Facility requires that the Company maintain a working capital ratio, exclusive of bank indebtedness, of at least 1 to 1. For purposes of this calculation, the undrawn availability under the Revolving Operating Demand Loan Facility is added to current assets. The Company was in compliance with this debt covenant at December 31, 2010 and September 30, 2011. There is no similar working capital requirement for the Acquisition/Development Demand Loan. There is no debt to equity requirements related to either of the facilities.

The last scheduled review of the Company's borrowing limits occurred in September 2011. There can be no assurance that other amounts or terms will not change at the next review scheduled in November 2011.

## 12. Share Capital

Share capital comprises:

(\$ 000's)	September 30, 2011	December 31, 2010	December 31, 2009
Common voting shares	67,403	49,204	45,521
Warrants	-	533	316
<b>Total</b>	<b>67,403</b>	<b>49,737</b>	<b>45,837</b>

### Common Voting Shares

Authorized:

An unlimited number of common voting shares and an unlimited number of preferred shares issuable in series for which the directors may fix, among other things, the rights, privileges, restrictions, conditions, voting rights, rates, method of calculation and dates of payment of dividends and terms of redemption, purchase and conversion if any, and any other provisions.

## Issued and outstanding, Common Voting Shares:

	Number of Shares	\$ 000's
Balance, December 31, 2009	12,853,197	45,521
Issued by way of private placement	1,500,004	2,483
Issued by way of private placement, flow through common shares	500,000	1,000
Premium on private placement, flow through shares		(100)
Issued in connection with the acquisition of Radius Resources Inc.	748,000	524
Share issuance costs, net of tax		(26)
Received and cancelled on settlement of Radius debt (Note 6)	(64,262)	(198)
Balance, December 31, 2010	15,536,939	49,204
Exercise warrants	706,683	1,794
Issued by way of short form prospectus – common shares	3,000,000	8,850
Issued by way of short form prospectus – flow through common shares	1,000,000	3,700
Issued by way of private placement, flow through common shares	2,000,000	6,700
Premium on short form prospectus issue , flow through common shares	-	(750)
Premium on private placement issue, flow through common shares	-	(900)
Share issuance costs, net of tax	-	(1,195)
Balance, September 30, 2011	22,243,622	67,403

On February 11, 2011, the Company closed a bought deal issue of 3,000,000 common shares by way of short form prospectus for total proceeds of \$8,850,000. At the same time it closed a bought deal issue of 1,000,000 flow through common shares by way of short form prospectus for gross proceeds of \$3,700,000.

A premium liability is recorded on the issuance of flow through shares. As qualifying expenditures are incurred, the premium liability is reversed and a deferred income tax liability is recorded. The implied premium on this issue of flow through common shares was computed to be \$0.75 per share. This was determined to be the difference between the issue price of the flow through common shares and the issue price of the common shares that had no tax attributes that were issued at the same time. The premium liability that was initially recorded on issuance aggregated \$0.8 million. All of the qualifying expenditures related to this issuance of flow through common shares were made and the related premium liability was extinguished and the related income tax liability was recorded by the end of the first quarter of 2011.

On July 12, 2011, the Company issued an additional 2,000,000 flow through common shares pursuant to a bought deal private placement at a price of \$3.35 per flow through common share for aggregate proceeds of \$6.7 million. The implied premium on this issue of flow through common shares was computed to be \$0.45 per share. This implied premium was the difference between the issue price of the flow through common shares and the closing price of the common shares on the TSX immediately preceding the date that the agreement with the underwriters was consummated. The premium liability that was initially recorded on issuance aggregated \$0.9 million. The Company is obligated to spend \$6.7 million on qualifying Canadian exploration expenditures before December 31, 2012 to satisfy the flow through commitment in connection with this issue. The premium liability that had been initially recorded has been reduced by \$0.5 million and a deferred tax liability of \$1 million has been recorded to reflect the fact that the Company has incurred \$4.0 million of such qualifying Canadian exploration expenditures as at September 30, 2011.

## Warrants:

	Number of Warrants	\$ 000's
Balance, January 1, 2010	1,097,180	316
Private Placement	750,003	217
Balance December 31, 2010	1,847,183	533
Warrants exercised	(706,683)	(204)
Warrants cancelled	(1,140,500)	(329)
Balance September 30, 2011	-	-

The allocation of the issue price of units between common shares and share purchase warrants was based on fair values of the common shares and warrants. The fair market value of the common shares was based on the closing price of the Company's shares on the TSX on the closing date. The common share purchase warrants were valued using a Black-Scholes model using the following terms and assumptions:

- Share price \$1.27
- Exercise price \$2.25
- Time to expiry 1.5 years
- Risk free rate 1.3%
- Volatility 83%

In addition, a provision in the warrant indenture provided that the exercise period of the Argosy warrants may be accelerated in the event that the 20-day trading volume weighted average price of the Argosy shares meets or exceeds \$3.00 during the period such warrants remaining remain outstanding.

The 20-day trading volume weighted average price of the Argosy exceeded \$3.00 as at April 29, 2011. Accordingly, the Company served notice to the remaining warrant holders that the expiry date of the warrants was accelerated to May 13, 2011. A total of 200,734 warrants were exercised prior to the accelerated expiry date for proceeds of \$451,652. The holders of 1,140,500 warrants did not exercise their warrants by the end of the accelerated expiry date. Those warrants that were not exercised by the end of the accelerated expiry date were cancelled.

## Per share calculations:

The following reconciles the weighted average number of common shares outstanding used in calculating net income or loss per common share ("EPS"):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Weighted average common voting shares outstanding - basic	21,982,752	15,601,201	20,162,568	14,625,068
Effect of dilutive stock options	-	-	-	-
Weighted average common voting shares outstanding - diluted	21,982,752	15,601,201	20,162,568	14,625,068

The 2010 figure of vested options and the warrants that were outstanding at September 30, 2010 were out of the money.

## Stock Options

### Options outstanding:

Under the terms of the Argosy Energy Inc. 2008 Incentive Stock Option Plan, (the “plan”), directors, officers, employees are eligible to be granted options to purchase common shares.

The following tables summarize information about stock options outstanding at September 30, 2011:

Balance, December 31, 2008	580,000
Granted	473,000
Forfeited	(3,000)
Balance, January 1, 2010	1,050,000
Granted	403,000
Forfeited	(20,000)
Balance December 31, 2010	1,433,000
Granted 2011	790,500
Balance, September 30, 2011	2,223,500

Grant Price (\$/Share)	Repriced	Options Outstanding	Remaining Contractual Life	Number Exercisable (Vested)
4.60	1.28 <sup>(1)</sup>	571,000	1.91 Years	571,000
1.20	n/a	465,000	3.22 Years	310,000
0.91	n/a	377,000	3.56 Years	251,333
0.79	n/a	20,000	3.86 Years	13,333
2.40	n/a	425,000	4.42 Years	141,667
2.33	n/a	365,500	5.00 Years	121,833
		2,223,500		1,409,166

Grant Price	\$4.60/\$1.28 <sup>(1)</sup>	\$1.20	\$0.91	\$0.79	\$2.40	\$2.33
Fair value at grantor repricing date	\$4.60/\$1.28	\$1.20	\$0.91	\$0.79	\$2.40	\$2.33
Fair value for stock based compensation cost	\$1,345,000	\$373,000	\$222,000	\$9,800	578,000	486,000
Expected forfeiture rate	2%	2%	2%	2%	2%	2%
Risk free interest rate	4.5%	1.3%	3.5%	2.29%	2.39%	2%
Expected life	5 years	5 years	5 years	5 years	5 years	4 years
Expected volatility	46%/83%	83%	76%	75%	75%	73%
Expected dividend yield	-	-	-	-	-	-

(1) At a special meeting held on October 6, 2009, the shareholders of the Company approved the repricing from \$4.60 to \$1.28

Stock based compensation expense of \$31,000 was capitalized for the 9 months and \$21,000 was capitalized for the 3 months ended September 30, 2011 (\$72,000 and \$21,000 the equivalent periods in 2010).

### 13. Derivative Contracts

Derivative contracts were designated as “fair value through profit and loss” and recorded at the estimated fair market value.

All derivative contracts previously held by the Company expired on March 31, 2011. No new contracts were entered into in 2011.

As at December 31, 2010, the following derivative contracts were outstanding:

Type of Hedge	Commodity Hedged	Volume	Price	Period	Fair Value \$ 000	Unrealized Gain(Loss) \$ 000
Financial fixed price bought put	Natural Gas	2,000 GJ/day	Cdn \$5.00 /Gj	January 1, 2010 to March 31, 2011	134	289
Financial fixed price sold call	Natural Gas	2,000 GJ/day	Cdn \$7.70/Gj	January 1, 2010 to March 31, 2011	-	197
					134	486

Note: A gigajoule (GJ) converts to a mcf at the rate of 1.055056 GJs per mcf.

The fair-value level of the Company’s derivative contracts at December 31, 2010 was as follows:

(000’s)	Fair Value	Level 1	Level 2	Level 3
Financial fixed price sold call	134	-	134	-
	134	-	134	-

### 14. Subsequent events

On October 18, 2011 the Company began actively marketing the sale of its Edson and Ante Creek CGU’s. The closing date for bids on such CGU’s is November 22, 2011.

On November 14, 2011, the Company announced that it had agreed to a bought-deal financing under which it would issue 1,500,000 common shares at a price of \$2.00 per share and 3,404,256 common shares on a flow through basis at a price of \$2.35 per share for total gross proceeds of \$11 million. The Company has also agreed an overallotment option to its underwriters for an additional 225,000 common shares for additional gross proceeds of \$0.5 million if exercised.

### 15. Reconciliation from Canadian GAAP to IFRS

The accounting policies in note 3 have been applied in preparing the unaudited interim condensed consolidated financial statements for the three and nine months ended September 30, 2011, and the comparative information presented in these interim condensed consolidated financial statements for both the three and nine months ended September 30, 2010.

## Statement of financial position – September 30, 2010:

(\$000's)	Canadian GAAP	Impairment (Note a)	E&E Assets (Note b)	Depletion and depreciation (Note b)	Gain on Sale	Onerous contracts (Note c)	Share - based payments (Note d)	Flow through Shares (Note e)	IFRS
<b>ASSETS</b>									
Current Assets:									
Cash and cash equivalents	601	-	-	-	-	-	-	-	601
Accounts receivable and accruals	1,020	-	-	-	-	-	-	-	1,020
Prepaid expenses and deposits	933	-	-	-	-	-	-	-	933
Fair value of derivative contracts	304	-	-	-	-	-	-	-	304
	2,858	-	-	-	-	-	-	-	2,858
Exploration and evaluation assets	-	-	2,921	-	-	-	72	-	2,993
Property, plant and equipment	56,907	(19,754)	(2,921)	2,478	6,174	-	-	-	42,884
	59,765	(19,754)	-	2,478	6,174	-	72	-	48,735
<b>LIABILITIES AND EQUITY</b>									
Current liabilities:									
Accounts payable and accruals	2,647	-	-	-	-	-	-	-	2,647
Bank indebtedness	8,504	-	-	-	-	-	-	-	8,504
Deferred income taxes	81	-	-	-	-	-	-	(81)	-
Onerous contracts	-	-	-	-	-	84	-	-	84
	11,232	-	-	-	-	84	-	(81)	11,235
Onerous contracts	-	-	-	-	-	508	-	-	508
Decommissioning obligations	1,357	-	-	-	-	-	-	-	1,357
Deferred tax liability	4,793	(4,938)	-	619	1,544	(148)	(162)	331	2,039
	17,382	(4,938)	-	619	1,544	444	(162)	250	15,139
Shareholders' Equity:									
Share capital	48,655	-	-	-	-	-	-	1,279	49,934
Contributed surplus	1,691	-	-	-	-	-	(7)	-	1,684
Deficit (note h)	(7,963)	(14,816)	-	1,859	4,630	(444)	241	(1,529)	(18,022)
	42,383	(14,816)	-	1,859	4,630	(451)	25	(250)	33,596
	59,765	(19,754)	-	2,478	6,174	-	72	-	48,735

Reconciliation of unaudited consolidated statement of operations and comprehensive loss for the nine month period ended September 30, 2010

(\$000's)	Canadian GAAP	Impairment (Note a)	Depletion and Depreciation (Note b)	Gain on Sale	Onerous contracts (Note c)	Share- based payments (Note d)	Flow Through Shares (Note e)	IFRS
Oil and gas sales	8,714	-	-	-	-	-	-	8,713
Royalties	(596)	-	-	-	-	-	-	(596)
Revenue, net of royalties	8,118	-	-	-	-	-	-	8,117
Realized gain on derivative contracts	256	-	-	-	-	-	-	256
Unrealized gain on derivative instruments	656	-	-	-	-	-	-	656
	9,030	-	-	-	-	-	-	9,030
Operating expenses	1,861	-	-	-	-	-	-	1,861
Depletion and depreciation	6,195	-	(2,558)	-	-	-	-	3,637
Gain on Disposition	-	-	-	(6,174)	-	-	-	(6,174)
Impairment of property, plant and equipment	-	10,050	-	-	-	-	-	10,050
General and administrative expenses, including stock based compensation	3,565	-	-	-	(28)	(186)	-	3,351
Income (loss) from operating activities	(2,591)	(10,050)	2,558	6,174	28	186	-	(3,695)
Financing expenses including accretion	687	-	79	-	-	-	-	766
Income (loss) before taxes	(3,278)	(10,050)	2,479	6,174	28	186	-	(4,461)
Gain on acquisition – Radius Resources Corp.	2,228	-	-	-	-	-	-	2,228
Deferred income taxes	654	2,512	(619)	(1,544)	(7)	(162)	-	951
Income (loss) and comprehensive loss for the period	(396)	(7,538)	1,860	4,630	21	24	-	(1,284)

Reconciliation of unaudited consolidated statement of operations and comprehensive loss for the three month period ended September 30, 2010

(\$000's)	Canadian GAAP	Impairment (Note a)	Depletion and Depreciation (Note b)	Gain on Sale	Onerous contracts (Note c)	Share - based payments (Note d)	Flow Through Shares (Note e)	IFRS
Oil and gas sales	2,456	-	-	-	-	-	-	2,456
Royalties	(100)	-	-	-	-	-	-	(100)
Revenue, net of royalties	2,356	-	-	-	-	-	-	2,356
Realized gain on derivative contracts	183	-	-	-	-	-	-	183
Unrealized gain on derivative instruments	150	-	-	-	-	-	-	150
	2,689	-	-	-	-	-	-	2,689
Operating expenses	566	-	-	-	-	-	-	566
Depletion and depreciation	1,879	-	(740)	-	-	-	-	1,139
Gain on Disposition	-	-	-	(6,174)	-	-	-	(6,174)
Impairment on property, plant and equipment	-	10,050	-	-	-	-	-	10,050
General and administrative expenses, including stock based compensation	1,309	-	-	-	(9)	(259)	-	1,041
Income (loss) from operating activities	(1,065)	(10,050)	740	6,174	9	259	-	(3,933)
Financing expenses including accretion	213	-	42	-	-	-	-	255
Income (loss) before taxes	(1,278)	(10,050)	698	6,174	9	259	-	(4,188)
Gain on acquisition – Radius Resources Corp.	-	-	-	-	-	-	-	-
Deferred income taxes	278	2,512	(175)	(1,544)	(2)	(29)	534	1,540
Income (loss) and comprehensive loss for the period	(1,000)	(7,538)	523	4,630	7	230	534	(2,650)

## Notes to reconciliations

- (a) IAS 36 Adjustments – Impairment of Assets. Under Canadian GAAP, impairment of nonfinancial assets is assessed on the basis of an asset's estimated undiscounted future cash flows compared with the asset's carrying amount and if impairment is indicated, discounted cash flows are prepared to quantify the amount of the impairment. Under IFRS, impairment is assessed based on recoverable amount (greater of value in use or fair value less costs to sell) compared with the asset's carrying amount to determine the recoverable amount and measure the amount of the impairment. In addition, under IFRS, where a non-financial asset does not generate largely independent cash inflows, the Company is required to perform its test at cash generating unit level, which is the smallest identifiable grouping of assets that generates largely independent cash inflows. Canadian GAAP impairment is based on undiscounted cash flows using asset groupings with both independent cash inflows and cash outflows. As a result of this impairment testing at cash generating unit level, the Company recognized an impairment of \$9.7million at January 1, 2010 with a corresponding reduction to retained earnings. This impairment was based its estimate of the fair value less costs to sell.
- (b) IAS 6 and16 Adjustments – Property, Plant and Equipment. Depletion and depreciation.

Under Canadian GAAP the Company used the full cost method of oil and gas accounting whereby all costs relating to the exploration for and development of petroleum and natural gas reserves were capitalized and included with property and equipment. Such costs include land acquisition, drilling of productive and non-productive wells, geological and geophysical, production facilities, carrying costs directly related to unproved properties and corporate expenses directly related to acquisition, exploration and development activities.

IFRS 6 requires that E&E costs must be separated from PP&E into tangible or intangible pools according to the nature of the assets acquired. These costs include acquisition of rights to explore, exploration drilling, carrying costs of unproved properties, and any other activities relating to evaluation of technical feasibility and commercial viability of extracting an oil and gas resource. Application of this policy impacted the financial statements significantly. The balance sheet adjustment for this policy change reclassified \$2.9 million at September 30, 2010 from PP&E to intangible E&E. This adjustment had no impact on net loss.

Upon transition to IFRS, the Company adopted a policy of depleting and depreciating oil and natural gas interests on a unit of production basis over proved plus probable reserves. The depletion and depreciation policy under Canadian GAAP was based on units of production over proved reserves. In addition, depletion and depreciation was calculated on the Canadian full cost pool under Canadian GAAP. IFRS requires depletion and depreciation to be calculated based on individual components. There was no impact of this difference on adoption of IFRS at January 1, 2010 as a result of the policy as discussed above. For the nine months ended September 30, 2010, the use of proved plus probable reserves as well as the lower net book value due to the transition impairment of the Claresholm, Edson and Saxon CGUs resulted in a decrease to depletion of \$2.5 million (three months ended September 30, 2010 \$0.7 million, year ended December 31, 2010 – \$3.2 million) with a corresponding increase to property, plant and equipment.

(c) IAS 37 Adjustments – Provisions, Contingent Liabilities and Contingent Assets.

Consistent with IFRS, decommissioning obligations (asset retirement obligations under Canadian GAAP) were measured under Canadian GAAP based on the estimated cost of decommissioning, discounted to their net present value upon initial recognition.

Under Canadian GAAP accretion of the discount was included in depletion and depreciation. Under IFRS, it is included in finance expenses.

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by estimating the expected future cash flows at a rate that reflects current market assessments of the time value of money and the risks specific to the liability. The unwinding of the discount is recognized as finance cost.

A provision for onerous contracts is recognized when the expected benefits to be derived by the Company from a contract are lower than the unavoidable cost of meeting its obligations under the contract. The provision is measured at the present value of the lower of the expected cost of terminating the contract and the expected net cost of continuing with the contract. Before a provision is established, the Company recognizes any impairment loss on the assets associated with that contract.

(d) IFRS 2 Adjustments – Share-based Payments.

Under Canadian GAAP, the Company recognized an expense related to stock-based compensation on a straight-line basis through the date of full vesting and incorporated a forfeiture multiple, which was optional under Canadian GAAP. Under IFRS, the Company is required to recognize the expense over the individual vesting periods for the graded vesting awards and estimate a forfeiture rate. Upon transition to IFRS, this resulted in a \$0.1 million increase in contributed surplus with a corresponding decrease in retained earnings. For the nine months ended September 30, 2010, the Company decreased the amount of stock-based compensation expense by \$186,000 (year ended December 31, 2010 – \$0.2 million). In addition, under Canadian GAAP, stock-based compensation was disclosed separately on the consolidated statement of operations and comprehensive loss. Under IFRS, stock-based compensation is included in general and administrative expenses.

(e) Flow Through Shares

Under Canadian GAAP, the Company recorded the deferred tax impact on renouncement of flow through shares against share capital. Under IFRS, the Company is required to record a premium liability when the flow through shares are issued, which is relieved upon qualifying expenditures being incurred, with the difference going to deferred tax expense. As a result of this change in the treatment of deferred taxes, at transition, the Company recorded an additional \$0.5 million to share capital with a corresponding reduction in retained earnings for flow through shares that had been previously issued and fully renounced at transition.

## (f) IAS 12 Adjustments – Income Taxes

The aforementioned changes increased (decreased) the net deferred tax liability as follows based on a tax rate of 25 percent:

(\$000's)	September 30, 2010	December 31, 2010
Impairment of property plant and equipment	(4,938)	(7,451)
Depletion and depreciation	619	793
Gain on sale of property, plant and equipment	1,544	1,571
Onerous contracts	(148)	(145)
Flow through shares	331	400
Stock based compensation	(162)	59
<u>Decrease in deferred tax liabilities</u>	<u>(2,754)</u>	<u>(4,773)</u>

Under Canadian GAAP, the Company was required to present its future income tax assets and liabilities in the same current and long-term classification from which the timing differences arose. There is no such requirement under IFRS, therefore the Company reclassified \$41,000 at September 30, 2010 and \$36,000 at December 31, 2010 from current future income tax assets to the deferred tax asset. The effect on the consolidated statements of operations and comprehensive loss for the three and nine months ended September 30, 2010 and the year ended December 31, 2010 was to decrease the previously reported tax charge for the period by \$0.3 million, \$1.0 million and \$30.2 million, respectively.

## (g) The adoption of IFRS had the following effect on the Company's deficit:

	September 30, 2010	December 31, 2010
Impairment of property, plant and equipment	(14,816)	(29,804)
Flow through shares	(1,529)	(1,280)
Depletion and depreciation	1,859	3,170
Gain on sale of property, plant and equipment	4,630	6,284
Deferred taxes	-	4,773
Onerous contracts	(444)	(582)
Stock based compensation	241	130
<u>Total change</u>	<u>(10,059)</u>	<u>(17,309)</u>

## (h) Adjustments to cash flow

The reconciling items enumerated in this footnote have no material impact on cash flows generated by the Company.