



Management Discussion and Analysis For the Quarter Ended March 31, 2014

Date of Report: May 13, 2014

The following management's discussion and analysis ("MD&A") for Argent Energy Trust (the "Trust" or "Argent"), dated May 13, 2014, should be read in conjunction with unaudited interim consolidated financial statements for the period ended March 31, 2014, the audited annual consolidated financial statements for the year ended December 31, 2013, and the MD&A for the year ended December 31, 2013 that are available on www.sedar.com and on the Trust's website at www.argentenergytrust.com.

The Trust's audited annual consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"), specifically International Accounting Standard ("IAS") 34, Interim Financial Reporting. Items included in the financial statements of each of the Trust's subsidiaries are measured using the currency of the primary economic environment in which the entity operates (the "functional currency"). The annual audited consolidated financial statements are presented in Canadian dollars, which is the functional and presentation currency of the Trust. Figures within this MD&A are presented in Canadian dollars unless otherwise indicated.

Certain information contained in this MD&A constitutes "forward-looking statements". Investors should read the "Note about Forward Looking Statements" section at the end of this MD&A.

Non-IFRS financial measures

Statements throughout this MD&A make reference to the terms "netbacks" and "funds flow from operations" which are non-IFRS financial measures that do not have any standardized meaning prescribed by IFRS and are therefore unlikely to be comparable to similar measures presented by other issuers. Management believes that "netbacks" and "funds flow from operations" provide useful information to investors and management since such measures reflect the quality of production, the level of profitability, the ability to drive growth through the funding of future capital expenditures and the sustainability of distributions to unit holders. "Netbacks" is equal to oil, natural gas and NGL sales revenue less royalties, transportation costs, production taxes and operating expenses. Funds flow from operations is calculated based on cash flow provided by operating activities before changes in non-cash working capital. See the "Non-IFRS financial measures" section of this MD&A for a reconciliation of funds flow from operations and netbacks to income for the period, the most directly comparable measure in the Trust's audited annual consolidated financial statements. Other financial data has been prepared in accordance with IFRS.

Overview of the Trust

The Trust is an unincorporated limited purpose open-ended trust established under the laws of the Province of Alberta. The Trust operates as a foreign asset trust with properties held in the U.S. therefore the Trust is not subject to the same taxation rules applicable to a Canadian Specified Investment Flow Through (“SIFT”) trust. The objective of the Trust is to create stable, consistent returns for investors through the acquisition and development of oil and natural gas reserves and production with low-risk exploitation potential, located primarily in the U.S., and to pay out a portion of available cash to Unitholders on a monthly basis. The Trust provides investors with a publicly traded, petroleum focused, distribution producing investment, with favourable tax treatment relative to taxable Canadian trusts.

The Trust was created on January 31, 2012 and owns all of the issued and outstanding shares of Argent Energy (Canada) Holdings Inc. (“Canada Holdco”), which in turn owns all of the issued and outstanding shares of Argent Energy (US) Holdings Inc. (“US Opco”). Canada Holdco was incorporated on May 4, 2012 to acquire and hold all of the issued and outstanding shares of US Opco. US Opco was incorporated on May 4, 2012 to acquire, develop and operate oil and gas assets in the United States.

Throughout this MD&A, Argent Energy Trust and its subsidiaries are collectively referred to as the “Trust” or “Argent” for purposes of convenience. In addition, references to the results of operations refer to operations of the Trust’s U.S. subsidiary, US Opco.

Strategic Objectives

The Trust is strongly committed to maximizing value from its asset base and delivering results. The Trust's objective is to create positive returns for investors through the acquisition and development of oil and natural gas reserves and production, with low risk exploitation potential and to pay out a portion of available cash to Unitholders on a monthly basis.

In order to achieve this objective, the Trust has set a capital budget and distribution amount that is sensible given the cash flow generated from production. Working towards sustainability is of great importance for the Trust. In order to meet this goal of sustainability, the Trust is exercising a disciplined capital investment program to achieve a balance between production maintenance and value growth through reserves additions by drilling.

The Trust believes that careful utilization of debt can positively contribute to distribution stability and increased returns. The Trust actively identifies assets within its portfolio to monetize at attractive levels to pay down debt when necessary.

The Trust has targeted long-life, low decline, oil and natural gas assets on shore U.S. This asset class typically has a lower risk development and exploitation potential and a longer reserve life which provides a natural hedge against short term commodity price cycles. Since the IPO, the Trust has acquired four accretive properties with similar characteristics. Specifically, oil weighted properties with high netbacks (over \$40 per boe) and low declines (typically 10% to 20% declines), that increase the value of the Trust through increasing production and reserves per unit, increasing cash flow per unit and creating an improvement in both the payout ratio and sustainability ratio.

As part of the Trust's risk management strategy, it uses financial instruments to reduce its commodity price and currency risk exposure. The Trust has implemented a rolling hedging program that aims to reduce the Trust's exposure to changes in commodity prices for up to 36 months into the future, with the capacity to hedge up to 70% of forecasted production 12 months forward; up to 60% of forecasted production 24 months forward; and up to 50% of forecasted production 36 months forward. The Trust uses swaps, collars and fixed contracts to reduce volatility in cash flows, protect acquisition economics, and to maintain stability of cash distributions. Currently, the Trust has hedged approximately 3,100 bbl per day of its 2014 forecast oil production and approximately 2,000 bbl per day of its 2015 forecast oil production, all at US\$90 per barrel WTI or better. The Trust also has hedged approximately 7,000 mMBTU of its 2014

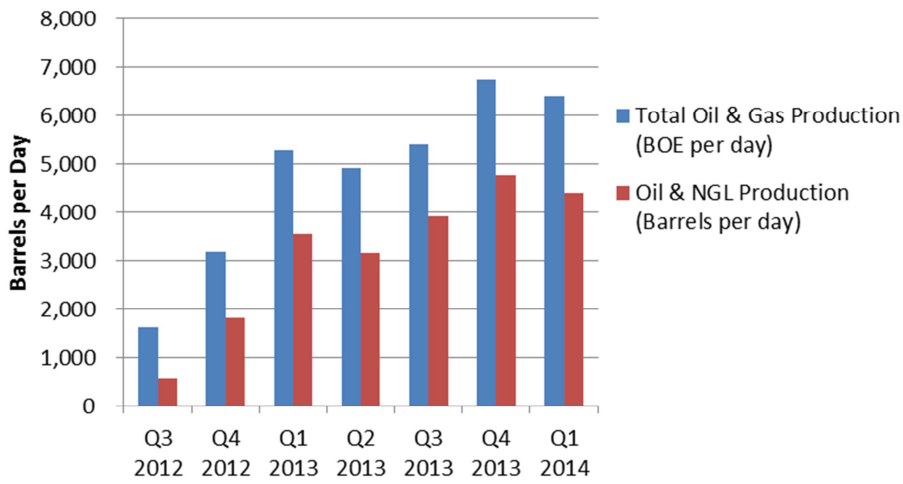
natural gas production and approximately 6,000 mmBTU of its 2015 forecast natural gas production at US\$4.00 per mmBTU or better.

Highlights for the three months ended March 31, 2014

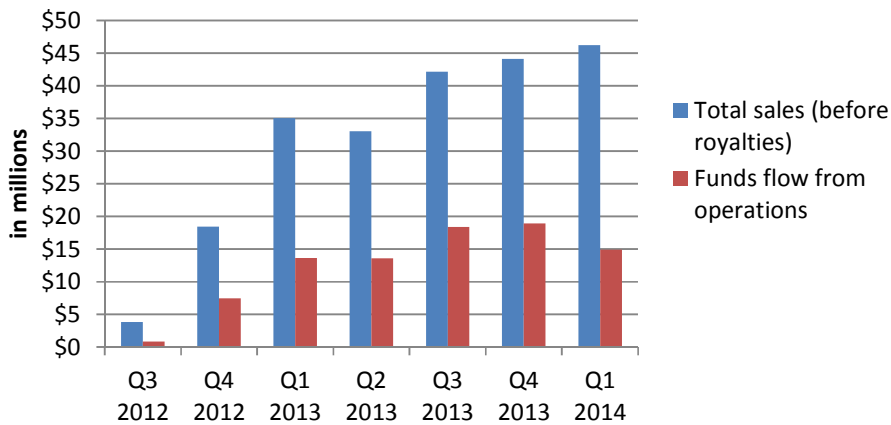
- Increased production by 21% to 6,390 boe/d (69% Oil & NGL) in Q1 2014 from 5,278 boe/d (67% Oil & NGL) in Q1 2013, reflecting new, mainly oil wells coming on production and the acquisition of oil weighted properties during 2013.
- Successfully drilled and completed two Eagle Ford wells (Hayden 1H, Hrcir 5H) and one South Escobas well (Violeta Ranch #7) and put these three wells on production during the quarter. The Trust also completed drilling operations on two additional Eagle Ford wells (Makers 1H and Makers 3H).
- Q1 2014 oil & gas sales increased by 32% to \$46.2 million, as compared to \$35.0 million in Q1 2013.
- Netbacks from sales volume for Q1 2014 were \$22.9 million, or \$39.53 per boe, as compared to \$18.7 million, or \$39.37 per boe for Q1 2013. An additional \$2.2 million in netback was received from overriding royalties in Q1 2014 (compared to \$1.0 million in Q1 2013).
- Q1 2014 funds flow from operations was \$14.9 million, or \$0.24 per Unit, compared to \$13.6 million, or \$0.28 per Unit in Q1 2013. This reflects a charge for ad valorem taxes of \$3.6 million in Q1, 2014, (compared to budgeted \$1.3 million) and a \$1.7 million increase from previously reported for Q1, 2013, due to the application of a new International Financial Reporting Interpretation Committee (“IFRIC”) 21 accounting standard that required the full year ad valorem taxes on all leases, except those in Wyoming, to be recognized on January 1st of each year, rather than accrued on a monthly or quarterly basis. As such, there will be a significantly lower charge in the remaining quarters of 2014 related only to Wyoming.
- Q1 2014 loss was \$2.3 million, or \$0.038 per Unit, as compared to Q1 2013 income of \$3.6 million, or \$0.075 per Unit.
- Declared unitholder distributions of \$0.2625 per Unit during Q1 2014 (\$0.0875 per Unit per month).

Note: Funds flow from operations and netbacks are non-IFRS financial measures. See the Non-IFRS Measures section of this MD&A.

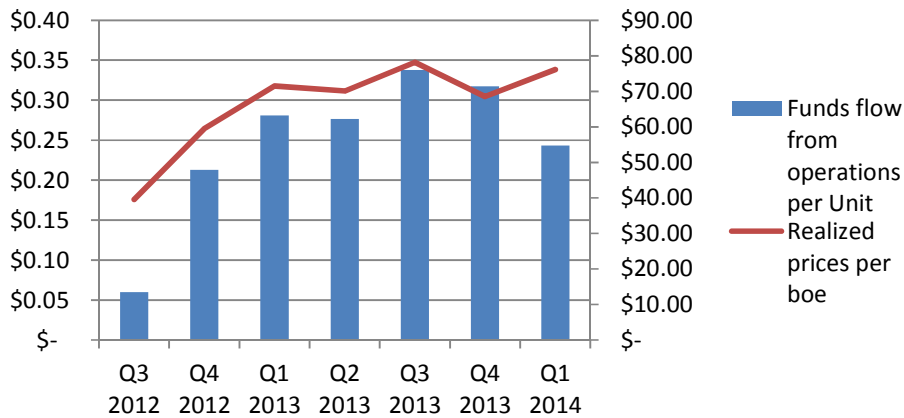
Average Daily Production



Sales and Funds Flow from Operations



Funds flow from operations per Unit



Outlook

As previously announced (April 10, 2014 Press Release), the Trust has reduced its 2014 capital program to US\$55 million (including US\$45 million for drilling and US\$10 million in maintenance) from US\$70 million (including US\$60 million for drilling and US\$10 million in maintenance). The majority of this budget will be incurred by the end of June 2014, with minimal capital expenditure expected in the second half of the year. This reduced capital program will result in the Trust deferring the drilling of 3 gas wells (2 South Escobas and 1 AA Wells) and one shallow oil well (Manvel) until 2015. Consequently, the Trust also reduced its production guidance from an annual average rate of 7,000 boe/d to an average rate of approximately 6,000 boe/d (70% oil and NGL) for 2014, a modest increase year over year from the 2013 average achieved of 5,591 boe/d.

Given the capital expenditure spending profile, production for each of Q2 2014 and Q3 2014 is expected to average in the 6,100 – 6,200 boe/d range, with natural declines leading to approximately 5,600 boe/d average exit rate of production in December 2014, which the Trust is targeting to maintain in 2015.

The Trust expects production from its most recently drilled Eagle Ford well pair (Makers 1H and 3H) to commence in mid-May 2014 after completion of fracking operations.

The Trust continues to review plans to rationalize a portion of its assets targeting a reduction in debt as use of proceeds. As part of this review process, the Trust has engaged BMO Capital to sell a production payment and royalty interest it currently receives from a third party. Any proceeds will be used to reduce the amounts drawn under the credit facility to improve the Trust's financial flexibility.

The Trust has also undertaken measures to reduce general and administrative costs in both the Houston and Calgary offices. These cost reductions, taken with capital spending reductions and portfolio rationalization will help strike a more reasonable balance between yield and growth with improving payout and sustainability ratios going forward.

Results of Operations

Production and Oil, NGL and Natural Gas Sales

| <i>(Amounts in Cdn\$)</i> | Q1 2014 | Q1 2013 |
|--|----------|----------|
| Oil volumes (bbl/d) | 4,085 | 3,118 |
| NGL volumes (bbl/d) | 326 | 438 |
| Natural gas volumes (mcf/d) | 11,876 | 10,331 |
| Total sales volumes (boe/d) | 6,390 | 5,278 |
| % Oil & NGL | 69% | 67% |
| Total BOE | 575,102 | 475,008 |
| <i>Benchmark Prices:</i> | | |
| WTI crude oil spot (\$/bbl) | \$108.91 | \$95.11 |
| Henry Hub natural gas Spot (\$/MMBtu) | \$5.72 | \$3.52 |
| <i>Realized sales prices:</i> | | |
| Oil (\$/bbl) | \$101.61 | \$106.56 |
| NGLs (\$/bbl) | \$41.63 | \$29.96 |
| Natural gas (\$/mcf) | \$4.86 | \$3.07 |
| Per Boe | \$76.10 | \$71.45 |
| <i>(\$000s):</i> | | |
| Oil sales | \$37,353 | \$29,899 |
| NGL sales | 1,222 | 1,183 |
| Natural gas sales | 5,193 | 2,858 |
| | \$43,768 | \$33,940 |
| Overriding royalty revenue | 2,480 | 1,097 |
| Oil and gas sales, before royalties and risk management gain(loss) | \$46,248 | \$35,037 |

Sales volumes in Q1 2014 averaged 6,390 boe per day (69% oil and NGLs), as compared to 5,278 boe per day (67% oil and NGLs) in Q1 2013. The increase was primarily attributable to higher volumes associated with the Kansas and Wyoming assets acquired in 2013.

Total oil, NGL and gas sales before royalties and risk management gain or loss in Q1 2014 were \$46.2 million, as compared to \$35.0 million in Q1 2013, an increase of 32%, as a result of bringing new wells on production and the acquisitions of oil & gas properties during 2013. Oil and NGL sales in Q1 2014 were \$38.6 million, or approximately 88% of the total sales of \$43.8 million, as compared to \$31.1 million, or approximately 92% of total sales of \$33.9 million in Q1 2013. Natural Gas sales in Q1 2014 totaled \$5.2 million, or 12% of the total sales, as compared to \$2.9 million, or 8% of total sales in Q1 2013. The increased production from the new South Texas gas wells and increase in natural gas price during Q1 2014 resulted in natural gas being a larger portion of total sales amount.

Revenue from overriding royalties increased from \$1.1 million in Q1 2013 to \$2.5 million in Q1 2014, due mainly to the recent success of the third party operator's drilling in the Eagle Ford. The majority of the overriding royalty revenue of \$2.5 million was derived from the Forest Override royalty (Production Payment) that was acquired from Denali upon closing of the over-allotment option of the IPO on August 28, 2012. The production payment is equivalent to approximately 3.4% net revenue interest in currently producing Eagle Ford oil production developed by a third party on certain leases in the Wilson and Gonzales Counties in Texas, and represents the equivalent of revenue from approximately 251 boe/d of additional production during the quarter.

In Q1 2014, the average realized oil price was \$101.61 per bbl as compared to \$106.56 per bbl in Q1 2013. Oil prices realized in Q1 2014 reflect a discount of \$7.30 per bbl from the average West Texas Intermediate ("WTI") oil price of \$108.91 per bbl as compared to an uplift of \$11.45 per bbl over the average WTI price in Q1 2013. This decrease compared to WTI was due mainly to changes in oil differentials and the location of the acquired oil production. Oil premiums that were being received from the Trust's assets in Texas diminished as a result of Gulf Coast regional market changes. The average realized oil price was also affected by the acquisitions of Kansas Assets and Wyoming Assets in Q3 and Q4 2013, which have lower realized prices than that of the Trust's assets in Texas.

The average realized natural gas price was \$4.86 per mcf in Q1 2014, compared to \$3.07 per mcf in Q1 2013, reflecting higher natural gas prices in the commodities market.

Royalty and Production Taxes

| (\$000s): | Q1 2014 | Q1 2013 |
|---|-----------------|----------------|
| Royalties | \$8,379 | \$7,423 |
| Production taxes: | | |
| - on Oil, NGL and Natural Gas sales | 1,638 | 1,233 |
| - on Overriding royalty revenue | 111 | 40 |
| Total Royalties and production taxes | \$10,128 | \$8,696 |

Royalties and production taxes for Q1 2014 totaled \$10.1 million or 22% of oil and gas sales, as compared to \$8.7 million or 25% of oil and gas sales in Q1 2013. Royalties and production taxes as a percentage of total oil and gas sales for Q1 2014 decreased from Q1 2013 as a result a lower royalties' percentage associated with the Kansas and Wyoming assets. Royalties are paid to mineral lease owners on acreages that have production, while production tax expenses are severance taxes paid to the State governments on mineral production based on the value and/or quantity of production. Depending on the commodity and State where the Trust operates, severance tax rates range from 4% to 8% of total oil and gas sales.

Operating Expenses

| (\$000s): | Q1 2014 | Q1 2013 |
|--|-----------------|----------------|
| Operating expenses: | | |
| - on Oil, NGL and Natural Gas sales | \$9,034 | \$5,313 |
| - on Overriding Royalty revenue | 16 | 20 |
| Operating expenses (excluding workovers) | \$9,050 | \$5,333 |
| - Workovers | 1,978 | 1,273 |
| Total Operating Expenses | \$11,028 | \$6,606 |

Note: Operating expenses exclude ad valorem taxes that are based on factors independent to the production volume.

Operating expenses excluding workovers relating to Oil, NGL and Natural Gas sales for Q1 2014 were approximately \$9.1 million, or \$15.71 per boe, as compared to \$5.3 million, or \$11.18 per boe in Q1 2013. The increase in operating expenses is primarily attributable to the acquisitions undertaken in 2013. The acquisitions of mature assets in Kansas and Wyoming require on average higher operating expenses than the Trust's South Texas assets.

Netbacks

| Netbacks (\$/boe) | Q1 2014 | Q1 2013 |
|--|-----------------|-----------------|
| Oil, NGL and Natural Gas sales ⁽ⁱ⁾ | \$76.10 | \$71.45 |
| <i>Less:</i> | | |
| Royalties and Production taxes ⁽ⁱ⁾ | 17.43 | 18.22 |
| Operating expenses ⁽ⁱ⁾ | 15.71 | 11.18 |
| Operating expenses - workovers | 3.44 | 2.68 |
| Netbacks from sales volume (\$/boe) ⁽ⁱⁱ⁾ | \$39.53 | \$39.37 |
| <i>Netbacks (000s):</i> | | |
| - from sales volumes | \$22,865 | \$18,695 |
| - from Overriding royalty | \$2,227 | \$1,040 |
| Total Netbacks | \$25,092 | \$19,735 |

(i) Excludes hedging gain or loss and items related to overriding royalty revenue as no production or boes are associated with this revenue.

(ii) Netbacks is a non-IFRS financial measure. See the Non-IFRS Measures section of this MD&A.

Netbacks from sales volume for Q1 2014 were approximately \$22.9 million, or \$39.53 per boe, as compared to \$19.7 million or \$39.37 per boe for Q1 2013. The increase in Q1 2014 netbacks was a result of the increase in oil & gas volumes attributable to acquired properties. On a per boe basis, netbacks in Q1 2014 were fairly consistent with that in Q1 2013.

Ad valorem taxes

Ad valorem taxes increased to \$3.6 million in Q1 2014, as compared to \$2.2 million in Q1 2013. The Trust incurred higher ad valorem taxes associated with the Kansas and Wyoming assets.

Effective January 1, 2014, the International Financial Reporting Interpretation Committee (“IFRIC”) 21 Levies (“IFRIC 21”) clarified that an entity recognizes a liability for a levy when the activity that triggers payment occurs. The effect of the retrospective application of this policy was a \$2.3 million and \$1.7 million increase in ad valorem taxes recognized for Q1 2014 and Q1 2013 respectively. This is because ad valorem taxes for the full fiscal years are required to be accrued in the first quarters under IFRIC 21 instead of being accrued on a quarterly basis under the Trust’s previous policy.

General and administrative expenses

General and administrative expenses for Q1 2014 were \$4.9 million, or \$8.55 per boe, as compared to \$3.0 million, or \$6.37 per boe, in Q1 2013. These general and administrative overhead costs are in line with expectations considering the acquisitions and operations growth in 2013.

Going forward, with the change in strategic direction and cost reduction initiatives, announced on April 10, 2014, there are a number of executive position rationalizations. The Trust is committed to reduce general and administrative expenses in the remainder of 2014 and in 2015.

Foreign Exchange Gain

The foreign exchange gains or losses are primarily a non-cash period end accounting adjustment resulting from translating the Trust's US dollar denominated inter-company loan issued to its subsidiary into Canadian dollars, the presentation currency of the Trust. Under IFRS, this US\$226 million inter-company loan is eliminated on consolidation and is not part of the net investment in the subsidiary and any related period end foreign exchange translation adjustment is recorded in income or loss.

During Q1 2014, the Trust recorded a foreign exchange gain of \$9.8 million, as compared to a foreign exchange gain of \$5.3 million in Q1 2013. The foreign exchange gain during Q1 2014 was due to the increase of the US dollar relative to the Canadian dollar during the quarter.

Unit based compensation

Unit based compensation is a non-cash item representing the period amortization of the fair value of Restricted Trust Units ("RTUs") and Phantom Unit Rights ("PURs") that were granted.

For Q1 2014, unit based compensation decreased to a non-cash recovery of \$2.7 million, from an expense of \$2.5 million in Q1 2013. The decrease was due to the decline in the Trust's Unit price during Q1 2014, resulting in lower fair value of the RTUs and PURs previously granted. Under IFRS, the Trust is required to re-measure the fair value of this non-cash liability at the end of each reporting period and record any changes in fair value through the income statement.

Depreciation, depletion and amortization

Depreciation, depletion and amortization expenses were \$20.7 million in Q1 2014, as compared to \$10.4 million in Q1 2013, due primarily to acquisitions completed in 2013 in addition to a higher depletion rate for the quarter as discussed below. The majority of this expense relates to non-cash depletion expenses on oil & gas properties recognized on a unit-of-production basis over its reserves.

The Trust revised its estimate of the depletion rate of its oil and gas properties effective October 1, 2013 to exclude probable reserves and associated future development costs. The Trust believes that proved reserves are a better reflection of the useful life of the Trust's assets.

Risk management loss

As part of the Trust's strategy to mitigate the impact of fluctuating commodity prices on its funds flow from operations, the Trust has entered into derivatives contracts to manage commodity price risk. Risk management gain and loss include the realized gain and loss from settlements of derivatives contracts, and period-end unrealized mark-to-market adjustments of the Trust's derivative contracts.

During Q1 2014, the Trust recorded \$5.2 million as risk management loss on its derivative contracts, as compared to \$2.3 million as risk management loss in Q1 2013.

The loss in Q1 2014 mainly reflected the period-end unrealized mark-to-market adjustments of the Trust's derivative contracts due to the increase in oil and gas forward strip prices at March 31, 2014.

Loss on change in fair value of convertible debentures

During Q1 2014, the Trust recorded a non-cash loss gain of \$17.4 million to comprehensive income on the change in fair value of convertible debentures. This is due to the decrease in market price of its convertible debentures on the Toronto Stock Exchange. The Trust did not have any convertible debentures issued in Q1 2013.

During 2013, the Trust issued a total of \$149.3 million in convertible debentures. The Trust has designated these convertible debentures as fair value through profit or loss (“FVTPL”) in accordance with IFRS 9, Financial Instruments. As such, the convertible debentures are recorded at their fair value, and are marked to market at each financial reporting date. Changes in the fair value due to changes in market risks are recorded through income and loss, and changes in fair value due to changes in the Trust’s internal credit risk is recognized through other comprehensive income.

Finance expense

For Q1 2014, finance expense was \$3.7 million, as compared to \$0.8 million in Q1 2013. The increase was due to interest on the \$148.3 million convertible debentures issued during Q2 and Q4 of 2013. The Trust did not have any convertible debentures issued in Q1 2013.

Funds Flow and Income (Loss)

Q1 2014 funds flow from operations was \$14.9 million, or \$0.24 per Unit, as compared to \$13.6 million, or \$0.28 per Unit in Q1 2013. The increase in funds flow from operations was mainly due to higher production and the higher netbacks, as the Trust brought new, mainly oil wells on production and acquired oil & gas properties during 2013. On a per Unit basis, funds flow from operations decreased, as more Units were issued to fund the acquisitions made in 2013.

The Q1 2014 loss was \$2.3 million, or \$0.038 per Unit, as compared to Q1 2013 income of \$3.6 million, or \$0.075 per Unit. The Q1 2014 loss was mainly due to higher non-cash depreciation, depletion and amortization expenses, which more than offset the non-cash foreign exchange gain and the increase in the cash funds flow from operations achieved.

Effective January 1, 2014, the Trust adopted IFRIC 21, which clarified that an entity recognizes a liability for a levy when the activity that triggers payment occurs. Under IFRIC 21, ad valorem taxes for the full fiscal years are required to be accrued in the first quarters instead of being accrued on a quarterly basis under the Trust’s previous policy. The effects of the retrospective application of this policy to funds flow and income (loss) are described in the table below:

| (\$000 unless stated) | Q1 2014 | Q4 2013 | Q3 2013 | Q2 2013 | Q1 2013 |
|---|------------|-------------|-------------|-----------|------------|
| Funds flow from operations (Without IFRIC 21) | \$ 17,143 | \$ 18,324 | \$ 17,804 | \$ 12,980 | \$ 15,294 |
| IFRIC 21 Adjustment | \$ (2,277) | \$ 560 | \$ 560 | \$ 560 | \$ (1,680) |
| Funds flow from operations (After IFRIC 21) | \$ 14,866 | \$ 18,884 | \$ 18,364 | \$ 13,540 | \$ 13,614 |
| Income (Loss) (Without IFRIC 21) | \$ (17) | \$ (82,691) | \$ (16,546) | \$ 6,680 | \$ 5,329 |
| IFRIC 21 Adjustment | \$ (2,277) | \$ 560 | \$ 560 | \$ 560 | \$ (1,680) |
| Income (Loss) (After IFRIC 21) | \$ (2,294) | \$ (82,131) | \$ (15,986) | \$ 7,240 | \$ 3,649 |

Note: Funds flow from operations and netbacks are non-IFRS financial measures. See the Non-IFRS Measures section of this MD&A.

Summary of Quarterly Results

| (\$000 unless stated) | Q1 2014 | Q4 2013 ⁽³⁾ | Q3 2013 ⁽³⁾ | Q2 2013 ⁽³⁾ | Q1 2013 ⁽³⁾ | Q4 2012 | Q3 2012 ⁽¹⁾ | Q2 2012 |
|---|-----------|------------------------|------------------------|------------------------|------------------------|-----------|------------------------|----------|
| Oil and gas sales, before royalties | \$46,248 | \$44,146 | \$42,151 | \$33,022 | \$35,037 | \$18,412 | \$3,843 | \$ - |
| Production | | | | | | | | |
| - Oil (bbl/d) | 4,085 | 4,432 | 3,396 | 2,840 | 3,118 | 1,657 | 461 | - |
| - NGL (bbl/d) | 326 | 347 | 516 | 310 | 438 | 163 | 115 | - |
| - Natural Gas (mcf/d) | 11,876 | 11,805 | 8,967 | 10,616 | 10,331 | 8,096 | 6,258 | - |
| Oil & gas production (boe/d) | 6,390 | 6,747 | 5,407 | 4,920 | 5,278 | 3,169 | 1,618 | - |
| % Oil and NGLs | 69% | 71% | 72% | 64% | 67% | 57% | 36% | - |
| Total Netback ⁽⁴⁾ | \$25,092 | \$23,707 | \$24,274 | \$16,864 | \$19,735 | \$10,968 | \$2,405 | N/A |
| Netback from sales volume only | \$22,865 | \$22,152 | \$21,079 | \$15,321 | \$18,695 | \$9,989 | \$1,928 | N/A |
| - per boe | \$39.53 | \$34.33 | \$41.37 | \$33.12 | \$39.36 | \$34.26 | \$22.89 | N/A |
| Funds flow from (used in) operations ⁽⁴⁾ | \$14,866 | \$18,884 | \$18,364 | \$13,540 | \$13,614 | \$7,444 | \$826 | (\$757) |
| - per boe | \$25.85 | \$30.43 | \$36.92 | \$30.25 | \$28.66 | \$25.53 | \$9.82 | N/A |
| - per Trust Unit, basic | \$0.24 | \$0.32 | \$0.34 | \$0.28 | \$0.28 | \$0.21 | \$0.06 | (\$1.26) |
| Income (Loss) | (\$2,294) | (\$82,131) | (\$15,986) | \$7,240 | \$3,649 | \$270 | (\$4,482) | (\$368) |
| - per Trust Unit, basic | (\$0.038) | (\$1.38) | (\$0.29) | \$0.15 | \$0.08 | \$0.01 | (\$0.33) | (\$0.61) |
| - per Trust Unit, fully diluted | (\$0.038) | (\$1.38) | (\$0.29) | \$0.14 | \$0.07 | \$0.01 | (\$0.33) | (\$0.61) |
| Total Assets | \$751,718 | \$712,407 | \$668,668 | \$621,849 | \$570,104 | \$548,475 | \$278,911 | \$3,586 |
| Non-current Liabilities | \$253,399 | \$257,073 | \$132,642 | \$110,947 | \$82,514 | \$62,107 | \$14,310 | \$0 |
| Distribution per Trust Unit | \$0.26 | \$0.26 | \$0.26 | \$0.26 | \$0.26 | \$0.26 | \$0.15 | \$0 |
| Capital Expenditures ⁽²⁾ | \$28,128 | \$16,720 | \$36,285 | \$32,893 | \$19,911 | \$39,695 | \$12,967 | \$0 |
| Unitholders' Equity | \$427,781 | \$405,259 | \$478,798 | \$478,798 | \$419,645 | \$421,810 | \$217,298 | \$1,484 |

Note (1): Oil, NGL and Natural Gas sales and production levels in Q3 2012 reflect the period from close of the Denali Assets acquisition on August 10th through September 30, 2012.

Note (2): Capital expenditures exclude corporate acquisitions

Note (3): Netback, funds flow from operation and income (loss) figures for 2013 were restated, per the retrospective application of IFRIC 21 that was effective January 1, 2014.

Note (4): Netbacks and funds flow from operations are non-IFRS financial measures. See the Non-IFRS Measures section of this MD&A.

Oil and gas sales before royalties, and Netback, in Q1 2014 remained relatively consistent with Q4 2013 levels. Higher commodity prices realizing \$76.10 per boe in Q1 2014, compared to \$68.48 per boe in Q4 2013 offset lower oil and gas production. Production decreased from 6,747 boe/d in Q4 2013 to 6,390 boe/d in Q1 2014 mainly due to natural declines notably from early production rates in the Moesker #2H Eagle Ford well and the Violeta Ranch #6 gas well.

Funds flow from operations decreased by approximately 21% from Q4 2013 to Q1 2014. The decrease was mainly because of lower level of capitalized general and administrative expenses and the adoption of new accounting standard IFRIC 21. Under IFRIC 21, the Trust is required to recognize the ad valorem tax expense for the full fiscal year in Q1 2014. Without the adoption of IFRIC 21, funds flow from operations would be higher by approximately \$2.3 million, to \$17.1 million.

Loss for Q1 2014 decreased to \$2.3 million from \$82.7 million in Q4 2013. Higher loss in Q4 2013 was mainly due to non-cash impairment charges of \$69.3 million and non-cash exploration expenses of \$6.7 million. In Q1 2014, due to the lower unit price, the Trust recorded a non-cash unit based compensation recovery of \$2.7 million, as compared to a non-cash unit based compensation expense of \$1.5 million in Q4 2013.

Tax Horizon

The tax horizon as determined from a full cycle corporate model developed by the Trust and incorporating all applicable U.S. deductions, indicates that no material U.S. taxes are expected to be payable in respect of income attributable to the Trust's U.S. assets until at least 2021. The Trust expects to maintain this position through capital investments and acquisitions primarily in the U.S.

No taxes are expected to be payable by the Trust in Canada as the Trust intends to distribute all of its taxable income each year to Unitholders and will not be a SIFT trust provided that the Trust does not hold any "non-portfolio property", as defined in the Income Tax Act (Canada). The model developed by the Trust is based on production and cost assumptions from an independent engineering reserve report as of December 31, 2013 using the WTI and NYMEX forward strip commodity pricing as of December 31, 2013.

Liquidity and Capital Resources

Generally, three sources of funding for future capital expenditures are expected by the Trust to be available: (i) internally generated cash flow from operations; (ii) external debt financing, when appropriate; (iii) new capital through the issuance of additional Units, if available on favourable terms, including proceeds obtained from the Trust's Distribution Reinvestment Plan ("DRIP"); and (iv) divestitures of non-core assets.

Bank Credit Facility

As at March 31, 2014, the Trust had US\$92.0 million (CAD\$101.7 million) outstanding under its credit facility and had an undrawn credit limit of US\$68 million (CAD\$75.2 million). The credit facility has a maturity date of August 12, 2015.

This credit facility contains a financial covenant that restricts the Trust such that the aggregate cash distributions of the Trust do not exceed 115% of the annualized cash flow of the Trust, as adjusted for major acquisitions. The Trust was in compliance with this financial covenant as at March 31, 2014.

Capital Resources

Based on the March 31, 2014 balance sheet, the Trust had \$33.5 million of capital resources available, calculated as follows:

| (\$000) | As at March 31, 2014 |
|---|----------------------|
| Working capital deficit | \$(45,340) |
| Add: | |
| March 2014 distributions paid in Units | 3,675 |
| Adjusted working capital deficit | \$(41,665) |
| Add: | |
| Long term credit facility availability (US\$68.0 million) | \$ 75,174 |
| Capital resources available | \$ 33,509 |

As at March 31, 2014, the Trust had an adjusted working capital deficit of \$41.7 million, which takes into account having incurred \$27.5 million of its annual \$55 million capital budget for 2014. The Trust plans to fund the working capital deficit with the undrawn availability on its US\$160 million long term credit facility.

The Trust monitors capital based on the ratio of external debt to funds flow from operations. This ratio is calculated as external debt, defined as outstanding loans and borrowings, divided by annualized funds flow from operations. The Trust's objective is to maintain an external debt (excluding convertible debentures) to estimated funds flows from operations not to exceed 1.5 to 1.0. This ratio may increase temporarily at certain times as a result of acquisitions and short term requirements. In order to facilitate the management of this ratio, the Trust prepares annual operating and capital expenditure budgets, which are updated as necessary depending on varying factors including current and forecast prices, successful capital deployment and general industry conditions. The annual and updated budgets are approved by the Board of Directors.

Funds Flow from Operations, Premium DRIP Suspension and Distribution Level

During Q1 2014, the Trust generated \$14.9 million of funds flow from operations. The Trust believes that its expected funds flow from operations and the availability under its long term bank credit facility will be sufficient to fund its working capital, its current capital investment program, enable it to meet all current and expected financial requirements and maintain the revised Unitholder distributions, described below.

Subsequent to Q1 2014, the Trust announced the suspension of its Premium DRIP program that has become significantly dilutive to Unitholders due to the decline in Unit price during Q1 2014.

The Premium DRIP program provided significant additional cash flow to the Trust to fund both the distribution and capital program, and as such, the suspension of the Premium DRIP program creates a substantial change in the Trust's financial structure and financing capabilities. As a result, the Trust is reducing its distribution level to \$0.24 per unit per year (\$0.02 per unit per month) beginning in April 2014.

As at the date of this MD&A, the balance drawn on the Trust's credit facility was US\$101.0 million (CAD\$110.2 million).

Potential Divestiture

The Trust is actively reviewing the monetization of a portion of its assets to reduce indebtedness. In keeping with this review, the Trust has engaged an Agent and is in the process of selling a production payment and overriding royalty interest it receives on third party acreage. This production payment and overriding royalty interest is not presently recognized in Argent's current borrowing base, and as such, the sale is not expected to materially impact Argent's borrowing base.

Note: Funds flow from operations is a non-IFRS financial measure. See the Non-IFRS Measures section of this MD&A.

Capital Budget

On April 10, 2014, the Trust announced it has revised its 2014 capital program to US\$55 million (including US\$45 million for drilling and US\$10 million in maintenance) from US\$70 million (including US\$60 million for drilling and US\$10 million in maintenance).

The Trust plans to fund the expenditures through existing cash resources, unused line of credit, future production revenues and additional financing if necessary, including debt, equity or joint venture financing, or disposal of non-core assets. Based on the availability of financing on favorable terms, the Trust may adjust its future capital expenditure plans.

Capital Expenditures

The following table summarizes the capital expenditures on oil & gas properties in Q1 2014 and Q1 2013:

| (\$000s): | Q1 2014 | Q1 2013 |
|---|----------|----------|
| Drilling & Completion | \$23,080 | \$16,096 |
| Minor asset and working interests acquired | 85 | 1,495 |
| Site Preparation for Drilling | 1,025 | 894 |
| Facilities, capital equipment & other | 3,310 | 1,309 |
| Additions to oil and gas properties | \$27,500 | \$19,794 |

During Q1 2014, the Trust incurred capital expenditures of approximately \$27.5 million (excluding \$0.9 million of purchase price adjustments) in the development of its oil & gas properties, focusing on the Eagle Ford drilling program. This represents approximately 50% of the annual capital expenditure budget of US\$55 million, with the majority of the balance of the budget expected to be spent in Q2 2014.

During Q1 2014, the Trust had successfully drilled and completed two Eagle Ford wells (Hayden 1H, Hrcir 5H) and one South Escobas well (Violeta Ranch #7). The Trust also completed drilling and completion operations on two additional Eagle Ford wells (Makers 1H and Makers 3H). Subsequent to Q1 2014, the Trust began early flow back from the completion on these two Makers' Eagle Ford wells. Drilling operations commenced on two new Eagle Ford wells (Haydens 2H and Haydens 3H) and one new South Escobas well (Violeta Ranch #8) which drilling operations were in progress at the end of Q1 2014.

In addition, \$3.3 million was spent on facilities and capital equipment on approximately 32 wells. The Trust also incurred \$0.6 million on office property and equipment and \$31,000 on additions to exploration and evaluation assets.

Distributions

As required by National Policy 41-201, “Income Trusts and Other Indirect Offerings”, the following table outlines the differences between net cash provided by operating activities and cash distributions as well as the differences between net income and cash distributions.

| (\$000) | Q1 2014 | Year Ended December 31, 2013 |
|--|-----------|------------------------------------|
| Net cash provided by operating activities ⁽¹⁾ | \$10,775 | \$65,298 |
| Loss for the period | (\$2,294) | (\$87,228) |
| Actual cash distributions paid or payable ⁽²⁾ | \$4,812 | \$21,367 |
| Excess of net cash provided by operating activities over cash distributions paid | \$5,963 | \$43,931 |
| Shortfall of Loss over cash distributions paid | (\$7,106) | (\$108,595) |

(1) Takes into account changes in non-cash working capital balances

(2) Cash distributions paid or payable exclude distributions reinvested in units pursuant to the Trust’s unitholder distribution reinvestment plan.

For Q1 2014 and the year ended December 31, 2013, net cash provided by operating activities exceeded actual cash distribution by \$6.0 million and \$43.9 million respectively. The adoption of the DRIP in February 2013 has reduced the amount of cash required by the Trust to pay distributions, as new units will be issued in place of cash distribution.

For all periods in the above table, distributions exceeded loss for the period due to non-cash items which are deducted or added in determining loss for the period. Examples of non-cash items include depreciation, depletion and amortization, impairment, exploration and evaluation expenses, and unrealized risk management losses, all of which have no impact on cash available to pay distributions.

This amount of shortfall of actual cash distributions over income (loss) is expected to diminish over the remainder of 2014, as the Trust had reduced its cash distribution beginning April 2014.

Outstanding Unit Data

At the date of this MD&A, the Trust had approximately 63.3 million units outstanding. The outstanding Restricted Trust Units (“RTUs”) and Phantom Unit Rights (“PURs”), including reinvested distribution, were approximately 845,000 and 962,000 respectively.

Transactions with Related Parties

As at March 31, 2014, the Trust had accounts payable of \$655,000 (December 31, 2013 - \$755,000) to Aston Hill Financial Inc. (“Aston Hill”), a company with a common director. The Trust has an Administrative Services Agreement (the “Agreement”) with Aston Hill in which, for the period ended March 31, 2014, the Trust has recorded administration charges of \$500,000 (March 31, 2013 - \$500,000). For the period ended March 31, 2014, the Trust has also recorded \$155,000 (March 31, 2013 - \$379,000) in overhead expenses for costs that have been reimbursed to Aston Hill by the Trust. For the period ended March 31, 2014, the Trust has also recorded a recovery of \$174,000 (March 31, 2013 – expense of \$430,000) in unit based compensation related to RTUs which were issued as a part of the Trust’s RTU plan for services rendered by Aston Hill under the Contract. All expenses paid to Aston Hill are in relation to services performed in accordance with the Agreement.

The Agreement has an initial term of three years from August 10, 2012 and may be automatically renewed for subsequent one year terms unless terminated by either party. The Agreement will provide for the recovery by Aston Hill of its direct costs incurred in providing the services plus an annual overhead allocation (the “Overhead Allocation”) based on the enterprise value of the Trust (such amount being calculated as the market capitalization of the Trust plus its aggregate bank and other interest bearing indebtedness less any cash or cash equivalents).

The Overhead Allocation shall be based on the following:

| Enterprise Value of the Trust | Annual Overhead Allocation Charge |
|--------------------------------------|--|
| Less than \$250 million | \$ 700,000 |
| \$250 million to \$500 million | \$1,200,000 |
| \$500 million to \$1 billion | \$2,000,000 |
| Over \$1 billion | \$4,000,000 |

During the period ended March 31, 2014, the Trust paid US\$6.0 million to satisfy their deferred land payment which was an obligation related to the acquisition of Denali Oil and Gas (“Denali”) which was completed on August 10, 2012. Denali shares a common director and member of key management with the Trust. For the period ended March 31, 2014, The Trust also incurred \$nil (March 31, 2013 - \$116,000) in relation to overriding royalty payments related to the Eagle Ford Shale Deep Rights. As at March 31, 2014, \$nil (December 31, 2013 - \$238,000) of trade and other payables was related to overriding royalty payments to Denali.

All related party transactions are in the normal course of operations and have been measured at the agreed to exchange amounts, which is the amount of consideration established and agreed to by the related parties.

Risk Management

Overview:

The Trust's operations are affected by a number of underlying risks, both internal and external to the Trust. These risks are similar to those affecting conventional oil and natural gas exploration and production companies. The Trust's financial position, results of operations, and cash distributions are directly impacted by these factors.

A full listing of the operational and business risks is set out in the Trust's 2013 Annual Information Form filed on SEDAR at www.sedar.com.

The Trust's activities expose it to a variety of financial risks that arise as a result of its operating, investing, and financing activities such as:

- Credit risk;
- Liquidity risk;
- Market risk; and
- Foreign exchange risk.

This note presents information about the Trust's exposure to each of the above risks, the Trust's objectives, policies and processes for measuring and managing risk, and the Trust's management of capital. Further quantitative disclosures are included throughout the consolidated financial statements.

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

a) Credit Risk:

Credit risk is the potential for financial loss to the Trust if a counterparty in a transaction fails to meet its obligations. The Trust's cash and restricted cash, trade and other receivables and risk management are exposed to credit risk. The Trust monitors its credit risk management policies continuously to evaluate their effectiveness and feels that the credit worthiness of its counterparties is satisfactory at this time.

The Trust's operations are conducted in the United States. Exposure to credit risk is primarily influenced by the individual characteristics of each customer, and is primarily limited to the Trust's product marketer and joint venture partners.

As at March 31, 2014, the Trust's most significant customer is a US oil and natural gas marketer, accounting for approximately 26% of trade receivables at March 31, 2014. This customer accounts for approximately 31% of the Trust's Q1 2014 oil and gas sales.

Receivables from the Trust's product marketers are normally collected in the month following production. The Trust's policy to mitigate credit risk associated with these balances is to establish marketing relationships with reputable purchasers with good credit, and over time, by spreading this risk over as many marketers as is reasonable. The Trust historically has not experienced collection issues with its marketers. The Trust does not typically obtain collateral from its marketers.

Joint venture receivables are with customers in the oil and gas industry and are subject to normal industry credit risks. The Trust attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures prior to the expenditure. In certain circumstances, the Trust may request an operating advance or cash call a partner in advance of capital expenditures being incurred.

The Trust does not anticipate any default as it transacts with creditworthy customers and Management does not expect any losses from non-performance by these customers. As such, no provision for doubtful accounts has been recorded at March 31, 2014.

b) Liquidity Risk:

Liquidity risk is the risk that the Trust will not be able to meet its financial obligations as they fall due. The Trust's approach to managing liquidity is to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Trust's reputation.

Typically the Trust ensures that it has sufficient cash or available credit on the Trust's credit facility to meet expected operational expenses for a period of 120 days, including the servicing of financial obligations; this excludes the potential impact of extreme circumstances that cannot reasonably be predicted. To achieve this objective, the Trust prepares annual operational and capital expenditure budgets which are regularly monitored and updated as considered necessary. The Trust also attempts to match its payment cycle with collection of its oil revenue each month. The Trust also utilizes authorizations for expenditures ("AFEs") on both operated and non-operated projects to manage capital expenditures.

As at March 31, 2014, the Trust had US\$92.0 million (CDN\$101.7 million) outstanding under its credit facility and had an undrawn credit limit of US\$68.0 million (CDN\$75.2 million). The credit facility has a maturity date of August 12, 2015. The borrowing base of the credit facility is subject to semi-annual redetermination by the lenders. The next redetermination date is May 31, 2014. Any change in the borrowing base by the lenders can impact the liquidity position of the Trust.

The following are the contractual maturities of financial liabilities including estimated interest payments at March 31, 2014:

(\$000)

| As at March 31, 2014 | Carrying amount | Contractual cash flows | Less than one year | One - two years | Two - five years | More than five years |
|------------------------------------|------------------------|-------------------------------|---------------------------|------------------------|-------------------------|-----------------------------|
| Financial liabilities: | | | | | | |
| Trade and other payables | \$ 49,310 | \$ 49,310 | \$ 49,310 | \$ - | \$ - | \$ - |
| Risk management liability | 5,619 | 5,619 | 4,845 | 774 | - | - |
| Convertible debentures - principal | 128,893 | 149,250 | - | - | 149,250 | - |
| - interest | 2,305 | 43,763 | 9,270 | 9,270 | 25,223 | - |
| Credit Facility - principal | 100,822 | 100,822 | - | 100,822 | - | - |
| - interest (ii) | 374 | 4,425 | 374 | 4,051 | - | - |
| Deferred land payment | 7,739 | 7,737 | 7,737 | - | - | - |
| | \$ 295,062 | \$ 360,926 | \$ 71,536 | \$ 114,917 | \$ 174,473 | \$ - |
| Decommission liability | 21,811 | 46,760 | 922 | 1,013 | 4,526 | 40,299 |
| Total: | \$ 316,873 | \$ 407,687 | \$ 72,458 | \$ 115,930 | \$ 178,999 | \$ 40,299 |

c) Market Risk:

Market risk is the potential for loss to the Trust from changes in the values of its financial instruments due to changes in commodity prices, interest rates or foreign exchange rates.

The Trust may use both financial derivatives and physical delivery sales contracts to manage market risks. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors.

Commodity Price Risk

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by not only the relationship between the Canadian and United States dollar, but also world economic events that dictate the levels of supply and demand.

The Trust may enter into certain financial derivative instruments periodically to economically hedge some oil and natural gas sales through the use of various financial derivative forward sales contracts and physical sales contracts. The Trust does not apply hedge accounting for these contracts. The Trust's production is usually sold using "spot" or near term contracts, with prices fixed at the time of transfer of custody or on the basis of a monthly average market price. The Trust, however, may give consideration in certain circumstances to the appropriateness of entering into long term, fixed price marketing contracts.

As part of the Trust's strategy to mitigate the impact of fluctuating commodity prices on its funds flow from operations, the Trust had entered in to the following financial contracts at March 31, 2014, with an unrealized loss at that date as shown:

| | Commodity | Volume | Measure | Beginning | Term | Floor US\$ | Ceiling US\$ |
|---|-------------|--------|---------|-----------|-----------------------|--------------------------|--------------|
| Costless collars ⁽ⁱ⁾ | | | | | | | |
| WTI | Oil | 100 | bbl/d | Apr-14 | Aug-14 | 90.00/bbl | 96.40/bbl |
| WTI | Oil | 300 | bbl/d | Apr-14 | Dec-14 | 90.00/bbl | 91.70/bbl |
| WTI | Oil | 200 | bbl/d | Apr-14 | Dec-14 | 90.00/bbl | 94.65/bbl |
| WTI | Oil | 200 | bbl/d | Apr-14 | Jun-14 | 90.00/bbl | 98.50/bbl |
| BRENT | Oil | 200 | bbl/d | Apr-14 | Jun-14 | 100.00/bbl | 107.50/bbl |
| | Commodity | Volume | Measure | Beginning | Term | Fixed US\$ | |
| Fixed contract swaps | | | | | | | |
| WTI ⁽ⁱⁱ⁾ | Oil | 1,000 | bbl/d | Apr-14 | Dec-14 | 92.29/bbl | |
| BRENT ⁽ⁱⁱ⁾ | Oil | 100 | bbl/d | Apr-14 | Dec-14 | 104.50/bbl | |
| LLS ⁽ⁱⁱ⁾ | Oil | 1,000 | bbl/d | Apr-14 | Dec-14 | 99.65/bbl | |
| NYMEX ⁽ⁱⁱⁱ⁾ | Natural gas | 7,000 | MMBtu/d | Apr-14 | Dec-14 | 4.09/MMBtu | |
| BRENT/WTI ^(iv) | Oil | 200 | bbl/d | Apr-14 | Jun-14 | 11.50/bbl | |
| WTI ⁽ⁱⁱ⁾ | Oil | 800 | bbl/d | Jan-15 | Dec-15 | 91.11/bbl | |
| LLS ⁽ⁱⁱ⁾ | Oil | 1,200 | bbl/d | Jan-15 | Dec-15 | 92.63/bbl | |
| NYMEX ⁽ⁱⁱⁱ⁾ | Natural gas | 6,000 | MMBtu/d | Jan-15 | Dec-15 | 4.12/MMBTU | |
| NYMEX ⁽ⁱⁱⁱ⁾ | Natural gas | 4,000 | MMBtu/d | Jan-16 | Dec-16 | 4.06/MMBTU | |
| | Commodity | Volume | Measure | Beginning | Term | Fixed US\$ | |
| Sold (wrote) call options ^(v) | | | | | | | |
| WTI Call | Oil | 200 | bbl/d | Jan-15 | Dec-15 | 95.60/bbl | |
| WTI Call | Oil | 600 | bbl/d | Jan-16 | Dec-16 | 91.40/bbl | |
| WTI Call | Oil | 200 | bbl/d | Jan-16 | Dec-16 | 90.25/bbl | |
| | | | | | March 31, 2014 | December 31, 2013 | |
| Total liability for unrealized loss on risk management | | | | | \$ (5,593) | \$ (2,315) | |

- (i) Represents costless collar transactions created by buying puts and selling calls (WTI or BRENT reference prices).
- (ii) Represents fixed price financial swap transactions with a set forward sale oil reference prices that are based on West Texas Intermediary ("WTI"), Brent or Louisiana Light Sweet ("LLS") oil.
- (iii) Represents fixed price financial swap transactions based on the NYMEX natural gas forward sale reference price.
- (iv) Represents a fixed price financial swap transaction with a set forward sale price based on spreads between BRENT and WTI reference prices.
- (v) Represents the selling of call options, giving the counter party the right (but not obligation) on the December 31 of the year preceding the contract terms to enter into fixed price financial swap transactions with a set forward sales reference price.

The total fair value of the Trust's unrealized risk management positions at March 31, 2014, was a net liability of \$5.6 million and has been calculated using both quoted prices in active markets and observable market-corroborated data. During the quarter ended March 31, 2014, the Trust recorded a loss of \$5.2 million on its risk management positions.

A \$1 per bbl increase in the forward strip price of oil would have resulted in a decrease of net income due to a change in unrealized risk management loss of approximately \$1.3 million as a result of the change in fair value of the Trust's risk management position at March 31, 2014. A \$0.25 per mcf increase in the

forward strip price of natural gas would have resulted in a decrease of net income due to a change in unrealized risk management loss of approximately \$1.4 million.

Securities Price Risk

The Trust's convertible debentures are subject to securities price risk as they are traded on a public exchange.

As at March 31, 2014, had the securities price of the convertible debentures increased or decreased by 1%, net income would have decreased or increased by approximately \$1.3 million due to a change in the fair value of the convertible debentures.

Foreign Exchange Risk

Foreign exchange risk is the risk that future cash flows will fluctuate as a result of changes in market foreign exchange rates. The Trust's operating cash flows are generated in US dollars and distributions are declared in Canadian dollars. As a consequence, there is an element of foreign exchange risk to the Trust. The Trust's treasury management function is responsible for managing funding requirements and investments, which include banking and cash flow management. Prices for oil are determined in global markets and generally denominated in US dollars. The exchange rate effect cannot be quantified but generally an increase in the value of the Cdn\$ as compared to the US\$ will reduce the prices received by the Trust for its petroleum and natural gas sales but will also reduce the operating expenses associated with those sales.

The Trust has entered into a number of Cdn/US\$ forward swap contracts on US\$1.0 million per month from April to June 2014 at an average rate of US \$1.00 = Cdn \$1.0492 and from July to December 2014 at an average rate of US\$1.00 = Cdn \$1.1123.

The average exchange rate for the period ended March 31, 2014 was US \$1 equal to \$1.1036 (March 31, 2013 – US \$1 equal to \$1.0083). A \$0.01 increase (decrease) in the value of CDN\$ versus US\$ on March 31, 2014 would have decreased (increased) profit or loss by approximately \$2.3 million (March 31, 2013 - \$2.5 million) due to the unrealized foreign exchange loss (gain) from the Trust's inter-company loan to its US subsidiary of approximately US\$226 million. Under IFRS, this inter-company loan is not part of the net investment in the subsidiary and any period end foreign exchange translation adjustment is required to be recorded in income or loss. This analysis assumes that all other variables, in particular interest rates, remain constant.

Critical accounting estimates and judgments

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates. Such estimates and assumptions are based on historical experience and various other factors that are believed to be reasonable in the circumstances and constitute Management's best judgment at the date of the financial statements. In the future, actual experience may deviate from these estimates and assumptions.

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

The significant areas of estimation uncertainty in applying accounting policies that have the most significant effect on the amounts recognized in the financial statements are summarized as follows:

Estimation of oil and gas reserves

Oil and gas reserves are the estimated quantities of oil and gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Estimates of oil and gas reserves are inherently imprecise, require the application of judgment and are subject to future revision. Accordingly, financial and accounting measures (such as the impairment calculation, depletion charges, and decommissioning provisions) that are based on reserves are also subject to change.

Capitalized exploration and evaluation expenditures

In making decisions about whether to continue to capitalize exploration and evaluation expenditures, it is necessary to make judgments about the commercial reserves and the level of activities that constitute ongoing evaluation determination. If there is a change in any judgment in a subsequent period, then the related capitalized exploration and evaluation expenditure would be expensed in that period, resulting in a charge to income.

Impairment indicators

Cash-generating units ("CGUs") are reviewed for impairment at each reporting date or more frequently if changes in circumstances indicate that the carrying value may be impaired. The values associated with CGUs involve significant estimates and assumptions, including those with respect to future cash inflows and outflows, reserve estimates, discount rates, and asset lives.

Classification of Trust units as equity

Trust units issued by the Trust give the holder the right to put the units back to the issuer in exchange for cash. IAS32 "Financial Instruments: Presentation" establishes the general principle that an instrument which gives the holder the right to put the instrument back to the issuer for cash should be classified as a financial liability, unless such instrument has all of the features and meets the conditions of the IAS 32 "puttable instrument exemption". If these "puttable instrument exemption" criteria are met, the instrument is classified as equity. The Trust has examined the terms and conditions of its Trust Indenture and classifies its outstanding Trust units as equity because the Trust units meet the "puttable instrument exemption" criteria as there is no contractual obligation to distribute cash.

The significant areas of critical judgment in applying accounting policies that have the most significant effect on the amounts recognized in the financial statements are summarized as follows:

Measurement of unit based compensation

The cost of services received in exchange for awards of equity instruments recognized is estimated using fair value methods as determined by management which require the use of assumptions.

Acquisition and business combinations

The Trust has made significant estimates and assumptions in determining the fair value of assets and liabilities acquired through business combination. These estimates require judgment to assess the fair value of assets and liabilities acquired.

New standards and interpretations adopted in 2013:

The following standards and amendments have been adopted as of January 1, 2014. No restatement of financial statement line items was required as a result of the adoption of the following policies.

IFRIC 21 – Levies

International Financial Reporting Interpretation Committee (“IFRIC”) 21 Levies (“IFRIC 21”) clarified that an entity recognizes a liability for a levy when the activity that triggers payment occurs. For a levy that is triggered upon reaching a minimum threshold, the interpretation clarified that no liability should be anticipated before the minimum threshold is reached. The effect of the retrospective application of this policy was a \$1.7 million revision in net income for the period ended March 31, 2013 due to the ad valorem taxes for the full 2013 fiscal year being required to be accrued in the first quarter results under IFRIC 21 instead of being accrued on a quarterly basis under the Trust’s previous policy. The retrospective application of the policy had no effect on the comparative balance sheets of December 31, 2013 and January 1, 2013.

Internal Controls Over Financial Reporting

During Q1 2014, there was no change in the Trust’s internal controls over financial reporting (“ICFR”) that has materially affected, or is reasonably likely to materially affect, the Trust’s internal controls over financial reporting. It should be noted, that the Trust’s control system, no matter how well designed, can provide only reasonable, but not absolute assurance of detecting, preventing and deterring errors or fraud.

Non-IFRS Measures

The following table reconciles the non-IFRS financial measures “funds flow from operations” and “netbacks” to “net cash from operating activities”, the most directly comparable measure in the Trust’s consolidated financial statements:

| (\$000s): | Q1 2014 | Q1 2013 |
|---|----------|----------|
| Net cash provided by operating activities | \$10,775 | \$16,255 |
| - Changes in non-cash working capital | 4,091 | (2,641) |
| Funds flow from operations | \$14,866 | \$13,614 |
| Add back (subtract) items not directly related to operations: | | |
| - Realized risk management loss | 1,998 | 191 |
| - General and administrative expenses | 4,918 | 467 |
| - Ad valorem and property taxes | 3,605 | 2,240 |
| - Realized foreign exchange (gain) loss | (198) | 3,026 |
| - Property costs and others | 136 | 170 |
| - Income tax expense (recovery) | (233) | 27 |
| Total Netbacks | \$25,092 | \$19,735 |

Note about forward-looking statements

Certain of the statements made and information contained in this MD&A are forward-looking statements and forward looking information (collectively referred to as “forward-looking statements”) within the meaning of Canadian securities laws. All statements other than statements of historic fact are forward-looking statements. The Trust cautions investors that important factors could cause the Trust’s actual results to differ materially from those projected, or set out, in any forward-looking statements included in this MD&A.

In particular, and without limitation, this MD&A contains forward looking statements pertaining to the following:

- Argent’s capital budget and drilling and tie in plans;
- the Trust's expectation regarding its average working interest production for 2014;
- commodity prices and exchange rates; and
- management’s objective to maintain a debt to funds flow from operations ratio below 1.5 times.

With respect to forward-looking statements contained in this MD&A, assumptions have been made regarding, among other things:

- future oil and natural gas commodity prices;
- future currency exchange and interest rates;
- the regulatory framework governing taxes in the US and Canada and the Trust’s status as a “mutual fund trust” and not a “SIFT trust;”

- estimates of anticipated production from its oil & gas assets, which estimates are based on the proposed drilling program with a success rate that, in turn, is based upon historical drilling success and an evaluation of the particular wells to be drilled;
- future recoverability of reserves for its oil & gas assets;
- future capital expenditures and the ability of the Trust to obtain financing on acceptable terms for its capital projects and future acquisitions;
- the Trust's capital budget, which is subject to change in light of ongoing results, prevailing economic circumstances, commodity prices and industry conditions and regulations;
- not including capital required to pursue future acquisitions in the forecasted capital expenditures;
- the ability of the Trust to compete for new acquisitions; and
- the borrowing base of the Trust's credit facility, which is subject to redetermination by its lenders.

The Trust's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and included in the Trust's prospectus for the IPO:

- volatility of commodity prices;
- commodity supply and demand;
- fluctuations in currency and interest rates;
- inherent risks and changes in costs associated in the drilling and development of petroleum properties;
- unexpected operational delays and challenges
- access to drilling equipment on a timely basis and at reasonable prices;
- ultimate recoverability of reserves;
- timing, results and costs of drilling activities and resulting production;
- availability of financing and capital; and
- new regulations and legislation that apply to the Trust and the operations of its subsidiaries.

Additional risks and uncertainties affecting the Trust are contained in the Trust's prospectus for the IPO under the heading "Risk Factors".

The success of Argent's drilling program is a key assumption in the production estimates for the 2014 financial year. The primary risk factors which could lead to Argent not meeting its production targets are: (i) production additions from drilling activity are less than expected; (ii) a lack of access to drilling rigs and related equipment on a timely basis and at reasonable prices due to high industry demand or poor weather; and (iii) unexpected operational delays and challenges. Increases in capital costs from forecast amounts can result from the foregoing reasons as well as general cost inflation in the industry.

Additionally, Argent may choose to decrease capital expenditures from those anticipated in its budget projections, therefore affecting production estimates for the 2014 financial year. There are many factors that could result in production levels being less than anticipated, including greater than anticipated declines in existing production due to poor reservoir performance, the unanticipated encroachment of water or other

fluids into the producing formation, mechanical failures or human error or inability to access production facilities, among other factors.

As a result of these risks, actual performance and financial results in 2014 may differ materially from any projections of future performance or results expressed or implied by these forward looking statements. New factors emerge from time to time, and it is not possible for management to predict all of these factors or to assess, in advance, the impact of each such factor on the Trust's business, or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward looking statement. Undue reliance should not be placed on forward-looking statements, which are inherently uncertain, are based on estimates and assumptions, and are subject to known and unknown risks and uncertainties (both general and specific) that contribute to the possibility that the future events or circumstances contemplated by the forward looking statements will not occur. Although Management believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date the forward-looking statements were made, there can be no assurance that the plans, intentions or expectations upon which forward-looking statements are based will in fact be realized. Actual results will differ, and the difference may be material and adverse to the Trust and its Unitholders. The Trust does not undertake any obligation, except as required by applicable securities legislation, to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise.

Note regarding barrel of oil equivalency

This MD&A contains disclosure expressed as "boe" or "boe/d". All oil and natural gas equivalency volumes have been derived using the conversion ratio of six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of oil. Equivalency measures may be misleading, particularly if used in isolation. A conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head. In addition, given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalent of six to one, utilizing a boe conversion ratio of 6 Mcf: 1 bbl would be misleading as an indication of value.