STORM RESOURCES

Q1 2016 REPORT

Highlights

Thousands of Cdn$, except volumetric and per-share amounts	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015
FINANCIAL		
Revenue from product sales(1)	16,121	18,512
Funds from operations(2)	7,855	13,712
Per share - basic ($)	0.07	0.12
Per share - diluted ($)	0.07	0.12
Net loss	(4,984)	(3,565)
Per share - basic ($)	(0.04)	(0.03)
Per share - diluted ($)	(0.04)	(0.03)
Net capital invested		
Operations capital expenditures	23,946	35,680
Debt including working capital deficiency(3)	77,162	85,098
Common shares (000s)		
Weighted average - basic	119,591	111,322
Weighted average - diluted	119,591	111,322
Outstanding end of period – basic	119,742	111,322
OPERATIONS		
(Cdn$ per Boe)		
Revenue	13.20	21.04
Royalties	(0.76)	(0.54)
Production	(6.71)	(8.67)
Transportation	(0.53)	(1.68)
Field operating netback	5.20	10.15
Hedging gains	3.03	8.36
General and administrative	(1.25)	(2.24)
Interest and finance costs	(0.56)	(0.70)
Funds from operations – per Boe	6.42	15.57
Barrels of oil equivalent per day (6:1)	13,418	9,776
Gas Production		
Thousand cubic feet per day	66,012	47,713
Price (Cdn$ per Mcf)	1.62	2.85
NGL production		
Barrels per day	2,416	1,493
Price (Cdn$ per barrel)	29.12	37.10
Oil Production		
Barrels per day	-	330
Price (Cdn$ per barrel)	-	43.08
Wells drilled (100% working interest)	7.0	6.0
Wells completed (100% working interest)	2.0	3.0

(1) Excludes hedging gains and losses.
(2) Certain financial amounts shown above are non-GAAP measurements, including funds from operations and funds from operations per share, operations capital expenditures, debt including working capital deficiency and all measurements per Boe. See discussion of Non-GAAP Measurements on page 24 of the attached Management's Discussion and Analysis ("MD&A") and the reconciliation of funds from operations to the most directly comparable measurement under GAAP, cash flows from operating activities, on page 17 of the attached MD&A.
(3) Excludes the fair value of commodity price contracts.

PRESIDENT'S MESSAGE

2016 FIRST QUARTER HIGHLIGHTS

- Production averaged 13,418 Boe per day (18% NGL), a per-share increase of 25% from the previous quarter and 27% from the previous year. Low natural gas prices resulted in production being reduced to meet firm processing and transportation commitments with approximately 800 Boe per day shut in at Umbach plus the startup of new horizontal wells was delayed.

- NGL production was 2,416 barrels per day, an increase of 62% from the previous year. The price was $29.12 per barrel which was 71% of the average Edmonton light oil price (60% of the NGL volume was higher value condensate and plant pentanes).

- NGL was 18% of total production but amounted to 40% of revenue from product sales versus 27% in the prior year period.

- Activity was focused at Umbach where seven horizontal wells were drilled, two horizontal wells were completed and one horizontal well commenced production.

- At the end of the quarter, there was an inventory of 12 horizontal wells (12.0 net) that had not started producing (includes three completed wells).

- Montney horizontal well performance at Umbach continues to improve with the four most recent wells averaging 5.8 Mmcf per day gross raw gas over the first 90 calendar days, a 23% increase from the average 2014 and 2015 wells. As a result, the type curve used for forecasting future horizontal well performance is being increased to 7.0 Bcf raw from 6.3 Bcf raw.

- Controllable cash costs (operating, cash G&A, interest expense) were $8.52 per Boe, a year-over-year decrease of 27%. Transportation cost is excluded given that the sales price for volumes sold on the Alliance Pipeline includes a deduction for the pipeline tariff (artificially reduces the transportation cost).

- Funds from operations was $7.9 million which is a decrease of 42% from the previous year. Production growth of 37% was more than offset by a 45% decrease in revenue plus hedging gains per Boe.

- With 67% of first quarter natural gas production being sold in the higher priced Chicago market, the natural gas price net of transportation was approximately 9% higher versus selling at BC Station 2.

- Net loss was $5.0 million or $4.09 per Boe and reflects the extremely low first quarter commodity prices with funds from operations at $6.42 per Boe being less than the depletion and depreciation rate of $8.15 per Boe.

- Net capital investment was $23.9 million and included $15.9 million for drilling and completions plus $6.1 million to purchase major equipment for the third field compression facility at Umbach.

- Debt including working capital deficiency was $77.2 million, which is 2.4 times annualized first quarter funds flow. Subsequent to quarter end, the bank credit facility was set at $130.0 million after the annual review was completed (previously $140.0 million).

OPERATIONS REVIEW

Umbach, Northeast British Columbia

Storm's land position at Umbach is prospective for liquids-rich natural gas from the Montney formation and currently totals 109,000 net acres (155 net sections). Two sections (2.0 net) were acquired during the first quarter of 2016. To date, 48 horizontal wells have been drilled (44.4 net) with 36 horizontal wells producing at the end of the first quarter (32.4 net).

First quarter 2016 production was 13,398 Boe per day with NGL recovery at 37 barrels per Mmcf sales (60% of the NGL volume is higher priced field condensate plus pentanes recovered at the gas plant).

In the first quarter of 2016, seven horizontal wells (7.0 net) were drilled, two wells (2.0 net) were completed, and one well (1.0 net) started production. There is currently an inventory of 12 horizontal wells (12.0 net) that have not started producing which includes three completed wells.

Storm's two operated field compression facilities have total capacity of 80 Mmcf per day raw gas with actual throughput in the first quarter averaging 70 Mmcf per day raw gas. As a result of the low natural gas price at AECO and BC Station 2, construction of the third field compression facility with initial capacity of 35 Mmcf per day is being deferred with startup now planned for April 2017 (was November 2016). Estimated total cost is unchanged at $25.0 million (expandable to 70 Mmcf per day raw gas for an additional $7.0 million) with $10.9 million invested to date for site preparation and to purchase major equipment ($6.1 million Q1 2016, $4.8 million 2015).

Raw gas from Storm's field compression facilities is sent to the McMahon and Stoddart Gas Plants where Storm has firm processing commitments totaling 65 Mmcf per day raw gas in 2016.

A summary of horizontal well performance and costs is provided below. The four most recent horizontal wells have averaged 5.8 Mmcf per day gross raw gas over the first 90 calendar days, a 23% improvement from the average 2014 and 2015 horizontal well. On a per-stage basis, the drill and complete cost in 2015 has decreased by 17% from 2014.

Year of Completion	Frac Stages	Completed Length	Actual Drill & Complete Cost	IP 90 Cal Day Mmcf/d Raw	IP 180 Cal Day Mmcf/d Raw	IP 365 Cal Day Mmcf/d Raw
2013 6 wells	17	1,190 m	$4.6 million $270 K/stage	3.5 Mmcf/d 6 hz's	2.9 Mmcf/d 6 hz's	2.2 Mmcf/d 6 hz's
2014 13 wells	19	1,170 m	$4.6 million $240 K/stage	4.6 Mmcf/d 13 hz's	4.2 Mmcf/d 13 hz's	3.3 Mmcf/d 13 hz's
2015 11 wells	22	1,360 m	$4.4 million $200 K/stage	4.8 Mmcf/d 10 hz's	3.5 Mmcf/d* 6 hz's	
Q4/15 (62-A pad) 5 wells	23	1,435 m	$4.3 million $190 K/stage	5.8 Mmcf/d 4 hz's		

* Performance to date of the 2015 wells was reduced by the downtime experienced in the second half of 2015.

Based on the performance of the most recent horizontal wells completed in Q4/15, which are longer and have more frac stages, Storm management is increasing the type curve used for forecasting performance of future horizontal wells to 7.0 Bcf raw from 6.3 Bcf raw (type curve has the same decline profile as the type curve used by InSite in the 2015 reserve evaluation). Future horizontal wells are being planned for greater than 1,600 metres of completed length with more than 28 frac stages. For reference, the previous 6.3 Bcf type curve was based on performance of the average 2014 and 2015 wells which have a completed length of 1,265 metres and an average of 21 frac stages. More information on the type curve and well economics is provided in the presentation on Storm's website.

Horn River Basin, Northeast British Columbia

Storm has a 100% working interest in 119 sections in the Horn River Basin (78,000 net acres) which are prospective for natural gas from the Muskwa, Otter Park and Evie/Klua shales. Storm's one horizontal well, producing 280 Boe per day, was shut in during July 2015 due to the low natural gas price at BC Station 2.

HEDGING AND TRANSPORTATION

Commodity price hedges are used to support longer term growth by providing some certainty regarding future revenue and funds flow. A maximum of 50% of the most recent monthly production will be hedged; anticipated production growth is not hedged. Although Storm has no oil production, the WTI price is hedged as approximately 80% of NGL production is priced in reference to WTI (condensate, plant pentane and butane). A summary for 2016 is provided below.

	Volume	Price
Crude Oil	500 Bopd	Collar - WTI Cdn$75.00 X Cdn$90.75/Bbl
Natural Gas	21,250 GJ/d (17,000 Mcf/d)	AECO Cdn$2.98/GJ ($3.72/Mcf)
	11,000 GJ/d (8,800 Mcf/d)	BC Stn 2 price = AECO – Cdn$0.3375/GJ
	33,000 Mmbtu/d (27,800 Mcf/d)	Chicago price = AECO + US$0.672/Mmbtu

Storm's strategy with respect to natural gas transportation commitments is to ensure natural gas sales are diversified by selling at Chicago, AECO and BC Station 2. Current transportation commitments total 63 Mmcf per day in 2016 and increase to 92 Mmcf per day in 2018 (interruptible capacity on the Alliance Pipeline adds up to 11 Mmcf per day in 2016 and 13 Mmcf per day in 2018). A summary is provided below.

2016	2017	2018
44 Mmcf/d (55,000 GJ/d)(1) sale at McMahon (Alliance Pipeline) Chicago price - Cdn$1.30/GJ(2)	48 Mmcf/d (61,000 GJ/d)(1) sale at McMahon (Alliance Pipeline) Chicago price - Cdn$1.30/GJ(2)	53 Mmcf/d (67,000 GJ/d)(1) sale at McMahon (Alliance Pipeline) Chicago price - Cdn$1.30/GJ(2)
9.0 Mmcf/d (11,400 GJ/d) sale at BC Stn 2 -Cdn$0.15/GJ pipeline tariff	24.0 Mmcf/d (30,200 GJ/d) sale at BC Stn 2 -Cdn$0.15/GJ pipeline tariff	29.0 Mmcf/d (36,500 GJ/d) sale at BC Stn 2 -Cdn$0.15/GJ pipeline tariff
9.8 Mmcf/d (12,400 GJ/d) sale at McMahon AECO - Cdn$0.68/GJ differential		10.0 Mmcf/d (12,600 GJ/d) sale at AECO -Cdn$0.43/GJ pipeline tariffs

(1) Interruptible capacity on the Alliance Pipeline adds up to 25% of contracted capacity.
(2) The Alliance Pipeline tariff of $1.30 per GJ is determined assuming US$1 = Cdn$1.29, Chicago US$2.20 per Mmbtu and 5.25% shrinkage for fuel gas (fuel gas shrinkage adds $$0.14 per GJ).

OUTLOOK

Production in the second quarter is forecast to be approximately 12,500 Boe per day and, until the natural gas price improves, production will be maintained at this level which fulfills firm processing and transportation commitments. Capital investment in the second quarter is expected to be under $2.0 million.

Natural gas prices remain weak with April daily spot prices averaging US$1.92 per Mmbtu at Chicago and $1.04 per GJ at AECO. Forward strip pricing for natural gas for the remainder of 2016 is not materially different from pricing realized in the first quarter where the operating netback excluding hedging gains was $5.20 per Boe. This is less than the cost of adding reserves (the 2015 all-in PDP FD&A cost was $6.53 per Boe) and, as a result, producing more than what's required to fulfill firm processing and transportation commitments is not economically justifiable. As a result, capital investment in 2016 will be reduced to between $37.0 and $42.0 million with the startup of the third facility at Umbach deferred to April 2017 when the forward strip is supportive of production growth. With the benefit of commodity price hedges and with the majority of natural gas production being sold in Chicago at a higher price than at BC Station 2, forecast funds flow in 2016 is expected to provide most of the capital required to maintain production at current levels. Revised guidance is provided below with assumed commodity prices being approximately equal to realized prices to date and the current forward strip.

2016 Guidance	**Original Guidance Nov 11, 2015**	**Revised Feb 25, 2016**	**Revised May 12, 2016**
Chicago natural gas price		US$2.20 per Mmbtu	US$2.20 per Mmbtu
AECO natural gas price	$2.50 per GJ	$2.00 per GJ	$1.60 per GJ
BC STN 2 natural gas price	$1.90 per GJ	$1.45 per GJ	$1.25 per GJ
Edmonton light oil price	Cdn$57 per Bbl	Cdn$46 per Bbl	Cdn$50 per Bbl
Estimated average operating costs	$7.00 - $7.50 per Boe	$7.00 per Boe	$7.00 per Boe
Estimated average royalty rate (% production revenue before hedging)	7% - 8%	5% - 6%	5% - 6%
Estimated operations capital (excluding acquisitions & dispositions)	$105.0 million	$80.0 million	$37.0 - $42.0 million
Estimated cash G&A net of recoveries	$5.0 million $0.80 per Boe	$5.0 million $0.95 per Boe	$5.7 million $1.20 per Boe
Estimated funds flow		$39.0 million	$31.0 million
Forecast fourth quarter production	20,000 – 21,000 Boe/d (17% NGL)	15,500 – 16,500 Boe/d (18% NGL)	13,000 – 14,000 Boe/d (18% NGL)
Forecast annual production	16,000 – 18,000 Boe/d (17% oil + NGL)	14,000 – 15,000 Boe/d (18% oil + NGL)	12,500 – 13,500 Boe/d (18% oil + NGL)
Umbach horizontal wells drilled	14 gross (14.0 net)	12 gross (12.0 net)	8 gross (8.0 net)
Umbach horizontal wells completed	14 gross (14.0 net)	10 gross (10.0 net)	6 gross (6.0 net)
Umbach horizontal wells connected	16 gross (16.0 net)	12 gross (12.0 net)	8 gross (8.0 net)

With respect to the revised guidance, estimated cash G&A net of recoveries for 2016 has increased as a result of lower overhead recoveries associated with lower capital investment (no change to gross G&A excluding overhead recoveries). As well, capital investment in 2016 includes $6.1 million incurred in the first quarter to purchase major equipment for the third field compression facility.

The AECO - BC Station 2 price differential was -$0.41 per GJ in the first quarter, an improvement from -$0.85 per GJ in 2015 and closer to historical levels (-$0.20 per GJ for 2010 to 2014). Although the low AECO price in the first quarter ($1.74 per GJ) has more than offset the improvement, having the differential return to historical levels is supportive of Storm's future production growth given that incremental production would be sold at BC Station 2.

Reducing cash costs and improving capital efficiency has always been a focus at the current and predecessor 'Storm' companies. Further improvements are expected in 2016 with the largest being the transition to drilling longer horizontal wells with more frac stages which is expected to result in a reduction of the cost to add reserves. Cash costs are also expected to decrease by reducing third party processing fees and through initiatives to reduce field level operating expenses.

Further weakening of natural gas prices in North America over the last three months is the result of reduced demand from a warmer than normal winter combined with continued growth in natural gas production. At current pricing, the business is 'broken' for natural gas producers in Western Canada as funds flow excluding hedges fails to generate sufficient capital to offset declines; as well, rates of return are too low to justify growing production on a full-cycle basis (including the cost of expanding infrastructure). Pricing will improve once the oversupply of natural gas is reduced through natural declines and shut-ins. Not knowing when the natural gas price will improve, Storm's primary objective in 2016 is to maintain a strong balance sheet by ensuring capital investment is approximately equal to funds flow and thus avoid increasing debt. This will preserve the ability to accelerate growth when the price does improve.

Although Storm is reducing capital investment in 2016 as a result of deterioration in the price of natural gas, annual average production in 2016 is still forecast to increase by 30% on a year-over-year basis.

Storm's land position in the Horn River Basin continues to be a core, long-term asset with significant leverage to higher natural gas prices.

Respectfully,

B. Lavergne

Brian Lavergne,
President and Chief Executive Officer

May 12, 2016

Boe Presentation – For the purpose of calculating unit revenues and costs, natural gas is converted to a barrel of oil equivalent ("Boe") using six thousand cubic feet ("Mcf") of natural gas equal to one barrel of oil unless otherwise stated. Boe may be misleading, particularly if used in isolation. A Boe conversion ratio of six Mcf to one barrel ("Bbl") is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All Boe measurements and conversions in this report are derived by converting natural gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil. Mboe means 1,000 Boe.

Forward-Looking Statements – Such statements made in this report are subject to the limitations set out in Storm's Management's Discussion and Analysis dated May 12, 2016 for the three months ended March 31, 2016.

MANAGEMENT'S DISCUSSION & ANALYSIS

INTRODUCTION

Set out below is management's discussion and analysis ("MD&A") of financial and operating results for Storm Resources Ltd. ("Storm" or the "Company") for the three months ended March 31, 2016. It should be read in conjunction with (i) the Company's unaudited condensed interim consolidated financial statements for the three months ended March 31, 2016, (ii) the Company's audited consolidated financial statements for the year ended December 31, 2015, and (iii) the press release issued by the Company on May 12, 2016, and other operating and financial information included in this report. All of these documents as well as the Company's Annual Information Form dated March 31, 2016 are filed on SEDAR (www.sedar.com) and appear on the Company's website (www.stormresourcesltd.com).

The Company trades on the TSX Venture Exchange under the symbol "SRX".

This MD&A is dated May 12, 2016.

See "Forward Looking Statements", "Boe Presentation", and "Non-GAAP Measurements" beginning on page 23.

BASIS OF PRESENTATION

Financial data presented below have largely been derived from the Company's unaudited condensed interim consolidated financial statements (the "financial statements") for the three months ended March 31, 2016, prepared in accordance with International Financial Reporting Standards ("IFRS"). Accounting policies adopted by the Company are referred to in Note 3 to the audited consolidated financial statements for the year ended December 31, 2015. The reporting and the measurement currency is the Canadian dollar.

Unless otherwise indicated, tabular financial amounts, other than per-share amounts, are in thousands. Comparative information is provided for the immediately prior three month period ended December 31, 2015 and for the three month period ended March 31, 2015.

OPERATIONAL AND FINANCIAL RESULTS

Overview

The pricing rout of 2015 continued throughout the first quarter of 2016 and beyond. Earlier hopes for a seasonal increase in natural gas prices were not realized due to unusually mild weather in most key markets. In addition, supply stubbornly continued to increase in the United States, although recent weeks have seen indications of a possible rollover. Steps taken by Storm to broaden the market for its natural gas and reduce its exposure to the Station 2 pricing volatility, which prevailed in 2015, were not rewarded with increased revenue as the pricing malaise became continent wide. The Company's realized price for the first quarter was $1.62 per Mcf, the lowest price since the Company began business in 2010. Using the AECO Monthly Index as a benchmark, first quarter 2016 average price was the lowest since the second quarter of 1997. This comparison is not inflation adjusted; furthermore, this two decade period saw a considerable increase in supply costs. Gas production from the Western Canadian Sedimentary Basin has begun and will continue to fall in response to the price collapse; further evidenced by lower rig counts. Also much of the increase in recent production has come from new wells completed using hydraulic fracturing; wells so completed are subject to high initial declines. Additionally, production from wells which are operating at sub-economic levels has in many situations been shut in. Many producers will be unable to replace falling production due to lack of capital. Cash flows for reinvestment have collapsed; equity is available only to very few producers; and borrowing base loans are being reduced as the value of bank security falls. One issue facing Canadian producers is whether falling supply will encourage a pricing response; or whether reduced production will, in whole or in part, be satisfied by increased deliveries from the United States. However, US producers face the same economic pressures as their Canadian counterparts.

In the first quarter of 2016 Storm's Boe per day production grew by 37% year over year and by 25% when compared to the immediately prior quarter. The growth in production was required to meet transportation and processing commitments which became effective late in the final quarter of 2015 and resulted in production being priced in three markets: AECO, Station 2 and Chicago. Storm's production is currently 12,800 Boe per day, which corresponds to contractual obligations. Productive capacity is about 1,500 to 2,500 Boe per day higher; however, production will remain at the lower level absent any pricing improvement. Increasing production beyond 14,500 to 15,000 Boe per day requires the installation of additional compression capacity. The Company has secured key components but will not commission additional capacity unless pricing improves. The additional compressor station will result in additional capacity of 35,000 Mcf per day and this capacity can be twinned for less than $8 million.

Field netback and funds from operations per Boe for the quarter amounted to $5.20 and $6.42 respectively. Realized hedging gains amounted to 47% of funds from operations per Boe. In addition, the high NGL content of the Company's gas stream, which includes a high percentage of WTI-priced condensate, also contributed to financial results, which, although shockingly bad on the revenue line, should compare favourably to most peer companies in terms of funds flow per Boe. Almost all per-unit costs fell year over year and quarter over quarter and field operations in the quarter proceeded satisfactorily. However, it should be recognized that netback measurements do not reflect the wellhead cost of supply. The best proxy for such a number would be the most recent measurement of the finding cost for proved producing reserves, which for Storm amounted to $6.53 per Boe in 2015. Thus a cash flow netback less than this amount means the Company is losing money and growing production in such a pricing environment means that it would lose even more.

Capital expenditures for the first quarter of 2016 totalled $23.9 million and included the drilling of seven wells for a total amount of $11.9 million. Although the number of wells drilled is ahead of production requirements, six wells were drilled on two multi-well pads, where the economics of pad drilling require that all of the wells on a multi-well pad be drilled as part of one program, with this program beginning in the final quarter of 2015. During the quarter, two wells were completed and tied in. One other completed well began production. At quarter end the Company had an inventory of 12 wells drilled: of this number, nine wells await completion and three wells were completed and tied in but were not producing. Wells will be brought on to production to maintain capacity at a level required to meet contractual commitments. The Company does not expect to drill any additional wells in 2016 as the existing well inventory, in the absence of any unexpected mechanical or formation difficulties, is sufficient to satisfy production requirements for the remainder of 2016 and into 2017. Additionally, the number of fracs required to complete wells in inventory will be increased; it has been the Company's experience that additional fracs result in a near-linear improvement in well productivity, such that future completions may result in new wells exceeding type curve. Other capital expenditures in the quarter included $6.1 million spent on equipment relating to future compression requirements. Capital expenditures in the first quarter were about 3.0 times cash flow for the quarter; however, this outlay represented well over 50% of the total capital budget for 2016. Capital outlays for future quarters should be closer to or less than cash flow.

Subsequent to the quarter end, the Company's bank line was reduced by $10 million to $130 million, a reduction of 7%. The bank line is largely based on the banking syndicate's assessment of the security value of the Company's proved producing reserves. Although proved producing reserves grew by 54% year over year, growth in reserves was not sufficient to offset the effect of lower commodity prices. The Company believes that the line reduction is likely to be modest in comparison to other producers with similar banking arrangements and it will have no effect on the Company's capital or operating programs. No additional covenants were required and the interest rate structure is unchanged.

Production and Revenue

Production by Area

The Company reported production from the following areas:

	Three Months Ended March 31, 2016			
Producing Area	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Crude Oil (Bbls/d)(1)	Boe/d
Umbach – NE BC	65,894	2,416	-	13,398
Horn River Basin – NE BC(2)	-	-	-	-
Grande Prairie – AB	118	-	-	20
Total	66,012	2,416	-	13,418

(1) Crude oil production was sold early third quarter of 2015.
(2) Production shut in due to pricing.

	Three Months Ended March 31, 2015			
Producing Area	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Crude Oil (Bbls/d)	Boe/d
Umbach – NE BC	42,888	1,431	-	8,579
Horn River Basin – NE BC	1,684	-	-	281
Grande Prairie – AB	3,141	62	330	916
Total	47,713	1,493	330	9,776

	Three Months Ended December 31, 2015			
Producing Area	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Crude Oil (Bbls/d)	Boe/d
Umbach – NE BC	53,142	1,872	-	10,729
Horn River Basin – NE BC	-	-	-	-
Grande Prairie – AB	5	-	-	1
Total	53,147	1,872	-	10,730

In the first quarter of 2016, average Boe-per-day volumes increased by 37% when compared to the first quarter of 2015, and increased by 25% when compared to the immediately preceding quarter. Production increases for natural gas and NGL, when compared to both periods in 2015, came from growth at Umbach where the Company had production from 36 wells (32.4 net) at the end of the quarter. The Company's crude oil producing properties were sold in mid-2015. Production for the first quarter from the remaining Alberta properties was 20 Boe per day. During the first quarter of 2016, 1,500 Boe per day of production was shut in, including the Company's production from the Horn River Basin and Grande Prairie, due to uneconomical natural gas pricing. Production to date in the second quarter of 2016 has averaged approximately 12,800 Boe per day based on field estimates.

Daily production per million shares outstanding at the end of the first quarter averaged 112 Boe per day, compared to 88 Boe per day for the first quarter of 2015 and 90 Boe per day for the final quarter of 2015.

The Horn River Basin produces dry natural gas, while Umbach produces natural gas and associated NGL. Production in the first quarter approximated 82% natural gas and 18% NGL.

Average Daily Production

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015	Three Months Ended December 31, 2015
Natural gas (Mcf/d)	66,012	47,713	53,147
Natural gas liquids (Bbls/d)	2,416	1,493	1,872
Crude oil (Bbls/d)	-	330	-
Total (Boe/d)	13,418	9,776	10,730

Production Profile and Per-Unit Prices(1)

	Three Months Ended March 31, 2016		Three Months Ended March 31, 2015		Three Months Ended December 31, 2015	
	Percentage of Total Boe Production	Average Selling Price Before Transportation Costs	Percentage of Total Boe Production	Average Selling Price Before Transportation Costs	Percentage of Total Boe Production	Average Selling Price Before Transportation Costs
Natural gas - Mcf	82%	$ 1.62	81%	$ 2.85	83%	$ 1.78
Natural gas liquids - Bbl	18%	29.12	15%	37.10	17%	33.50
Crude oil - Bbl	-	-	4%	43.08	-	-
Per Boe	100%	$ 13.20	100%	$ 21.04	100%	$ 14.67

(1) Before realized hedging gains of $3.03 per Boe for the three months ended March 31, 2016 (Q1 2015 – gains of $8.36 per Boe, Q4 2015 – gains of $4.20 per Boe).

Following the introduction of new marketing arrangements late in 2015, the Company's production during the first quarter of 2016 was sold as follows:

- 42% - Chicago monthly index price less US$0.03 per Mmbtu
- 25% - Chicago daily index price
- 18% - Station 2 daily spot price
- 15% - AECO daily index price less Cdn$0.68 per GJ

Natural gas sold with reference to the Chicago daily index price receives a price which is a discount from the index price which corresponds to the pipeline tariff as title to the gas transfers at the natural gas processing plant in British Columbia. A summary of reference prices for the last five quarters, with natural gas prices in gigajoules, is set out below. Storm's realized prices differ due to heat content of the Company's natural gas.

	AECO Daily Index (Cdn$/GJ)	Station 2 (Cdn$/GJ)	Edmonton Par (Cdn$/Bbl)
Q1 – 2015	2.81	2.02	51.93
Q2 – 2015	2.52	2.01	67.72
Q3 – 2015	2.75	1.72	56.23
Q4 – 2015	2.34	1.04	52.95
Q1 – 2016	1.74	1.33	40.81

In 2015, transmission interruptions and curtailments in Alberta resulted in increased natural gas volumes moving to the Station 2 market. Further, natural gas production also increased in geographic areas where production is normally directed to Station 2. The consequence was a considerable widening in the AECO – Station 2 differential with average Station 2 prices at a discount to AECO of $0.58 for the first quarter of 2015 and $1.30 for the last quarter of 2015. The widening AECO – Station 2 differential emerged in a period of declining natural gas prices resulting in the differential becoming a growing and large percentage of the index price. The pipeline restrictions that contributed to the widening differential were partially reduced in December 2015 which resulted in a differential of $0.41 per GJ in the first quarter of 2016.

The realized price for NGL in the first quarter of 2016 fell by 22% and 13% relative to the first and fourth quarters of 2015. Storm's NGL stream in the quarter contained 60% condensate and pentanes, which are generally priced with reference to crude oil. Correspondingly, realized prices fell in alignment with lower crude oil prices. For the first quarter, WTI averaged US$33.45 per barrel and Edmonton light oil was Cdn$40.81 per barrel, resulting in an exchange rate adjusted differential between WTI and Edmonton light oil of Cdn$5.15 per barrel, compared to Cdn$8.41 per barrel in the first quarter of 2015 and Cdn$3.35 per barrel in the final quarter of 2015. Production of crude oil is now an insignificant part of the Company's operations and is likely to remain so under the Company's current investment program.

As Storm continues to increase natural gas production at Umbach, higher value condensate and pentane production will also increase. The importance of this is illustrated by the contribution from NGL which comprised 18% of Boe production but amounted to 40% of revenue from product sales in the first quarter of 2016.

On a per-Boe basis, the realized price for the first quarter of 2016 declined by 37% and 10% relative to the first and fourth quarters of 2015.

Average quarterly natural gas index prices in gigajoules are as follows:

(Cdn$/GJ)	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015	Three Months Ended December 31, 2015
AECO Monthly Index	$ 2.00	$ 2.80	$ 2.51
AECO Daily Index (spot)	$ 1.74	$ 2.60	$ 2.34
BC Station 2 Daily Index (spot)	$ 1.33	$ 2.02	$ 1.04

Revenue from Product Sales[1]

(000s)	Three Months Ended March 31, 2016		Three Months Ended March 31, 2015		Three Months Ended December 31, 2015	
Natural gas	$	9,719	$	12,245	$	8,710
Natural gas liquids		6,402		4,985		5,770
Crude oil		-		1,282		-
Total	$	16,121	$	18,512	$	14,480

(1) Excludes hedging gains and losses.

Revenue from product sales for the first quarter of 2016 decreased by 13% when compared to the first quarter of 2015 and increased by 11% when compared to the immediately preceding quarter. Quarterly production volumes grew 37% year over year and by 25% when compared to the immediately preceding quarter; however, this was offset by the calamitous and continuing fall in commodity prices.

A reconciliation of year-over-year revenue changes is as follows:

(000s)	Natural Gas		Natural Gas Liquids		Crude Oil		Total	
Revenue from product sales – Q1 2015	$	12,245	$	4,985	$	1,282	$	18,512
Effect of increased (decreased) production		4,863		3,098		(1,282)		6,679
Effect of changes in average product prices		(7,389)		(1,681)		-		(9,070)
Revenue from product sales – Q1 2016	$	9,719	$	6,402	$	-	$	16,121

The disparity between growth in production and the fall in revenue corresponds to price declines as follows:

Realized Prices per Commodity Unit	Three Months Ended March 31, 2015			Three Months Ended December 31, 2015			Three Months Ended March 31, 2016		
Natural gas (Mcf/d)	$	2.85	100%	$	1.78	62%	$	1.62	57%
Natural gas liquids (Bbls/d)		37.10	100%		33.50	90%		29.12	78%
Crude oil (Bbls/d)		43.08	100%		-	N/A		-	N/A
Total	$	21.04	100%	$	14.67	70%	$	13.20	63%

Realized and Unrealized Gain (Loss) on Commodity Price Contracts

The realized gain on commodity price contracts comprises cash settlements on contracts which, in whole or in part, have come to term during the reporting period, plus cash settlements relating to contracts which the Company terminated prior to the expiry date.

The term liquids below refers to crude oil contracts. Although the Company has no crude oil production, much of the NGL stream is priced with reference to crude oil. In the absence of a liquid market for NGL price contracts, the Company may enter into crude oil contracts as a proxy for an NGL hedge.

The unrealized gain (loss) on commodity price contracts results from the mark-to-market valuation of the unexpired portion of hedging contracts outstanding at the end of the reporting period. The change in fair value recognizes not only the mark-to-market change in the value of contracts outstanding both at the beginning and end of the reporting period, but includes the opening value of contracts which have come to term during the reporting period.

	Three Months Ended March 31, 2016		Three Months Ended March 31, 2015		Three Months Ended December 31, 2015	
Realized gain (loss)						
Liquids	$ 1,323	$ 6.02/Bbl	$ 5,137	$ 172.75/Bbl	$ -	$ - /Bbl
Natural gas	2,382	$ 0.40/Mcf	2,222	$ 0.52/Mcf	4,144	$ 0.85/Mcf
Total realized gain/(loss) - cash	$ 3,705	$ 3.03/Boe	$ 7,359	$ 8.36/Boe	$ 4,144	$ 4.20/Boe

The anomalously large realized gain in the first quarter of 2015 is the result of the early termination of a crude oil hedge.

	Three Months Ended March 31, 2016		Three Months Ended March 31, 2015		Three Months Ended December 31, 2015	
Unrealized gain (loss)						
Liquids – change in fair value	$ (505)	$ (2.30)/Bbl	$(4,861)	$(163.46)/Bbl	$ 1,289	$ 7.49/Bbl
Natural gas – change in fair value	(1,466)	$ (0.24)/Mcf	(1,976)	$ (0.46)/Mcf	763	$ 0.16/Mcf
Total unrealized gain/(loss) - non-cash	$(1,971)	$ (1.61)/Boe	$(6,837)	$ (7.77)/Boe	$ 2,052	$ 2.08/Boe

The Company had in place the following hedging arrangements at the date of this report:

Period Hedged	Daily Volume	Average Price
Crude Oil Collar		
Apr – Dec 2016	500 Bbls	$75.00 - $90.75 Cdn$/Bbl
Natural Gas Swaps		
Apr – Dec 2016	20,000 GJ	AECO Cdn$2.98/GJ
Natural Gas Differential Swaps		
Apr – Dec 2016	11,000 GJ	Price at Stn 2 = AECO minus Cdn$0.3375/GJ
Jan – Dec 2017	5,000 GJ	Price at Stn 2 = AECO minus Cdn$0.445/GJ
Apr – Dec 2016	33,000 Mmbtu	Price at Chicago = AECO plus US$0.672/Mmbtu
Jan – Dec 2017	35,000 Mmbtu	Price at Chicago = AECO plus US$0.577/Mmbtu

The fair market value of these contracts of $6.0 million (December 31, 2015 – $8.0 million) is included in current assets. For the three months ended March 31, 2016, this resulted in an unrealized mark-to-market loss of $2.0 million (2015 – loss of $6.8 million) when measured against the fair market value of contracts outstanding at the end of the preceding reporting period.

During the three months ended March 31, 2016, the Company realized gains from commodity price contracts in place or terminated in the amount of $3.7 million (2015 – gains of $7.4 million).

Natural gas swaps are priced at the AECO monthly index and the Company sells equal physical volumes of natural gas at the same price.

The Company's hedging program is not based on a speculative assessment of the direction of commodity prices. The program's purpose is to reduce the effect of commodity price volatility on cash flow to enable the Company to maintain a disciplined and sustainable development program. This is of particular importance at Umbach, where exploitation of the resource is at an early stage and capital investment programs necessary to delineate the scope and scale of a potentially decades-long project have to be insulated from the effects of near-term price movements.

Royalties

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015	Three Months Ended December 31, 2015
Charge for period	$ 922	$ 473	$ (54)
Percentage of revenue from product sales	5.7%	2.5%	(0.4%)
Per Boe	$ 0.76	$ 0.54	$ (0.05)

Royalties for the first quarter of 2016 increased to 5.7% from 2.5% of revenue from product sales when compared to the first quarter of 2015. Infrastructure royalty credits of $1.0 million received in each of January 2015 and December 2015 were the primary drivers of lower royalties in the first and fourth quarters of 2015. These credits apply to production in British Columbia and are recognized for accounting purposes when realized.

Future production will further benefit from British Columbia's Infrastructure Royalty Credit Program. Since 2012, Storm has received approval for $14.6 million of royalty credits for various projects. Storm realized credits of $0.8 million in 2013, $1.9 million in 2014 and $2.0 million in 2015. The remaining credits total $9.9 million which will reduce future royalties. The timing of receipt of future credits is dependent on commodity prices and thus cannot be readily forecast; correspondingly, royalty rates reported in future quarters will vary.

In March 2014, the British Columbia provincial government announced the expansion of the Deep Well Royalty Credit Program by extending royalty credits to all horizontal wells. Hitherto, wells with a vertical depth of less than 1,900 metres were not eligible for the program. Horizontal wells at Umbach, drilled after April 1, 2014, will receive a royalty credit of $0.5 million to $0.7 million per well, depending on the total measured vertical depth of the well. In conjunction with this change, wells that are eligible for this expanded credit program will bear a minimum royalty at a rate of 6%. Again, the timing of receipt of royalty credits under the program cannot be readily predicted. Correspondingly, the royalty rate reported in future quarters may vary considerably.

No accounting recognition has been given to future benefits potentially accruing to Storm from neither the Infrastructure Royalty Credit nor the Deep Well Royalty Credit programs.

The Alberta government's royalty review will not have a material impact on Storm given the limited production base in Alberta.

Production Costs

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015	Three Months Ended December 31, 2015
Charge for period	$ 8,193	$ 7,624	$ 6,920
Percentage of revenue from product sales	50.8%	41.2%	47.8%
Per Boe	$ 6.71	$ 8.67	$ 7.01

Total production costs for the first quarter increased by 7% when compared to the first quarter of 2015 and by 18% when compared to the final quarter of 2015. The increase in total production costs is aligned with increased production at Umbach. Per-Boe charges continue to decline.

Production costs per Mcf of natural gas for the first quarter averaged $1.36 with total production costs averaging $6.71 per Boe. Production costs of natural gas liquids are included with natural gas costs. The equivalent charges for the first quarter of 2015 were $1.64 per Mcf of natural gas with total production costs averaging $8.67 per Boe, a year-over-year reduction of 23%. Production costs per Mcf for natural gas for the final quarter of 2015 averaged $1.42 with total production costs averaging $7.01 per Boe, a reduction of 4%.

Growing production results in the fixed cost component of production costs per Boe falling. In addition, lower service costs also contributed to the decline in per-unit production costs. The sale of higher cost properties in Alberta in mid-2015 also caused a year-over-year decline in per-unit production costs.

Transportation Costs

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015	Three Months Ended December 31, 2015
Charge for period	$ 645	$ 1,476	$ 783
Percentage of revenue from product sales	4.0%	8.0%	5.4%
Per Boe	$ 0.53	$ 1.68	$ 0.79

Transportation costs largely comprise pipeline tariffs for natural gas, as well as trucking costs for wellhead condensate. Total transportation costs for the first quarter of 2016 decreased by 56% and by 68% on a per-Boe basis over the same period in 2015 as a result of the sale of oil properties in Alberta during 2015 as well as lower NGL trucking costs. Transportation costs for the first quarter of 2016 decreased by 18% over the final quarter of 2015 while per-Boe transportation costs declined 33% mainly due to new natural gas marketing arrangements which began in December 2015. As the sales point for natural gas shipped on the Alliance Pipeline is the processing facility in British Columbia, the sales price is net of the cost to the shipper of moving natural gas to Chicago.

Field Netbacks

Details of field netbacks per commodity unit produced are as follows:

Three Months Ended March 31, 2016	Natural Gas ($/Mcf)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/Bbl)	Total ($/Boe)
Production revenue	$ 1.62	$ 29.12	$ -	$ 13.20
Royalties	(0.05)	(2.71)	-	(0.76)
Production costs	(1.36)	-	-	(6.71)
Transportation costs	(0.04)	(1.89)	-	(0.53)
Field operating netback before hedging	$ 0.16	$ 24.52	$ -	$ 5.20
Realized hedging gains (losses)	0.40	6.02	-	3.03
Total operating income per commodity unit	$ 0.56	$ 30.54	$ -	$ 8.23
Total operating income (000s)	$ 6,716	$ 3,350	$ -	$ 10,066

Production costs of natural gas liquids are included with natural gas costs.

Three Months Ended March 31, 2015	Natural Gas ($/Mcf)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/Bbl)	Total ($/Boe)
Production revenue	$ 2.85	$ 37.10	$ 43.08	$ 21.04
Royalties	0.11	(6.26)	(3.35)	(0.54)
Production costs	(1.64)	-	(19.42)	(8.67)
Transportation costs	(0.19)	(3.80)	(4.88)	(1.68)
Field operating netback before hedging	$ 1.13	$ 27.04	$ 15.43	$ 10.16
Realized hedging gains (losses)	0.52	-	172.75	8.36
Total operating income per commodity unit	$ 1.65	$ 27.04	$ 188.18	$ 18.52
Total operating income (000s)	$ 7,069	$ 3,633	$ 5,596	$ 16,298

Three Months Ended December 31, 2015	Natural Gas ($/Mcf)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/Bbl)	Total ($/Boe)
Production revenue	$ 1.78	$ 33.50	$ -	$ 14.67
Royalties	0.15	(3.94)	-	0.05
Production costs	(1.42)	-	-	(7.01)
Transportation costs	(0.10)	(1.66)	-	(0.79)
Field operating netback before hedging	$ 0.41	$ 27.90	-	$ 6.92
Realized hedging gains (losses)	0.85	-	-	4.20
Total operating income per commodity unit	$ 1.26	$ 27.90	-	$ 11.12
Total operating income (000s)	$ 6,174	$ 4,800	$ -	$ 10,974

Total operating income in the first quarter of 2016 declined respectively by 38% and by 8% when compared to the first and final quarters of 2015. Per Boe, excluding hedging gains and losses, field operating netback fell by 49% in the first quarter of 2016 in comparison to the same quarter of 2015, and by 25% compared to the final quarter of 2015. Year over year, production and transportation costs per Boe each fell considerably, but these cost reductions were insufficient to counter the effect of reduced commodity prices. The result was that year over year per-Boe production revenue fell by $7.84, or 37%. This also resulted in per-Boe operating income falling by 56%.

Controllable cash costs per Boe, comprising production costs, general and administrative costs and interest and finance costs, amounted to $8.52 for the first quarter of 2016, $11.61 for the equivalent quarter of 2015 and $8.82 for the final quarter of 2015. Transportation costs are excluded as the sales price received by the Company is net of the imputed cost to the purchaser of shipping on the Alliance Pipeline to Chicago. Comparing the first quarter of 2016 to the same quarter of 2015 and the final quarter of 2015, all components of cash costs decreased on a per-Boe basis except for a small increase in interest costs relative to the fourth quarter of 2015. Although it is reasonable to expect future reductions in cash costs per commodity unit, they are likely to be small in the absence of production growth and because the oilfield service industry is probably at its limit in terms of being able to absorb further price reductions.

General and Administrative Costs

Total Costs	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015	Three Months Ended December 31, 2015
Charge for period – before recoveries	$ 1,942	$ 2,852	$ 1,675
Overhead recoveries	(415)	(883)	(420)
Charge for period – net of recoveries	$ 1,527	$ 1,969	$ 1,255
Per Boe	$ 1.25	$ 2.24	$ 1.27

Gross general and administrative costs for the first quarter of 2016 decreased by 32% when compared to the first quarter of 2015 and increased by 16% compared to the final quarter of 2015. The increase in general and administrative costs relative to the immediately preceding quarter is attributable to the payout of bonus amounts earned under the 2015 compensation program. The decrease relative to the same period in 2015 is due to lower bonus payouts. Year over year, overhead recoveries decreased as a result of lower field capital spending and were flat relative to the fourth quarter of 2015.

On a per-Boe measure, net general and administrative costs decreased by 44% compared to the first quarter of 2015, and by 2% compared to the final quarter of 2015. General and administrative costs for the fourth and first quarters of a fiscal year tend to be higher due to the inclusion of certain costs specific to year end reporting.

Share-Based Compensation

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015	Three Months Ended December 31, 2015
Charge for period	$ 823	$ 985	$ 878
Per Boe	$ 0.67	$ 1.12	$ 0.89

Share-based compensation is a non-cash charge which reflects the estimated value of stock options issued to Storm's directors, officers and employees. Share-based compensation decreased by 16% in the first quarter of 2016 compared to the same quarter of 2015 and decreased by 6% when compared to the immediately prior quarter. The decrease in share-based compensation is attributable to options granted in 2012 being fully expensed in 2015.

Depletion and Depreciation

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015	Three Months Ended December 31, 2015
Depletion	$ 8,719	$ 7,825	$ 7,199
Depreciation	1,229	1,394	1,108
Charge for period	$ 9,948	$ 9,219	$ 8,307
Per Boe	$ 8.15	$ 10.48	$ 8.42

Property and equipment are subject to depletion and depreciation charges. Depletion is calculated using unit-of-production methodology under which intangible drilling and completion costs plus future development costs associated with individual cash generating units are depleted using a factor calculated by dividing production for each reporting period by proved plus probable reserves at the beginning of the period.

The charge for depreciation for the period relates to facility and tangible equipment costs and office equipment included with property and equipment costs. Such costs are depreciated over the useful life of the asset on a straight line basis.

Higher production volumes resulted in the total charge for depletion and depreciation increasing by 8% in the first quarter of 2016 compared to the same quarter of 2015. The quarterly year-over-year per-Boe charge fell by 22% as the finding and development cost for proved plus probable reserves fell, reflecting Storm's successful development program at Umbach, as well as the sale of higher cost Alberta properties in mid-2015. Decreased depreciation charges year over year correspond to the sale of these Alberta properties.

Accretion

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015	Three Months Ended December 31, 2015
Charge for period	$ 87	$ 133	$ 87
Per Boe	$ 0.07	$ 0.15	$ 0.09

Accretion represents the time value increase for each reporting period for the Company's decommissioning liability. The decreased year-over-year charge for accretion is due to the sale of Alberta properties in mid-2015, which carried a disproportionately high future abandonment cost.

Interest and Finance Costs

(000s)	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015	Three Months Ended December 31, 2015
Charge for period	$ 684	$ 617	$ 537
Percentage of revenue from product sales	4.2%	3.3%	3.7%
Per Boe	$ 0.56	$ 0.70	$ 0.54

Interest costs for the first quarter of 2016 increased by 11% compared to the same quarter of 2015, and increased by 27% compared to the final quarter of 2015, as a result of additional bank borrowings used to fund development of the Company's Umbach property.

The interest rate on the Company's bank facility is based on bankers acceptance rates plus a stamping fee which is amended each quarter in response to changes in the Company's debt to funds from operations ratio.

Unrealized Revaluation Loss on Investment

In the first quarter of 2016 the Company recognized a loss of $10,000 representing the mark-to-market reduction in the carrying amount of the Company's investment in Chinook Energy Inc. ("Chinook"), as measured against the market value at the previous year end.

Income Taxes

Due to uncertainty of realization, no deferred income tax asset has been recognized in respect of potential future income tax reductions resulting from the use of accumulated tax losses. Details of Storm's tax pools are as follows:

Tax Pool	As at March 31, 2016	Maximum Annual Deduction
Canadian oil and gas property expense	$ 45,000	10%
Canadian development expense	111,000	30%
Canadian exploration expense	22,000	100%
Undepreciated capital cost	85,000	20 - 100%
Operating losses	180,000	100%
Other	4,000	20 - 100%
Total	$ 447,000	

Net Income (Loss)

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015	Three Months Ended December 31, 2015
Net income (loss)	$ (4,984)	$ (3,565)	$ 1,850
Per basic and diluted share	$ (0.04)	$ (0.03)	$ 0.02

Other Comprehensive Loss

Other comprehensive income comprises net loss for the period plus unrealized gains and losses resulting from the mark-to-market valuation of certain assets and liabilities. For the three months ended March 31, 2015, a loss of $50,000 was recognized in other comprehensive income, representing the reversal of prior mark-to-market gains in value of the investment in Chinook.

Listed Securities	Holding	Number of Shares(1)	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015	Three Months Ended December 31, 2015
Chinook Energy Inc.	Common Shares	1,000,000	$ -	$ (50)	$ -
Other comprehensive loss for period			$ -	$ (50)	$ -

(1) Shares owned at March 31, 2016.

Cash Flows from Operating Activities and Non-GAAP Funds from Operations

	Three Months Ended March 31, 2016		Three Months Ended March 31, 2015		Three Months Ended December 31, 2015	
		Per diluted share		Per diluted share		Per diluted share
Cash flows from operating activities	$ 10,745	$ 0.09	$ 13,937	$ 0.12	$ 7,050	$ 0.06
Net change in non-cash working capital items	(2,890)	(0.02)	(225)	-	2,132	0.02
Non-GAAP funds from operations	$ 7,855	$ 0.07	$ 13,712	$ 0.12	$ 9,182	$ 0.08

The reconciling item between funds from operations and cash flows from operating activities is the change in non-cash operating working capital items.

Non-GAAP funds from operations for the first quarter of 2016 decreased by 43% from the first quarter of 2015, and decreased by 14% compared to the final quarter of 2015, as production growth was insufficient to overcome the continuing commodity price collapse.

Non-GAAP funds from operations is not a measure recognized by GAAP, although it is widely used by investors, analysts and other financial statement users. It is also used by the Company's banking syndicate to determine debt to cash flow ratios and other measures of credit worthiness and thus determines interest rates on borrowings. The most directly comparable measure under GAAP is cash flows from operating activities, as set out above.

Corporate Netbacks

($/Boe)	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015	Three Months Ended December 31, 2015
Revenue from product sales	13.20	21.04	14.67
Realized hedging gains	3.03	8.36	4.20
Royalties	(0.76)	(0.54)	0.05
Production	(6.71)	(8.67)	(7.01)
Transportation	(0.53)	(1.68)	(0.79)
General and administrative	(1.25)	(2.24)	(1.27)
Interest and finance costs	(0.56)	(0.70)	(0.54)
Funds from operations	6.42	15.57	9.31
Share-based compensation	(0.67)	(1.12)	(0.89)
Depletion, depreciation and accretion	(8.22)	(10.63)	(8.51)
Exploration and evaluation costs expensed	-	(0.12)	-
Unrealized revaluation loss on investments	(0.01)	-	(0.03)
Loss on sale of oil and gas properties	-	-	(0.08)
Unrealized gain (loss) on commodity price contracts	(1.61)	(7.77)	2.08
Net income (loss) per Boe	(4.09)	(4.07)	1.88

INVESTMENT AND FINANCING

Financial Resources and Liquidity

At the beginning of 2015, Storm's bank facility amounted to $130.0 million. In April 2015, the facility was increased to $150.0 million in recognition of production and reserve growth at Umbach. In July 2015, subsequent to the disposal of non-core assets in Alberta, the facility was reduced to $140.0 million, of which amount 50% was drawn at March 31, 2016. Subsequent to March 31, 2016 the facility was further reduced to $130.0 million in response to a lower lending value consequent on falling commodity prices. The facility is available until April 28, 2017 at which time the borrowing base amount will be reviewed. In the ordinary course, the Company has the option to extend for an additional year; if this does not happen, the facility will be termed out with the amount outstanding becoming payable in full one year later.

The Company is in compliance with all covenants under the credit facility, the sole financial covenant being that debt including working capital deficiency cannot exceed the facility credit limit. At March 31, 2016 debt including working capital deficiency, excluding mark-to-market value of hedging contracts, amounted to $77.2 million.

In quarters of high field activity, Storm operates with a working capital deficit, which will be reduced in quarters of lower field activity. The Company's capital budget is set by management at the beginning of the calendar year and approved by the Board of Directors. It is updated regularly with changes subject to approval by the Board of Directors. Management is accountable to the Board of Directors for the execution of the business plan represented by the budget and reports to the Board at least four times a year.

Capital Expenditures

In the first quarter of 2016, the Company spent $23.9 million (2015 - $35.7 million) on field operations to further develop the high liquids content natural gas play at Umbach.

During the quarter, seven 100% working interest horizontal wells were drilled, two horizontal wells were completed, and one horizontal well was brought on production. At March 31, 2016 there were 12 wells awaiting tie-in, of which three were completed.

Major field capital outlays in the first quarter include $15.9 million on drilling and completions and $7.3 million on facilities, equipping and tie-ins, all in the Umbach area.

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015	Three Months Ended December 31, 2015
Land and lease	$ 686	$ 336	$ 235
Drilling	11,856	12,253	7,954
Completions	4,089	6,887	14,478
Facilities, equipping and pipelines	7,280	15,378	3,958
Recompletions and workovers	33	806	(45)
Property acquisition, adjustments and administrative assets	2	20	120
Total expenditures	$ 23,946	$ 35,680	$ 26,700
Land acquisitions	-	-	4,381
Net capital invested	$ 23,946	$ 35,680	$ 31,081

Net capital investment was allocated as follows:

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015	Three Months Ended December 31, 2015
Exploration and evaluation	$ 675	$ 316	$ 4,616
Property and equipment	23,271	35,364	26,465
Total – net of dispositions	$ 23,946	$ 35,680	$ 31,081

Accounts Payable and Accrued Liabilities

Accounts payable and accrued liabilities include operating, general and administrative and capital costs payable. When appropriate, net payables in respect of cash calls issued to partners regarding capital projects and estimates of amounts owing but not yet invoiced to the Company are included in accounts payable. The level of accounts payable and accrued liabilities at March 31, 2016 reflects field activity at Umbach, the first quarter likely being the most active quarter of 2016.

Decommissioning Liability

The Company's decommissioning liability represents the present value of estimated future costs to be incurred to abandon and reclaim wells and facilities, drilled, constructed or purchased by Storm. The undiscounted amount of the liability at March 31, 2016 was $28.2 million and reflects (i) liabilities accruing to the Company as a result of field activity and acquisitions, (ii) revisions of estimates of inflation and discount rates, (iii) changes in estimates of future costs and timing of incurrence of such costs, (iv) less decommissioning obligations associated with dispositions of oil and gas properties, (v) less actual decommissioning costs incurred, (vi) plus the time-related increase in the present value of the liability. The risk-free discount rate used to establish the present value is 2.25%. Future costs to abandon and reclaim the Company's properties are based on a continuous internal evaluation, including monitoring of actual abandonment and reclamation costs, supported by external information from industry sources. It also has regard to industry best practices, as well as provincial and other regulation and evolution of same.

Shareholders' Equity

Details of share issuances from inception to March 31, 2016 are as follows:

		Number of Shares (000s)	Price per Share	Gross Proceeds[1] ($000s)
June 8, 2010	Issued upon incorporation		$ 1.00	$ -
August 17, 2010	Issued under the Arrangement	17,515	$ 3.28	57,600
August 17, 2010	Issued under private placement	2,300	$ 3.28	7,544
September 22, 2010	Issued upon exercise of warrants	6,562	$ 3.28	21,522
		26,377		86,666
January 12, 2012	Issued on acquisition of SGR	11,761	$ 3.73	43,869
March 23, 2012	Issued under private placement	6,946	$ 3.40	23,615
March 23, 2012	Issued on acquisition of Bellamont	16,740	$ 2.37	39,674
		35,447		107,158
May 1, 2013	Issued under private placement	12,580	$ 1.88	23,650
May 1, 2013	Issued under insider private placement	3,000	$ 1.88	5,640
June 30, 2013	Shares cancelled	(21)	$ 2.37	(50)
November 19, 2013	Issued under private placement	9,000	$ 3.35	30,150
November 19, 2013	Issued under insider private placement	1,100	$ 3.35	3,685
		25,659		63,075
January 31, 2014	Issued pursuant to Umbach acquisition	13,629	$ 4.25	57,925
February 14, 2014	Issued under private placement	7,250	$ 4.10	29,725
February 14, 2014	Issued under insider private placement	1,250	$ 4.10	5,125
Year ended Dec.31/14	Stock option exercises	1,710	$ 3.26	5,580
		23,839		98,355
June 10, 2015	Issued under private placement	8,000	$ 4.55	36,400
Year ended Dec.31/15	Stock option exercises	145	$ 1.81	262
		8,145		36,662
Three months to Mar.31/16	Stock option exercises	275	$ 2.40	659
Total at March 31, 2016		119,742	$ 3.28	$ 392,575

(1) Before share issue costs.

On January 31, 2014, the Company issued 13,629,442 common shares at a fair value under IFRS of $4.25 per share, as partial consideration for the acquisition of two horizontal wells producing 359 Boe net per day and 29 sections of undeveloped land directly adjacent to Storm's 100% working interest lands in Umbach South. The total cost of the acquisition was approximately $87.9 million including $30.0 million in cash.

In February 2014, the Company issued 7,250,000 common shares pursuant to a bought deal financing at a price of $4.10 per common share for gross proceeds of $29,725,000. At the same time, the Company issued to certain directors, officers and employees of the Company 1,250,000 common shares pursuant to a non-brokered financing at a price of $4.10 per common share for gross proceeds of $5,125,000. Both of these financings closed on February 14, 2014. Net proceeds received totaled $33.0 million.

In June 2015, the Company issued 8,000,000 common shares pursuant to a bought deal financing at a price of $4.55 per common share for gross proceeds of $36,400,000. This financing closed on June 10, 2015. Net proceeds received totaled $34.2 million.

During 2015, stock options were exercised at an average price of $1.81 per optioned share and 145,000 common shares were issued for proceeds of $262,000. During the first quarter of 2016, stock options were exercised at an average price of $2.40 per optioned share and 275,000 common shares were issued for proceeds of $659,000.

Issued and outstanding common shares at March 31, 2016 totaled 119,741,812 and at May 12, 2016, the date of this MD&A, totaled 119,786,812.

CONTRACTUAL OBLIGATIONS

In the course of its business, Storm enters into various contractual obligations, including the following:

- purchase of services;
- royalty agreements;
- operating agreements;
- processing and transportation agreements;
- right of way agreements;
- lease obligations for accommodation, office equipment and automotive equipment;
- banking agreement; and
- hedging contracts.

All such contractual obligations reflect market conditions at the time of contract and do not involve related parties. At present the Company has a lease of office premises for a period of five years commencing October 1, 2013 for a base rent, not including operating costs, totaling approximately $3.0 million over the term of the lease. Current monthly operating costs amount to $28,600. In addition, the Company has gas transportation and processing commitments valued at a total of approximately $153.1 million over the period to December 31, 2020.

QUARTERLY RESULTS

Summarized information by quarter for the two years ended March 31, 2016 appears below. Although there are variations between quarters in various elements of revenue and cost, as set out in the MD&A for each quarter, the results for the period from the second quarter of 2014 to the first quarter of 2016 have been affected by one dominant trend – production growth has been insufficient to offset the relentless fall in commodity prices.

	2016				2015			2014
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Production revenue ($000s)(1)	19,826	18,624	18,256	20,236	25,871	28,556	24,131	20,202
Non-GAAP funds from operations ($000s)(2)	7,855	9,182	7,982	8,170	13,712	13,892	11,784	11,076
Per share								
- basic ($)	0.07	0.08	0.07	0.07	0.12	0.13	0.11	0.10
- diluted ($)	0.07	0.08	0.07	0.07	0.12	0.12	0.11	0.10
Net income (loss) ($000s)	(4,984)	1,850	(961)	(4,191)	(3,565)	(7,422)	5,473	6,598
Per share								
- basic ($)	(0.04)	0.02	(0.01)	(0.04)	(0.03)	(0.07)	0.05	0.06
- diluted ($)	(0.04)	0.02	(0.01)	(0.04)	(0.03)	(0.07)	0.05	0.06
Net capital expenditures ($000s)	23,946	31,081	(4,116)(4)	8,864	35,680	20,095	30,426	33,640
Average daily production - Boe	13,418	10,730	9,654	9,657	9,776	10,173	7,160	5,462
Net debt ($000s)(3)	77,162	61,721	39,994	28,051	85,098	63,080	56,157	41,837

(1) Includes realized hedging gains and losses.
(2) See Non-GAAP Measurements on page 24 of this MD&A.
(3) Includes working capital deficiency and excludes the fair value of commodity price contracts.
(4) Net of property disposition for proceeds of $23.6 million.

CRITICAL ACCOUNTING ESTIMATES

Financial amounts included in this MD&A and in the financial statements for the reporting period ended March 31, 2016 are based on accounting policies, estimates and judgments which reflect information available to management at the time of preparation. Certain amounts in the financial statements are derived from a fully completed transaction cycle, or are validated by events subsequent to the end of the reporting date, or are based on established and effective measurement and control systems. However, certain other amounts, as described below, are based on estimations made by management using information which involves an element of measurement uncertainty. The degree of uncertainty related to each of the following items will vary: further, it may change between reporting periods. Variations between amounts estimated and actual results subsequently realized could have a material effect on Storm's operating results and financial position.

Oil and Gas Reserves

Estimates of quantities of proven and probable reserves of natural gas and NGL are not a financial measurement. However, estimated future cash flows associated with reserves are used in impairment assessments for exploration and evaluation assets and property and equipment, the measurement of decommissioning obligations and depletion and depreciation of property and equipment. Such estimates of cash flows involve assumptions regarding future commodity prices, exchange rates, discount rates, inflation rates and future production and transportation costs. Reserve estimates are prepared by independent qualified reserve evaluators in accordance with independently established industry standards using, in part, data supplied by the Company. The results of the independent reserve evaluation are reviewed by the Reserves Committee of the Company's board of directors.

Accounts Receivable, Accounts Payable and Accrued Liabilities

At the end of each reporting period the Company estimates the amount receivable from product sales and from joint venture partners to the extent that these amounts are not determinable from purchaser statements or amounts invoiced to partners. In addition, the Company estimates the cost of services and materials provided by suppliers during the reporting period if these costs have not been invoiced to the Company by the reporting date. The Company estimates and recognizes such revenues and costs using well established measurement procedures. Nonetheless, such procedures generally reflect judgment by management and are thus subject to measurement uncertainty. In addition, estimates of services and materials not invoiced, either to or by the Company, relate in large part to the Company's capital programs, the level of which can vary considerably between reporting periods. As a result, the amount of accounts receivable, accounts payable and accrued liabilities subject to estimation will vary and in periods of high field activity the amount subject to estimation may be a large part of the total amount.

Commodity Price Contracts

The Company periodically enters into contracts which fix a price or a price range for future periods for natural gas and crude oil. Each such contract is valued at the end of each reporting period, with the change in value of outstanding contracts being included in the measurement of income for the period. The period end value is based on option pricing models using estimates for future circumstances and is correspondingly subject to both mathematical and input uncertainty.

Exploration and Evaluation Assets

Costs incurred by the Company in the initial assessment phase of a property offering development potential are categorized as exploration and evaluation assets. Such costs are transferred to CGUs, generally when production commences or reserves are assigned, or are expensed if management determines that the costs incurred will yield no future economic benefit or if the lease associated with the property expires. The amounts transferred to property and equipment, or expensed, and the timing of the decisions relative to each, are subject to measurement uncertainty. Furthermore, the residual balance of exploration and evaluation assets at the end of each reporting period represents an asset whose value can only be established in future periods.

Property and Equipment, and Depletion and Depreciation

Amounts transferred from exploration and evaluation assets to property and equipment represent the accumulated net costs associated with the property transferred. The timing and the measure of the amount to be transferred involves estimation and judgment by management, and the estimates used could differ from similar estimates developed by other parties.

Property and equipment are subject to depletion and depreciation, and charges for depletion and depreciation are based on estimates which may only be validated in future periods, if ever. Such charges involve estimates by management of the useful economic life for assets subject to depletion and depreciation, the quantities of oil and gas reserves used in the depletion calculation, the future prices at which such reserves may be sold, and future costs to develop and produce such reserves. Further, for non-reserve assets such as facilities and pipelines, estimates of the useful life of these assets must be made.

The carrying amounts of property and equipment are reviewed each reporting period to determine whether there are indicators of impairment. If there are such indicators, an impairment test per CGU is completed involving the calculation of an estimated recoverable amount; as a result adjustments to the carrying amount may be made. All of these involve assumptions regarding uncertain future events and circumstances.

Decommissioning Liability

Storm records as a liability the discounted estimated fair value of obligations associated with the decommissioning of field assets. The carrying amount of exploration and evaluation assets and property and equipment is increased by an amount equivalent to the liability. In summary, the decommissioning liability reflects the present value of estimated costs to complete the abandonment and reclamation of field assets as well as the estimated timing of incurrence of these costs. The liability is increased each reporting period to reflect the passage of time, with the charge for accretion included in earnings. The liability is also adjusted to reflect changes in the amount and timing of future retirement obligations as well as asset dispositions and is reduced by the amount of any costs incurred in the period. The amount of future decommissioning costs, the timing of incurrence of such costs, the discount rate and, correspondingly, the charge for accretion, are subject to uncertainty of estimation. In addition, the decommissioning activities to which the estimates relate are likely to take place many years, potentially decades, in the future. The long timeline between incurrence and eventual satisfaction of the obligation will inevitably affect the accuracy of the estimation process.

Share-Based Compensation

To determine the charge for share-based compensation, the Company estimates the fair value of stock options at the time of issue using assumptions regarding the life of the option, dividend yields, interest rates and the volatility of the security under option. Although the assumptions used to value a specific option remain unchanged throughout the life of the option, assumptions may change with respect to subsequent option grants. In addition, the assumptions used may not properly represent the fair value of stock options at any time; as no alternative valuation model is applied, the difference between the Company's estimation of fair value and the actual value of the option is not measurable. Although the methodology used to measure the charge for share-based compensation is largely uniform across Storm's peers, inputs to the calculation, and thus the charge, may vary considerably.

Income Taxes

The measurement of Storm's tax pools, losses and deferred tax assets and liabilities requires interpretation of complex laws and regulations. All tax filings and compliance with tax regulations are subject to audit and reassessment, potentially several years after the initial filing. In addition, the amount and timing of use of tax pools may be affected by future legislation. Accordingly, the amounts of tax pools available for future use may differ significantly from the amounts estimated in the financial statements.

LIMITATIONS

Forward-Looking Statements – Certain information set forth in this document, including management's assessment of Storm's future plans and operations, contains forward-looking information (within the meaning of applicable Canadian securities legislation). Such statements or information are generally identifiable by words such as "anticipate", "believe", "intend", "plan", "expect", "estimate", "budget", "outlook", "forecast" or other similar words and include statements relating to or associated with individual or groups of wells, facilities, regions or projects. Without limitation, any statements regarding the following are forward-looking statements:

- future commodity prices;
- future production volumes, production volumes by commodity and production declines;
- future revenues and production costs (including royalties) and revenues and production costs per commodity unit;
- future capital expenditures and their allocation to specific projects, activities or periods;
- future drilling, completion and tie-in of wells;
- future facility access, acquisition, construction and entry in service;
- future earnings or losses, including per-share amounts;
- future non-GAAP funds from operations and future cash flows, including per-share amounts and the categorization of such cash flows;
- future availability of financing;
- future asset acquisitions or dispositions;
- future sources of funding for capital programs and future availability of such sources;
- development plans;
- estimates regarding the carrying amount of exploration and evaluation costs;
- estimates regarding the carrying amount of property and equipment;
- future levels of debt including working capital deficiency;
- availability and use of credit facilities;
- future decommissioning costs, inflation rates and discount rates used to determine the net present value of such costs;
- future use of tax pools and losses;
- measurement and recoverability of reserves or contingent resources including estimates of DPIIP and timing of such recoverability;
- estimates of ultimate recovery from wells;
- future finding and development costs;
- estimates of the future life of depreciable assets;
- future royalties, transportation costs, operating costs, interest and general and administrative costs in total and by commodity unit;
- effect of existing and future agreements with respect to processing, transportation and marketing of natural gas;

- future provisions for depletion and depreciation and accretion;
- future share-based compensation charges;
- future interest rates and interest and financing costs;
- estimates on a per-share basis and per-Boe basis;
- dates or time periods by which wells will be drilled, completed and tied in, facility and pipeline construction completed and brought into service, geographical areas developed, facilities and pipelines accessed;
- future effect of regulatory regimes and tax and royalty laws, including incentive programs;
- effect of existing or future contractual obligations; and
- changes to any of the foregoing.

Statements relating to "reserves" or "resources" including related financial measurements, such as net present value, are forward-looking statements, as they imply, based on estimates and assumptions, including assumptions regarding future prices, that the reserves and resources described exist in the quantities predicted or estimated, and can be profitably produced in the future.

The forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include the material uncertainties and risks described or incorporated by reference in this MD&A under "Critical Accounting Estimates"; "Business Risks"; "Financial Reporting Update"; and the material assumptions and observations described under the headings "Overview"; "Production and Revenue"; "Realized and Unrealized Gain (Loss) on Commodity Price Contracts"; "Royalties"; "Production Costs"; "Transportation Costs"; "Field Netbacks"; "General and Administrative Costs"; "Share-Based Compensation"; "Depletion and Depreciation"; "Accretion"; "Interest and Finance Costs"; "Net Income (Loss)"; "Other Comprehensive Loss"; "Cash Flows from Operating Activities and Non-GAAP Funds from Operations"; "Financial Resources and Liquidity"; "Capital Expenditures"; "Accounts Payable and Accrued Liabilities"; "Decommissioning Liability"; "Shareholders' Equity"; "Contractual Obligations"; industry conditions including commodity prices, capacity constraints and access to processing facilities and to market for production, currency fluctuations, imprecision of reserve estimates and related costs, including future royalties, production and transportation costs and future development costs; environmental risks; competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility, ability to access sufficient capital from internal and external sources and the ability of the Company to realize value from its properties. All of these caveats should be considered in the context of current economic conditions, in particular very low prices for all commodities produced by the Company, increased supply resulting from evolving exploitation methods, the attitude of lenders and investors towards corporations in the energy industry, potential changes to royalty and taxation regimes and to environmental and other government regulations, the condition of financial markets generally, as well as the stability of joint venture and other business partners, all of which are outside the control of the Company. Readers are advised that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Storm's actual results, performance or achievement, could differ materially from those expressed in, or implied by, these forward-looking statements. Storm disclaims any intention or obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required under securities law. **The forward-looking statements contained therein are expressly qualified by this cautionary statement.**

Boe Presentation – Natural gas is converted to a barrel of oil equivalent ("Boe") using six thousand cubic feet ("Mcf") of natural gas equal to one barrel of oil unless otherwise stated. Boe may be misleading, particularly if used in isolation. A Boe conversion ratio of six Mcf to one barrel ("Bbl") is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All Boe measurements and conversions in this report are derived by converting natural gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil.

Non-GAAP Measurements - Within this MD&A, references are made to terms which are not recognized under Generally Accepted Accounting Principles ("GAAP"). Specifically, "funds from operations", "funds from operations per share", "debt including working capital deficiency", "netbacks", "field operating netbacks", "corporate netbacks", "field operating netback", "field operating netback before hedging", "total operating income", "cash costs", and measurements "per Boe" do not have any standardized meaning as prescribed by GAAP and are regarded as non-GAAP measures. These non-GAAP measures may not be comparable to the calculation of similar amounts for other entities and readers are cautioned that use of such measures to compare enterprises may not be valid. In particular, funds from operations is not intended to represent, or be equivalent to, cash flow from operating activities calculated in accordance with GAAP, which is measured on the Company's consolidated statements of cash flows. Funds from operations and other non-GAAP terms are used to benchmark operations against prior periods and peer group companies and are widely used by investors, analysts and other parties. Funds from operations is also used by lenders to measure compliance with debt covenants and thus set interest costs. Reference is made to the discussion in this MD&A under “Cash Flows from Operating Activities and Non-GAAP Funds from Operations”.

BUSINESS RISKS

There are a number of risks facing participants in the Canadian oil and gas industry. Some risks are common to all businesses while others are specific to the industry. Information with respect to such risks is set out in Storm’s Annual Information Form dated March 31, 2016 for the year ended December 31, 2015 under the heading “Risk Factors” and in Storm’s MD&A for the period ended December 31, 2015 under the heading “Business Risks”.

FINANCIAL REPORTING UPDATE

Accounting Changes

Future Accounting Policies

Leases

In January 2016 the IASB issued IFRS 16 Leases, which requires lessees to recognize assets and liabilities for most leases. The standard replaces IAS17 and will be effective for annual periods beginning on or after January 1, 2019.

Financial Instruments

IFRS 9 Financial Instruments is intended to replace IAS 39 Financial Instruments: Recognition and Measurement and uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, and also requires a single impairment method to be used, replacing the multiple rules of IAS 39. Although new hedge accounting requirements have been introduced, Storm does not employ hedge accounting for risk management contracts currently in place. This standard is effective for annual periods beginning on or after January 1, 2018.

Revenue

In May 2014, the IASB issued IFRS 15 Revenue from Contracts with Customers which replaces IAS18 and IAS11. The standard is required to be adopted for fiscal years beginning on or after January 1, 2018.

The Company is currently evaluating the effect of these standards on Storm’s financial statements.

ADDITIONAL INFORMATION

Additional information relating to the Company can be viewed at www.sedar.com or on the Company’s website at www.stormresourcesltd.com. Information can also be obtained by contacting the Company at Storm Resources Ltd., Suite 200, 640 – 5th Avenue S.W., Calgary, Alberta T2P 3G4.

CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

Interim Consolidated Statements of Financial Position

(Canadian $000s) (unaudited)	March 31, 2016	December 31, 2015
ASSETS		
Current		
Accounts receivable (Note 10)	$ 7,932	$ 9,635
Prepaids and deposits	1,221	728
Fair value of commodity price contracts (Note 10)	6,013	7,984
	15,166	18,347
Exploration and evaluation (Note 3)	120,031	119,356
Property and equipment (Note 4)	317,798	302,955
	$ 452,995	$ 440,658
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities	$ 15,863	$ 15,007
	15,863	15,007
Bank indebtedness (Note 5)	70,452	57,077
Decommissioning liability (Note 6)	17,624	16,016
	103,939	88,100
Shareholders' equity		
Share capital (Note 7)	386,634	385,766
Contributed surplus (Note 8)	7,352	6,738
Deficit	(44,930)	(39,946)
	349,056	352,558
Commitments (Note 12)		
	$ 452,995	$ 440,658

See accompanying notes to the condensed interim consolidated financial statements.

On behalf of the Board:

Director

Director

Interim Consolidated Statements of Loss and Comprehensive Loss

(Canadian $000s except per-share amounts) (unaudited)	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015
Revenue		
Revenue from product sales	$ 16,121	$ 18,512
Royalties	(922)	(473)
Net revenue	$ 15,199	$ 18,039
Realized gain on commodity price contracts (Note 10)	3,705	7,359
Unrealized loss on commodity price contracts (Note 10)	(1,971)	(6,837)
Income from hedging activities	$ 1,734	$ 522
Expenses		
Production	8,193	7,624
Transportation	645	1,476
General and administrative (Note 12)	1,527	1,969
Share-based compensation (Note 8)	823	985
Depletion and depreciation (Note 4)	9,948	9,219
Exploration and evaluation costs expensed (Note 3)	-	103
Accretion (Note 6)	87	133
	21,223	21,509
Loss before the following:	(4,290)	(2,948)
Interest and finance costs	(684)	(617)
Unrealized revaluation loss on investments	(10)	-
Net loss for the period	(4,984)	(3,565)
Other comprehensive loss	-	(50)
Comprehensive loss for the period	$ (4,984)	$ (3,615)
Net loss per share (Note 9)		
- basic	$ (0.04)	$ (0.03)
- diluted	$ (0.04)	$ (0.03)

See accompanying notes to the condensed interim consolidated financial statements.

Interim Consolidated Statements of Changes in Shareholders' Equity

(Canadian $000s) (unaudited)				Three Months Ended March 31, 2016	
	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income	Total Equity
Balance, beginning of period	$ 385,766	$ 6,738	$ (39,946)	$ -	$ 352,558
Net loss for the period	-	-	(4,984)	-	(4,984)
Issue of common shares (Note 7)	659	-	-	-	659
Share-based compensation (Note 8)	-	823	-	-	823
Share-based compensation on options exercised (Note 7)	209	(209)	-	-	-
Balance, end of period	$ 386,634	$ 7,352	$ (44,930)	$ -	$ 349,056

(Canadian $000s) (unaudited)				Three Months Ended March 31, 2015	
	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income	Total Equity
Balance, beginning of period	$ 351,161	$ 3,363	$ (33,079)	$ 110	$ 321,555
Net loss for the period	-	-	(3,565)	-	(3,565)
Share-based compensation (Note 8)	-	985	-	-	985
Reversal of prior period unrealized gain on investments (Note 10)	-	-	-	(50)	(50)
Balance, end of period	$ 351,161	$ 4,348	$ (36,644)	$ 60	$ 318,925

See accompanying notes to the condensed interim consolidated financial statements.

Interim Consolidated Statements of Cash Flows

(Canadian $000s) (unaudited)	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015
Operating activities		
Net loss for the period	$ (4,984)	$ (3,565)
Non-cash items:		
Share-based compensation (Note 8)	823	985
Depletion, depreciation and accretion (Notes 4 and 6)	10,035	9,352
Exploration and evaluation costs expensed (Note 3)	-	103
Unrealized revaluation loss on investments (Note 10)	10	-
Unrealized loss on commodity price contracts (Note 10)	1,971	6,837
Net change in non-cash working capital items (Note 11)	2,890	225
	10,745	13,937
Financing activities		
Proceeds from issue of common shares (Note 7)	659	-
Increase in bank indebtedness	13,375	17,717
	14,034	17,717
Investing activities		
Additions to exploration and evaluation assets (Note 3)	(675)	(316)
Additions to property and equipment (Note 4)	(23,271)	(35,364)
Net change in non-cash working capital items (Note 11)	(833)	4,026
	(24,779)	(31,654)
Change in cash during the period	-	-
Cash, beginning of period	-	-
Cash, end of period	$ -	$ -

See accompanying notes to the condensed interim consolidated financial statements.

NOTES TO THE CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

As at and for the three months ended March 31, 2016 and 2015

Tabular amounts in thousands of Canadian dollars, except per-share amounts
(unaudited)

1. REPORTING ENTITY

Storm Resources Ltd. (the “Company” or "Storm"), is an oil and gas exploration and development company incorporated in the province of Alberta, Canada on June 8, 2010 and is listed on the TSX Venture Exchange under the symbol “SRX”. The Company operates primarily in the province of British Columbia with minor operations in Alberta and its head office is located at Suite 200, 640 – 5th Avenue S.W., Calgary, Alberta T2P 3G4. The Company became a reporting issuer in August 2010.

These unaudited condensed interim consolidated financial statements (the “financial statements”) include the accounts of Storm and its wholly owned subsidiary.

2. BASIS OF PRESENTATION

Statement of Compliance

The financial statements have been prepared in accordance with IAS 34 Interim Financial Reporting, based on International Financial Reporting Standards (“IFRS”) as issued and amended from time to time by the International Accounting Standards Board (“IASB”). The financial statements follow the same accounting policies and methods of computation as used in the audited consolidated financial statements for the years ended December 31, 2015 and 2014. The note disclosures do not include all disclosures applicable to annual audited consolidated financial statements. Accordingly, the financial statements should be read in conjunction with the audited consolidated financial statements as at and for the years ended December 31, 2015 and 2014 and the notes thereto.

These financial statements were authorized for issue by the Board of Directors on May 12, 2016.

Basis of Measurement

The Company’s financial statements have been prepared on a going concern basis consistent with prior years, and under the historical cost convention, except for certain financial assets and financial liabilities, which are measured at fair value, as explained in Note 10.

Use of Estimates and Judgments

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

Estimates and underlying assumptions are continuously reviewed with the financial statement effect being recognized in the reporting period changes to estimates are made.

Judgments applied by management to accounting policies that have the most significant effect on the amounts in the financial statements are described in Note 3 to the Company’s audited consolidated financial statements for the year ended December 31, 2015.

3. EXPLORATION AND EVALUATION

	Three Months Ended March 31, 2016	Year ended December 31, 2015
Balance, beginning of period	$ 119,356	$ 126,805
Additions	675	5,350
Exploration and evaluation expenditures expensed	-	(154)
Future decommissioning costs	-	313
Disposals	-	(2,843)
Transfer to property and equipment	-	(10,115)
Balance, end of period	$ 120,031	$ 119,356

4. PROPERTY AND EQUIPMENT

	Three Months Ended March 31, 2016	Year ended December 31, 2015
Cost		
Balance, beginning of period	$ 389,781	$ 379,207
Additions	23,271	89,749
Future decommissioning costs	1,520	1,831
Disposals	-	(91,121)
Transfer from exploration and evaluation assets	-	10,115
Balance, end of period	$ 414,572	$ 389,781
Accumulated depletion and depreciation		
Balance, beginning of period	$ (86,826)	$ (110,744)
Depletion and depreciation	(9,948)	(34,583)
Disposals	-	58,501
Reduction in carrying amount of property and equipment	-	-
Balance, end of period	$ (96,774)	$ (86,826)
Net book value, beginning of period	$ 302,955	$ 268,463
Net book value, end of period	$ 317,798	$ 302,955

Management reviewed the carrying amounts of exploration and evaluation and property and equipment assets for indicators of impairment at March 31, 2016 and none were identified.

5. BANK INDEBTEDNESS

As at March 31, 2016, the Company had an extendible revolving bank facility in the amount of $140.0 million (December 31, 2015 – $140.0 million) based on the Company's producing reserves. The revolving facility is available to the Company until April 28, 2017, at which time the borrowing base amount will be reviewed and the Company has the option to extend the facility for an additional year. If the revolving facility is not extended, the facility moves into a term phase whereby the loan is to be retired with one payment one year later, in an amount equal to the outstanding principal. Interest is paid on the revolving facility at bankers acceptance rates, plus a stamping fee. Collateral comprises a floating charge demand debenture on the assets of the Company. At March 31, 2016, the Company is in compliance with all covenants under the credit facility. The only financial covenant is that debt including working capital deficiency should not exceed the facility amount.

The Company has issued letters of credit in the amount of $4.2 million, which reduce the amount available under the Company's bank facility, in support of future gas transportation and processing obligations. (Note 12)

Subsequent to March 31, 2016 the Company's bank syndicate completed the annual borrowing base review with the result that the Company's credit facility was reduced to $130.0 million. No additional covenants were imposed.

6. DECOMMISSIONING LIABILITY

The Company provides for the future cost of decommissioning oil and gas production assets, including well sites, gathering systems and facilities. The total decommissioning obligation is estimated based on the Company's net ownership interest in wells and facilities, the estimated costs to abandon and reclaim the wells, gathering systems and facilities and the estimated timing of future costs. The total estimated undiscounted amount required to settle the Company's decommissioning obligation is approximately $28.2 million (December 31, 2015 - $25.6 million), which is expected to be paid over the next 25 years. A risk-free discount rate of 2.25% (December 31, 2015 – 2.25%) and an inflation rate of 1.9% (December 31, 2015 – 1.9%) was used to calculate the present value of the decommissioning obligation, amounting to $17.6 million.

The following table provides a reconciliation of the carrying amount of the obligation:

	Three Months Ended March 31, 2016	Year Ended December 31, 2015
Balance, beginning of period	$ 16,016	$ 23,553
Obligations incurred	1,521	1,961
Obligations disposed	-	(10,122)
Change in rate estimates(1)	-	(68)
Change in cost estimates(2)	-	251
Accretion expense	87	441
Balance, end of period	$ 17,624	$ 16,016

(1) Relates to changes in the inflation and discount rates.
(2) Cost estimates were adjusted based on actual costs for abandonments and reclamations.

7. SHARE CAPITAL

Authorized

An unlimited number of voting common shares without nominal or par value
An unlimited number of first preferred shares without nominal or par value

Issued

	Number of Common Shares	Consideration
Balance as at December 31, 2014	111,322	$ 351,161
Shares issued pursuant to private placement(1)	8,000	36,400
Share issue costs(1)	-	(2,149)
Shares issued on stock option exercises(2)	145	354
Balance as at December 31, 2015	119,467	$ 385,766
Shares issued on stock option exercises(3)	275	868
Balance as at March 31, 2016	119,742	$ 386,634

(1) On June 10, 2015 the Company issued 8,000,000 common shares, pursuant to a bought deal financing, at a price of $4.55 per common share for gross proceeds of $36,400,000 before issue costs of approximately $2.1 million.

(2) During 2015, 145,000 common shares were issued upon the exercise of stock options for proceeds of $262,000 and related prior period share-based compensation of $92,000 was transferred to share capital from contributed surplus.

(3) During the first three months of 2016, 275,000 common shares were issued upon the exercise of stock options for proceeds of $659,000 and related prior period share-based compensation of $209,000 was transferred to share capital from contributed surplus.

8. SHARE-BASED COMPENSATION

The Company has a stock option plan under which it may grant, at the Company's discretion, options to purchase common shares to directors, officers and employees. Options are granted at the market price of the shares on the last business day prior to the date of grant, have a four-year term and vest in tranches of one third over three years. Under the stock option plan, at March 31, 2016, a total of 11,974,181 common shares were available for issuance. Options in respect of 10,008,500 common shares have been issued, of which 2,580,500 have been exercised or cancelled at March 31, 2016. Options in respect of 7,428,000 common shares were issued and outstanding at March 31, 2016, with options in respect of 4,546,181 common shares available for future issue.

At May 12, 2016, the date of this quarterly report, 11,978,681 common shares are available for issuance and options in respect of 7,383,000 common shares are currently issued and outstanding, leaving options in respect of 4,595,681 common shares available for future grants.

Details of the options outstanding at March 31, 2016 are as follows:

	Number of Options (000s)	Weighted Average Exercise Price
Outstanding at December 31, 2014	5,957	$ 3.54
Granted during the year	1,941	$ 3.38
Exercised during the year	(145)	$ 1.81
Outstanding at December 31, 2015	7,753	$ 3.53
Exercised during the period	(275)	$ 2.40
Cancelled during the period	(50)	$ 4.20
Outstanding at March 31, 2016	7,428	$ 3.57
Number exercisable at March 31, 2016	3,594	$ 3.19

Range of Exercise Price	Outstanding Options			Exercisable Options	
	Number of Options Outstanding (000s)	Weighted Average Remaining Life (years)	Weighted Average Exercise Price	Number of Options Outstanding (000s)	Weighted Average Exercise Price
$1.75 - $2.63	1,767	0.7	$ 1.77	1,767	$ 1.77
$2.64 - $3.95	1,881	3.7	$ 3.35	-	$ -
$3.96 - $5.20	3,780	2.3	$ 4.52	1,827	$ 4.57
Total	7,428	2.3	$ 3.57	3,594	$ 3.19

The fair value of employee stock options is measured using the Black-Scholes option pricing model. Measurement inputs include the share price on measurement date, exercise price of the instrument, expected volatility, forfeiture rate, weighted average expected life of the instruments (based on historical experience and general option holder behaviour), expected dividends and the risk-free interest rate (based on government bonds).

No options were granted in the first quarters of 2016 and 2015.

Share-based compensation expense of $823,000 was charged to the consolidated statement of loss during the three months to March 31, 2016 (2015 - $985,000) with an equivalent offset to contributed surplus. Volatility is based on the historical trading price variances of the Company's share price using market data.

9. NET INCOME (LOSS) PER SHARE

Basic and diluted net income (loss) per share were calculated as follows:

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015
Net loss for the period	$ (4,984)	$ (3,565)
Weighted average number of common shares outstanding – basic		
Common shares outstanding at beginning of period	119,467	111,322
Effect of shares issued	124	-
Weighted average number of common shares outstanding – basic	119,591	111,322
Effect of outstanding options	-	-
Weighted average number of common shares outstanding - diluted	119,591	111,322
Net loss per share		
- basic	$ (0.04)	$ (0.03)
- diluted	$ (0.04)	$ (0.03)

At March 31, 2016 and 2015, all outstanding stock options were considered anti-dilutive as the Company was in a loss position.

10. FINANCIAL INSTRUMENTS

The fair value of the Company's commodity contracts described below is based on forward prices of commodities available in the market place and they are therefore classified as Level 2 financial instruments.

Risk Management

Credit risk

Credit risk is the risk of financial loss to the Company if a customer, joint venture partner or counterparty to a financial instrument fails to meet its contractual obligations. The maximum exposure to credit risk at March 31, 2016 is as follows:

		Carrying Amount as at March 31, 2016
Accounts receivable	$	7,932
Fair value of commodity price contracts		6,013
Total	$	13,945

Derivative Contracts

The Company enters into derivative contracts with counterparties with an acceptable credit rating and with a demonstrated capability to execute such contracts. The contracts, individually and in aggregate, are subject to controls established by the Board of Directors and limitations set out in the Company's banking agreement.

Accounts receivable

The Company's accounts receivable tend to be concentrated with a limited number of marketers of the Company's production as well as joint venture partners and are subject to normal industry credit risk. The Company's production is sold to organizations whose credit worthiness is assessable from publicly available information. The Company attempts to mitigate the risk from joint venture receivables by obtaining pre-approval and cash call deposits from its partners in advance of significant capital expenditures. The Company does not typically obtain collateral from joint venture partners.

No default on outstanding receivables is anticipated as none of the Company's outstanding receivables are considered past due at March 31, 2016.

Market risk

Commodity Prices

At the date of this report, Storm has the undernoted commodity price contracts in place.

Period Hedged	Daily Volume	Average Price
Crude Oil Collar		
Apr – Dec 2016	500 Bbls	$75.00 - $90.75 Cdn$/Bbl
Natural Gas Swaps		
Apr – Dec 2016	20,000 GJ	AECO Cdn$2.98/GJ
Natural Gas Differential Swaps		
Apr – Dec 2016	11,000 GJ	Price at Stn 2 = AECO minus Cdn$0.3375/GJ
Jan – Dec 2017	5,000 GJ	Price at Stn 2 = AECO minus Cdn$0.445/GJ
Apr – Dec 2016	33,000 Mmbtu	Price at Chicago = AECO plus US$0.672/Mmbtu
Jan – Dec 2017	35,000 Mmbtu	Price at Chicago = AECO plus US$0.577/Mmbtu

The fair market value of these contracts of $6.0 million (December 31, 2015 – $8.0 million) is included in current assets. For the three months ended March 31, 2016, this resulted in an unrealized mark-to-market loss of $2.0 million (2015 – loss of $6.8 million) when measured against the fair market value at the end of the preceding reporting period.

During the three months ended March 31, 2016, the Company realized gains from commodity price contracts in place or terminated in the amount of $3.7 million (2015 – gains of $7.4 million).

Sensitivities

Using the Company's actual production volumes, royalty rates and bank indebtedness for the first three months of 2016, the estimated after-tax effect that changes in certain factors would have on net income and net income per share is set out below:

	Three Months Ended March 31, 2016	
Factor	Change in Net Income	Change in Net Income Per Share
US$1.00/Bbl change in the price of WTI(1)	$ 270,000	$ -
$0.10/Mcf change in the price of natural gas	$ 580,000	$ -
1% change in the interest rate	$ 690,000	$ 0.01

(1) A portion of the Company's NGL production is sold at a price based on WTI.

The Company's income tax assets are sufficient to eliminate taxes payable on any increases to income resulting from above; accordingly, before and after tax amounts are the same.

11. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital

	Three months Ended March 31, 2016	Three Months Ended March 31, 2015
Accounts receivable	$ 1,693	$ (1,289)
Prepaids and deposits	(493)	(2,231)
Accounts payable and accrued liabilities	857	7,771
Change in non-cash working capital	$ 2,057	$ 4,251
Relating to:		
Operating activities	$ 2,890	$ 225
Investing activities	(833)	4,026
	$ 2,057	$ 4,251
Interest paid during the period	$ 573	$ 519
Income taxes paid during the period	$ -	$ -

12. COMMITMENTS

The Company has the following long-term commitments over the next five years:

	2016	2017	2018	2019	2020	Total
Office lease	$ 708	$ 943	$ 708	$ -	$ -	$ 2,359
Natural gas sales commitments	32,355	42,187	36,777	22,187	19,630	153,136
Total	$ 33,063	$ 43,130	$ 37,485	$ 22,187	$ 19,630	$ 155,495

In the first quarter of 2016, the Company made office lease payments of approximately $236,000 (2015 - $231,000) which were included in general and administrative expense.

CORPORATE INFORMATION

Officers

Brian Lavergne
President & CEO

Robert S. Tiberio
Chief Operating Officer

Donald G. McLean
Chief Financial Officer

John Devlin
Vice President, Finance

Jamie P. Conboy
Vice President, Geology

H. Darren Evans
Vice President, Exploitation

Bret A. Kimpton
Vice President, Production

Directors

Matthew J. Brister (2)(3)

John A. Brussa

Mark A. Butler (1)(3)

Stuart G. Clark (1)
Chairman

Brian Lavergne
CEO

Gregory G. Turnbull (2)

P. Grant Wierzba (2)(3)

James K. Wilson (1)

(1) Member, Audit Committee (2) Member, Reserves Committee (3) Member, Compensation, Governance and Nomination Committee

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Stock Exchange Listing

TSX Venture Exchange
Trading Symbol "SRX"

Solicitors

McCarthy Tétrault LLP
Burnet Duckworth & Palmer LLP
Calgary, Alberta

Auditors

Ernst & Young LLP
Calgary, Alberta

Registrar & Transfer Agent

Alliance Trust Company
Calgary, Alberta

Bankers

ATB Financial
Canadian Imperial Bank of Commerce
Royal Bank of Canada
Calgary, Alberta

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Abbreviations

3-D	Three-dimensional
API	American Petroleum Institute
Bbls	Barrels of oil or natural gas liquids
Bbls/d	Barrels per day
Bcf	Billions of cubic feet
Bcfe	Billions of cubic feet equivalent
Boe	Barrels of oil equivalent
Boe/d	Barrels of oil equivalent per day
Bopd	Barrels of oil per day
Btu	British thermal unit
Cdn$	Canadian dollar
CGU	Cash generating unit
DPIIP	Discovered Petroleum Initially in Place
GJ	Gigajoules
GJ/d	Gigajoules per day
kPa	One thousand pascals
LMR	Liability Management Rating
Mbbls	Thousands of barrels
Mboe	Thousands of barrels of oil equivalent
Mcf	Thousands of cubic feet
Mcf/d	Thousands of cubic feet per day
Mmbbls	Millions of barrels
Mmboe	Millions of barrels of oil equivalent
Mmbtu	Millions of British Thermal Units
Mmbtu/d	Millions of British Thermal Units per day
Mmcf	Millions of cubic feet
Mmcf/d	Millions of cubic feet per day
Mstb	Thousand stock tank barrels
NAV	Net Asset Value
NGL	Natural gas liquids
NPV	Net present value
OGIP	Original Gas in Place
OPEC	Organization of Petroleum Exporting Countries
psig	pounds per square inch gage pressure
Scf/ton	Standard cubic foot per ton
STOOIP	Stock Tank Original Oil in Place
Tcf	Trillions of cubic feet
TSX	Toronto Stock Exchange
US	United States
US$	United States dollar
WTI	West Texas Intermediate

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