



**Arsenal** Energy Inc.

**ANNUAL INFORMATION FORM**

**For the Year Ended December 31, 2010**

**March 22, 2011**

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## DEFINITIONS

In this Annual Information Form, the capitalized terms set forth below have the following meanings:

“**ABCA**” means the *Business Corporations Act*, S.A. 1981, c. B-15 or the *Business Corporations Act*, R.S.A. 2000, c. B-9, as the context requires, together with any amendments thereto and all regulations promulgated there under;

“**Arsenal**” or the “**Corporation**” means Arsenal Energy Inc.;

“**Arsenal Shares**” means common shares in the share capital of the Corporation;

“**Board**” means the board of directors of the Corporation;

“**Flow-Through Shares**” means Arsenal Shares issued on a “flow-through share” basis within the meaning of the *Income Tax Act* (Canada);

“**NI 52-110**” means Canadian Securities Administrators’ National Instrument 52-110 - *Audit Committees*;

“**NI 51-101**” means Canadian Securities Administrators’ National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities*;

“**Option**” means an option to purchase an Arsenal Share;

“**Preferred Shares**” means preferred shares of Arsenal;

“**SEDAR**” means the computer system for the transmission, receipt, acceptance, review and dissemination of information filed in electronic format known as the System for Electronic Document and Retrieval maintained by CDS Inc. and available at [www.sedar.com](http://www.sedar.com); and

“**TSX**” means the Toronto Stock Exchange Inc.

## CURRENCY

In this Annual Information Form, unless otherwise noted, all dollar amounts are expressed in Canadian dollars.

## GLOSSARY OF ABBREVIATIONS

<b>bbbl</b>	Barrels
<b>bbbl/d</b>	Barrels per day
<b>boe</b>	Barrel of oil equivalent (6 Mcf = 1Bbl)
<b>boe/d</b>	Barrels of oil equivalent per day
<b>GJ</b>	Gigajoules
<b>GJ/d</b>	Gigajoules per day
<b>Mbbl</b>	1,000 Barrels
<b>Mcf</b>	1,000 cubic feet
<b>Mcf/d</b>	1,000 cubic feet per day
<b>MMcf</b>	1,000,000 cubic feet
<b>MMbtu</b>	One Million British Thermal Units
<b>NGL</b>	Natural gas liquids
<b>WTI</b>	West Texas Intermediate
<b>MS</b>	Thousands of dollars
<b>MMS</b>	Millions of dollars

## CONVERSION OF UNITS

<b>1 acre</b>	0.4 hectares
<b>2.5 acres</b>	1 hectare
<b>1 bbl</b>	0.159 cubic metres
<b>6.29 bbl</b>	1 cubic metre
<b>1 foot</b>	0.3048 metres
<b>3.281 feet</b>	1 metre
<b>1 Mcf</b>	28.2 cubic metres
<b>0.035 Mcf</b>	1 cubic metre
<b>1 MMBtu</b>	1.054 GJ
<b>0.949 MMBtu</b>	1 GJ

In this Annual Information Form where amounts are expressed on a barrel of oil equivalent basis, natural gas volumes have been converted to oil equivalence at six thousand cubic feet per barrel. The term boe may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet per barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

## FORWARD-LOOKING STATEMENTS

This Annual Information Form contains forward-looking statements and forward-looking information (collectively, “**forward-looking statements**”) within the meaning of applicable Canadian securities legislation. These forward-looking statements relate to future events or the Corporation’s future performance. All forward-looking statements contained herein that are not clearly historical in nature constitute forward-looking statements, and the words “may”, “will”, “should”, “could”, “expect”, “plan”, “intend”, “anticipate”, “believe”, “estimate”, “propose”, “predict”, “potential”, “continue”, or the negative of these terms or other comparable terminology are generally intended to identify forward-looking statements. Such statements represent the Corporation’s internal projections, estimates or beliefs concerning, among other things, an outlook on the estimated amounts and timing of capital expenditures, anticipated future debt levels and revenues or other expectations, beliefs, plans, objectives, assumptions, intentions or statements about future events or performance. These statements are not guarantees of future performance and involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in the forward-looking statements. In addition, this Annual Information Form may contain forward-looking statements attributed to third party industry sources. Arsenal believes that the expectations reflected in these forward-looking statements are reasonable, however, undue reliance should not be placed on these forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur.

Forward-looking statements in this Annual Information Form include, but are not limited to, statements with respect to:

- the business plan of Arsenal;
- the ability of Arsenal to retain and attract skilled persons in the future;
- acquisition, including the considerations taken into account, and financing opportunities;
- drilling inventory, drilling plans and timing of drilling, re-completion and tie-in of wells;
- the ability of internally generated cash flow and unused bank credit facilities to fund future development costs;
- drilling, completion and facilities costs;
- growth expectations within Arsenal;
- timing of development of undeveloped reserves;
- the tax horizon of Arsenal;
- abandonment and reclamation costs;
- the performance and characteristics of Arsenal’s oil and natural gas properties;
- oil and natural gas production levels;
- the quantity of oil and natural gas reserves;
- capital expenditure programs;
- expected royalty rates, operating and general administrative costs, costs of services and other costs and expenses.

Some of the risks and other factors which could cause actual results to differ materially from those expressed in the forward-looking statements contained in this Annual Information Form include, but are not limited to:

- general economic and business conditions in Canada, the United States and globally;
- the ability of management to execute its business plan;
- fluctuations in the price of oil and natural gas, interest and exchange rates;
- the risks of the oil and gas industry both domestically and internationally, such as operational risks in exploring for, developing and producing crude oil and natural gas and market demand;
- actions taken by governmental authorities, including increases in taxes and changes in government regulations and incentive programs;
- geological, technical, drilling and processing problems;
- risks and uncertainties involving geology of oil and gas deposits;
- risks inherent in marketing operations, including credit risk;
- the ability to enter into or renew leases;
- the uncertainty of estimates and projections relating to production, costs and expenses;
- potential delays or changes in plans with respect to exploration or development projects or capital expenditures;
- availability of sufficient financial resources to fund the Corporation’s capital expenditures;
- uncertainty of finding reserves, developing and marketing those reserves;

- unanticipated operating events, which could reduce production or cause production to be shut in or delayed;
- incorrect assessments of the value of acquisitions;
- ability to locate satisfactory properties for acquisition or participation;
- shut-ins of connected wells resulting from extreme weather conditions;
- insufficient storage or transportation capacity;
- hazards such as fire, explosion, blowouts, cratering and spills, each of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury;
- encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations;
- the ability to add production and reserves through development and exploration activities;
- the possibility that government policies or laws, including laws and regulations related to the environment, may change or governmental approvals may be delayed or withheld;
- uncertainty in amounts and timing of royalty payments;
- uncertainties inherent in estimating quantities of oil and natural gas reserves and cash flows to be derived therefrom;
- failure to obtain industry partner and other third party consents and approvals, as and when required;
- stock market volatility and market valuations;
- changes in hydrocarbon or investment policies;
- competition for and/or inability to retain drilling rigs and other services;
- the need to obtain required approvals from regulatory authorities;
- competition for, among other things, capital, acquisition of reserves, undeveloped land and skilled personnel; and
- the other factors considered under “Risk Factors” in this Annual Information Form.

Forward-looking statements contained in certain documents incorporated by reference into this Annual Information Form are based on the key assumptions described in such documents. The reader is cautioned that such information, although considered reasonable by the Corporation may prove to be incorrect. Actual results achieved during the forecast period will vary from the forward-looking statements provided in this Annual Information Form and in the documents incorporated by reference herein as a result of numerous known and unknown risks and uncertainties and other factors which are discussed in the documents incorporated herein by reference.

With respect to forward-looking statements contained in this Annual Information Form, the Corporation has made assumptions regarding: the impact of increasing competition; the general stability of the economic and political environment in which the Corporation operates; the timely receipt of any required regulatory approvals; the ability of the Corporation to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects in which the Corporation has an interest to operate the field in a safe, efficient and effective manner; the ability of the Corporation to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development of exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of the Corporation to secure adequate product transportation; future oil and natural gas prices; currency exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Corporation operates; and the ability of the Corporation to successfully market its oil and natural gas products. Readers are cautioned that this information may not be appropriate for other purposes.

**Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form are expressly qualified by this cautionary statement. In addition, please note that information relating to reserves are deemed to be forward-looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described can be economically produced in the future.**

This forward-looking statements is made as of the date of this Annual Information Form, and the Corporation disclaims any intent or obligation to update publicly any such forward-looking information, whether as a result of new information, future events or results or otherwise, other than as required by applicable Canadian securities laws.

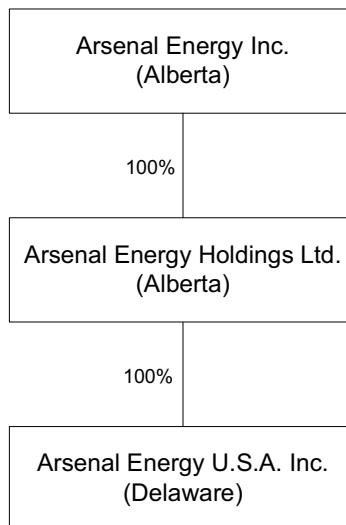
## NAME, ADDRESS AND INCORPORATION

Arsenal Energy Inc. was incorporated under the ABCA on August 3, 2000 as Arsenal Capital Inc. (“**Arsenal Capital**”). On October 18, 2002, Arsenal Capital amalgamated with A.C. Global Capital Corp. (the “**ACG Amalgamation**”). Subsequent to the ACG Amalgamation, the resulting issuer amalgamated with Legend Capital Corp., a capital pool company, pursuant to a certificate of amalgamation issued under the ABCA on May 29, 2003, and continued under the name “**Arsenal Energy Inc.**”. Pursuant to a Certificate of Amalgamation issued under the ABCA on April 1, 2005, Arsenal amalgamated with a number of wholly-owned subsidiaries and continued under the name of “**Arsenal Energy Inc.**”. On March 13, 2006, Arsenal amalgamated with Tiverton Petroleum Ltd., Quadra Resources Corp. and Fulcrum Exploration Ltd. and continued under the name “**Arsenal Energy Inc.**”. On January 1, 2009, Arsenal amalgamated with GEOCAN Energy Inc. and continued under the name “**Arsenal Energy Inc.**”. On January 1, 2010, Arsenal amalgamated with its wholly owned subsidiary, McDrake Investments Ltd. and continued under the same name “**Arsenal Energy Inc.**”.

The head office of Arsenal is located at Suite 1900, 639-5<sup>th</sup> Avenue S.W., Calgary, Alberta, T2P 0M9 and the registered office is located at 1900, 520 - 3rd Avenue S.W., Calgary, Alberta T2P 0R3.

## INTERCORPORATE RELATIONSHIPS

The percentage of votes attaching to all voting securities of Arsenal’s subsidiaries beneficially owned, or controlled or directed, directly or indirectly, by Arsenal, as well as the jurisdiction where the subsidiary was incorporated, continued, formed or organized, as the case may be, is set forth below.



## GENERAL DEVELOPMENT OF THE BUSINESS

### Three Year History of Arsenal

#### 2008

On March 28, 2008, Arsenal completed the first closing of its previously announced brokered private placement (the “**2008 Brokered Private Placement**”) by issuing a total of 959,800 Arsenal Shares at a subscription price of \$0.63 per Arsenal Share and 4,498,700 Flow-Through Shares at a subscription price of \$0.72 per share for aggregate gross proceeds of \$3,843,738.

On April 16, 2008, Arsenal closed the second and final portion of the 2008 Brokered Private Placement and issued 289,500 Arsenal Shares at a subscription price of \$0.63 per Arsenal Share and 1,056,855 Flow-Through Shares at a subscription price of \$0.72 for aggregate gross proceeds of \$943,321. Nineteen thousand of the Flow-Through Shares issued on April 16, 2008 were issued on a non-brokered basis.

On August 7, 2008, Arsenal announced that it had entered into an agreement whereby Arsenal would acquire all of the issued and outstanding shares of GEOCAN Energy Inc. (“**GEOCAN**”) pursuant to a plan of arrangement (the “**Arrangement**”) under the ABCA. Pursuant to the Arrangement, Arsenal was to acquire all of the outstanding class “A” common shares of GEOCAN (“**GEOCAN Shares**”) for consideration of \$0.70 per GEOCAN Share, payable, at the election of each GEOCAN shareholder, in cash or 0.81 of an Arsenal Share, subject to a maximum aggregate of \$30,000,000 and a minimum aggregate of \$26,000,000 in cash being paid to the GEOCAN shareholders pursuant to the Arrangement. In the event that the GEOCAN shareholders elected, in the aggregate, to receive more than \$30,000,000 in cash, the amount of cash to be received by a holder electing to receive cash with respect to a GEOCAN Share was to be reduced proportionately and the balance of the purchase price for that GEOCAN Share would be paid by a portion of an Arsenal Share at a deemed price of \$0.795 per Arsenal Share. In the event that the GEOCAN shareholders elected, in the aggregate, to receive less than \$26,000,000 in cash, the number of Arsenal Shares to be received by a holder electing to receive Arsenal Shares with respect to a GEOCAN Share would be reduced proportionately and the balance of the purchase price for that GEOCAN Share would be paid in cash. On October 8, 2008, the Arrangement was completed for consideration of \$30.0 million in cash and the issuance of 10,623,498 Arsenal Shares.

In connection with the GEOCAN acquisition, Arsenal increased its operating credit facility to \$55,000,000.

On October 8, 2008, Arsenal incorporated Arsenal Energy Holdings Ltd. (“**Arsenal Holdings**”) and on October 31, 2008, Arsenal sold all of the issued and outstanding shares in Arsenal Energy USA Inc. to Arsenal Holdings for a fair market value estimated at \$35,000,000.

On October 14, 2008, Arsenal announced that it intended to purchase for cancellation up to 4,539,307 Arsenal Shares by way of normal course issuer bid (the “**NCIB**”) through the facilities of the TSX. The 4,539,307 Arsenal Shares represented approximately 4.5% of the number of then outstanding Arsenal Shares, being 101,409,646 Arsenal Shares. Purchases under the NCIB terminated on October 15, 2009.

Pursuant to the NCIB, and on November 18, 2008 and November 20, 2008, Arsenal respectively purchased 80,000 Arsenal Shares at a price of \$0.20 per share and 80,000 Arsenal Shares at a price of \$0.19 per share. These Arsenal Shares were cancelled in November, 2008. No purchases were made pursuant to the NCIB in 2009.

## **2009**

On January 1, 2009, Arsenal amalgamated with GEOCAN and continued under the name “**Arsenal Energy Inc.**”.

On February 15, 2009, Arsenal redeemed the convertible debentures (the “**Debentures**”) assumed by it when it purchased all of the issued and outstanding shares of Tiverton Petroleum Ltd. by payment of \$3,480,000 to the holders of the Debentures.

On March 20, 2009, the Board adopted a shareholders’ rights plan (the “**Shareholders’ Rights Plan**”) which was ratified and confirmed by the shareholders of the Corporation at the annual and special meeting of shareholders held on June 19, 2009.

The Board adopted the Shareholders’ Rights Plan to ensure, to the extent possible, that all shareholders of the Corporation are treated equally and fairly in connection with any takeover bid or similar offer for all or a portion of the outstanding Arsenal Shares. The Shareholders’ Rights Plan discourages discriminatory, coercive or unfair takeovers of the Corporation and gives the Board time, if in the circumstances, the Board determines it is appropriate to take such time, to pursue alternatives to maximize shareholder value in the event an unsolicited takeover bid is made for all or a portion of the outstanding Arsenal Shares.

In connection with the adoption of the Shareholders’ Rights Plan by shareholders, the Corporation issued one right in respect of each Arsenal Share outstanding at the close of business on March 20, 2009 (the “**Record Time**”) and authorized the issuance of one right in respect of each additional Arsenal Share issued after the Record Time. The rights trade with and are represented by the Corporation’s share certificates, including certificates issued prior to the Record Time. The Shareholders’ Rights Plan (unless earlier terminated) will remain in effect until termination of the annual meeting of shareholders of the Corporation in 2012 unless the term of the Shareholder Rights Agreement (the “**Shareholder Rights Agreement**”) dated effective March 20, 2009 between the Corporation and Computershare Trust Company of Canada, as rights agent is extended beyond such date by resolution of shareholders at such meeting. The Shareholders’ Rights Plan has been implemented by way of a Shareholder Rights

Agreement. A copy of the Shareholder Rights Agreement has been filed and is available on SEDAR at [www.sedar.com](http://www.sedar.com).

On September 3, 2009, Arsenal closed a brokered private placement and issued 8,750,000 Flow-Through Shares at a subscription price of \$0.40 per Flow-Through Share for aggregate gross proceeds of \$3,500,000.

On December 17, 2009, Arsenal closed a brokered private placement and issued 8,000,000 Arsenal Shares at a subscription price of \$0.50 per Arsenal Share and 2,500,000 Flow-Through Shares at a subscription price of \$0.60 per Flow-Through Share for aggregate gross proceeds of \$5,500,000.

During 2009, Arsenal disposed of non-core properties for proceeds of \$4,121,234. Production from these properties totalled slightly less than 200 boe/d.

## **2010**

On January 1, 2010, Arsenal amalgamated with its wholly owned subsidiary, McDrake Investments Ltd. and continued under the name “**Arsenal Energy Inc.**”.

On February 10, 2010, Arsenal announced it had filed its NI 51-101 Form F1, F2 and F3 dated February 10, 2010 relating to the filing of Arsenal’s Reserve Data and Other Oil & Gas Information for the year ended December 31, 2009.

On February 26, 2010, Arsenal closed a bought deal short form prospectus offering and issued 11,283,000 Arsenal Shares at a subscription price of \$0.85 per share and 3,000,000 Flow-Through Shares at a subscription price of \$1.00 per share for aggregate gross proceeds of \$12,590,550.

On April 19, 2010, Arsenal announced an increase in Arsenal’s credit facility from \$31 million to \$40 million.

On May 27, 2010, Arsenal announced that it intended to purchase for cancellation up to 6,740,767 Arsenal Shares by way of normal course issuer bid (the “**2010 NCIB**”) through the facilities of the TSX. The 6,740,767 Arsenal Shares represented approximately 5% of the number of then outstanding Arsenal Shares, being 134,815,340 Arsenal Shares. Purchases under the 2010 NCIB will terminate on May 30, 2011. Pursuant to the 2010 NCIB Arsenal has purchased 1,504,718 Arsenal Shares at an average price of \$0.82 per share. These Arsenal Shares have been cancelled. Additional purchases may be made under the 2010 NCIB prior to the expiry date.

On October 7, 2010, Arsenal closed a bought deal private placement offering and issued 7,300,000 Flow-Through Shares at a subscription price of \$0.96 per share for aggregate gross proceeds of \$7,008,000.

During 2010, Arsenal sold several non-core properties for aggregate gross proceeds of \$5,919,077. Production from these properties totalled slightly less than 200 boe/d. Included in the properties sold was all of Arsenal’s interests in property located in British Columbia.

In December 2010, Arsenal purchased the 35% working interest of a partner in a spacing unit in Stanley North Dakota for \$2,184,049. Arsenal completed drilling of a well on the spacing unit in March 2011.

## **2011**

On February 15, 2011, Arsenal closed a bought deal short form prospectus offering and issued 22,158,500 Arsenal Shares at a subscription price of \$0.95 per share for aggregate gross proceeds of \$21,050,575.

## **NARRATIVE DESCRIPTION OF THE BUSINESS**

Arsenal is engaged in the exploration for, and the development and production of, oil and natural gas. Arsenal’s current activities are focused in Central and East Central Alberta, Western Saskatchewan and in North Dakota, United States.

## **Business of Arsenal**

The business plan of Arsenal is to create sustainable and profitable growth as a participant in the oil and gas industry. Arsenal has and will continue to identify and acquire strategic acquisitions of oil and natural gas properties where it believes further exploitation, development and exploration opportunities exist. In addition, Arsenal implements a full cycle exploration program. Arsenal therefore pursues exploration and development drilling together with focused acquisitions both within its existing geographical project areas in the Western Canada Sedimentary Basin and in other areas of Alberta, Saskatchewan and North Dakota, which present opportunities which are of interest to its management.

In reviewing potential drilling or acquisition opportunities, Arsenal generally gives consideration to the following criteria:

- risked capital required to secure or evaluate the investment opportunity;
- the potential return on the project, if successful;
- the likelihood of success;
- if successful, the timing to bring production on-stream;
- proximity to infrastructure and available capacity;
- follow-up development potential and ability to source required capital; and
- the risked return versus cost of capital.

## **Business Risks**

The business of exploring for, developing and producing oil and natural gas reserves is inherently risky. There is substantial risk that the manpower and capital employed will not result in the finding of new reserves in economic quantities. There is a risk that the sale of Arsenal's reserves may be delayed indefinitely due to processing constraints, lack of pipeline capacity or lack of markets. The price Arsenal receives for its oil and gas production fluctuates continuously and, for the most part, is beyond Arsenal's control. Arsenal is also subject to the risks associated with owning oil and gas properties, including environmental risks such as the pollution of air, land and water. In all areas of the business, Arsenal competes against entities that may have greater technical and financial resources. Arsenal's growth is dependent upon external sources of financing which may not be available on acceptable terms. For a further description of risks applicable to Arsenal, see "*Risk Factors*" herein.

Arsenal mitigates these risks by hiring qualified personnel, either directly as employees or indirectly when contracting for services. To control the cost and pace of development, Arsenal attempts to acquire high working interests in each prospect and to operate wherever possible. Arsenal may enter into commodity price and interest rate hedging strategies to add a degree of certainty to cash flow. Arsenal diversifies its oil and gas market portfolio among various marketers and among a variety of contracts with respect to pricing and term.

## **Seasonal Considerations**

Certain of Arsenal's properties in the Evi and Lubicon region of Northern Alberta are accessible only during winter months. The majority of Arsenal's properties are accessible year round, except during spring break-up. Major facilities through which Arsenal's production is processed may temporarily be shut down for a short period of time during the year to conduct repair and maintenance operations.

## **Future Commitments**

Arsenal may use certain financial instruments to hedge its exposure to commodity price fluctuations on a portion of its crude oil and natural gas production. Arsenal has initiated and has outstanding as of December 31, 2010 the following fixed swap hedging transactions with the ATB Financial:

(\$Cdn.)

Commodity Sold	Volume Sold	Remaining Term	Pricing
Oil	100 bbl per day	Jan 1, 2010 – Apr 30, 2011	\$79.50 per bbl
Oil	100 bbl per day	Jan 1, 2011 – Dec 31, 2011	\$85.50 per bbl
Oil	100 bbl per day	Jan 1, 2011 – Dec 31, 2011	\$89.50 per bbl
Oil	100 bbl per day	May 1, 2011 – Dec 31, 2012	\$87.05 per bbl
Oil	100 bbl per day	Jan 1, 2011 – Dec 31, 2011	\$88.00 per bbl
Oil	100 bbl per day	Jan 1, 2012 – Dec 31, 2012	\$90.65 per bbl

In January 2011, Arsenal initiated the following two additional hedging transactions with ATB Financial:

(\$Cdn.)

Commodity Sold	Volume Sold	Remaining Term	Pricing
Oil	100 bbl per day	Feb 1, 2011 – Dec 31, 2011	\$93.30 per bbl
Oil	300 bbl per day	Jan 1, 2012 – Dec 31, 2012	\$95.15 per bbl

### **Environmental Matters**

The oil and gas industry is subject to environmental regulations pursuant to applicable legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, and requires that well and facility sites be abandoned and reclaimed to the satisfaction of environmental authorities. As at December 31, 2010, Arsenal recorded a provision on its balance sheet of \$12,465,634 for asset retirement obligations for future site restoration, reclamation and abandonment costs. Arsenal maintains an insurance program consistent with industry practice to protect against losses due to accidental destruction of assets, well blowouts, pollution and other operating accidents or disruptions. Arsenal also has operational and emergency response procedures and safety and environmental programs in place to reduce potential loss exposure. No assurance can be given that the application of environmental laws to the business and operations of Arsenal will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Arsenal's financial condition, results of operations or prospects.

### **Competitive Conditions**

Arsenal will actively compete for reserve acquisitions, exploration leases, licences and concessions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial resources than Arsenal. Arsenal's competitors will include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators.

The oil and gas industry is highly competitive. Arsenal's completion for the acquisition, exploration, production and development of oil and natural gas properties, and for capital to finance such activities, include companies that have greater financial and personnel resources available to them than Arsenal.

Certain of Arsenal's customers and potential customers may themselves explore for oil and natural gas and the results of such exploration efforts could affect Arsenal's ability to sell or supply oil or gas to these customers in the future. Arsenal's ability to successfully bid on and acquire additional property rights, to discover reserves to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with its future industry partners and joint operators and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment.

### **Employees & Specialized Skill and Knowledge**

As at December 31, 2010, Arsenal had 18 employees and 1 full time and two part time contract personnel employed at its head office and nil employees and 20 contractors at its field operations.

The Corporation requires the services of engineers and other professionals to explore and analyze oil prospects and to determine a method in which the oil prospects may be developed in a cost-effective manner. In addition, the

Corporation relies on the owners and operators of oil drilling equipment to drill and develop prospects to production. The Corporation has been able to acquire the services of these persons as needed in the past and believes that it will be able to continue to acquire these services as needed in the future.

### **Foreign Operations**

Arsenal explores for and drills for oil and natural gas in North Dakota, United States, and therefore the Corporation is dependant upon foreign operations.

### **Bankruptcies and Reorganization**

There has not been any bankruptcy, or any receivership or similar proceedings against the Corporation or any of its subsidiaries or any voluntary bankruptcy, receivership or similar proceedings by the Corporation or any of its subsidiaries, within the three most recently completed financial years for which financial statements have been filed, or during or proposed for the current financial year. Other than as disclosed herein, there have been no material reorganizations of the Corporation or any of its subsidiaries within the three most recently completed financial years, nor have any been proposed for the current financial year.

### **Environmental and Social Policies**

The Corporation has not implemented any social or environmental policies that are fundamental to its operations.

## **STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION**

AJM Petroleum Consultants (“AJM”), independent petroleum engineers of Calgary, Alberta, prepared a report entitled “Arsenal Energy Inc. - Reserve Estimation and Economic Evaluation (as of December 31, 2010)” (the “AJM Report”), effective December 31, 2010, and dated March 9, 2011, evaluating the proved and probable reserves attributable to Arsenal’s interest in 100% of its North American properties and the net present value of estimated future cash flow from such reserves, based on forecast price and cost assumptions. The reserves information presented herein was prepared and is presented in accordance with the requirements of NI 51-101.

In preparing the AJM Report, AJM obtained information from Arsenal, which included land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans. Other engineering, geological or economic data required to conduct the evaluation and upon which the AJM Report is based, was obtained from public records, other operators and from AJM’s non-confidential files. The extent and character of ownership and the accuracy of all factual data supplied for the independent evaluation, from all sources, was accepted by AJM as represented.

**All evaluations of the present value of estimated future net revenue in the AJM Report are stated after provision for estimated future capital expenditures, well abandonment and reclamation costs (including the offsetting salvage value of tangible equipment after abandonment) but prior to income taxes and indirect costs and do not necessarily represent the fair market value of the reserves. It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumption will be attained and variances could be material. Actual reserves may be greater than or less than the estimates provided herein. Please note that information relating to reserves are deemed to be forward-looking statements, as they involve the implicit assessment, based on certain estimates and assumptions, that the reserves described can be economically produced in the future. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.**

**Reference to oil, gas, natural gas liquids, coalbed methane, reserves (gross, net, proved, probable, possible, developed, developed producing, developed non producing, undeveloped), forecast prices and costs, operating costs, development costs, future net revenue and future income tax expenses shall, unless expressly stated to be to the contrary, have the meaning attributed to such terms as set out in NI 51-101, the companion policy to NI 51-101 and all forms referenced therein.**

Throughout the following summary, table differences may arise due to rounding.

In accordance with the requirements of NI 51-101, attached hereto are the following appendices:

Appendix A: Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor in Form 51-101F2; and

Appendix B: Report of Management and Directors on Reserves Data and Other Information in Form 51-101F3.

Definitions used for reserve categories in the AJM Report are attached as Appendix C hereto.

**For the purposes herein, and unless otherwise noted, “Gross” means: (a) in relation to the Corporation’s interest in production or reserves, its “company gross reserves”, which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interest of the Corporation; (b) in relation to wells, the total number of wells in which the Corporation has an interest; and (c) in relation to properties, the total area of properties in which the Corporation has an interest.**

**For the purposes herein, and unless otherwise noted, “Net” means: (a) in relation to the Corporation’s interest in production or reserves, the Corporation’s working interest (operating or non-operating) share after deduction of royalty obligations, plus the Corporation’s royalty interest in production or reserves; (b) in relation to the Corporation’s interest in wells, the number of wells obtained by aggregating the Corporation’s working interest in each of its gross wells; and (c) in relation to a Corporation’s interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.**

The following tables summarize certain information related to Arsenal’s oil and gas reserves as of December 31, 2010 based on forecast price and cost assumptions:

SUMMARY OF OIL AND GAS RESERVES — CANADIAN OIL & GAS ASSETS										
as of December 31, 2010										
FORECAST PRICES AND COSTS										
Reserves Category	Reserves									
	Light and Medium Oil		Heavy Oil		Natural Gas <sup>(1)</sup>		Natural Gas Liquids		Coalbed Methane	
	Gross (Mbb1)	Net (Mbb1)	Gross (Mbb1)	Net (Mbb1)	Gross (MMcf)	Net (MMcf)	Gross (Mbb1)	Net (Mbb1)	Gross (MMcf)	Net (MMcf)
<b>PROVED</b>										
Developed Producing	763.6	641.0	186.7	201.0	2,772.4	2,332.7	41.0	29.1	125.0	107.8
Developed Non-Producing	60.3	49.0	29.5	27.3	708.0	657.4	4.3	3.1	-	-
Undeveloped	76.0	56.9	18.6	17.0	11.9	11.3	0.5	0.4	-	-
<b>TOTAL PROVED</b>	<b>900.0</b>	<b>746.8</b>	<b>234.8</b>	<b>245.3</b>	<b>3,492.3</b>	<b>3,001.4</b>	<b>45.8</b>	<b>32.6</b>	<b>125.0</b>	<b>107.8</b>
Probable	415.0	335.2	371.2	327.2	1,568.9	1,313.4	19.7	14.0	43.2	37.2
<b>TOTAL PROVED PLUS PROBABLE</b>	<b>1,315.0</b>	<b>1,082.0</b>	<b>605.9</b>	<b>572.6</b>	<b>5,061.1</b>	<b>4,314.9</b>	<b>65.5</b>	<b>46.6</b>	<b>168.2</b>	<b>145.0</b>

Note:

(1) Natural gas volumes include associated, non-associated and solution gas but not coalbed methane.

SUMMARY OF OIL AND GAS RESERVES — UNITED STATES OIL & GAS ASSETS										
as of December 31, 2010										
FORECAST PRICES AND COSTS										
Reserves Category	Reserves									
	Light and Medium Oil		Heavy Oil		Natural Gas <sup>(1)</sup>		Natural Gas Liquids		Coalbed Methane	
	Gross (Mbb1)	Net (Mbb1)	Gross (Mbb1)	Net (Mbb1)	Gross (MMcf)	Net (MMcf)	Gross (Mbb1)	Net (Mbb1)	Gross (MMcf)	Net (MMcf)
<b>PROVED</b>										
Developed Producing	1,525.7	1,220.9	-	-	876.2	704.2	101.4	81.2	-	-
Developed Non-Producing	111.3	96.4	-	-	13.7	11.9	0.5	0.4	-	-
Undeveloped	3,469.4	2,671.7	-	-	379.9	300.8	15.2	12.5	-	-
<b>TOTAL PROVED</b>	<b>5,106.3</b>	<b>3,989.0</b>	-	-	<b>1,269.8</b>	<b>1,016.8</b>	<b>117.1</b>	<b>94.1</b>	-	-
Probable	2,058.8	1,620.7	-	-	454.3	366.3	38.5	31.3	-	-
<b>TOTAL PROVED PLUS PROBABLE</b>	<b>7,165.1</b>	<b>5,609.7</b>	-	-	<b>1,724.1</b>	<b>1,383.0</b>	<b>155.6</b>	<b>125.4</b>	-	-

Note:

- (1) Natural gas volumes include associated, non-associated and solution gas but not coalbed methane.

SUMMARY OF OIL AND GAS RESERVES — AGGREGATED CANADA AND UNITED STATES OIL & GAS ASSETS										
as of December 31, 2010										
FORECAST PRICES AND COSTS										
Reserves Category	Reserves									
	Light and Medium Oil		Heavy Oil		Natural Gas <sup>(1)</sup>		Natural Gas Liquids		Coalbed Methane	
	Gross (Mbb1)	Net (Mbb1)	Gross (Mbb1)	Net (Mbb1)	Gross (MMcf)	Net (MMcf)	Gross (Mbb1)	Net (Mbb1)	Gross (MMcf)	Net (MMcf)
<b>PROVED</b>										
Developed Producing	2,289.3	1,861.9	186.7	201.0	3,648.5	3,036.9	142.5	110.3	125.0	107.8
Developed Non-Producing	171.6	145.4	29.5	27.3	721.7	669.2	4.7	3.5	-	-
Undeveloped	3,545.4	2,728.5	18.6	17.0	391.8	312.0	15.7	12.9	-	-
<b>TOTAL PROVED</b>	<b>6,006.3</b>	<b>4,735.8</b>	<b>234.8</b>	<b>245.3</b>	<b>4,762.1</b>	<b>4,018.2</b>	<b>162.9</b>	<b>126.7</b>	<b>125.0</b>	<b>107.8</b>
Probable	2,473.8	1,955.9	371.2	327.2	2,023.2	1,679.7	58.2	45.3	43.2	37.2
<b>TOTAL PROVED PLUS PROBABLE</b>	<b>8,480.1</b>	<b>6,691.7</b>	<b>605.9</b>	<b>572.6</b>	<b>6,785.3</b>	<b>5,697.9</b>	<b>221.1</b>	<b>172.0</b>	<b>168.2</b>	<b>145.0</b>

Note:

- (1) Natural gas volumes include associated, non-associated and solution gas but not coalbed methane.

**SUMMARY OF NET PRESENT VALUES OF  
FUTURE NET REVENUE - CANADIAN OIL & GAS ASSETS  
as of December 31, 2010**

**FORECAST PRICES AND COSTS**

Reserves Category	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)					UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/YEAR (\$/BOE)
	0 (M\$)	5 (M\$)	10 (M\$)	15 (M\$)	20 (M\$)	0 (M\$)	5 (M\$)	10 (M\$)	15 (M\$)	20 (M\$)	
<b>PROVED</b>											
Developed	32,574.8	28,699.6	25,598.9	23,094.2	21,046.5	24,216.2	21,354.4	19,066.7	17,220.8	15,713.6	20.03
Producing											
Developed	5,480.6	4,585.2	3,961.6	3,497.2	3,136.1	4,073.7	3,382.7	2,903.6	2,548.4	2,273.5	20.97
Non-Producing											
Undeveloped	4,425.3	3,044.7	2,161.7	1,574.9	1,171.6	3,316.2	2,252.4	1,573.2	1,122.2	812.3	28.41
<b>TOTAL PROVED</b>											
Probable	42,480.8	36,329.5	31,722.3	28,166.3	25,354.2	31,606.0	26,989.6	23,543.5	20,891.4	18,799.4	20.56
<b>TOTAL PROVED PLUS PROBABLE</b>											
	41,927.5	29,705.3	22,194.2	17,264.8	13,857.3	31,232.8	22,103.9	16,493.0	12,810.0	10,263.8	24.62
<b>TOTAL PROVED PLUS PROBABLE</b>	84,408.2	66,034.9	53,916.4	45,431.1	39,211.5	62,838.9	49,093.5	40,036.5	33,701.4	29,063.2	22.06

**SUMMARY OF NET PRESENT VALUES OF  
FUTURE NET REVENUE – UNITED STATES OIL & GAS ASSETS  
as of December 31, 2010**

**FORECAST PRICES AND COSTS**

Reserves Category	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)					UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/YEAR (\$/BOE)
	0 (M\$)	5 (M\$)	10 (M\$)	15 (M\$)	20 (M\$)	0 (M\$)	5 (M\$)	10 (M\$)	15 (M\$)	20 (M\$)	
<b>PROVED</b>											
Developed	84,235.9	53,530.4	39,745.6	31,915.1	26,841.4	52,542.3	33,411.7	24,827.3	19,952.8	16,796.5	28
Producing											
Developed	8,390.2	4,460.2	3,027.6	2,319.2	1,898.5	5,226.8	2,764.1	1,867.3	1,424.4	1,161.8	30.64
Non-Producing											
Undeveloped	211,010.5	108,964.0	68,815.8	47,895.9	35,060.2	129,930.1	65,952.9	40,784.0	27,669.8	19,623.2	25.17
<b>TOTAL PROVED</b>											
Probable	303,636.6	166,954.6	111,589.1	82,130.2	63,800.0	187,699.2	102,128.7	67,478.6	49,047.0	37,581.4	26.24
<b>TOTAL PROVED PLUS PROBABLE</b>											
	200,793.8	71,486.9	35,935.9	21,949.6	14,987.7	125,949.2	44,894.7	22,604.5	13,833.1	9,466.4	20.98
<b>TOTAL PROVED PLUS PROBABLE</b>	504,430.4	238,441.4	147,525.0	104,079.9	78,787.8	313,648.4	147,023.4	90,083.1	62,880.1	47,047.8	24.73

**SUMMARY OF NET PRESENT VALUES OF  
FUTURE NET REVENUE— AGGREGATED CANADA AND UNITED STATES OIL & GAS ASSETS**

**as of December 31, 2010**

**FORECAST PRICES AND COSTS**

Reserves Category	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)					UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/YEAR
	0 (M\$)	5 (M\$)	10 (M\$)	15 (M\$)	20 (M\$)	0 (M\$)	5 (M\$)	10 (M\$)	15 (M\$)	20 (M\$)	(\$/BOE)
<b>PROVED</b>											
Developed Producing	116,810.7	82,230.0	65,344.5	55,009.3	47,887.8	76,758.4	54,766.1	43,893.9	37,173.6	32,510.1	24.23
Developed Non-Producing	13,870.9	9,045.4	6,989.3	5,816.3	5,034.6	9,300.5	6,146.8	4,770.9	3,972.8	3,435.3	24.29
Undeveloped	215,435.8	112,008.7	70,977.5	49,470.9	36,231.8	133,246.3	68,205.3	42,357.3	28,792.0	20,435.5	25.26
<b>TOTAL PROVED</b>	346,117.4	203,284.1	143,311.3	110,296.5	89,154.2	219,305.2	129,118.3	91,022.1	69,938.4	56,380.9	24.73
Probable	242,721.3	101,192.2	58,130.1	39,214.4	28,845.1	157,182.1	66,998.6	39,097.5	26,643.1	19,730.1	22.23
<b>TOTAL PROVED PLUS PROBABLE</b>	588,838.6	304,476.3	201,441.4	149,510.9	117,999.3	376,487.3	196,116.9	130,119.6	96,581.6	76,111.0	23.95

**TOTAL FUTURE NET REVENUE  
(UNDISCOUNTED) — CANADIAN OIL & GAS ASSETS**

**as of December 31, 2010**

**FORECAST PRICES AND COSTS**

Reserves Category	Revenue (M\$)	Royalties (M\$)	Operating Costs (M\$)	Development Costs (M\$)	Well Abandonment Reclamation and Costs (M\$)	Future Net Revenue Before Income Taxes (M\$)	Future Income Taxes and Expenses (M\$)	Future Net Revenue After Deducting Income Taxes (M\$)
<b>PROVED</b>								
Developed Producing	91,821.4	14,463.6	32,671.6	-	12,111.3	32,574.8	8,358.7	24,216.2
Developed Non-Producing	12,094.0	1,850.0	4,032.3	731.1	-	5,480.6	1,406.9	4,073.7
Undeveloped	10,073.5	2,306.4	2,151.5	1,173.8	16.5	4,425.3	1,109.1	3,316.2
<b>TOTAL PROVED</b>	113,988.9	18,620.1	38,855.4	1,904.9	12,127.8	42,480.8	10,874.7	31,606.0
Probable	85,661.7	14,621.1	27,046.8	1,725.2	341.1	41,927.5	10,694.6	31,232.8
<b>TOTAL PROVED PLUS PROBABLE</b>	199,650.6	33,241.2	65,902.2	3,630.1	12,468.9	84,408.2	21,569.4	62,838.9

<b>TOTAL FUTURE NET REVENUE</b> <b>(UNDISCOUNTED) - UNITED STATES OIL &amp; GAS ASSETS</b> <b>as of December 31, 2010</b> <b>FORECAST PRICES AND COSTS</b>								
Reserves Category	Revenue (M\$)	Royalties (M\$)	Operating Costs (M\$)	Development Costs (M\$)	Well Abandonment and Reclamation Costs (M\$)	Future Net Revenue Before Income Taxes (M\$)	Future Income Taxes and Expenses (M\$)	Future Net Revenue After Deducting Income Taxes (M\$)
<b>PROVED</b>								
Developed Producing	133,065.1	6,371.1	39,940.1	454.0	2,064.1	84,235.9	27,481.8	52,542.3
Developed Non-Producing	11,549.5	577.5	2,467.3	90.9	23.5	8,390.2	2,739.4	5,226.8
Undeveloped	300,205.4	14,220.0	41,893.6	32,743.7	337.6	211,010.5	70,519.5	129,930.1
<b>TOTAL PROVED</b>	<b>444,820.0</b>	<b>21,168.6</b>	<b>84,301.0</b>	<b>33,288.6</b>	<b>2,425.2</b>	<b>303,636.6</b>	<b>100,740.7</b>	<b>187,699.2</b>
Probable	231,967.7	11,190.9	19,885.3	-0.6	98.4	200,793.8	64,804.9	125,949.2
<b>TOTAL PROVED PLUS PROBABLE</b>	<b>676,787.7</b>	<b>32,359.4</b>	<b>104,186.3</b>	<b>33,288.1</b>	<b>2,523.5</b>	<b>504,430.4</b>	<b>165,545.5</b>	<b>313,648.4</b>

<b>TOTAL FUTURE NET REVENUE</b> <b>(UNDISCOUNTED) - AGGREGATED CANADA AND UNITED STATES OIL &amp; GAS ASSETS</b> <b>as of December 31, 2010</b> <b>FORECAST PRICES AND COSTS</b>								
Reserves Category	Revenue (M\$)	Royalties (M\$)	Operating Costs (M\$)	Development Costs (M\$)	Well Abandonment and Reclamation Costs (M\$)	Future Net Revenue Before Income Taxes (M\$)	Future Income Taxes and Expenses (M\$)	Future Net Revenue After Deducting Income Taxes (M\$)
<b>PROVED</b>								
Developed Producing	224,886.5	20,834.7	72,611.7	454.0	14,175.4	116,810.7	35,840.4	76,758.4
Developed Non-Producing	23,643.5	2,427.5	6,499.6	822.1	23.5	13,870.9	4,146.3	9,300.5
Undeveloped	310,278.9	16,526.5	44,045.1	33,917.5	354.1	215,435.8	71,628.6	133,246.3
<b>TOTAL PROVED</b>	<b>558,808.9</b>	<b>39,788.7</b>	<b>123,156.4</b>	<b>35,193.6</b>	<b>14,552.9</b>	<b>346,117.4</b>	<b>111,615.4</b>	<b>219,305.2</b>
Probable	317,629.5	25,812.0	46,932.1	1,724.6	439.5	242,721.3	75,499.5	157,182.1
<b>TOTAL PROVED PLUS PROBABLE</b>	<b>876,438.4</b>	<b>65,600.6</b>	<b>170,088.5</b>	<b>36,918.2</b>	<b>14,992.5</b>	<b>588,838.6</b>	<b>187,114.9</b>	<b>376,487.3</b>

<b>FUTURE NET REVENUE BY PRODUCTION GROUP — CANADIAN OIL &amp; GAS ASSETS as of December 31, 2010</b>			
<b>FORECAST PRICES AND COSTS</b>			
<b>RESERVES CATEGORY</b>	<b>PRODUCTION GROUP</b>	<b>FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M\$)</b>	<b>FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (\$/MCF) (\$/BBL)</b>
<b>PROVED</b>	Light and Medium Oil (including solution gas and associated by-products)	22,291.9	24.67
	Heavy Oil (including solution gas and other associated by-products)	6,896.7	27.10
	Natural Gas (including associated by-products but excluding solution gas and by-products from oil wells)	2,426.0	6.62
	Coalbed Methane (including associated by-products)	107.6	5.90
	Non-Conventional Oil & Gas Activities (excluding coalbed methane)	-	-
	<b>Total</b>	<b>31,722.3</b>	<b>20.56</b>
<b>PROVED PLUS PROBABLE</b>	Light and Medium Oil (including solution gas and associated by-products)	33,694.6	25.81
	Heavy Oil (including solution gas and associated by-products)	15,711.9	26.31
	Natural Gas (including associated by-products but excluding solution gas and by-products from oil wells)	4,350.9	8.41
	Coalbed Methane (including associated by-products)	159.0	6.48
	Non-Conventional Oil & Gas Activities (excluding coalbed methane)	-	-
	<b>Total</b>	<b>53,916.4</b>	<b>22.06</b>

<b>FUTURE NET REVENUE BY PRODUCTION GROUP — UNITED STATES OIL &amp; GAS ASSETS as of December 31, 2010</b>			
<b>FORECAST PRICES AND COSTS</b>			
<b>RESERVES CATEGORY</b>	<b>PRODUCTION GROUP</b>	<b>FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M\$)</b>	<b>FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (\$/MCF) (\$/BBL)</b>
<b>PROVED</b>	Light and Medium Oil (including solution gas and associated by-products)	111,589.1	26.24
	Heavy Oil (including solution gas and other associated by-products)	-	-
	Natural Gas (including associated by-products but excluding solution gas and by-products from oil wells)	-	-
	Non-Conventional Oil & Gas Activities	-	-
	<b>Total</b>	<b>111,589.1</b>	<b>26.24</b>
<b>PROVED PLUS PROBABLE</b>	Light and Medium Oil (including solution gas and associated by-products)	147,525.0	24.73
	Heavy Oil (including solution gas and associated by-products)	-	-
	Natural Gas (including associated by-products but excluding solution gas and by-products from oil wells)	-	-
	Non-Conventional Oil & Gas Activities	-	-
	<b>Total</b>	<b>147,525.0</b>	<b>24.73</b>

<b>FUTURE NET REVENUE                      BY PRODUCTION GROUP — AGGREGATED CANADIAN &amp; UNITED STATES OIL &amp; GAS ASSETS                      as of December 31, 2010</b>			
<b>FORECAST PRICES AND COSTS</b>			
<b>RESERVES                      CATEGORY</b>	<b>PRODUCTION GROUP</b>	<b>FUTURE NET                      REVENUE BEFORE                      INCOME TAXES                      (discounted at                      10%/year)                      (M\$)</b>	<b>FUTURE NET                      REVENUE BEFORE                      INCOME TAXES                      (discounted at                      10%/year)                      (\$/MCF)                      (\$/BBL)</b>
<b>PROVED</b>	Light and Medium Oil (including solution gas and associated by-products)	133,881.0	25.97
	Heavy Oil (including solution gas and other associated by-products)	6,896.7	27.10
	Natural Gas (including associated by-products but excluding solution gas and by-products from oil wells)	2,426.0	6.62
	Coalbed Methane (including associated by-products)	107.6	5.90
	Non-Conventional Oil & Gas Activities (excluding coalbed methane)	-	-
	<b>Total</b>		143,311.3
<b>PROVED PLUS                      PROBABLE</b>	Light and Medium Oil (including solution gas and associated by-products)	181,219.6	24.92
	Heavy Oil (including solution gas and associated by-products)	15,711.9	26.31
	Natural Gas (including associated by-products but excluding solution gas and by-products from oil wells)	4,350.9	8.41
	Coalbed Methane (including associated by-products)	159.0	6.48
	Non-Conventional Oil & Gas Activities (excluding coalbed methane)	-	-
	<b>Total</b>		201441.4

**PRICING ASSUMPTIONS**

AJM employed the following pricing, exchange rate and inflation rate assumptions in estimating Arsenal's reserves data using forecast prices and costs as of December 31, 2010.



Arsenal's weighted average realized sales prices for the year ended December 31, 2010 were \$64.48 /bbl for heavy oil, \$69.99 /bbl for light oil and medium oil, and \$3.91/Mcf for natural gas and coalbed methane.

### RECONCILIATION OF CHANGES IN RESERVES

#### Reserves Reconciliation (Canada)

The following tables set forth a reconciliation of Arsenal's total gross proved, probable and proved plus probable reserves as at December 31, 2010 against such reserves as at December 31, 2009 based on forecast price and cost assumptions:

FACTORS	LIGHT AND MEDIUM OIL			HEAVY OIL			NATURAL GAS <sup>(1)</sup>		
	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)
<b>December 31, 2009</b>	903.0	448.8	1,351.8	311.7	491.4	803.2	4075.2	2315.5	6390.7
Acquisitions	3.3	1.5	4.8	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
Dispositions	-13.7	-11.4	-25.1	-28.3	-144.3	-172.6	-947.0	-813.2	-1760.2
Extensions and Improved Recovery	130.1	59.5	189.7	34.5	69.1	103.6	137.0	139.8	276.8
Technical Revisions <sup>(2)</sup>	77.8	-104.7	-27	11.0	-44.9	-33.9	1262.6	110.3	1372.9
Economic Factors	-	-	-	-	-	-	-209.8	-181.6	-391.4
Gross Production	-219.6	-	-219.6	-94.4	-	-94.4	-830.4	-	-830.4
<b>December 31, 2010</b>	880.9	393.7	1,274.6	234.8	371.2	605.9	3487.7	1570.7	5058.4

FACTORS	NATURAL GAS LIQUIDS			COALBED METHANE		
	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)
<b>December 31, 2009</b>	51.1	25.3	76.5	130.9	85.1	216.0
Acquisitions	0	0	0	-	-	-
Discoveries	0	0	0	-	-	-
Dispositions	-12.3	-10.4	-22.7	-	-	-
Extensions and Improved Recovery	0	0	0	-	-	-
Technical Revisions <sup>(2)</sup>	18.9	6.4	25.2	52.3	-44.3	8.0
Economic Factors	-1.1	-1.6	-2.7	-14.6	2.4	-12.2
Gross Production	-10.8	0	-10.8	-43.7	-	-43.7
<b>December 31, 2010</b>	45.9	19.7	65.5	125.0	43.2	168.2

**Notes:**

(1) Natural gas volumes include associated, non-associated and solution gas but does not include coalbed methane.  
 Technical revisions to reserve volumes for December 31, 2010.

#### Reserves Reconciliation (United States)

The following tables set forth a reconciliation of Arsenal's total gross proved, probable and proved plus probable reserves as at December 31, 2010 against such reserves as at December 31, 2009 based on forecast price and cost assumptions:

FACTORS	LIGHT AND MEDIUM OIL			HEAVY OIL			NATURAL GAS <sup>(1)</sup>		
	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)
<b>December 31, 2009</b>	3,451.5	1,608.5	5,060.0	-	-	-	644.3	212.8	857.1
Acquisitions	584.6	265.8	850.3	-	-	-	98.5	47.9	146.4
Discoveries	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	545.6	170.1	715.7	-	-	-	-	-	-
Technical Revisions <sup>(2)</sup>	709.6	14.5	724.1	-	-	-	630.9	195.5	826.4
Economic Factors	-	-	-	-	-	-	0.5	-1.9	-1.4
Gross Production	-185.0	-	-185.0	-	-	-	-104.5	-	-104.5
<b>December 31, 2010</b>	5,106.3	2,058.8	7,165.1	-	-	-	1,269.8	454.3	1724.1

FACTORS	NATURAL GAS LIQUIDS			COALBED METHANE		
	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)
<b>December 31, 2009</b>	92.0	29.8	121.9	-	-	-
Acquisitions	3.3	1.6	5.0	-	-	-
Discoveries	0	0	0	-	-	-
Dispositions	0	0	0	-	-	-
Extensions and Improved Recovery	0	0	0	-	-	-
Technical Revisions <sup>(2)</sup>	32.9	7.4	40.3	-	-	-
Economic Factors	0.1	-0.3	-0.2	-	-	-
Gross Production	-11.3	0	-11.3	-	-	-
<b>December 31, 2010</b>	117.1	38.5	155.6	-	-	-

**Notes:**

- (1) Natural gas volumes include associated, non-associated but does not include coalbed methane.
- (2) Technical revisions to reserve volumes for December 31, 2010.

**ADDITIONAL INFORMATION RELATING TO RESERVES DATA**

**Proved Undeveloped Reserves and Probable Undeveloped Reserves**

Proved undeveloped reserves are generally those reserves related to wells that have been tested and not yet tied-in, wells drilled near the end of the fiscal year or wells further away from Arsenal gathering systems. In addition, such reserves may relate to planned infill drilling locations. These reserves are planned to be on stream within a two year timeframe.

Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. These reserves are planned to be on stream within a two year timeframe.

The following provides the gross volumes of proved undeveloped reserves and probable undeveloped reserves of Arsenal that were first attributed and booked in each of the most recent three financial years of Arsenal ending on the date of the AJM Report, and in the aggregate, before that time:

TOTAL CORPORATION																				
TIME PERIOD	LIGHT AND MEDIUM OIL				HEAVY OIL				NATURAL GAS LIQUIDS				NATURAL GAS				COAL BED METHANE			
	(Mbbbl)				(Mbbbl)				(Mbbbl)				(Mmcf)				(Mmcf)			
	PROVED		PROBABLE		PROVED		PROBABLE		PROVED		PROBABLE		PROVED		PROBABLE		PROVED		PROBABLE	
	A*	B*	A*	B*	A*	B*	A*	B*	A*	B*	A*	B*	A*	B*	A*	B*	A*	B*	A*	B*
2010	958.6	3545.4	453.1	2473.8	0	18.6	51	371.2	3.3	16	0	58	99	392	69	2066.4	0	0	0	0
2009	1956.9	2367.2	897.0	2056.9	0	18.6	0	491.4	0	2.8	0	55.1	0	21.2	0	2613.4	0	0	0	0
2008	468	382	760	1,478	0	116	0	738	3.6	3.8	11	113	26	30	204	4,878	0	0	0	89
Prior to 2007	425	68	0	872	19	341	35	1695	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

\* A: First Attributed  
B: Booked

### Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It requires significant judgment and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, commodity prices and economic conditions. Arsenal's reserves are evaluated by AJM, an independent engineering firm.

Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, commodity prices, economic conditions and governmental restrictions. Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. Arsenal's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material.

### Future Development Costs

The following table outlines development costs deducted in the estimation of future net revenue attributable to proved reserves and proved plus probable reserves using forecast prices and costs:

Year	Canada		United States	
	Proved Reserves (M\$)	Proved Plus Probable Reserves (M\$)	Proved Reserves (M\$)	Proved Plus Probable Reserves (M\$)
2011	1,111.2	1796.2	32,662.9	32,662.9
2012	176.0	225.0	625.7	625.7
2013	197.7	197.7	0	0
2014	0.0	224.2	0	0
2015	0.0	108.2	0	0
Remaining Years	420.1	1078.8	0	0
<b>Total Undiscounted</b>	<b>1904.9</b>	<b>3630.1</b>	<b>33,288.6</b>	<b>33,288.6</b>

Arsenal has established a \$54 million capital program (the "2011 Capital Program") to fund its exploration and development activities for 2011. The 2011 Capital Program does not include any new acquisition opportunities, which Arsenal believes will likely be financed through debt or equity financings.

Arsenal estimates that its internally generated cash flow, equity funds raised in February 2011 and unused bank credit facilities are sufficient to fund the future development costs disclosed above. Arsenal typically has available three sources of funding to finance its capital expenditure program: internally generated cash flow from operating activities, debt financing when appropriate and new equity issues, if available on favourable terms.

## OTHER OIL AND GAS INFORMATION

### Properties

Arsenal has interests in 12 major and 14 minor Canadian properties and four core and two minor U.S. properties. These Canadian and U.S. areas are the subjects of the AJM Report. The following provides a description of Arsenal's most important properties. All of Arsenal's properties are located on-shore.

### Canada

#### *Alberta*

##### *Chauvin/Ribstone*

The Chauvin and Ribstone properties are located in close proximity in east central Alberta in Townships 42-43, Range 2 W4M. Arsenal holds a 100% working interest in both. A combined total of 35 oil wells produce medium-heavy oil from the Cretaceous Sparky, General Petroleum, Rex, McLaren and Colorado formations. In 2010, this area averaged 313 boe/d net. Oil is transported by a tanker truck to a terminal on the Bow River pipeline system.

##### *Galahad*

The Galahad property is located in Township 40, Range 15 W4M and produces oil from the Mannville group, Lloydminster, Glauconite and Ellerslie sands. The property consists of 13 producing oil wells, with Arsenal ownership ranging from 50 to 100%. Production averaged 239 boe/d net. Oil is transported to the Hardisty pipeline terminal.

##### *Evi*

The Evi area is located in Township 87, Range 12 W5M in north central Alberta. Light oil is produced from the Devonian Slave Point, Gilwood and Granite Wash formations. Production averaged 209 boe/d net in 2010. The oil is processed at the 11-1-87-13 W5M battery operated by Harvest Energy Trust and transported by pipeline to market. Arsenal drilled six successful oil wells and one dry hole in 2010.

##### *Princess*

The Princess area is located in Township 19, Range 10 W4M in southeast Alberta. Medium oil is produced from the Cretaceous Glauconite and Detrital sands. Production averaged 41 boe/d net in 2010. Arsenal drilled three successful wells and one dry hole in 2010. Arsenal is pursuing water disposal and battery upgrades in support of future activity on this property.

##### *Other/Minor*

Other producing properties in Alberta include Provost, Alderson, Blueridge, Nevis, Tomahawk and various minor properties which made up 519 boe/d net production in Alberta in 2010. Activity in these areas was limited to maintenance of production through workovers. Low gas prices persisted throughout 2010 limiting the potential to develop gas production.

### *British Columbia*

Arsenal divested all properties in BC in 2010, and no longer operates in that Province.

### *Saskatchewan*

Arsenal has two significant heavy oil properties, Lashburn and Dee Valley East, and minor non-core interests in Buzzard and Rush Lake. Production from Saskatchewan averaged 128 boe/d net in 2010.

**United States**

***North Dakota***

*Stanley*

The Stanley property is located in Mountrail County, North Dakota. Production from seven Mission Canyon formation oil wells and six Bakken/Three Forks horizontals were producing at the end of 2010. One additional Bakken/Three Forks well was drilled by a partner on Arsenal interest lands and was waiting on completion at the end of 2010. Production averaged 367 boe/d net in 2010. Further drilling is anticipated in 2011, and Arsenal plans to operate some drills on high working interest lands.

*Lindahl*

This property is located in Williams County, North Dakota. Production from twelve Madison carbonate oil wells and three Bakken/Three Forks horizontals were producing at the end of 2010. Production averaged 148 boe/d net in 2010. Industry activity is ongoing in the Bakken and the Three Forks oil plays in the vicinity of Lindahl.

*Rennie Lake/Black Slough*

Located in Burke County, North Dakota, the Rennie Lake property produces oil, natural gas and liquids from eight wells completed in the Midale and Nesson zones of the Madison formation. Working interests range from 45 to 100%. In 2010, the production averaged 33 boe/d net. Recent industry activity in the vicinity on the Bakken/Three Forks formations is expected to indicate the future potential of these zones on Arsenal lands.

Wells

As at December 31, 2010, Arsenal had an interest in 183 gross (122 net) producing and 294 gross (178.1 net) non-producing oil and natural gas wells and 9 gross (9 net) service wells as follows:

Location	PRODUCING				NON-PRODUCING				SERVICE WELLS	
	Oil		Natural Gas		Oil		Natural Gas		Gross <sup>(1)</sup>	Net <sup>(2)</sup>
	Gross <sup>(1)</sup>	Net <sup>(2)</sup>	Gross <sup>(1)</sup>	Net <sup>(2)</sup>	Gross <sup>(1)</sup>	Net <sup>(2)</sup>	Gross <sup>(1)</sup>	Net <sup>(2)</sup>		
Alberta	85	66	33	14	143	95.9	72	41.5	9	9
Saskatchewan	15	5.9	0	0	30	13.4	5	1.6	0	0
British Columbia	0	0	0	0	0	0	0	0	0	0
North Dakota, USA	50	36.5	0	0	44	25.7	0	0	0	0
<b>TOTAL</b>	<b>150</b>	<b>108.4</b>	<b>33</b>	<b>14</b>	<b>217</b>	<b>135</b>	<b>77</b>	<b>43.1</b>	<b>9</b>	<b>9</b>

**Properties With No Attributed Reserves**

The following table sets forth the gross and net acres of unproved properties (properties with no attributed reserves) held by Arsenal and the net area of unproved property for which Arsenal expects its rights to explore, develop and exploit to expire during the 2011 fiscal year.

UNPROVED PROPERTIES - UNDEVELOPED LAND (Acres)			
LOCATION	Gross <sup>(1)</sup>	Net <sup>(2)</sup>	Net Area to Expire in 2011
Alberta	90,853	59,914	8,730
British Columbia	Nil	Nil	Nil
Saskatchewan	1,674	427	Nil
Total Canada	92,527	60,341	8,730
North Dakota, United States	5,144	3,800	nil
<b>TOTAL</b>	<b>96,671</b>	<b>64,141</b>	<b>8,730</b>

There are no costs or work commitments associated with Arsenal's non-producing properties except for annual lease rental payments and abandonment costs.

## Forward Contracts

Arsenal may use certain financial instruments to hedge its exposure to commodity price fluctuations on a portion of its crude oil and natural gas production. See “Narrative Description of Business – Future Commitments” herein.

## Additional Information Concerning Abandonment and Reclamation Costs

Arsenal estimates the costs associated with well abandonment and reclamation cost for surface leases, wells, facility and pipeline based on its previous experience, current regulations, costs, technology and industry standards. Arsenal expects to incur abandonment and reclamation costs on 486 gross wells (309.1 net), including 178.1 net non-producing and 9.0 net service wells. Arsenal’s share of the expected total abandonment and reclamation costs for wells with assigned reserves, non-producing and service wells and facilities, net of salvage value are summarized, without discount and using a discount rate of 10%, in the following table:

Category	Forecast Pricing (M\$)			
	Proved 0%	Proved 10%	Proved Plus Probable 0%	Proved Plus Probable NPV-10%
Canada				
Wells with reserves assigned <sup>(1)</sup>	12,127.8	9,144.2	12,468.9	8,755.3
Wells with no reserves assigned <sup>(2)</sup>	3,334.5	1,250.7	3,334.5	1,250.7
<b>Total</b>	<b>15,513.3</b>	<b>10,394.9</b>	<b>15,803.4</b>	<b>10,006.0</b>
United States				
Wells with reserves assigned <sup>(1)</sup>	2,245.2	954.2	2,523.5	869.2
Wells with no reserves assigned and facilities <sup>(2)</sup>	538.0	171.4	538.0	171.4
<b>Total</b>	<b>2,783.2</b>	<b>1,125.6</b>	<b>3,061.5</b>	<b>1,040.6</b>
Total				
Wells with reserves assigned	14,373.0	10,098.4	14,992.4	9,624.5
Wells with no reserves assigned	3,872.5	1,422.1	3,872.5	1,422.1
<b>Total</b>	<b>18,245.5</b>	<b>11,520.5</b>	<b>18,864.9</b>	<b>11,046.6</b>
Total abandonment and reclamation cost provision				
Portion forecast to be paid during the next three years				

### Notes:

- (1) Abandonment and reclamation costs were estimated by AJM and included in the AJM Report for all wells assigned reserves.
- (2) Arsenal has estimated the timing and the costs associated with the abandonment and reclamation for wells with no reserves assigned and for facilities. This represents the total abandonment and reclamation costs that were not deducted in computing future net revenue.

## Tax Horizon

At the end of 2010, Arsenal had estimated income tax deductions of approximately \$76.3million in Canada and US\$9.1million in the United States available to reduce future taxable income. Arsenal did not incur current income taxes in 2009 in Canada or the United States. Arsenal could, if sufficient income tax deductions are not generated by future business operations, incur income taxes in 2011 in Canada and the United States.

## Costs Incurred \*\*Need info. from Paul\*\*

The following table summarizes Arsenal’s property acquisition costs, exploration costs and development costs (before property dispositions) incurred during the financial year ended December 31, 2010:

Nature of Cost	Property Acquisitions and Capital Expenditures	
	Canada Amount (M\$)	United States Amount (M\$)
Property Acquisition Costs		
Proved	0	2.2
Unproved	4.0	0
Exploration Costs	9.3	0
Development Costs	7.1	7.7
<b>Total</b>	<b>20.4</b>	<b>9.9</b>

## Exploration and Development Activities

The following table summarizes the results of exploration and development activities in Canada and the United States during the financial year ended December 31, 2010:

Wells Completed in 2010	CANADA		UNITED STATES	
	Gross	Net	Gross	Net
<b>Development</b>				
Gas	0	0	0	0
Oil	3	2.00	5	1.09
Unsuccessful	0		0	0
Service/Drilling at year end	0		2	1.40
<b>Exploratory</b>				
Gas	1	1.00	0	0
Oil	6	4.02	0	0
Unsuccessful	3	3.00	0	0
Service	0	0	0	0
<b>Total</b>	<b>13</b>	<b>10.02</b>	<b>7</b>	<b>2.49</b>

The 2011 Capital Program has now been established at \$54 million and it is to be funded from cash flow from operating activities, the equity issued in February 2011 and bank debt. In the United States, approximately \$30 million has been allocated to exploration and development programs, focused primarily on drilling Bakken horizontal wells. The remaining \$24 million has been allocated to exploration and development programs in Canada, targeted primarily to drill exploration wells in Evi, Princess, and Edgerton, to drill development wells in Chauvin, to upgrade facilities at Princess, to pursue well optimizing workovers, to shoot 3D seismic at Edgerton and to acquire land.

## Production Estimates

The following tables disclose the estimated average daily production for 2011 for each product type associated with the first year of the gross proved reserves and gross probable reserves reported in the AJM Report effective December 31, 2010, based on forecast prices and costs:

### Canada

Corporation	Light/Medium Oil (Bbl/d)	Heavy Oil (Bbl/d)	Natural Gas <sup>(1)</sup> (Mcf/d)	Natural Gas Liquids (Bbl/d)	Coal-Bed Methane (Mcf/d)	Combined (BOE/d)
<b>Proved</b>						
Developed Producing	593	188	2,237.5	27.3	99	1,280
Developed Non-Producing and Undeveloped	83	13	50.0	0.5	-	104
<b>Total Proved</b>	<b>676</b>	<b>201</b>	<b>2,287.5</b>	<b>27.8</b>	<b>99</b>	<b>1,384</b>
Probable	17	44	188	2	3	98
<b>Total Proved Plus Probable</b>	<b>693</b>	<b>245</b>	<b>2,475.5</b>	<b>29.8</b>	<b>102</b>	<b>1,482</b>

**Note:**

(1) Natural gas volume includes associated and non-associated gas.

There are no properties with production in excess of 20% of the estimated production set forth in the immediately preceding table.

### United States

Corporation	Light/Medium Oil (Bbl/d)	Heavy Oil (Bbl/d)	Natural Gas <sup>(1)</sup> (Mcf/d)	Natural Gas Liquids (Bbl/d)	Coal-Bed Methane (Mcf/d)	Combined (BOE/d)
<b>Proved</b>						
Developed Producing	470	0	270	26.5	0	542
Developed Non-Producing and Undeveloped	736	0	76	0.7	0	749
<b>Total Proved</b>	<b>1,206</b>	<b>0</b>	<b>346</b>	<b>27.2</b>	<b>0</b>	<b>1,291</b>
Probable	6	0	0	0	0	12
<b>Total Proved Plus Probable</b>	<b>1,218</b>	<b>0</b>	<b>346</b>	<b>27.2</b>	<b>0</b>	<b>1,303</b>

**Note:**

(1) Natural gas volume includes associated and non-associated gas.

The Stanley Field in North Dakota will account for 45% of Arsenal's US production and is anticipated to produce an average of 247 boe/d of light oil during 2011. The Lindahl Field in North Dakota will account for 25% of Arsenal's US production and is anticipated to produce an average of 140 boe/d of light oil during 2011.

### Production History

The following table summarizes the share of Arsenal's average daily production in Canada, before deduction of royalties, for the periods indicated:

Product	2010				
	Year	Q4	Q3	Q2	Q1
Heavy Oil (Bbl/d)	603	556	565	646	646
Natural Gas <sup>(1)</sup> (Mcf/d)	2,693	2,742	2,857	1,842	3,328
Light and Medium Oil & NGLs (Bbl/d)	397	363	330	426	471
<b>Total (BOE/d)</b>	<b>1,449</b>	<b>1,376</b>	<b>1,371</b>	<b>1,379</b>	<b>1,672</b>

**Note:**

(1) Natural gas volume includes associated, non-associated and solution gas.

The following table summarizes the share of Arsenal's average daily production in the United States, before deduction of royalties, for the periods indicated:

Product	2010				
	Year	Q4	Q3	Q2	Q1
Natural Gas <sup>(1)</sup> (Mcf/d)	339	384	435	348	189
Light and Medium Oil & NGLs (Bbl/d)	587	692	582	623	450
<b>Total (BOE/d)</b>	<b>644</b>	<b>756</b>	<b>655</b>	<b>681</b>	<b>482</b>

**Note:**

(1) Natural gas volume includes associated, non-associated and solution gas and coalbed methane.

### Netback History

The following table sets forth information respecting average net product prices received, royalties paid, production expenses and operating netbacks received by Arsenal in respect of Arsenal's Canadian production for the periods indicated.

Category	2010				
	Year	Q4	Q3	Q2	Q1
<b>Selling Prices</b>					
Heavy Oil (\$/Bbl)	64.48	66.81	61.09	60.56	69.44
Natural Gas <sup>(1)</sup> (\$/Mcf)	3.87	3.15	3.17	4.27	4.86
Light and Medium Oil + NGLs (\$/Bbl)	70.06	76.26	63.60	70.92	69.01
<b>Royalties</b>					
Heavy Oil (\$/Bbl)	10.23	11.03	13.23	7.61	9.50
Natural Gas <sup>(1)</sup> (\$/Mcf)	0.20	-0.15	0.74	0.27	-0.03
Light and Medium Oil + NGLs (\$/Bbl)	10.76	9.59	8.09	15.58	9.18
<b>Production Expenses<sup>(2)</sup></b>					
Heavy Oil (\$/Bbl)	23.61	21.97	17.11	27.46	26.96
Natural Gas <sup>(1)</sup> (\$/Mcf)	2.97	3.22	2.36	4.43	2.49
Light and Medium Oil + NGLs (\$/boe)	23.55	24.78	27.34	24.21	19.26
<b>Operating Netbacks</b>					
Heavy Oil (\$/Bbl)	30.64	33.81	30.75	25.49	32.98
Natural Gas <sup>(1)</sup> (\$/Mcf)	0.70	0.08	0.07	-0.43	2.40
Light and Medium Oil + NGLs (\$/boe)	35.75	41.89	28.17	31.13	40.57
<b>Total (BOE/d)</b>	<b>23.84</b>	<b>24.84</b>	<b>19.60</b>	<b>20.97</b>	<b>28.94</b>

**Notes:**

(1) Natural gas volume includes associated, non-associated and solution gas and coalbed methane.

- (2) Production expenses include petroleum and surface lease rentals, transportation costs, property taxes and expenses related to the operation and maintenance of wells, production facilities and gathering systems.

The following table sets forth information respecting average net product prices received, royalties paid, production expenses and operating netbacks received by Arsenal in respect of Arsenal's U.S. production for the periods indicated:-

Category	2010				
	Year	Q4	Q3	Q2	Q1
<b>Selling Prices</b>					
Natural Gas <sup>(1)</sup> (\$/Mcf)	4.24	3.78	4.10	4.10	5.80
Light and Medium Oil + NGLs (\$/Bbl)	69.95	68.50	67.13	70.11	75.74
<b>Royalties</b>					
Natural Gas <sup>(1)</sup> (\$/Mcf)	0.81	1.02	0.92	0.76	0.18
Light and Medium Oil + NGLs (\$/Bbl)	17.36	16.80	16.51	17.65	18.96
<b>Production Expenses<sup>(2)</sup></b>					
Natural Gas <sup>(1)</sup> (\$/Mcf)	1.80	1.09	2.15	1.87	2.34
Light and Medium Oil + NGLs (\$/boe)	14.49	11.82	16.38	12.72	18.65
<b>Operating Netbacks</b>					
Natural Gas <sup>(1)</sup> (\$/Mcf)	1.63	1.67	1.03	1.47	3.28
Light and Medium Oil + NGLs (\$/boe)	38.10	39.88	34.24	39.74	38.13
<b>Total (BOE/d)</b>	<b>35.62</b>	<b>37.36</b>	<b>31.15</b>	<b>37.10</b>	<b>36.93</b>

**Notes:**

- (1) Natural gas volume includes associated, non-associated and solution gas.  
(2) Production expenses include petroleum and surface lease rentals, transportation costs, property taxes and expenses related to the operation and maintenance of wells, production facilities and gathering systems.

**Production Volume by Field**

The following table discloses for each important field, and in total, Arsenal's production volumes for the financial year ended December 31, 2010 for each product type:

Field	Light and Medium Oil and Natural Gas Liquids <sup>(1)</sup> (Bbl/d)	Heavy Oil (Bbl/d)	Natural Gas (Mcf/d)	BOE (Boe/d)	%
<b>British Columbia</b>					
Currant	4.4	0.0	209.4	39.3	3%
Other	4.4	0.0	94.2	20.1	1%
<b>Total British Columbia</b>	<b>8.8</b>	<b>0.0</b>	<b>303.6</b>	<b>59.4</b>	<b>4%</b>
<b>Alberta</b>					
Evi	209.0	0.0	0.0	209.0	14%
Galahad	125.3	0.0	680.4	238.7	16%
Chauvin Ribstone	0.0	307.5	33.0	313.0	22%
Other	56.2	167.9	1662.6	501.2	35%
<b>Total Alberta</b>	<b>390.5</b>	<b>475.4</b>	<b>2376.0</b>	<b>1261.9</b>	<b>87%</b>
<b>Saskatchewan</b>					
Other	0.0	127.6	0.6	127.7	9%
<b>Total Saskatchewan</b>	<b>0.0</b>	<b>127.6</b>	<b>0.6</b>	<b>127.7</b>	<b>9%</b>
<b>Total Canada</b>	<b>399.3</b>	<b>603.0</b>	<b>2680.2</b>	<b>1449.0</b>	<b>100%</b>
<b>North Dakota</b>					
Stanley	355.4	0.0	70.8	367.2	57%
Lindahl	124.0	0.0	145.0	148.2	23%
Rennie Lake	22.0	0.0	69.0	33.5	5%
Other	86.0	0.0	55.2	95.1	15%
<b>Total United States</b>	<b>587.4</b>		<b>340.0</b>	<b>644.0</b>	<b>100%</b>

**Note:**

- (1) Includes associated, non-associated and solution gas and coalbed methane.

## **RISK FACTORS**

The business of exploring for, developing and producing oil and natural gas reserves is inherently risky. Oil and natural gas operations involve many risks that even a combination of experience and knowledge and careful evaluation may not be able to overcome. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by Arsenal.

Arsenal's business consists of the exploration and development of oil and gas in British Columbia, Alberta, Saskatchewan and North Dakota. There are a number of inherent risks associated with oil and gas operations and development. Many of these risks are beyond the control of Arsenal and may have a material adverse effect upon Arsenal's financial position and future results of operations.

### **Exploration, Development and Production Risks**

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long term commercial success of Arsenal depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves Arsenal may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Arsenal's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that Arsenal will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, Arsenal may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by Arsenal.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury. In accordance with industry practice, Arsenal is not fully insured against all of these risks, nor are all such risks insurable. Although Arsenal maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event Arsenal could incur significant costs that could have a material adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks could have a material adverse effect on future results of operations, liquidity and financial condition.

### **Current Economic Conditions**

The current economic downturn may negatively impact the Corporation's financial viability and cause increased volatility and uncertainty in market prices for oil and natural gas. Unfavourable economic conditions may adversely affect Arsenal's development and exploration activities and could also increase the Corporation's financing costs, decrease revenues, limit access to capital markets and negatively impact any of the availability of credit facilities to the Corporation.

### **No Assurance of Commerciality**

There is no assurance that oil, NGLs or natural gas will be capable of production in sufficient quantities to make existing fields or future discoveries commercially viable or economic for Arsenal or that the existing fields will be able to maintain their economic viability as projected. The long-term viability of Arsenal depends on its ability to find or acquire, develop and commercially produce additional oil, NGL and gas reserves. Without the addition of reserves through exploration, acquisition or development activities, Arsenal's reserves and production will decline over time as reserves are produced and exploited. Arsenal's future reserves levels will depend not only on Arsenal's ability to develop its present properties, but also on its ability to select and acquire suitable new producing properties or prospects. In the case of natural gas, to be economic, Arsenal will either have to find or may also have to establish a commercial market for gas discoveries.

### **Limitations of Insurance**

Arsenal's involvement in the exploration for and development of oil and gas properties may result in Arsenal becoming subject to liability for pollution, blow-outs, property damage, personal injury and other hazards. Although Arsenal has obtained insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not, in all circumstances be insurable or, in certain circumstances, Arsenal may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or for other reasons. The payment of such uninsured liabilities would reduce the funds available to Arsenal. The occurrence of a significant event that Arsenal is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Arsenal's financial position, results of operations or prospects.

### **Regulatory**

Oil and natural gas operations (exploration, production, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "*Industry Conditions*". Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. In order to conduct oil and gas operations, Arsenal will require licenses from various governmental authorities. There can be no assurance that Arsenal will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

### **Commodity Contracts**

From time to time Arsenal may enter into agreements to receive fixed prices on its oil and natural gas production to offset risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, Arsenal will not benefit from such increases. Similarly, from time to time Arsenal may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar, however, if the Canadian dollar declines in value compared to the United States dollar, Arsenal will not benefit from its fluctuating exchange rate.

### **Prices, Markets and Marketing of Crude Oil and Natural Gas**

Oil and natural gas are commodities whose prices are determined based on world demand, supply and other factors, all of which are beyond the control of Arsenal. World prices for oil and natural gas have fluctuated widely in recent years. Any material decline in prices will result in a reduction of net production revenue. Certain wells or other projects may become uneconomic as a result of a decline in world oil prices or natural gas prices, leading to a reduction in the future volume of Arsenal's oil and gas production. Arsenal might also elect not to produce from certain wells at lower prices. All these factors could result in a material decrease in Arsenal's future net production revenue, causing a reduction in its oil and gas acquisition and development activities. In addition, the borrowing base of Arsenal will in part determine bank borrowings available to Arsenal. A sustained material decline in prices from historical average prices could reduce Arsenal's future borrowing base, therefore reducing the bank credit available to Arsenal, and could require that a portion of any existing bank debt of Arsenal be repaid.

In addition to establishing markets for its oil and natural gas, Arsenal must also successfully market its oil and natural gas to prospective buyers. The marketability and price of oil and natural gas, which may be acquired or discovered by Arsenal, will be affected by numerous factors beyond its control. Arsenal will be affected by the differential between the price paid by refiners for light quality oil and the grades of oil produced by Arsenal. The

ability of Arsenal to market natural gas may depend upon its ability to acquire space on pipelines, which deliver natural gas to commercial markets. Arsenal will also likely be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities and related to operational problems with such pipelines and facilities and extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and the management of other aspects of the oil and natural gas business. Arsenal has limited direct experience in the marketing of oil and natural gas.

### **Decommissioning Costs Are Unknown**

Arsenal is responsible for costs associated with abandoning and reclaiming wells, facilities and pipelines, which it uses for production of its oil and gas reserves. Abandonment and reclamation of its current facilities and the costs associated therewith is often referred to as “decommissioning”. There are no immediate plans to establish a reserve account for these potential costs in respect of any of its current properties or facilities, rather, the costs of decommissioning are expected to be paid from the proceeds of future production in accordance with the practice generally employed in oilfield operations. Should decommissioning be required prior to economic depletion of Arsenal’s current properties or should the estimates of the costs of decommissioning exceed the value of the reserves remaining at any particular time to cover such decommissioning costs, Arsenal may have to draw on funds from other sources to satisfy such decommissioning costs. The use of other funds to satisfy such decommissioning costs could have a materially adverse effect on Arsenal’s financial position and future results of operations.

### **Substantial Capital Requirements**

Arsenal anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If Arsenal’s revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to Arsenal. The inability of Arsenal to access sufficient capital for its operations could have a material adverse effect on Arsenal’s financial condition, results of operations and prospects.

### **Additional Funding Requirements**

Arsenal’s cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, Arsenal may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause Arsenal to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If Arsenal’s revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, Arsenal’s ability to expend the necessary capital to replace its reserves or to maintain its production will be impaired. If Arsenal’s cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on favourable terms.

### **Foreign Currency Exchange Rates May Fluctuate**

Arsenal sells its oil production pursuant to marketing agreements that are denominated in US dollars. Many of the operational and other expenses incurred by Arsenal are paid in US dollars where operations are performed. The assets and liabilities of Arsenal (including reserve information) are recorded in Canadian dollars. As a result, fluctuations in the US dollar against the Canadian dollar and each of these currencies against local currencies in jurisdictions where properties of Arsenal are located and local costs incurred could result in unanticipated and material fluctuations in Arsenal financial results.

### **Non-Operated Properties**

Arsenal does not operate all of its oil and gas properties. The failure of the operator to properly and efficiently operate these properties could have a material adverse effect on Arsenal’s future financial condition and results of operations from such non-operated properties.

### **Title**

Title to oil and natural gas interests is often not capable of conclusive determination without incurring substantial expense. In accordance with industry practice, Arsenal will conduct such title reviews in connection with its

principal properties as it believes are commensurate with the value of such properties. However, no absolute assurances can be given that title defects do not exist. If title defects do exist, it is possible that Arsenal may lose all or a portion of its right, title and interest in and to the properties to which the title defects relate.

### **Reserve Replacement**

Arsenal's future oil and natural gas reserves, production, and cash flows to be derived therefrom are highly dependent on Arsenal successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves Arsenal may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Arsenal's reserves will depend not only on Arsenal's ability to develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. There can be no assurance that Arsenal's future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas.

### **Reliance on Operators and Key Employees**

To the extent Arsenal is not the operator of its oil and gas properties, Arsenal will be dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators. In addition, the success of Arsenal will be largely dependent upon the performance of its management and key employees. Arsenal does not have any key man insurance policies, and therefore there is a risk that the death or departure of any member of management or any key employee could have a material adverse effect on Arsenal.

### **Permits and Licenses**

The operations of Arsenal may require licenses and permits from various governmental authorities. There can be no assurance that Arsenal will be able to obtain all necessary licenses and permits that may be required to carry out exploration and development at its properties.

### **Issuance of Debt**

From time to time Arsenal may enter into transactions to acquire assets or the shares of other corporations. These transactions may be financed partially or wholly with debt, which may increase Arsenal's debt levels above industry standards. Neither Arsenal's articles nor its bylaws limit the amount of indebtedness that Arsenal may incur. The level of Arsenal's indebtedness from time to time could impair Arsenal's ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise. Arsenal's ability to meet its debt service obligations will depend on Arsenal's future operations, which are subject to prevailing industry conditions and other factors, many of which are beyond the control of Arsenal. As certain of the indebtedness of Arsenal bears interest at rates which fluctuate with prevailing interest rates, increases in such rates would increase Arsenal's interest payment obligations and could have a material adverse effect on Arsenal's financial condition and results of operations. Further, Arsenal's indebtedness is secured by substantially all of Arsenal's assets. In the event of a violation by Arsenal of any of its loan covenants or any other default by Arsenal on its obligations relating to its indebtedness, the lender could declare such indebtedness to be immediately due and payable and, in extreme cases, foreclose on Arsenal's assets.

### **Aboriginal Claims**

Aboriginal peoples have claimed aboriginal title and rights to portions of Western Canada. Management is not aware that any claims have been made in respect of the Corporation's property and assets; however, if a claim arose and was successful this could have an adverse effect on Arsenal and its operations.

### **Third Party Credit Risk**

Arsenal may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to Arsenal, such failures could have a material adverse effect on Arsenal and its cash flow from operations. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in Arsenal's ongoing capital program, potentially delaying the program and the results of such program until Arsenal finds a suitable alternative partner.

### **Reliance on Management**

Shareholders will be dependent on management and the board of directors of the Corporation in respect of the oversight, administration and management of all matters relating to Arsenal and its operations and administration. The loss of the services of key individuals could have a detrimental effect on Arsenal.

### **Availability of Drilling Equipment and Access Restrictions**

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to Arsenal and may delay exploration and development activities.

### **Enforcement of Civil Liabilities**

As some of Arsenal's assets are located outside of Canada it may be difficult or impossible to enforce judgments granted by a Canadian court against such assets, subsidiaries or directors and officers that are resident outside of Canada.

### **Tax Compliance**

The taxation of corporations is complex. In the ordinary course of business, Arsenal is subject to ongoing audits by tax authorities. While Arsenal believes that its tax filing positions are appropriate and supportable, it is possible that tax matters, including the calculation and determination of revenue, expenditures, deductions, credits and other tax attributes, taxable income, taxes payable and renouncements of flow through expenditures, may be reviewed and challenged by the tax authorities. If such challenge were to succeed, it could have a material adverse effect on Arsenal's tax position. Further, the interpretation of and changes in tax laws, whether by legislative or judicial action or decision, and the administrative policies and assessing practices of taxation authorities, could materially adversely affect Arsenal's tax position. As a consequence, Arsenal is unable to predict with certainty the effect of the foregoing on Arsenal's effective tax rate and earnings.

Arsenal will regularly review the adequacy of its tax provisions and believes that it has adequately provided for those matters. Should the ultimate outcomes materially differ from the provisions, Arsenal's effective tax rate and earnings may be affected positively or negatively in the period in which the matters are resolved. Arsenal intends to mitigate this risk through ensuring tax staff is well trained and supervised and that tax filing positions are carefully scrutinized by management and external consultants, as appropriate.

### **Management of Growth**

Arsenal may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of Arsenal to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of Arsenal to deal with this growth could have a material adverse impact on its business, operations and prospects.

### **International Financial Reporting Standards**

The Accounting Standards Board of the Canadian Institute of Chartered Accountants has announced that Canadian publicly accountable enterprises are required to adopt International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board, effective January 1, 2011. IFRS will require increased financial statement disclosure as compared to Canadian GAAP and accounting policy differences between Canadian GAAP and IFRS will need to be addressed by Arsenal.

The transition from current Canadian GAAP to IFRS is a significant undertaking that may materially affect the Corporation's reported financial position and results of operations. The Corporation is currently evaluating the impact of the conversion to IFRS will have on its future financial reporting. The Corporation's adoption of IFRS may adversely impact the Corporation's reported financial results. The requirement for the Corporation to implement IFRS to replace Canadian GAAP effective January 1, 2011 may materially affect the Corporation's financial results as reported in its financial statements and its results of operations.

### **Failure to Realize Anticipated Benefits of Acquisitions and Dispositions**

Arsenal makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as Arsenal's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of Arsenal. The integration of acquired businesses may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non core assets are periodically disposed of, so that Arsenal can focus its efforts and resources more efficiently. Depending on the state of the market for such non core assets, certain non core assets of Arsenal, if disposed of, could be expected to realize less than their carrying value on the financial statements of Arsenal.

### **Volatility of Commodity Prices**

Oil and natural gas prices fluctuate significantly in response to regional, national and global supply and demand factors beyond the control of Arsenal. Political and economic developments around the world can affect world oil and natural gas supply and prices. Any prolonged period of low oil and natural gas prices could result in a decision by Arsenal to suspend or terminate exploration, as it may become uneconomic to explore for and/or produce oil or natural gas at such prices.

### **Operational Matters**

The ownership and operation of oil and natural gas wells, pipelines and facilities involves a number of operating and natural hazards which may result in blowouts, environmental damage and other unexpected or dangerous conditions resulting in damage to Arsenal's properties and possible liability to third parties. Arsenal intends to employ prudent risk management practices and maintain suitable liability insurance, where available. Arsenal may become liable for damages arising from such events against which it cannot insure or against which it may elect not to insure because of high premium costs or other reasons. Costs incurred to repair such damage or pay such liabilities could have a material adverse effect on Arsenal, its operations and financial condition.

### **Availability of Equipment and Qualified Personnel and Related Costs**

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment and qualified personnel in the particular areas where such activities will be conducted. Demand for such limited equipment and qualified personnel may affect the availability of such equipment and qualified personnel to Arsenal and may delay Arsenal's exploration and development activities. In addition, the costs of qualified personnel and equipment in the areas where Arsenal's assets are located may, from time to time, be high due to the availability of, and demands for, such qualified personnel and equipment in the area.

### **Reserve Estimates**

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and cash flows to be derived therefrom, including many factors beyond Arsenal's control. The information concerning reserves and associated cash flow set forth in this Annual Information Form represents estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom prepared by different engineers, or by the same engineers at different times, may vary. Arsenal's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. Further, the evaluations are based, in part, on the assumed success of the exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluation.

In accordance with applicable securities laws, AJM has used forecast price and cost estimates in calculating reserve quantities. Actual future net cash flows will be affected by other factors such as actual production levels, supply and

demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs. Actual production and cash flows derived therefrom will vary from the estimates contained in the AJM Report, and such variations could be material. The AJM Report is based in part on the assumed success of activities Arsenal intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the AJM Report will be reduced to the extent that such activities do not achieve the level of success assumed in the AJM Report.

The AJM Report is effective as of a specific effective date and has not been updated and thus does not reflect changes in Arsenal's reserves since that date.

### **Environmental Concerns**

The oil and natural gas industry is subject to environmental regulations pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines or other penalties. Should Arsenal be unable to fully fund the cost of remedying an environmental problem, Arsenal might be required to suspend operations or enter into interim compliance measures pending completion of the required remedy. Environmental legislation is evolving in a manner expected to result in more strict standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require Arsenal to incur costs to remedy such discharge. Although Arsenal believes that it is in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Arsenal's financial condition, results of operations or prospects. See "Industry Conditions – Environmental Regulation".

### **Climate Change Legislation**

Canada is a signatory to the United Nations Framework Convention on Climate Change. Canada has ratified the Kyoto Protocol established thereunder and is thereby required to establish legally binding targets to reduce nation wide emissions of carbon dioxide, methane, nitrous oxide and other "greenhouse gases". Arsenal's exploration and production facilities and other operations and activities emit a small amount of greenhouse gases which may subject Arsenal to legislation in Canada regulating emissions of greenhouse gases. The Government of Canada put forward in April 2007, and March 2008, its "Turning the Corner" climate change plan that proposes regulations to set greenhouse gas "emissions intensity" reduction requirements for certain industrial sectors by 18% from 2006 levels, commencing in 2010, and including oil and natural gas exploration and production. This may require the reduction of emissions or emissions intensity from Arsenal's operations and facilities. The Province of Alberta implemented the Specified Gas Emitters Regulation under its Climate Change Emissions Management Act on July 1, 2007. This regulation requires facilities which emit in excess of 100,000 tonnes of greenhouse gases per year to reduce their emissions intensity by 12% from a baseline derived from the average of 2003 2005 emissions. The direct and indirect costs of complying with these emissions regulations may adversely affect the business of Arsenal. See "Industry Conditions – Environmental Regulation".

### **Forward Looking Information May Prove Inaccurate**

Investors are cautioned not to place undue reliance on forward looking information. By its nature, forward looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Additional information on the risks, assumptions and uncertainties are found in this Annual Information Form under the heading "Forward Looking Statements".

### **Investment Returns**

Arsenal has never paid a dividend nor made a distribution on any of its securities. Further, Arsenal may never achieve a level of profitability that would permit payment of dividends or making other forms of distributions to securityholders. In any event, given the stage of the Arsenal's development, it will likely be a long period of time before Arsenal could be in a position to make dividends or distributions to its investors. The payment of any future

dividends by Arsenal will be at the sole discretion of the Board. In this regard, Arsenal currently intends to retain earnings to finance the expansion of its business and does not anticipate paying dividends in the foreseeable future.

### **Competition**

There is strong competition relating to all aspects of the oil and natural gas industry. Arsenal will actively compete for capital, skilled personnel, access to rigs and other equipment, access to processing facilities and pipeline and refining capacity and in all other aspects of its operations with a substantial number of other organizations, many of which will have greater technical and financial resources than Arsenal.

### **Expiration of Licenses and Leases**

Arsenal's properties are held in the form of licences and leases and working interests in licences and leases. If Arsenal, a joint interest partner or the holder of the licence or lease fails to meet certain requirements of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that all of the obligations required to maintain each licence or lease will be met. The termination or expiration of Arsenal's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on Arsenal's results of operations and business.

### **Potential Conflicts of Interest**

Certain of the directors of Arsenal are also directors or officers of corporations which are in competition to the interests of Arsenal. No assurances can be given that opportunities identified by such members of the Board will be provided to Arsenal. Such conflicts must be disclosed in accordance with, and are subject to such other procedures and remedies as applicable under the ABCA.

### **Delays in Business Operations**

In addition to the usual delays in payments by purchasers of oil and natural gas to Arsenal or to the operators, and the delays by operators in remitting payment to Arsenal, payments between these parties may be delayed due to restrictions imposed by lenders, accounting delays, delays in the sale of delivery of products, delays in the connection of wells to a gathering system, adjustment for prior periods, or recovery by the operator of expenses incurred in the operation of the properties. Any of these delays could reduce the amount of cash flow available for the business of Arsenal in a given period and expose Arsenal to additional third party credit risks.

### **Changes in Legislation**

There can be no assurance that income tax laws, other laws or government incentive programs relating to the oil and gas industry will not be changed in a manner which will adversely affect Arsenal. The NRF (as defined herein) has not been fully implemented and there is uncertainty as to the final form it will take. There can be no assurance that tax authorities having jurisdiction will agree with how Arsenal calculates its income for tax purposes or that such tax authorities will not change their administrative practices to the detriment of Arsenal.

### **Seasonality and Climate**

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. A mild winter or wet spring may result in limited access to Arsenal's properties and, as a result, reduced operations or a cessation of operations. Municipalities and provincial transportation departments enforce road bans that restrict the movement of drilling rigs and other heavy equipment during periods of wet weather, thereby reducing activity levels. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity.

### **Borrowing**

Arsenal's lenders will be provided with security over substantially all of the assets of Arsenal. If Arsenal becomes unable to pay its debt service charges or otherwise commits an event of default, such as bankruptcy, these lenders may foreclose on or sell Arsenal's properties. The proceeds of any such sale would be applied to satisfy amounts owed to Arsenal's lenders and other creditors and only the remainder, if any, would be available to Arsenal.

## **Alternatives to and Changing Demand for Petroleum Products**

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for crude oil and other liquid hydrocarbons. Arsenal cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on Arsenal's business, financial condition, results of operations and cash flows.

## **Inflation Risks**

Inflation risks subject the Corporation to potential erosion of product netbacks. For example, domestic prices for oil and natural gas production equipment and services can inflate the costs of its operations.

## **INDUSTRY CONDITIONS**

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta and Saskatchewan all of which should be carefully considered by investors in the oil and natural gas industry. It is not expected that any of these controls or regulations will affect the operations of Arsenal in a manner materially different than they would affect other oil and gas corporations of similar size.

All current legislation is a matter of public record and Arsenal is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

### **Pricing and Marketing Oil and Natural Gas**

In Canada, the producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, value of refined products, the supply/demand balance, and other contractual terms. Oil exporters may receive "export orders" from the National Energy Board of Canada ("NEB") with terms not exceeding one year in the case of light crude oil and not exceeding two years in the case of heavy crude oil, provided that an order approving any such export has been obtained from the NEB. Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m<sup>3</sup>/day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

The Government of Alberta also regulates the volume of natural gas that may be removed from the province for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

### **Pipeline Capacity**

Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market oil and natural gas production. In addition, the pro-rationing of capacity on the interprovincial pipeline systems also continues to affect the ability to export oil and natural gas.

## **The North American Free Trade Agreement**

The North American Free Trade Agreement (“NAFTA”) among the governments of Canada, the United States of America and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada-United States Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price subject to an exception with respect to certain voluntary measures which only restrict the volume of exports; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export price requirements, prohibition in any circumstances in which any other form of quantitative restriction is prohibited, and in the case of import-price requirements, such requirements do not apply with respect to enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector by 2010 and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, which is important for Canadian oil and natural gas exports.

## **Provincial Royalties and Incentives**

### **General**

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection, and other matters. The royalty regime is a significant factor in the profitability of crude oil, NGL, sulphur, and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery, and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner’s interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the Western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays, and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and would increase the net income and funds from operations of such producers.

With the elimination of the corporate surtax effective January 1, 2008 and other recently enacted rate reductions initially introduced in the October 2007 Economic Statement, the federal corporate income tax rate will decrease to 15% in five steps: 19.5% on January 1, 2008, 19% on January 1, 2009, 18% on January 1, 2010, 16.5% on January 1, 2011 and 15% on January 1, 2012.

### **(a) Alberta**

Producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, currently at a rate of \$3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced. On October 25, 2007, the Government of Alberta released a report entitled “The New Royalty Framework” (“NRF”) containing the Government’s proposals for Alberta’s new royalty regime which were subsequently implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*. The NRF took effect on January 1, 2009.

With respect to conventional oil, the NRF eliminated the classification system used by the previous royalty structure which classified oil based on the date of discovery of the pool.

The new royalty formula for conventional oil operates on a sliding rate formula containing separate elements that account for oil price and well production. Royalty rates for conventional oil range up to 50 percent, an increase from the previous maximums of 30 percent to 35 percent depending on the vintage of the oil, with rate caps once the price of conventional oil reaches \$120 per Bbl.

Under the NRF, natural gas royalties are set by a sliding rate formula sensitive to price production volume and measured well depth. New natural gas royalty rates range from 5 percent to 50 percent, an increase from the previous maximums of 5 percent to 35 percent, with rate caps once the price of natural gas reaches \$17.50/Mmbtu. Royalties for natural gas liquids are set at 40 percent for pentanes and 30 percent for butanes and propane.

In August 2006, the Government of Alberta introduced the Innovative Energy Technologies Program (the “IETP”), which has a stated objective of promoting producers’ investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP is backed by a \$200 million funding commitment over a five-year period beginning April 1, 2005 and provides royalty adjustments to specific pilot and demonstration projects that utilize innovative technologies to increase recovery from existing reserves.

On April 10, 2008, the Government of Alberta announced its plan to implement two new deep resource royalty programs to address some of the unintended consequences of the NRF. These two, five-year royalty programs, which were implemented with the NRF on January 1, 2009, were designed to encourage the continued development of deep, high-cost oil and natural gas reserves.

On November 19, 2008, in response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The five-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well’s life when production rates are expected to be the highest. Under this new program companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 metres) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. In order to qualify for this program wells must be drilled during the period starting on November 19, 2008 and ending on December 31, 2013. Following this period all new wells drilled will automatically be subject to the NRF and wells that operated under the transitional royalty rates will revert to royalty rates determined by the NRF.

On March 3, 2009, the Government of Alberta announced a three-point incentive program to stimulate new and continued economic activity in Alberta which included a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program. Under the drilling royalty credit program a \$200 per meter royalty credit is available on new conventional oil and natural gas wells drilled between April 1, 2009 and March 31, 2010, subject to certain maximum amounts. The maximum credits available are determined by the company’s production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010. Based on Arsenal’s 2008 production it is entitled to a maximum credit of 10% of royalties payable in the period April 1, 2009 and March 31, 2010. The new well incentive program applies to wells beginning production of conventional oil and natural gas between April 1, 2009 and March 31, 2010 and provides for a maximum 5% royalty rate for the first 12 months of production, up to a maximum of 50,000 Bbls of oil or 500 Mmcf of natural gas. In June, 2009, the Government of Alberta announced the extension of these two incentives for one year to March 31, 2011. The three-point incentive program also includes an investment of \$30,000,000 by the Government of Alberta in abandonment and reclamation projects for orphan wells. The stated objective of this investment is to encourage the cleanup of inactive oil and natural gas wells and to stimulate new activity within the services sector.

On March 11, 2010, the Government of Alberta announced that the following will become permanent features of the royalty structure, effective with the January 2011 production month:

- Permanent 5% front-end royalty
  - The current incentive program rate of 5% on new natural gas and conventional oil wells will become a permanent feature of the royalty system, with the current time and volume limited.
- Lower Maximum Rates
  - The maximum royalty rate for conventional oil will be reduced at higher price levels from 50% to 40% to provide better risk-reward balance to investors.

- Recognizing the fundamental changes to the North American supply/demand balance and increased competition from other jurisdictions, the maximum royalty rate for conventional and unconventional natural gas will be reduced at higher price levels from 50% to 36%.
- Implementation/Transition
  - All royalty curves will be finalized and announced by May 31, 2010 and be effective for all production after January 1, 2011.
  - The transitional royalty framework for oil and natural gas introduced in November 2008 will continue until its original announced expiration on December 31, 2013. Effective January 1, 2011, no new wells will be allowed to select the transitional royalty rates. Wells that have already selected the transitional royalty rates will have the option to stay with those rates or switch to the new rates effective January 1, 2011.
  - The drilling royalty credit will continue until expiry on March 31, 2011 and all other programs will continue as designed.

On May 27, 2010, the Government of Alberta announced the royalty curve revisions including initiatives to stimulate new energy investments and new technology. As part of this initiative, a front-end royalty of 5% for each of new shale gas, coalbed methane, horizontal gas and horizontal oil well was put in place and is subject to certain time and volume limits for each type of well. The shale gas and coalbed methane royalty rates apply to wells that start producing gas exclusively from shale or coal zones, as applicable, on or after May 2010. The horizontal gas and horizontal oil well royalty rates apply to wells drilled or spud on or after May 2010.

The new well royalty rate (applicable to wells classified as “oil”, “gas”, or “crude bitumen” well when it commences or recommences production on or after April 2009) became a permanent feature of the royalty system effective May 2010. The maximum and minimum royalty rates in Alberta for conventional oil are 40% and 0% respectively. The conventional oil quantity component was kept the same as the existing royalty framework and the price component for natural gas was changed to moderate the increase in the rate at prices higher than \$535/m<sup>3</sup>. The maximum and minimum royalty rates in Alberta for natural gas are 36% and 5% respectively with the royalty rate being the sum of a price component and the quantity component. The natural gas quantity component was kept the same as the existing royalty framework and the price component for natural gas was changed to moderate the increase in the rate at prices higher than \$5.25 per GJ.

(b) Saskatchewan

In Saskatchewan, the amount payable as a royalty in respect of oil depends on the vintage of the oil, the type of oil, the quantity of oil produced in a month, and the value of the oil. For Crown royalty and freehold production tax purposes, crude oil is considered “heavy oil”, “southwest designated oil”, or “non-heavy oil other than southwest designated oil”. The conventional royalty and production tax classifications (“fourth tier oil” introduced October 1, 2002, “third tier oil”, “new oil” and “old oil”) of oil production are applicable to each of the three crude oil types. The Crown royalty and freehold production tax structure for crude oil is price sensitive and varies between the base royalty rates of 5% for all “fourth tier oil” to 20% for “old oil”. Marginal royalty rates are 30% for all “fourth tier oil” to 45% for “old oil”.

The amount payable as a royalty in respect of natural gas is determined by a sliding scale based on a reference price (which is the greater of the amount obtained by the producer and a prescribed minimum price), the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. The royalty and production tax classifications of natural gas production are “fourth tier gas” introduced October 1, 2002, “third tier gas”, “new gas”, and “old gas”. The Crown royalty and freehold production tax for gas is price sensitive and varies between the base royalty rate of 5% for “fourth tier gas” and 20% for “old gas”. The marginal royalty rates are between 30% for “fourth tier gas” and 45% for “old gas”.

On October 1, 2002, the following changes were made to the royalty and tax regime in Saskatchewan:

- A new Crown royalty and freehold production tax regime applicable to associated natural gas (gas produced from oil wells) that is gathered for use or sale and is produced from: (a) oil wells with a

finished drilling date on or after October 1, 2002, and (b) oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 cubic metres of gas for every cubic metre of oil. The royalty/tax will be payable on associated natural gas produced from an oil well that exceeds approximately 65,000 cubic metres in a month. The associated natural gas royalty/tax regime will apply to gas produced from oil wells affected by concurrent production approvals after October 1, 2002 if the oil wells meet (a) or (b) above.

- A modified system of incentive volumes and maximum royalty/tax rates applicable to the initial production from oil wells and natural gas wells with a finished drilling date on or after October 1, 2002, was introduced. The incentive volumes are applicable to various well types and are subject to a maximum royalty rate of 2.5% and a freehold production tax rate of zero per cent.
- The elimination of the re-entry and short section horizontal oil well royalty/tax categories. All horizontal oil wells with a finished drilling date on or after October 1, 2002, will receive the “fourth tier” royalty/ tax rates and new incentive volumes.
- A horizontal oil well, with a finished drilling date on or after October 1, 2002, that is a non-deep oil well qualifies for a 6,000 cubic metre incentive volume.
- A horizontal oil well, with a finished drilling date on or after October 1, 2002, that is a deep oil well qualifies for a 16,000 cubic metre incentive volume.

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate (“**RTR**”) as a response to the Government of Canada disallowing Crown royalties and similar taxes as a deductible business expense for income tax purposes. As of January 1, 2007, the remaining balance of any unused RTR will be limited in its carry forward to seven years since the Government of Canada’s initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income. Saskatchewan’s RTR will be wound down as a result of the Government of Canada’s plan to reintroduce full deductibility of provincial resource royalties for corporate income tax purposes.

On June 19, 2007, the Government of Saskatchewan introduced the Orphan Well and Facility Liability Management Program pursuant to the amendment of the *Oil and Gas Conservation Act* and the *Oil and Gas Conservation Regulations*, 1985. The program includes a security deposit, which has two purposes: (i) preventing any person with insufficient financial capability from acquiring oil and natural gas wells or facilities; and (ii) in the case of a bankrupt company, the funds cover the decommissioning and reclaiming of orphan properties. An additional change introduced is the mandatory licensing of all upstream oil and natural gas facilities in Saskatchewan.

## **Land Tenure**

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms from two years, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

## **Environmental Regulation**

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties.

The Province of Alberta’s environmental legislation is the *Environmental Protection and Enhancement Act* (Alberta) (the “**EPEA**”), the *Oil and Gas Conservation Act* (“**OGCA**”) and directives and guidelines issued by both Alberta Environment and the Energy Resources Conservation Board (“**ERCB**”). The EPEA and OGCA impose environmental standards with respect to releases of effluents and emissions, including reporting and monitoring

obligations, and impose significant penalties for non-compliance. For example, regulations enacted under the EPEA target sulphur oxide and nitrous oxide emissions from oil and gas operations. In addition, the greenhouse gas emissions intensity reduction requirement of the Specified Gas Emitters Regulation implemented under the *Climate Change and Emissions Management Act* (Alberta) came into effect on July 1, 2007. Under this legislation, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12%.

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the “**MRGGA**”) to regulate greenhouse gas emissions in the province. Although the MRGGA has only passed first reading in the Saskatchewan legislature and the specific details of the legislation have not yet been determined, it is expected that the MRGGA will adopt the goal of a 20% reduction in greenhouse gas emissions by 2020 and permit the use of technology fund contributions and emissions offsets in compliance, similar to both the federal and Alberta climate change initiatives. It remains unclear whether the scheme implemented by the MRGGA will be based on emissions intensity or an absolute cap on emissions.

In December, 2002, the Government of Canada ratified the Kyoto Protocol (“**Protocol**”). Bill C-288, which is intended to ensure that Canada meets its global climate change obligations under the Protocol, was passed by the House of Commons on February 14, 2007. It is questionable, however, whether the Federal Government will enforce the Protocol’s target of 6% below 1990 emission levels.

On April 26, 2007, the Federal Government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the “**Action Plan**”). The Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy-using products.

On March 10, 2008, the Government of Canada released “Turning the Corner – Taking Action to Fight Climate Change” (the “**Updated Action Plan**”) which provides some additional guidance with respect to the Federal Government’s plan to reduce greenhouse gas emissions by 20% by 2020 and by 60% to 70% by 2050.

The Updated Action Plan is primarily directed towards industrial emissions from certain specified industries including the oil sands, oil and gas and refining. There are mandatory reductions of 18% from the 2006 baseline starting in 2010 and an additional 2% in subsequent years for existing facilities. This target will be facility specific for the oil and gas industry. For new facilities (including major expansions constituting more than a 25% increase in a facility’s physical capacity) the 2% yearly emissions intensity reduction target will begin to apply on the fourth year of commercial operation, and the baseline will be the third year’s emissions intensity.

In the following regulated sectors, the Updated Action Plan will apply only to facilities exceeding a minimum annual emissions threshold: (i) for natural gas pipelines, 50,000 tonnes of CO<sub>2</sub> equivalent per year; and (ii) for upstream oil and gas facilities 3,000 tonnes of CO<sub>2</sub> equivalent per year or 10,000 boe/d/company. These proposed thresholds are significantly more strict than the current Alberta regulatory threshold of 100,000 tonnes of CO<sub>2</sub> equivalent per year per facility.

Four separate compliance mechanisms are provided in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. The most significant of these compliance mechanisms, at least initially, will be the Technology Fund and for which regulated entities will be able to contribute in order to comply with emissions intensity reductions. The contribution rate will increase over time, beginning at \$15 per tonne for the 2010-12 period, rising to \$20 per tonne in 2013, and thereafter increasing at the nominal rate of GDP growth. Contribution limits will correspondingly decline from 70% in 2010 to 0% in 2018.

In the United States, environmental compliance is governed by federal legislation, including the Clean Air Act, Clean Water Act, Resource Conservation and Recovery Act and Emergency Planning and Community Right-to-Know Act. Regulations promulgated under these statutes are administered by the U.S. Environmental Protection Agency (the “**EPA**”) at the federal level, or by various states whose programs have been granted primacy by the EPA. Arsenal’s U.S. operations are currently subject to various regulations under respective oil and gas acts from the North Dakota Department of Health and Oil & Gas Division. In addition, the EPA announced on December 7, 2009 its findings that emissions of carbon dioxide, methane and other “greenhouse gases” present an endangerment to human health and the environment. These findings by the U.S. EPA may allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. The EPA has also issued a final rule requiring the reporting of greenhouse gas emissions in the United States beginning in 2011 for emissions occurring in 2010 from specified large greenhouse gas emission sources, fractionated natural gas liquids, and the production of naturally occurring carbon

dioxide, even when such production is not emitted to the atmosphere. The implementation of more stringent environmental regulations on Arsenal's U.S. operations could adversely affect Arsenal's results from its U.S. operations.

Arsenal intends to meet its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and an expense nature as a result of the increasingly stringent laws relating to the protection of the environment, and will be taking such steps as required to ensure compliance with the EPEA, the OGCA and similar legislation in other jurisdictions in which it operates. Arsenal believes that it is in material compliance with applicable environmental laws and regulations. It also believes that it is reasonably likely that the trend towards strict standards in environmental legislation and regulation will continue.

Given the evolving nature of the debate related to climate change, the regulation of greenhouse gases and resulting requirements, it is not currently possible to predict either the nature of those requirements or the impact on Arsenal and its operations and financial condition at this time.

## **Trends**

There are a number of trends that have been developing in the oil and natural gas industry during the past several years that appear to be shaping the near future of the business.

The first trend is the volatility of commodity prices. A tight supply-demand balance for natural gas causes significant elasticity in pricing, whereas higher than average storage levels tend to depress natural gas pricing. Drilling activity, weather, fuel switching and demand for electrical generation are all factors that affect the supply-demand balance. Recently, liquefied natural gas shipments to North America have also resulted in natural gas supply and natural gas pricing being based more on factors other than supply and demand in North America. Changes to any of these or other factors create price volatility.

Crude oil is influenced by the world economy and the Organization of the Petroleum Exporting Countries' ability to adjust supply to world demand. Crude oil prices have been kept high by political events causing disruptions in the supply of oil and concern over potential supply disruptions triggered by unrest in the Middle East. Political events trigger large fluctuations in price levels.

The impact on the oil and natural gas industry from commodity price volatility is significant. During periods of high prices, producers generate sufficient cash flows to conduct active exploration programs without external capital. Increased commodity prices frequently translate into very busy periods for service suppliers triggering premium costs for their services. Purchasing land and properties similarly increase in price during these periods. During low commodity price periods, acquisition costs drop, as do internally generated funds to spend on exploration and development activities. With decreased demand, the prices charged by the various service suppliers also decline.

World oil and natural gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Such material increases in the value of the Canadian dollar may negatively impact production revenues from Canadian producers and further increases in the value of the Canadian dollar would exacerbate this negative impact. Such increases may also negatively impact the future value of such entities' reserves as determined by independent evaluators.

## **DESCRIPTION OF SHARE CAPITAL**

### **General Description of Share Capital**

Arsenal is authorized to issue an unlimited number of Arsenal Shares without nominal or par value, of which, as at the date hereof, 162,970,972 Arsenal Shares are issued and outstanding as fully paid and non-assessable. In addition, 12,754,500 Arsenal Shares are reserved for issuance pursuant to options granted to directors, officers, employees and consultants of Arsenal. Arsenal is also authorized to issue an unlimited number of Preferred Shares without nominal or par value. To date, no Preferred Shares have been issued.

## Arsenal Shares

The holders of Arsenal Shares are entitled to dividends as and when declared by the Board, to one vote per share at meetings of shareholders of Arsenal and, upon liquidation, to receive such assets of Arsenal as are distributable to the holders of the Arsenal Shares.

## Preferred Shares

The Preferred Shares may be issued from time to time in one or more series, each series consisting of the number of Preferred Shares as determined by the Board who may also fix the designations, rights, privileges, restrictions and conditions attaching to the shares of each series of Preferred Shares.

The Preferred Shares of each series shall, with respect to payment of dividends and distributions of assets in the event of liquidation, dissolution or winding-up of Arsenal, whether voluntary, or any other distribution of the assets of Arsenal among its shareholders for the purpose of winding-up its affairs, rank equally with the Preferred Shares of every other series and shall be entitled to preference over the Arsenal Shares, and the shares of any other class ranking junior to the Preferred Shares.

## DIVIDENDS OR DISTRIBUTIONS

Since incorporation, neither Arsenal nor its subsidiaries have declared any dividends or declared any distributions on any of their securities. Dividends (or distributions) on securities of Arsenal or its subsidiaries will be paid solely at the discretion of the Board after taking into account the financial condition of Arsenal and the economic environment in which it is operating. No dividends (or distributions) are expected to be paid in the foreseeable future.

## MARKET FOR SECURITIES

The following table sets forth the reported high and low sales prices (which are not necessarily the closing prices) and the trading volumes for the Arsenal Shares on the TSX as reported by sources Arsenal believes to be reliable for the periods indicated:

Date	Price Range (\$)		Trading Volume
	High	Low	
<b>2010</b>			
January	0.90	0.60	10,631,560
February	1.00	0.83	9,337,474
March	0.97	0.83	8,253,721
April	1.01	0.83	14,458,451
May	1.16	0.80	25,062,902
June	0.94	0.75	7,232,356
July	0.83	0.74	3,446,589
August	0.93	0.74	4,333,792
September	0.87	0.75	4,068,070
October	0.92	0.84	2,997,866
November	1.04	0.84	11,435,187
December	1.11	0.94	8,577,571

## PRIOR SALES

Other than as set forth below, no securities of the Corporation that are outstanding but not listed or quoted on a marketplace were issued during the financial year ended December 31, 2010:

Date of Grant	Number of Options <sup>(1)</sup>	Exercise Price
March 29, 2010	440,000 Options	\$0.88
June 1, 2010	450,000 Options	\$0.94
June 7, 2010	2,950,000 Options	\$0.88
June 18, 2010	300,000 Options	\$0.80
August 31, 2010	140,000 Options	\$0.81
January 12, 2011	500,000 Options	\$1.00

**Note:**

(1) Each Option entitles the holder thereof to purchase one Arsenal Share and expires five years from the date of issuance.

**ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER**

To the knowledge of the directors and officers of Arsenal, no securities of Arsenal are held in escrow or subject to a contractual restriction on transfer.

**DIRECTORS AND OFFICERS**

The following table sets forth the name, municipality of residence, the respective office or position held with Arsenal, and principal occupation for the past five years of each of the directors and executive officers of Arsenal. Notes to the table disclose the members of each committee of the Board. The term of office of each director will expire at the end of the next annual meeting of shareholders of Arsenal.

<b>Name and Residence</b>	<b>Offices with Arsenal</b>	<b>Principal Occupation During the Past Five Years</b>
<b>William Hews</b> <sup>(1)(3)</sup> Alberta, Canada	Director since October 30, 2000 <sup>(6)</sup>	President of Fideliter Inc. (private consulting company).
<b>R. Neil Mackay</b> <sup>(1)(4)</sup> Saskatchewan, Canada	Director since June 29, 2004	Partner of MacPherson Leslie & Tyerman LLP (law firm).
<b>R. H. (Harley) Kempthorne</b> <sup>(2)(4)</sup> Alberta, Canada	Director since June, 2008	Vice President Engineering AllPoints Energy, a private oil and gas exploration and production company since April 1, 2010. Prior thereto Vice President, Engineering of Gentry Resources Ltd. (a public oil and gas exploration and development company) from December 2006 to June 2008. Prior thereto, Manager, oil and gas for Petro-Canada from December 1981 to June 2006.
<b>Bill Powers</b> <sup>(1)(2)</sup> Illinois, U.S.A.	Director since June 23, 2008	Managing Member of Powers Asset Management LLC, an asset manager, since June 2005. Prior thereto, principal of Canadian Energy Viewpoint.
<b>Curtis R. Stewart</b> <sup>(2)(3)</sup> Alberta, Canada	Director since June 29, 2004	Partner of Bennett Jones LLP (law firm).
<b>Tony van Winkoop</b> Alberta, Canada	President and Chief Executive Officer and Director since June 23, 2008	President and Chief Executive Officer of Arsenal since July 2007 and Vice-President, Exploration from July 2006 to July 2007. Prior thereto, General Manager of Development for PrimeWest Energy Trust (oil and gas trust), from 2001 to July 2006.
<b>J. Paul Lawrence</b> Alberta, Canada	Vice President, Finance and Chief Financial Officer	Vice President, Finance and Chief Financial Officer of Arsenal since May 1, 2008. Prior thereto, Vice President, Finance and Chief Financial Officer of Clearwater Energy Inc. (a private oil and gas exploration and development company) from December 2005 to April 2008.
<b>Leo Nolte</b> Alberta, Canada	Vice President, Drilling and Completions	Vice President Drilling and Completions of Arsenal since May 2010. July 2008 to May 2010 Manager Drilling and Completions at Crocotta Energy Inc. May 2001 to February 2008 Manager Drilling and Completions at PrimeWest Energy Trust.
<b>Kent Sawatzky</b> Alberta, Canada	Vice President, Facilities	Vice President, Facilities of Arsenal since January 2011. June 2010 to January 2011 Manager Facilities Engineering at Perpetual Energy Trust. October 2002 to April 2010 Manager Facilities Engineering at TaqaNorth/PrimeWest Energy Trust.
<b>Gjoa Taylor</b> Alberta, Canada	Vice President, Land	Vice President, Land of Arsenal since February, 2008. Prior thereto, manager land negotiations for Primewest Energy Trust (oil and gas trust) from January 2001 to January 2008.
<b>Brenlee Taylor</b> Alberta, Canada	Controller	Controller of Arsenal since March 1, 2005.
<b>Donald B. Edwards</b> Alberta, Canada	Corporate Secretary	Partner with Borden Ladner Gervais LLP (law firm)

**Notes:**

- (1) Member of the Audit Committee.
- (2) Member of the Reserves Committee.
- (3) Member of the Compensation Committee.
- (4) Member of the Disclosure Committee.
- (5) Date of appointment as director or officer of Arsenal Capital Inc., a predecessor of Arsenal.

As at the date hereof, the directors and officers of Arsenal, as a group, beneficially owned, or controlled or directed, directly or indirectly, 15,402,008 Arsenal Shares or approximately 11.4% of the issued and outstanding Arsenal Shares. The information as to the Arsenal Shares, not being within the knowledge of Arsenal, has been furnished by the respective directors and officers of Arsenal individually.

**Corporate Cease Trade Orders, Bankruptcies, Penalties or Sanctions**

None of Arsenal's directors or officers, have, within 10 years prior to the date of this Annual Information Form, been a director, chief executive officer or chief financial officer of any company (including Arsenal) that:

- (c) was subject to a cease trade order, an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, that was in effect for a period of more than 30 consecutive days, and that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer of the relevant company; or
- (d) was subject to a cease trade order, an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, that was in effect for a period of more than 30 consecutive days, and that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer of the relevant company and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer of the relevant company.

**Penalties or Sanctions**

None of Arsenal's directors or officers, nor any shareholder holding a sufficient number of securities of Arsenal to affect materially the control of Arsenal, or any of the foregoing person's personal holding companies, have been subject to:

- (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or have entered into a settlement agreement with a securities regulatory authority; or
- (b) any other penalties or sanctions imposed by a court or regulatory body that would be likely to be considered important to a reasonable investor making an investment decision.

**Bankruptcies**

None of Arsenal's directors or officers, or a shareholder holding a sufficient number of securities of Arsenal to affect materially the control of Arsenal, or any of the foregoing person's personal holding companies, have within 10 years prior to the date of this Annual Information Form:

- (a) been a director or executive officer of any company (including Arsenal) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager, or trustee appointed to hold its assets; or
- (b) become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the person.

## **PROMOTER**

No person is or has been within the two years immediately preceding the date hereof, a promoter of Arsenal or a subsidiary of Arsenal.

## **CONFLICTS OF INTEREST**

There are potential conflicts of interest to which the directors and officers of Arsenal will be subject to in connection with the operations of Arsenal. In particular, certain of the directors and officers of Arsenal are involved in managerial or director positions with other oil and gas companies whose operations may, from time to time, compete with Arsenal. In addition, certain of the directors and officers of the Corporation are involved in managerial or director positions with corporations which provide financing to, or make equity investments in, competitors of Arsenal. Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA.

## **LEGAL PROCEEDINGS AND REGULATORY ACTIONS**

To the knowledge of the management of Arsenal, Arsenal and its subsidiaries are not a party to, nor is any of Arsenal's or its subsidiaries' properties subject to, any material legal proceedings. Furthermore, neither Arsenal nor any of its subsidiaries were a party to, nor were any of Arsenal's or its subsidiaries' properties subject to, any material legal proceedings since the beginning of Arsenal's most recently completed financial year. Management of Arsenal is not aware of any material legal proceedings that are currently being contemplated against Arsenal or any of its subsidiaries or against any of Arsenal's or its subsidiaries' properties.

To the knowledge of the management of Arsenal, no penalties or sanctions have been imposed against Arsenal or any subsidiary of Arsenal by a court relating to securities legislation or by a securities regulatory authority since the beginning of Arsenal's most recently completed financial year. Furthermore, there have been no penalties or sanctions imposed by a court or regulatory body against Arsenal or a subsidiary of Arsenal that would likely be considered important to a reasonable investor in making an investment decision. Neither Arsenal nor any of its subsidiaries have entered into any settlement agreements before a court relating to securities legislation or with a securities regulatory authority since the beginning of Arsenal's most recently completed financial year.

## **AUDIT COMMITTEE**

Pursuant to NI 52-110, the Corporation is required to include in its Annual Information Form the disclosure required under Form 52-110F1 with respect to its audit committee, including the text of its audit committee charter, the composition of the audit committee and the fees paid to the external auditor. This information is provided in Appendix A attached hereto.

## **INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS**

The management of the Corporation is not aware of any material interest, direct or indirect, of any of the following persons or companies in any transaction within the three most recently completed financial years of Arsenal or during the current financial year that has materially affected or is reasonably expected to materially affect Arsenal or a subsidiary of Arsenal:

- (a) a director or executive officer of Arsenal or a subsidiary of Arsenal;
- (b) a person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10 percent of the issued and outstanding Arsenal Shares; and
- (c) an associate or affiliate of any of the persons or companies referred to in paragraphs (a) or (b).

## **TRANSFER AGENT AND REGISTRAR**

The transfer agent and registrar for the Arsenal Shares is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta and Toronto, Ontario.

## **MATERIAL CONTRACTS**

Arsenal has not entered into any material contracts during its most recently completed financial year, or before the most recently completed financial year, that are still in effect.

## **INTEREST OF EXPERTS**

There is no person or company who is named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under NI 51-102 by Arsenal during, or relating to Arsenal's most recently completed financial year, and whose profession or business gives authority to the report, valuation, statement or opinion made by the person or company, other than KPMG LLP, the independent auditor of Arsenal and AJM Petroleum Consultants ("AJM"), the independent reserves evaluator for Arsenal.

None of the designated professionals of AJM has at any time held any registered or beneficial interest, direct or indirect, in any securities or other property of Arsenal or of one of Arsenal's associates or affiliates. None of the designated professionals of AJM have received, or is to receive, any registered or beneficial interest, direct or indirect, in any securities or other property of Arsenal or of one of Arsenal's associates or affiliates.

KPMG LLP is independent in accordance with the Rules of Professional Conduct as outlined by the Institute of Chartered Accountants of Alberta.

No director, officer or employee of any of the experts referred to herein is or is expected to be elected, appointed or employed as a director, officer or employee of Arsenal or of any associate or affiliate of Arsenal.

## **ADDITIONAL INFORMATION**

Additional information including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities, options to purchase securities and securities authorized for issuance under equity compensation plans will be contained in Arsenal's information circular for its next annual meeting of security holders. Additional financial information is provided in the Corporation's comparative financial statements and MD&A for its most recently completed financial year. Additional information relating to the Corporation may be found on SEDAR at [www.sedar.com](http://www.sedar.com).

APPENDIX A

FORM 51-101F2

**REPORT ON RESERVES DATA  
BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR**

To the Board of Directors of Arsenal Energy Inc. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2010 and identifies the respective portions thereof that we have evaluated and reported on to the Company's management/Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Arsenal Energy Inc. Reserve Estimation and Economic Evaluation	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (\$M, before income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
AJM Petroleum Consultants	March 9, 2011	Canada	-	\$53,916.4	-	\$53,916.4
AJM Petroleum Consultants	March 9, 2011	United States	-	\$147,525.0	-	\$147,525.0

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.
7. Because the reserves data are based on judgments regarding future events, actual events will vary and the variations may be material.

Executed as to our report referred to above:

**AJM Petroleum Consultants**  
**Fifth Avenue Place, East Tower**  
**6<sup>th</sup> Floor, 425 – 1<sup>st</sup> Street S.W.**  
**Calgary, Alberta**  
**T2P 3P8**

*"Douglas S. Ashton"*  
\_\_\_\_\_  
Douglas S. Ashton, P. Eng. Vice-President Engineering  
Execution date: March 9, 2011

## APPENDIX B

### FORM 51-101F3

#### REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Arsenal Energy Inc. (the “**Company**”) are responsible for the preparation and disclosure of information with respect to the Company’s oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company’s reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Company has:

- (a) reviewed the Company’s procedures for providing information to the independent qualified reserves evaluator;
- (b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
- (c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Company’s procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved:

- (d) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;
- (e) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and
- (f) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

*“Tony van Winkoop”*

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Tony van Winkoop  
President and Chief Executive Officer

*“J. Paul Lawrence”*

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J. Paul Lawrence  
Vice President, Finance and Chief Financial Officer

*“R.H. (Harley) Kempthorne”*

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R.H. (Harley) Kempthorne  
Director and Chairman of Reserves Committee

*“Curtis R. Stewart”*

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Curtis R. Stewart  
Director

Dated: March 22, 2011

## APPENDIX C

### OIL & GAS DEFINITIONS

The following definitions form the bases of the classification of reserves and values presented in the AJM Report. They have been prepared by the Standing Committee on Reserves Definitions of the Petroleum Society of the CIM (“CIM”), incorporated in the Society of Petroleum Evaluation Engineers (“SPEE”) Canadian Oil and Gas Evaluation Handbook (“**COGE Handbook**”) and specified by NI 51-101.

#### Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recovered from known accumulations, from a given date forward, based on:

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates.

#### 1. Proved Reserves

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

#### 2. Probable Reserves

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

#### 3. Possible Reserves

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

#### Development and Production Starts

Each of the reserves categories (proved, probable, and possible) may be divided into developed and undeveloped categories.

#### 1. Developed Reserves

Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities, or if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

#### 2. Developed Producing Reserves

Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing, or if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

### 3. Developed Non-Producing Reserves

Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

### 4. Undeveloped Reserves

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities, and completion intervals in the pool and their respective development and production status.

### **Levels of Certainty for Reported Reserves**

The qualitative certainty levels contained in the definitions above are applicable to individual reserves entities (which refer to the lowest level at which reserves calculations are performed), and to reported reserves (which refers to the highest-level sum of individual entity estimates for which reserve estimates are presented).

Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and
- at least 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

**APPENDIX D**  
**INFORMATION CONCERNING AUDIT COMMITTEE**

**1. The Audit Committee's Charter**

The following is the text of the Audit Committee's Charter:

Purpose

1. The purpose of the Audit Committee is to:
  - (a) review and recommend to the Board for acceptance, prior to their public release, all material financial information required to be gathered and disclosed by the Corporation;
  - (b) oversee management designed and implemented accounting systems and internal controls; and
  - (c) recommend, engage, supervise, arrange for the compensation and ensure the independence of the external auditor to the Corporation.

Composition

2. The Audit Committee will be comprised of at least three members of the Board each of whom will at all times be independent and financially literate as those terms are defined in Multilateral Instrument 52-110 and possess:
  - (i) an understanding of the accounting principles used by the Corporation to prepare its financial statements;
  - (ii) the ability to assess the general application of such accounting principles in connection with the accounting for estimates, accruals and reserves;
  - (iii) experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the Corporation's financial statements, or experience actively supervising one or more individuals engaged in such activities; and
  - (iv) an understanding of internal controls and procedures for financial reporting.

Meetings

3. The Audit Committee is required to meet in person, or by telephone conference call, at least once each quarter and as often thereafter as required to discharge the duties of the Audit Committee.
4. The Chair of the Audit Committee appointed by the Board will, in consultation with the members, determine the schedule, time and place of meetings, and in consultation with management and the external auditor, establish the agenda for meetings.
5. A quorum for a meeting of the Audit Committee shall be a majority of members present in person or by telephone conference call.
6. Notice of the time and place of every meeting shall be given in writing, by email or facsimile to each member of the Audit Committee at least 24 hours prior to the time fixed for such meeting, provided that a member may in any manner waive a notice of meeting.

Responsibilities

7. The Audit Committee is responsible to:

- (a) independently or together with the Board, investigate fraud, illegal acts and conflicts of interest and respond to existing and potential conflicts;
- (b) discuss issues of its choosing with the external auditor, management and corporate counsel;
- (c) establish procedures for the confidential anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters;
- (d) establish procedures for the receipt and treatment of complaints received by the Corporation regarding accounting, internal accounting controls and auditing matters and the retention (for at least 7 years) of copies of concerns and evidence of investigations; and
- (e) make inquiries of the external auditor and legal counsel to the Corporation regarding potential claims, assessments, contingent liabilities, and legal and regulatory matters that may have a material impact on the financial statements of the Corporation.

#### External Auditors

8. To preserve the independence of the external auditor responsible for preparing or issuing an auditor's report or performing other audit, review or attest services for the Corporation, the Audit Committee is responsible to:
- (a) recommend to the Board the external auditor to be nominated;
  - (b) recommend to the Board the external auditor's compensation;
  - (c) evaluate the external auditor's qualifications, performance and independence including by annually reviewing:
    - (i) a report of the auditor describing its internal quality-control procedures;
    - (ii) material issues raised by its most recent internal quality-control review; and
    - (iii) the results of any inquiry or investigation by government or professional authorities of the auditor within the last five years;
  - (d) review the experience and qualifications of the senior members of the external auditors, ensure that the lead audit partner is replaced periodically in accordance with applicable law, and that the audit firm continues to be independent;
  - (e) review and pre-approve any engagements for non-audit services to be provided by the external auditor and its affiliates in light of the estimated fees and impact on the external auditor's independence;
  - (f) review with management and with the external auditor:
    - (i) any proposed changes in major accounting policies;
    - (ii) the presentation and impact of significant risks and uncertainties; and
    - (iii) key estimates and judgments of management that may be material to financial reporting; and
  - (g) review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and most recent former external auditor of the Corporation in compliance with the requirements set out in section 2.4 of Multilateral Instrument 52-110.

9. The Audit Committee is required to:
- (a) maintain direct communications with the internal and external auditors;
  - (b) discuss and review specific issues with the external auditor;
  - (c) oversee the work of the external auditor;
  - (d) resolve any disagreements between management and the external auditor;
  - (e) meet with the external auditor at least annually in the absence of management;
  - (f) ensure that the external auditor is answerable to the Audit Committee, as representatives of the shareholders, rather than to the executive officers and management;
  - (g) pre-approve all audit services;
  - (h) meet with the external auditor prior to the audit to review the scope and general extent of the external auditor's annual audit including planning and staffing the audit and the factors considered in determining the audit scope, including risk factors;
  - (i) upon completion of the annual audit and prior to public disclosure, review the following with the CEO, CFO and executive officers:
    - (i) annual financial statements, footnotes and management discussion and analysis of financial condition and results of operations;
    - (ii) significant accounting judgements and reporting principles, practices and procedures applied in preparing the financial statements, including newly adopted accounting policies and the reasons for their adoption;
    - (iii) results of the combined audit of the financial statements and internal controls over financial reporting;
    - (iv) significant changes to the audit plan, if any, and any disputes or difficulties with management encountered during the audit, including any disagreements which, if not resolved, would have caused the external auditor to issue a non-standard report on the Corporation's financial statements; and
    - (v) co-operation received by the external auditor during its audit including access to all requested records, data and information.

Accounting Systems, Internal Controls and Procedures

10. The Audit Committee will:
- (a) be satisfied and obtain reasonable assurances from management and the external auditors that:
    - (i) accounting systems are reliable;
    - (ii) prescribed internal controls are effective; and
    - (iii) adequate procedures are in place for the review of the disclosure of financial information extracted or derived from the Corporation's financial statements;
  - (b) periodically assess the adequacy of accounting systems, internal controls and procedures for the review of disclosure of financial information;
  - (c) direct the external auditor's examinations to particular issues;

- (d) review control weaknesses identified by the external auditor and management's response; and
- (e) review with the external auditor its view of the qualifications and performance of the key financial and accounting executives.

### Reporting

11. The Audit Committee is responsible, following each meeting, to report to the Board regarding its activities, findings, recommendations, any issues that arise with respect to the quality or integrity of the Corporation's financial statements, compliance with applicable law, the performance and independence of the external auditor and the effectiveness of the internal audit function.
12. The Audit Committee is responsible for reviewing and recommending their approval to the Board, prior to their distribution, of all:
  - (a) interim and annual financial statements and notes thereto;
  - (b) managements' discussion and analysis of financial condition and results of operations;
  - (c) relevant sections of the annual report, annual information form and management information circular containing financial information;
  - (d) forecasted financial information and forward looking statements;
  - (e) press releases and other documents in which financial statements, earnings forecasts, results of operations or other financial information is disclosed; and
  - (f) disclosure of the selection of accounting policies (and changes thereto), major accounting judgments, accruals and estimates.
13. The Audit Committee will annually, prior to public disclosure of its annual financial statements, ensure that the external auditor has current participant status with, and is in compliance with any restriction or sanction imposed by the Canadian Public Accountability Board.
14. The Audit Committee will prepare any reports required to be prepared by the Committee under applicable law including quarterly reports regarding ongoing investigations made pursuant to the Corporation's Whistleblower Policy.
15. Receive reports from time to time from the Chair of the Reserves Committee and discuss with the Chair, and if appropriate the Committee, issues of overlapping relevance to the Audit Committee.

### Governance

16. The Audit Committee is responsible to annually review and in its discretion make recommendations to the Board regarding changes to its Mandate and the position description of its Chair.

### Materials

17. The Audit Committee has access to all books, records, facilities and personnel of the Corporation necessary for the discharge of its duties.

### Advisors

18. The Audit Committee has the power, at the expense of the Corporation, to retain, instruct, compensate and terminate independent advisors to assist the Audit Committee in the discharge of its duties.

## 2. Composition of the Audit Committee

During the year ended December 31, 2009 the Audit Committee of the Corporation was composed of the following individuals:

William Hews	Independent <sup>(1)</sup>	Financially literate <sup>(2)</sup>
R. Neil MacKay	Independent <sup>(1)</sup>	Financially literate <sup>(2)</sup>
Bill Powers	Independent <sup>(1)</sup>	Financially literate <sup>(2)</sup>

### Notes:

- (1) As defined by NI 52-110.  
(2) As defined by NI 52-110.

## 3. Relevant Education and Experience

Mr. Hews, the Chairman of the Audit Committee, holds a BSc. and MBA. He also has over 8 years of public issuer experience, both as an officer and a director.

Mr. MacKay holds a B.A. and LLB and has been a practicing lawyer for 30 years.

Mr. Powers holds a B.Sc. in Business Administration from Georgetown University. Mr. Powers is currently the editor of the Powers Energy Investor. A publication focused on oil and gas investment research.

## 4. Reliance on Certain Exemptions

At no time since the commencement of the Corporation's most recently completed financial year has the Corporation relied on:

- (a) the exemption in Section 2.4 (*De Minimis Non-Audit Services*) of NI 52-110;
- (b) the exemption in Section 3.2 (*Initial Public Offerings*) of NI 52-110;
- (c) the exemption in Section 3.4 (*Events Outside Control of Member*) of NI 52-110;
- (d) the exemption in section 3.5 (*Death, Disability or Resignation of Audit Committee Member*) of NI 52-110; or
- (e) an exemption from NI 52-110, in whole or in part, granted under Part 8 (*Exemptions*) of NI 52-110.

## 5. Reliance on the Exemption in Subsection 3.3(2) or Section 3.6

At no time since the commencement of the Corporation's most recently completed financial year has the Corporation relied on the exemptions in Sections 3.3(2) (*Controlled Companies*) or 3.6 (*Temporary Exemption for Limited and Exceptional Circumstances*) of NI 52-110.

## 6. Reliance on Section 3.8

At no time since the commencement of the Corporation's most recently completed financial year has the Corporation relied on Section 3.8 (*Acquisition of Financial Literacy*) of NI 52-110.

## 7. Audit Committee Oversight

At no time since the commencement of the Corporation's most recently completed financial year was a recommendation of the Audit Committee to nominate or compensate an external auditor not adopted by the Board.

## 8. Pre-Approval Policies and Procedures

The Audit Committee of the Corporation has adopted specific policies and procedures for the engagement of non-audit services entitled "Procedures for Approval of Audit and Non-Audit Services by the External Auditors" (the

“**Procedure**”). Under the Procedure, the auditors may not act in any capacity where they function as management, audit their own work or serve in an advocacy role on behalf of the Corporation. Various audit related services provided by the auditors have been pre-approved. Management is required, however, to obtain pre-approval of the Audit Committee for services where engagement fees are expected to exceed \$10,000. Where fees for a particular engagement are expected to be less than or equal to \$10,000, the Chairman of the Audit Committee is to be notified expeditiously of the commencement of such services. If an engagement with the auditors for a particular service is contemplated that is neither expressly forbidden under the Procedure nor covered under the range of services provided for therein, such an engagement must be pre-approved. The Audit Committee has delegated the authority to effect such pre-approval to the Chairman of the Audit Committee. Pre-approved non-audit services shall be provided pursuant to an engagement letter signed by the auditors, which shall set out the particular non-audit services to be provided. At every regularly scheduled meeting of the Audit Committee, management is required to report on all new pre-approved engagements of the auditors since the last such report.

### 9. External Auditor Service Fees (By Category)

The aggregate fees billed by the Corporation’s external auditors in each of the last two fiscal years are as follows:

Financial Period Ending December 31	Audit Fees <sup>(1)</sup>	Audit Related Fees <sup>(2)</sup>	Tax Fees <sup>(3)</sup>	All Other Fees <sup>(4)</sup>
2010	222,800	Nil	34,375	\$Nil
2009	173,000	Nil	53,056	\$Nil

**Notes:**

- (1) The aggregate audit fees billed by external auditor.
- (2) The aggregate fees billed by Arsenal’s external auditor for assurance and related services that are reasonably related to the performance of the audit or review of Arsenal’s financial statements that are not reported under ‘Audit Fees’.
- (3) The aggregate fees billed by Arsenal’s external auditor for professional services rendered for tax compliance, tax advice and tax planning.
- (4) The aggregate fees billed for products and services provided by Arsenal’s external auditor, other than services reported under ‘Audit Fees’, ‘Audit Related Fees’ and ‘Tax Fees’.