Birchcliff Energy Ltd.

2015

STAYING THE COURSE

ANNUAL REPORT

FINANCIAL AND OPERATIONAL HIGHLIGHTS

	Three months ended December 31,		Twelve months ended December 31,	
	2015	**2014**	**2015**	**2014**
OPERATING				
Average daily production				
Light oil – *(barrels)*	3,530	3,957	3,707	3,957
Natural gas – *(thousands of cubic feet)*	211,127	192,499	201,418	169,852
NGL – *(barrels)*	1,727	1,664	1,673	1,469
Total – barrels of oil equivalent *(6:1)*(1)	**40,445**	**37,704**	**38,950**	**33,734**
Average sales price *($ CDN)*(2)				
Light oil – *(per barrel)*	49.36	71.87	53.68	92.39
Natural gas – *(per thousand cubic feet)*	2.67	3.91	2.90	4.74
NGL – *(per barrel)*	47.98	66.10	50.76	85.13
Total – barrels of oil equivalent *(6:1)*(1)	**20.28**	**30.43**	**22.31**	**38.39**
NETBACK AND COST *($ per barrel of oil equivalent at 6:1)*(1)				
Petroleum and natural gas revenue(2)	20.28	30.44	22.32	38.41
Royalty expense	(0.94)	(1.84)	(0.81)	(2.99)
Operating expense	(4.16)	(5.33)	(4.54)	(5.22)
Transportation and marketing expense	(2.31)	(2.39)	(2.45)	(2.43)
Netback(3)	**12.87**	**20.88**	**14.52**	**27.77**
General & administrative expense, net	(2.01)	(2.02)	(1.61)	(1.81)
Interest expense	(1.80)	(1.42)	(1.60)	(1.57)
Realized gain on financial instruments	-	0.35	-	0.01
Funds flow netback(3)	**9.06**	**17.79**	**11.31**	**24.40**
Stock-based compensation expense, net	(0.21)	(0.26)	(0.23)	(0.39)
Depletion and depreciation expense	(9.66)	(11.17)	(10.35)	(11.07)
Accretion expense	(0.15)	(0.16)	(0.16)	(0.20)
Amortization of deferred financing fees	(0.06)	(0.06)	(0.06)	(0.08)
Gain on sale of assets	1.80	0.91	0.52	0.26
Unrealized gain on financial instruments	-	0.05	-	0.03
Dividends on Series C preferred shares	(0.24)	(0.25)	(0.25)	(0.28)
Income tax expense	(3.05)	(1.93)	(1.64)	(3.39)
Net income (loss)	**(2.51)**	**4.92**	**(0.86)**	**9.28**
Dividends on Series A preferred shares	(0.26)	(0.29)	(0.28)	(0.32)
Net income (loss) to common shareholders	**(2.77)**	**4.63**	**(1.14)**	**8.96**
FINANCIAL				
Petroleum and natural gas revenue *($000s)*(2)	75,476	105,598	317,304	472,888
Funds flow from operations *($000s)*(3)	33,697	61,717	160,756	300,498
Per common share – basic *($)*(3)	0.22	0.41	1.06	2.03
Per common share – diluted *($)*(3)	0.22	0.40	1.04	1.97
Net income (loss) *($000s)*	(9,322)	17,053	(12,160)	114,304
Net income (loss) to common shareholders *($000s)*	(10,322)	16,053	(16,160)	110,304
Per common share – basic *($)*	(0.07)	0.11	(0.11)	0.75
Per common share – diluted *($)*	(0.07)	0.10	(0.11)	0.72
Common shares outstanding *(000s)*				
End of period – basic	152,308	152,214	152,308	152,214
End of period – diluted	167,817	166,302	167,817	166,302
Weighted average common shares for period – basic	152,308	152,183	152,286	147,764
Weighted average common shares for period – diluted	153,627	155,304	154,078	152,243
Dividends on Series A preferred shares *($000s)*	1,000	1,000	4,000	4,000
Dividends on Series C preferred shares *($000s)*	875	875	3,500	3,500
Capital expenditures, net *($000s)*	33,533	109,682	247,207	450,932
Long-term bank debt *($000s)*	622,074	469,033	622,074	469,033
Working capital deficit *($000s)*	21,538	76,712	21,538	76,712
Total debt *($000s)*(3)	643,612	545,745	643,612	545,745

(1) See "*Advisories*" in this Annual Report.

(2) Excludes the effect of hedges using financial instruments.

(3) Please see "*Non-GAAP Measures*" in this Annual Report.

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Birchcliff Energy Ltd. is an intermediate oil and gas company based in Calgary, Alberta, with operations concentrated within one core area, the Peace River Arch of Alberta.

We had record annual average production in 2015 of 38,950 boe per day, which represents a 15% increase over our 2014 annual average production of 33,734 boe per day.

Our strategy is to continue to develop and expand our two very large resource plays in the Peace River Arch, the Montney/Doig Natural Gas Resource Play and the Charlie Lake Light Oil Resource Play, while maintaining low capital costs and operating costs. These resource plays are large enough to provide us with an extensive inventory of repeatable, consistent, low-cost and low-risk drilling opportunities that we expect will provide production and reserves growth for many years.

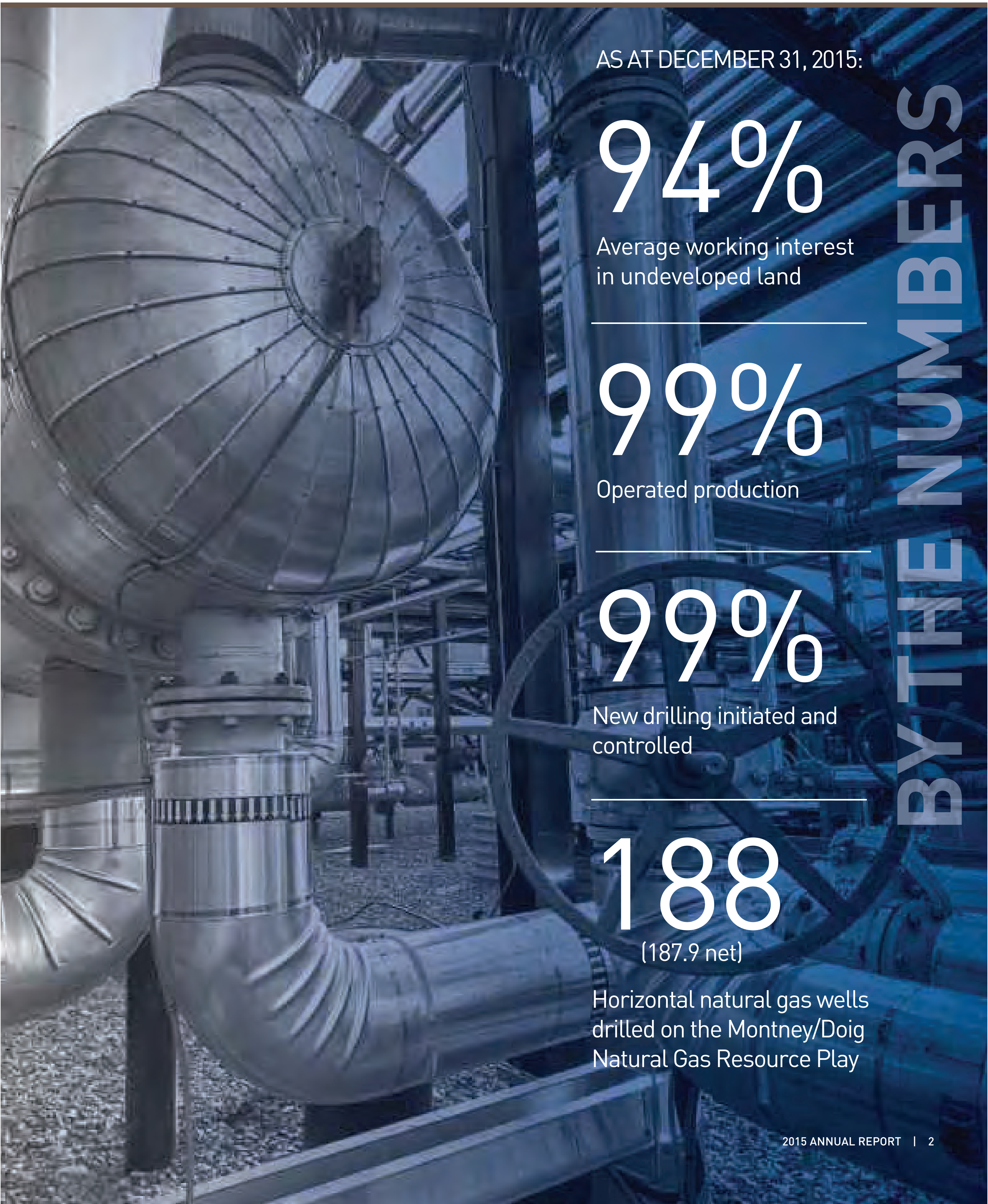
We continue to execute on our business strategy of operating essentially all of our high working interest production, which is surrounded by large contiguous blocks of high working interest lands where we own and/or control the infrastructure. Our operatorship, land position and infrastructure ownership give us a competitive advantage over our competitors in our areas of operation and supports our low finding and development ("**F&D**") costs and low operating cost structure, which helps us maximize our funds flow especially in a low commodity price environment. We believe that our 2015 F&D costs and operating costs rank as some of the lowest in the industry and we will continue to seek opportunities to reduce our costs further.

As at December 31, 2015, we have successfully drilled 188 (187.9 net) Montney/Doig horizontal natural gas wells. The key to making money from these wells is through our 100% owned and operated natural gas plant located in the Pouce Coupe South area of Alberta (the "**PCS Gas Plant**"). The PCS Gas Plant is the cornerstone of our strategy to develop our Montney/Doig Natural Gas Resource Play, to control and expand our production on the play and to further reduce our operating costs per boe. Since the PCS Gas Plant first became operational in March 2010, we have seen a significant reduction in our operating and processing costs to $0.31 per Mcf for gas processed at the PCS Gas Plant.

Our common shares are listed on the TSX under the symbol BIR and are included in the S&P/TSX Composite Index. Our Series A and Series C Preferred Shares are listed for trading on the TSX under the symbols BIR.PR.A and BIR.PR.C, respectively.

At March 16, 2016, Birchcliff had an enterprise value of approximately $1.5 billion.

*This Annual Report contains forward-looking information within the meaning of applicable securities laws. Such forward-looking information is based upon certain expectations and assumptions and actual results may differ materially from those expressed or implied by such forward-looking information. For further information regarding the forward-looking information contained herein, see "Advisories – Forward-Looking Information" in this Annual Report. In addition, this Annual Report contains references to "funds flow", "funds flow from operations", "funds flow per common share", "adjusted net income to common shareholders", "netback", "operating netback", "estimated operating netback", "funds flow netback", "operating margin", "total operating costs", "total cash costs", "profit before non-cash items", "profit margin" and "total debt", which do not have standardized meanings prescribed by generally accepted accounting principles ("**GAAP**") and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. For further information, see "Non-GAAP Measures" in this Annual Report and in the management's discussion and analysis for the year ended December 31, 2015 (the "**MD&A**").*



BY THE NUMBERS

AS AT DECEMBER 31, 2015:

94%

Average working interest in undeveloped land

99%

Operated production

99%

New drilling initiated and controlled

188

(187.9 net)

Horizontal natural gas wells drilled on the Montney/Doig Natural Gas Resource Play

MESSAGE TO SHAREHOLDERS

Dear Fellow Shareholder:

2015 proved to be a very challenging year for our industry. The AECO natural gas spot price averaged CDN$2.69 per Mcf in 2015, down 40% from 2014, and the WTI oil spot price averaged US$48.80 per bbl, down 48% from 2014. Commodity prices thus far in 2016 have continued to remain under pressure as supply continues to outpace the demand for oil and natural gas.

Despite the challenging business environment, we believe that we delivered results for 2015 that are top decile in the industry. Our results are a reflection of our business strategy. We are very focused, we have essentially 100% working interests in our lands and production, we operate virtually all of our production and we own and/or control most of our infrastructure, all of which leads to very low F&D and operating costs. We remain focused on developing our Montney/Doig Natural Gas Resource Play and our Charlie Lake Light Oil Resource Play. We are employing the same people and services, in the same areas of Alberta, using up-to-date leading edge technology to develop our areally extensive assets. This focus has ultimately defined our success. As a result of our high quality asset base, our forecast base production decline for 2016 is low at approximately 20%, which gives us the ability to spend less to keep production flat. Most importantly, our people are our best asset. They provide us with the knowledge and fierce competitiveness to achieve the excellent results reviewed below.

As a result of these attributes, we believe that we are in a unique position to "weather the storm" and we expect to continue to unlock value for our shareholders by developing our high quality resource plays.

2015 FINANCIAL AND OPERATING RESULTS

We had record annual average production in 2015 of 38,950 boe per day, which represents a 15% increase over our 2014 annual average production of 33,734 boe per day. We achieved this record production notwithstanding the numerous firm and interruptible service curtailments on TransCanada's NGTL System that affected us during 2015.

Funds flow was $160.8 million, a 47% decrease from 2014, which is largely a result of the decrease in commodity prices. After excluding two one-time, non-operational, deferred income tax expense items in the aggregate amount of $18.0 million, we recorded adjusted net income to common shareholders of $1.8 million in 2015. Net loss to common shareholders, which includes these one-time expense items, was $16.2 million.

We had record low operating costs of $4.54 per boe and record low general and administrative expense of $1.61 per boe during 2015, which we believe are some of the lowest in our industry. Our operating costs were down 13% and our general and administrative expense was down 11% from 2014. Operating costs per boe decreased from 2014 largely due to the continued cost benefits achieved from processing incremental volumes of natural gas through our PCS Gas Plant, the continued implementation of various cost saving and optimization initiatives and lower service costs due to reduced industry activity.

As a result of the strong production performance from our Montney/Doig horizontal natural gas wells drilled in 2015, 2014 and 2013 and the new reserves established by our 2015 drilling program, we achieved material increases to our proved developed producing, total proved and proved plus probable reserves volumes at year-end 2015.

As at December 31, 2015, our proved developed producing reserves were estimated to be 102.1 MMboe (a 21% increase from December 31, 2014), our proved reserves were estimated to be 351.2 MMboe (a 24% increase from December 31, 2014) and our proved plus probable reserves were estimated to be 572.9 MMboe (a 23% increase from December 31, 2014). The future net revenue attributable to our proved plus probable reserves (discounted at 10%, before income taxes) increased slightly to approximately $3.9 billion from $3.8 billion in 2014, notwithstanding materially lower commodity price forecasts.

Positive technical revisions accounted for 17% of the proved developed producing reserves additions, 31% of the proved reserves additions and 29% of the proved plus probable reserves additions in 2015. These positive revisions for proved and proved plus probable reserves, which did not require any increase to future development capital ("**FDC**"), resulted from our independent qualified reserves evaluator's recognition of improved well production performance from our 2015, 2014 and 2013 drilling programs. These technical revisions primarily resulted from the continued advancement of our drilling and completion technologies and improved well production performance on some of our existing wells. Improved well performance, coupled with reduced well costs, resulted in top-tier reserves and production capital efficiencies.

Our all-in proved developed producing reserves were added at a record low of $7.79 per boe during 2015. We added proved developed producing reserves for approximately 2/3 of the funds flow netback we received on the sale of production, which is a good measure of a low-cost finder and producer of oil and gas.

We achieved the above while posting an operating netback recycle ratio of 1.9 times and a funds flow netback recycle ratio of 1.5 times on our proved developed producing reserves. We are confident that our business is economically viable in the current commodity price environment and our operational execution has been on budget and on time.

As at December 31, 2015, we have 3,367.3 potential net future horizontal drilling locations on our Montney/Doig Natural Gas Resource Play. Our independent qualified reserves evaluator assigned proved plus probable reserves to only 513.9 potential net future drilling locations in our independent reserves evaluation effective December 31, 2015, leaving significant additional upside for production and reserves in the future.

OUTLOOK FOR 2016

With respect to 2016, we continue to see our production outperform our original estimates and our capital costs and operating costs per boe continue to fall. It is noteworthy that wells drilled in previous years continue to show lower than expected declines, which bolsters our average production rates and also gives us the ability to drill less wells and spend less capital to meet our previous guidance of modest growth. As a result, we have recently reduced our budgeted 2016 capital expenditures by approximately $12 million to approximately $128 million (the "**2016 Revised Capital Budget**"), down from our original capital expenditure program of $140 million. The 2016 Revised Capital Budget is projected to be less than our expected funds flow for 2016, assuming an average WTI price of US$40.00 per barrel of oil and an average AECO price of CDN$2.50 per GJ of natural gas during 2016.

As a result of our strong production performance to date in 2016, we are maintaining our annual average production guidance for 2016 at 40,000 to 41,000 boe per day, notwithstanding the decrease in capital expenditures under the 2016 Revised Capital Budget. This represents an increase of 3% to 5% over our 2015 annual average production.

Based on our 2016 Revised Capital Budget, our costs to drill, case, complete, equip and tie-in our Montney/Doig horizontal natural gas wells are expected to average approximately $4.0 million per well during 2016. The combination of these decreased capital costs and the improved well performance that we are now realizing is expected to have a positive effect on our reserves and production capital efficiencies and internal rates of return.

If in 2017 commodity prices remain low, we believe we could spend approximately $90 million of capital and run flat between 40,000 to 41,000 boe per day.

Our $800 million revolving credit facilities have a three-year term to May 11, 2018 and contain no financial covenants. As at December 31, 2015, our long-term bank debt was $622.1 million from available credit facilities of $800 million, which provides us with continued financial flexibility.

These attributes have positioned us to withstand the current collapse in commodity prices. As a result of operating essentially all of our production and having virtually 100% working interests and control of most of our infrastructure, we have the flexibility to speed up or slow down our capital expenditures very quickly to react to changes in commodity prices.

We remain focused on our strategy, growth by the drill bit, in our core area of the Peace River Arch of Alberta. We continue to use the same services, in the same area, directed by the same experienced Birchcliff personnel, which provides consistency, repeatability and reliability in our operations.

We thank Mr. Seymour Schulich, our largest shareholder, for his advice, unwavering commitment and his ongoing financial support. Mr. Schulich holds 42 million common shares representing 27.6% of the current issued and outstanding common shares. His purchase of 2 million common shares in December 2015 at $3.90 per share is a recent example of his extraordinary commitment to Birchcliff when both our stock price and the oil and natural gas industry were under serious pressure from the negative sentiment from low commodity prices.

On behalf of our management team and our board of directors, I thank all of our staff for their hard work and dedication to the achievement of our corporate goals. Thank you to all of our shareholders for your continued support and trust in all of us at Birchcliff.

Jeff Tonken

A. Jeffery Tonken
President and Chief Executive Officer

EXECUTIVE TEAM

Drawing on extensive backgrounds in the energy sector, our executive team brings a rich portfolio of skills and experience to Birchcliff's business operations.

MYLES BOSMAN,
VICE-PRESIDENT, EXPLORATION
AND CHIEF OPERATING OFFICER

BRUNO GEREMIA,
VICE-PRESIDENT AND
CHIEF FINANCIAL OFFICER

JEFF TONKEN,
PRESIDENT AND
CHIEF EXECUTIVE OFFICER

Under the oversight of our board of directors, our executive team collectively drives our day-to-day pursuit of operational excellence, while identifying and pursuing responsible growth opportunities. Deeply invested in our success and unified by a genuine sense of camaraderie, our executive team works together to provide effective leadership and strategic direction.

DAVE HUMPHREYS,
VICE-PRESIDENT,
OPERATIONS

JIM SURBEY,
VICE-PRESIDENT,
CORPORATE DEVELOPMENT

CHRIS CARLSEN,
VICE-PRESIDENT,
ENGINEERING

MANAGEMENT TEAM

Our management team and our people are Birchcliff's best asset. Birchcliff's management team is comprised of talented, high performing individuals who are driven to help Birchcliff succeed.

1. **JEFF ROGERS,** FACILITIES MANAGER
2. **GATES AURIGEMMA,** MANAGER, GENERAL ACCOUNTING
3. **PERRY BILLARD,** ASSET TEAM LEAD – NORTH
4. **ROBYN BOURGEOIS,** GENERAL COUNSEL
5. **WAYNE BROWN,** PRODUCTION MANAGER
6. **BRUCE PALMER,** MANAGER OF GEOLOGY
7. **RYAN SLOAN,** HEALTH, SAFETY AND ENVIRONMENT MANAGER
8. **RANDY ROUSSON,** DRILLING & COMPLETIONS MANAGER

With guidance from our executive team, Birchcliff's management team is instrumental in executing our business strategy and managing our day-to-day operations.

9 10 11 12 13 14 15 16 17

9. **ANDREW FULFORD,**
SURFACE LAND MANAGER

10. **GEORGE FUKUSHIMA,**
MANAGER OF ENGINEERING

11. **THEO VAN DER WERKEN,**
ASSET TEAM LEAD – WEST

12. **MICHELLE RODGERSON,**
OFFICE MANAGER

13. **JESSE DOENZ,**
CONTROLLER & INVESTOR RELATIONS MANAGER

14. **BILL PARTRIDGE,**
ASSET TEAM LEAD – EAST

15. **HUE TRAN,**
JOINT VENTURE AND MARKETING MANAGER

16. **ROBERT (BOB) GRISACK,**
LAND MANAGER

17. **PAUL MESSER,**
MANAGER OF INFORMATION TECHNOLOGY

OUR HISTORY

Birchcliff was incorporated as a private corporation on July 6, 2004 and in September 2004, it assembled a management team and began hiring a full technical team and a small complement of administrative staff. On January 18, 2005, Birchcliff amalgamated with Scout Capital Corp. pursuant to a plan of arrangement to form an amalgamated corporation that continued under the name "Birchcliff Energy Ltd." and on the same day it raised gross proceeds of approximately $60 million from the issuance of equity.

The following describes the major events in our history:

2004

Jul 6, 2004
Birchcliff incorporated as a private corporation

2005

Jan 18, 2005
Completed Scout amalgamation and equity financing of $60 million

Jan 19, 2005
Common shares commenced trading on the TSX Venture Exchange

Feb 6, 2005
Rig released first Montney/Doig vertical exploration gas well drilled by Birchcliff in the Pouce Coupe area

May 31, 2005
Completed acquisition of properties in the Peace River Arch for $242.8 million, including a significant undeveloped land position on the Montney/Doig Natural Gas Resource Play

Jul 21, 2005
Common shares commenced trading on the TSX

2007

Sep 22, 2007
Rig released first Montney/Doig horizontal natural gas well drilled by Birchcliff utilizing multi-stage fracture stimulation technology in the Pouce Coupe area

Since we started back in 2004, we have invested approximately $2.7 billion in capital, primarily in the Montney/Doig Natural Gas Resource Play and the Charlie Lake Light Oil Resource Play. These investments have generated $2.5 billion in revenue, paid $254 million in royalties to Albertans and delivered $1.3 billion in funds flow from operations, all of which has been re-invested. As at December 31, 2015, the net present value of the future net revenue attributable to our proved plus probable reserves (at a 10% discount rate, before income taxes) is $3.9 billion as estimated by Deloitte LLP ("**Deloitte**"), our independent qualified reserves evaluator.

Sep 27, 2007
Completed acquisition of the Worsley Property on the Worsley Charlie Lake Light Oil Resource Play for $270 million

2008

Mar 4, 2008
Rig released first Charlie Lake horizontal light oil well drilled by Birchcliff utilizing multi-stage fracture stimulation technology in the Worsley area

2010

Mar 20, 2010
Phase I of the PCS Gas Plant commenced operations with a processing capacity of 30 MMcf per day

Nov 2, 2010
Phase II of the PCS Gas Plant commenced operations with a combined processing capacity of 60 MMcf per day

2012

Oct 2, 2012
Phase III of the PCS Gas Plant commenced operations with a combined processing capacity of 150 MMcf per day

2014

Sep 1, 2014
Completed construction of Phase IV of the PCS Gas Plant with a combined processing capacity of 180 MMcf per day

2015

Dec 31, 2015
188 (187.9 net) Montney/Doig Horizontal Natural Gas Wells successfully drilled to date

FINANCIAL PERFORMANCE

The following table highlights our corporate annual profit before non-cash items during the last six years (coinciding with the period during which the PCS Gas Plant was operational), after taking into account the cost to find and develop our proved developing producing reserves, total cash costs to produce our oil and natural gas and the cash distributions on our preferred shares:

	6 year Avg.	2015	2014	2013	2012	2011	2010
WTI Cushing *($US/bbl)*	**$84.77**	$48.80	$92.99	$97.97	$94.21	$95.10	$79.52
AECO – C Daily *($/MMbtu)*	**$3.40**	$2.69	$4.50	$3.15	$2.39	$3.63	$4.01
Petroleum and Natural Gas Revenue *($/Mcfe)*	**$5.44**	$3.72	$6.40	$5.59	$5.13	$6.66	$6.62
PDP FD&A *($/Mcfe)*(1)	**($2.02)**	($1.30)	($2.14)	($2.12)	($2.06)	($2.71)	($2.44)
Total Cash Costs *($/Mcfe)*(2)	**($2.50)**	($1.83)	($2.34)	($2.59)	($2.73)	($3.37)	($3.13)
Dividend Payout *($/Mcfe)*(3)	**($0.07)**	($0.09)	($0.10)	($0.10)	($0.03)	-	-
Profit Before Non-Cash Items *($/Mcfe)*(4)	**$0.85**	**$0.50**	**$1.82**	**$0.78**	**$0.31**	**$0.58**	**$1.05**
Profit Margin – Corporate *(%)*(4)	**16%**	**13%**	**28%**	**14%**	**6%**	**9%**	**16%**

(1) Cost to find and develop proved developed producing (PDP) reserves based on finding, development and acquisition ("**FD&A**") costs.
(2) Comprised of royalty, operating, transportation and marketing, general and administrative and interest expenses.
(3) Cash distributions on Birchcliff's Series A and Series C preferred shares.
(4) Profit before non-cash items measures the amount, if any, during the relevant period by which revenues resulting from production exceed the sum of: (i) PDP FD&A (i.e. the costs of replacing production), (ii) royalty, operating and transportation and marketing expenses and, in the case of Birchcliff at the business-entity level, (iii) general and administrative expense, (iv) interest expense and (v) preferred share dividends. This measure is not intended to represent net income or net income to common shareholders as presented in accordance with IFRS. Profit margin is calculated by dividing profit before non-cash items for the period by petroleum and natural gas revenue for the period. We believe that profit before non-cash items and profit margin are useful measures as they assist management and investors in assessing our ability during a period of declining commodity prices to bear all of our total cash costs and the costs of replacing our production during the relevant period. Birchcliff had previously referred to profit before non-cash items as "profit". See *"Non-GAAP Measures"* in this Annual Report.

This measure demonstrates that we can find, develop and produce our reserves for less than what we receive in revenue from our production.

In 2015, we generated a profit before non-cash items of $0.50 per Mcfe down from $1.82 per Mcfe in 2014, notwithstanding a 40% decline in the average AECO natural gas spot price and a 48% decline in the average WTI USD oil price from last year.

On average during the last six years in which the PCS Gas Plant was operational, we generated a profit before non-cash items of $0.85 per Mcfe (a 16% profit margin) when the AECO natural gas spot price averaged $3.40 per Mcf. In 2012, when the AECO natural gas spot price averaged a low of $2.39 per Mcf, we were able to generate a profit before non-cash items of $0.31 per Mcfe, highlighting the low-cost nature of our asset base.

"In 2015, we generated a corporate profit margin of 13%, after taking into account the cost to find, develop and produce our oil and natural gas and pay our preferred share dividends."

BRUNO GEREMIA,
VICE-PRESIDENT AND CHIEF FINANCIAL OFFICER

2015 Corporate Financial Performance

In 2015, we had record annual average production, record low operating costs and delivered top-tier industry operating recycle ratios as highlighted below.

2015	2014	2015	2014
AVERAGE DAILY PRODUCTION (BOE/D) **38,950** ⬆15% FROM 2014	AVERAGE DAILY PRODUCTION (BOE/D) **33,734**	PRODUCTION PER COMMON SHARE[1] (BOE/D/MILLION SHARES) **256** ⬆12% FROM 2014	PRODUCTION PER COMMON SHARE[1] (BOE/D/MILLION SHARES) **228**
FUNDS FLOW PER COMMON SHARE[1] **$1.06** ⬇48% FROM 2014	FUNDS FLOW PER COMMON SHARE[1] **$2.03**	NET LOSS PER COMMON SHARE[1] **$0.11** ⬇115% FROM 2014	NET INCOME PER COMMON SHARE[1] **$0.75**
PDP RESERVES PER COMMON SHARE[2] (BOE/1,000 SHARES) **670** ⬆21% FROM 2014	PDP RESERVES PER COMMON SHARE[2] (BOE/1,000 SHARES) **556**	TOTAL CASH COSTS PER BOE **$11.01** ⬇21% FROM 2014	TOTAL CASH COSTS PER BOE **$14.02**

(1) Determined using the weighted average basic common shares outstanding in the period.
(2) Determined using the outstanding basic common shares at the end of the period.

2015	2014	2015	2014
PDP FD&A COSTS PER BOE[3]	PDP FD&A COSTS PER BOE[3]	2P FD&A COSTS PER BOE[3][4]	2P FD&A COSTS PER BOE[3][4]
$7.79 ⬇39% FROM 2014	**$12.81**	**$1.32** ⬇87% FROM 2014	**$10.45**
PDP FD&A OPERATING NETBACK RECYCLE RATIO[3]	PDP FD&A OPERATING NETBACK RECYCLE RATIO[3]	2P FD&A OPERATING NETBACK RECYCLE RATIO[3][4]	2P FD&A OPERATING NETBACK RECYCLE RATIO[3][4]
1.9x ⬇14% FROM 2014	**2.2x**	**11.0x** ⬆307% FROM 2014	**2.7x**
OPERATING COSTS PER BOE	OPERATING COSTS PER BOE	G&A COSTS PER BOE	G&A COSTS PER BOE
$4.54 ⬇13% FROM 2014	**$5.22**	**$1.61** ⬇11% FROM 2014	**$1.81**

(3) PDP means proved developed producing reserves and 2P means proved plus probable reserves. See "*Advisories – Oil and Gas Metrics*" for a description of the methodology used to calculate FD&A costs and recycle ratios.
(4) Including FDC.

STRATEGY

Our strategy is to continue to develop and expand our two very large resource plays in the Peace River Arch, the Montney/Doig Natural Gas Resource Play and the Charlie Lake Light Oil Resource Play, while maintaining low capital costs and operating costs. These resource plays are large enough to provide us with an extensive inventory of repeatable, consistent, low-cost and low-risk drilling opportunities that we expect will provide production and reserves growth for many years.

Our strategy is based on our current ownership of large contiguous blocks of high working interest land in our operating areas, our 100% ownership of our major facilities and infrastructure in proximity to our drilling operations and the fact that we operate essentially all of our production. Our operatorship, land position and infrastructure ownership give us a competitive advantage over our competitors in our areas of operation and supports our low F&D costs and low operating cost structure, which helps us maximize our funds flow in a low commodity price environment.

It has been a key component of our strategy that we continue to enhance our knowledge and expertise regarding drilling and completion operations on these plays. Since starting to develop these plays in 2005, we have significantly advanced and evolved our technical and operational expertise which has improved the results of our drilling and completion operations and reduced our costs.

Our long-term plan continues to rely on growth by the drill bit, emphasizing full-cycle exploration and development. We are technology oriented and we regularly evaluate new technologies for use in our operations. Our current strategy of high working interests, operated production, low F&D costs and low operating costs is succeeding. We continue to add to our large undeveloped land base where we have ownership and control or access to infrastructure, with a goal of self-funded capital expenditure programs, a strong balance sheet and strong production.

Our people are our number one asset. We strive to provide our people with a positive working environment, the opportunity for personal and professional growth and the business tools necessary to achieve our corporate goals.

We believe that our 2015 F&D costs and operating costs are some of the lowest in the industry and we continue to seek opportunities to reduce our costs further.

Our 100% owned and operated PCS Gas Plant located in Pouce Coupe South, Alberta is strategically situated in the heart of our Montney/Doig Natural Gas Resource Play, enabling us to process natural gas at a fraction of the costs borne by others who rely on third-party processing. The PCS Gas Plant is the cornerstone of our strategy to develop our Montney/Doig Natural Gas Resource Play, to control and expand our production on the play and to further reduce our operating costs on a per boe basis.

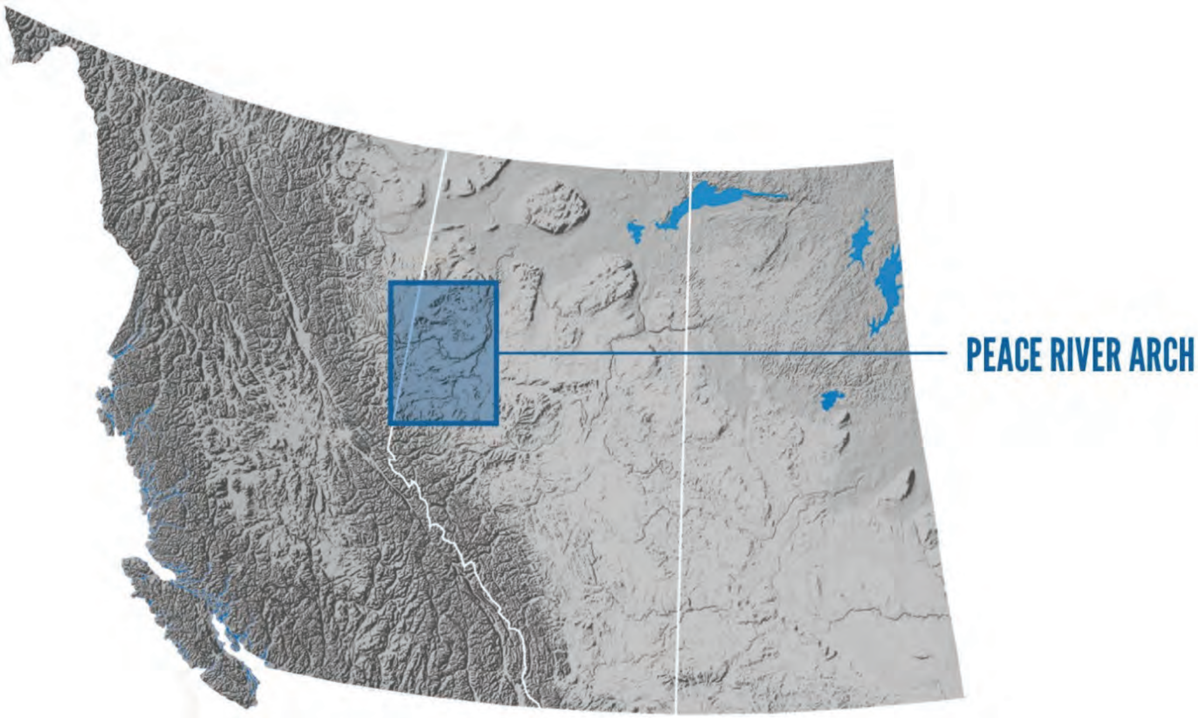
"We are confident that Birchcliff can weather the current storm of low natural gas prices. This confidence is based on the foundation of low processing costs, operating costs and F&D costs that we have strived for and achieved in recent years. Our low-cost structure has now become an extremely important differentiator in the current environment of low natural gas and crude oil prices."

JIM SURBEY,
VICE-PRESIDENT, CORPORATE DEVELOPMENT

AERIAL VIEW OF THE PCS GAS PLANT

PEACE RIVER ARCH

Our operations are concentrated within our one core area, the Peace River Arch, which is centred northwest of Grande Prairie, Alberta, adjacent to the Alberta/British Columbia border. The Peace River Arch is considered by management to be one of the most desirable natural gas and light oil drilling areas in North America.



The Peace River Arch is one of the most prolific natural gas and oil producing areas of the Western Canadian Sedimentary Basin and is generally characterized by multiple horizons with a myriad of structural, stratigraphic and hydrodynamic traps. There is an abundance of prolific resource plays, related in part to the proximity of the area to the Deep Basin, where generation and trapping of hydrocarbons preferentially occurs. The Peace River Arch provides all-season access that allows us to drill, equip and tie-in wells on an almost continuous basis.

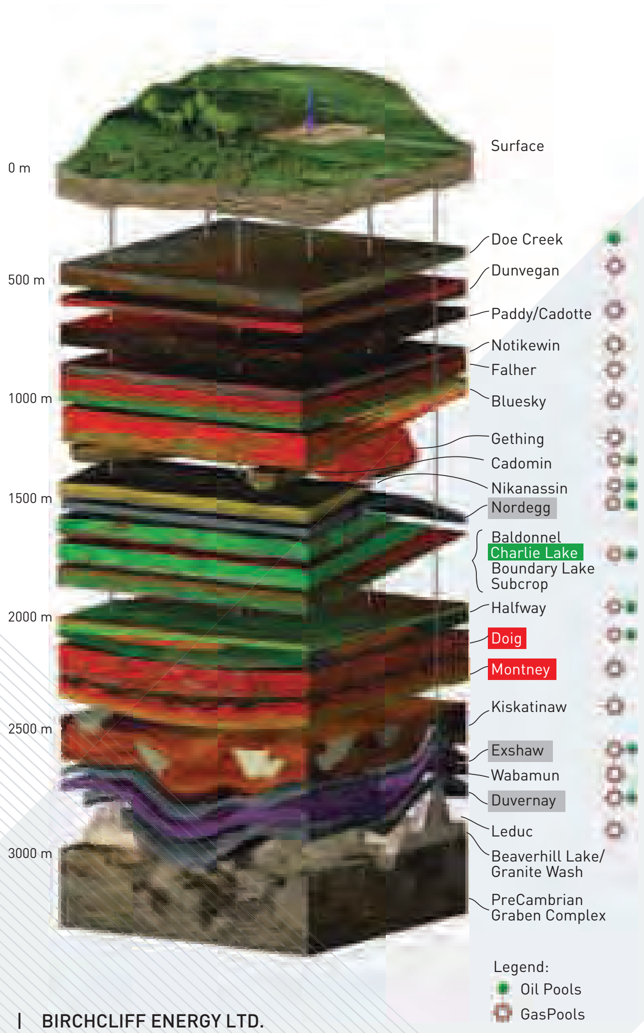
RESOURCE PLAYS

Established Resource Plays

We are focused on two established resource plays within the Peace River Arch: the Montney/Doig Natural Gas Resource Play and the Charlie Lake Light Oil Resource Play.

We characterize our resource plays as plays that have regionally extensive, continuous, low permeability hydrocarbon accumulations or systems that usually require intensive stimulation to produce. The production characteristics of these plays include steep initial declines that rapidly trend to much lower decline rates, yielding long-life production and reserves. Resource plays exhibit a statistical distribution of estimated ultimate recoveries and therefore provide a repeatable distribution of drilling opportunities. As more wells are drilled into a resource play, there is a substantial decrease in both the geological and technical risks. For example, we have successfully drilled 188 (187.9 net) Montney/Doig horizontal natural gas wells as at December 31, 2015 and over 99% of those wells have been successful. Our resource plays are ideally suited for the application of horizontal drilling and multi-stage fracture stimulation technology.

Stratigraphic Column and Production Zones



"Over our 11 years of focused multi-disciplinary efforts on the Montney/Doig Natural Gas Resource Play, we have learned a great deal about this complex reservoir and how to optimally drill, case, complete and produce horizontal wells utilizing multi-stage fracture stimulation technology. We have continued to improve our results and increase our production and reserves per well, while reducing our costs."

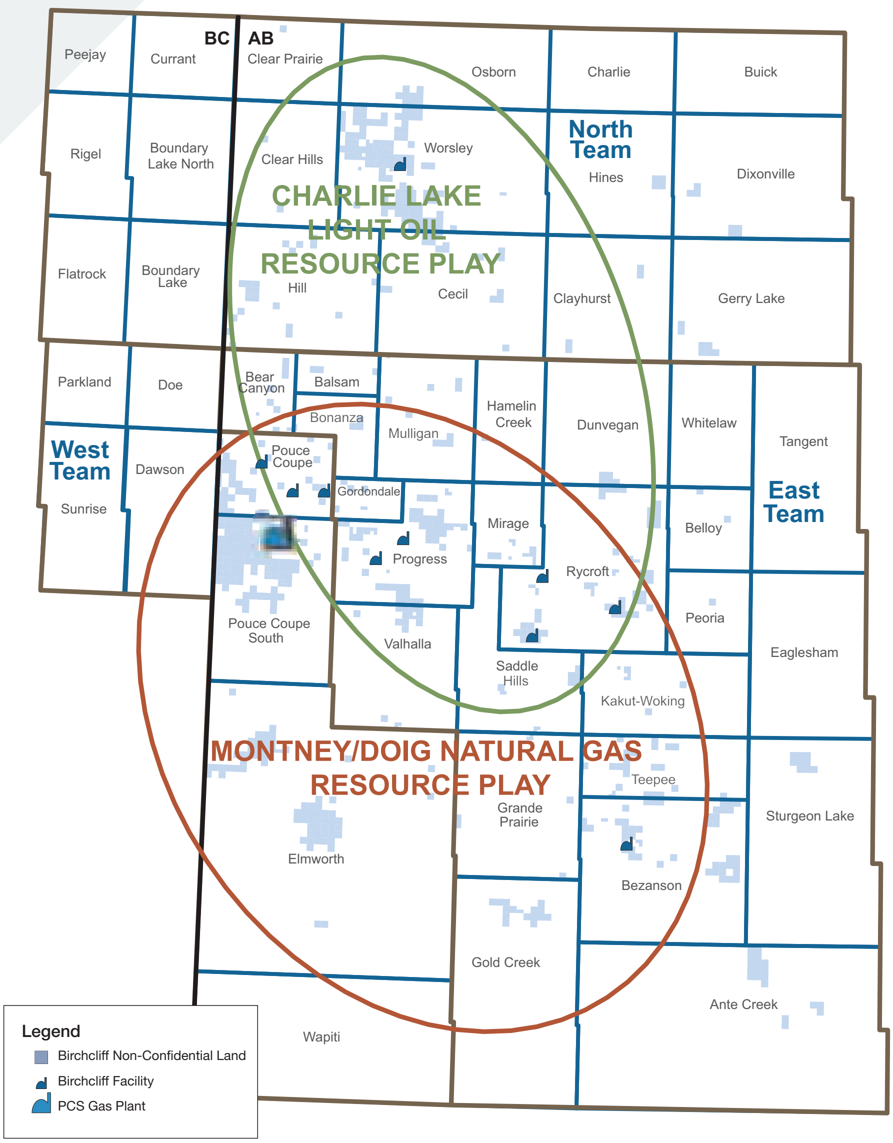
MYLES BOSMAN,
VICE-PRESIDENT, EXPLORATION & CHIEF OPERATING OFFICER

Birchcliff Operations in the Peace River Arch

Our 2016 Revised Capital Budget is focused on our two proven resource plays. The 2016 Revised Capital Budget contemplates the drilling of 13 (13.0 net) wells and includes approximately $39.0 million for facilities and infrastructure, including approximately $24.8 million of capital for the Phase V expansion of our PCS Gas Plant.

On our two established resource plays within the Peace River Arch, the Montney/Doig Natural Gas Resource Play and the Charlie Lake Light Oil Resource Play, we utilize the expertise of three technical teams: the North Team, the West Team and the East Team.

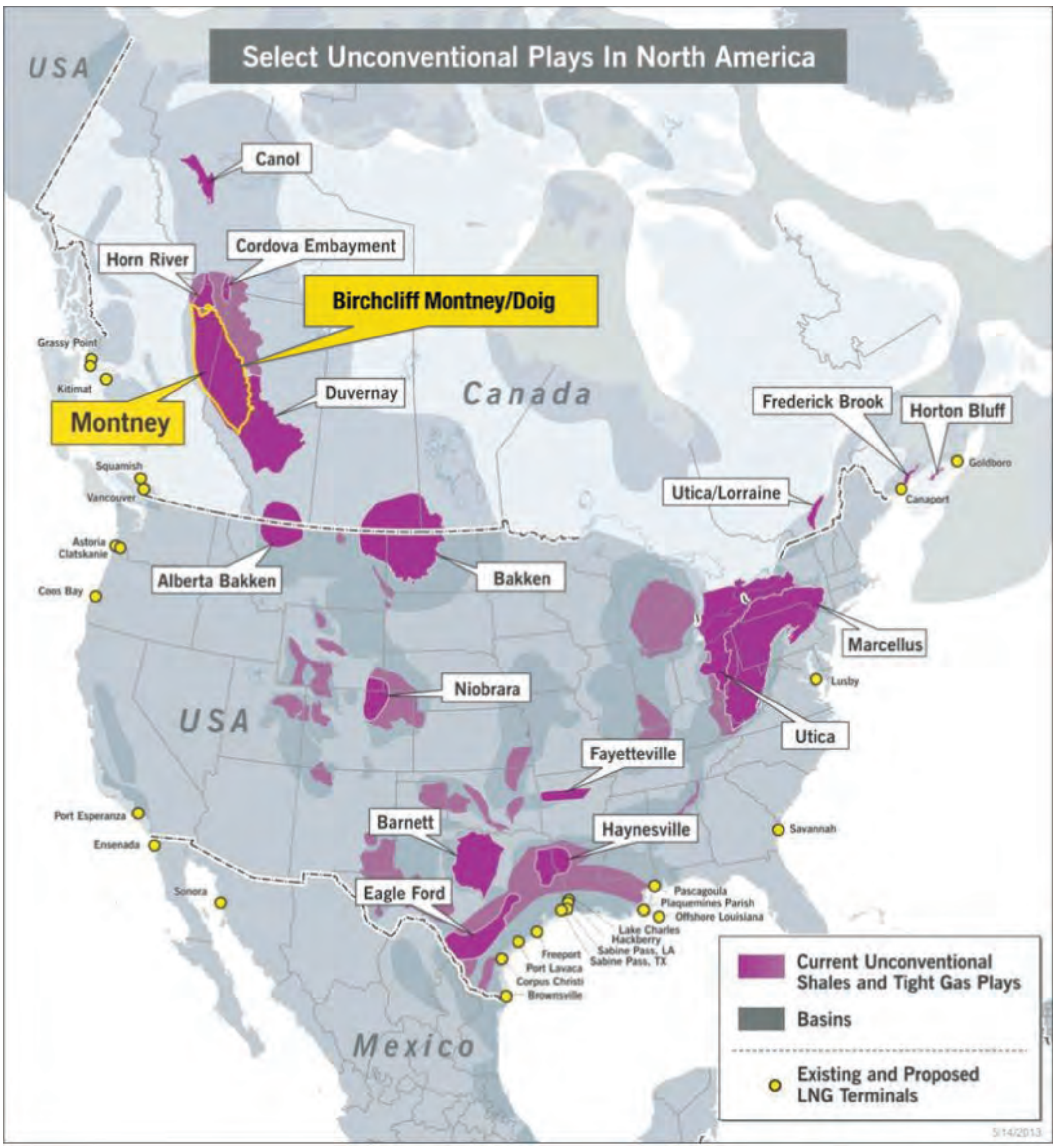
Birchcliff Resource Plays in the Peace River Arch



Montney/Doig Natural Gas Resource Play

Our Montney/Doig Natural Gas Resource Play is centred approximately 95 kilometres northwest of Grande Prairie, Alberta, Canada and, in the opinion of Birchcliff, is one of the most sought after natural gas resource plays in North America. Birchcliff's Montney/Doig Natural Gas Resource Play contains five primary producing regions: Pouce Coupe, Pouce Coupe South, Progress, Gordondale and Elmworth.

There are a number of attributes that the Montney/Doig Natural Gas Resource Play has that contributes to it being a world class resource play, including resource density, large areal extent, exceptional "fracability" and high permeability, as discussed in further detail below.



Source: Canadian Discovery, RBC Rundle, 2013

GEOLOGY

The Montney/Doig Natural Gas Resource Play in the Pouce Coupe area is approximately 300 metres (1,000 feet) thick. The play has a large areal extent covering in excess of 50,000 square miles. Another very important attribute is the mineralogy of the reservoir. The Montney/Doig is composed of a high percentage of hard minerals and a very low percentage of clay minerals resulting in exceptional "fracability". This, combined with the current stress regime, results in the rock shattering more like glass in a complex fracture style versus a simple biwing style. The rock parameters also yield exceptional fracture stability; the fractures stay open due to low proppant embedment. This is a key contributing factor to the very low terminal declines and large estimated ultimate recoveries of the play. Unlike most shale gas plays that are predominantly shale, the Montney/Doig is classified by Birchcliff as a hybrid resource play because it is comprised of gas saturated rock with both tight silt and sand reservoir rock interlayered with shale gas source rock. This results in relatively high permeability and productivity rates.

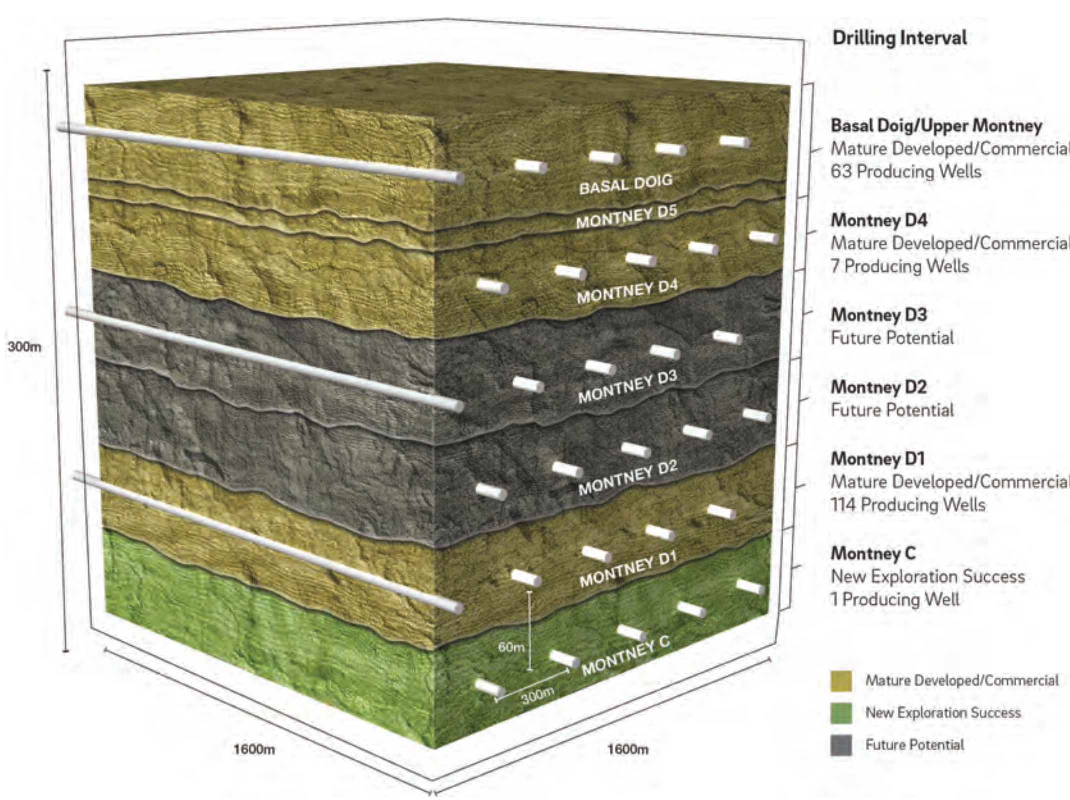
Hydrodynamics is another important attribute for resource plays. A large portion of the Montney/Doig Resource Play is over-pressured which reduces the potential for significant water production. The Pouce Coupe area is predominantly over-pressured which also results in higher gas in-place.

These rock properties result in high recovery factors.

The depositional environment is another very favourable attribute of the Montney/Doig Natural Resource Play. The Montney and a majority of the Doig were deposited in a lower to middle shore face environment that is regionally extensive and results in a widespread style deposit that provides for more repeatable results.

The Montney/Doig Natural Gas Resource Play exists in two geological formations: the Montney formation and the Doig formation. Due to the complexity of the geology, not all of the same intervals are present in all areas of the play trend. We have divided the geologic column in our area into six drilling intervals from youngest (top) to oldest (bottom): (i) the Basal Doig/Upper Montney; (ii) the Montney D4; (iii) the Montney D3; (iv) the Montney D2; (v) the Montney D1; and (vi) the Montney C. We have drilled wells in each of the Basal Doig/Upper Montney, the Montney D4, the Montney D1 and the Montney C intervals, as discussed in further detail below. To date, we have not drilled any wells in the Montney D3 or Montney D2 intervals; however, offsetting companies have recently drilled and produced from both of these intervals.

Birchcliff Montney/Doig Natural Gas Resource Play Full Development Plan: Hexastack



DRILLING AND PRODUCTION

We drilled our first vertical exploration well for the Montney/Doig in February 2005. With the success of this well, we aggressively pursued opportunities to consolidate a significant position on the play. In May 2005, we completed the acquisition of properties in the Peace River Arch for $242.8 million, which included a working interest in 11 gas plants and related pipelines and a significant undeveloped land position on the Montney/Doig Natural Gas Resource Play.

The technology relating to horizontal drilling and multi-stage fracture stimulation has rapidly expanded in the last 10 to 15 years. The industry's first Montney/Doig horizontal wells were drilled in 2005 and we drilled our first horizontal well in September 2007. As at December 31, 2015, we have now successfully drilled 188 (187.9 net) horizontal wells on the Montney/Doig Natural Gas Resource Play. The two drilling intervals that we have primarily focused on are the Montney D1, where we have drilled 117 wells, and the Basal Doig/Upper Montney, where we have drilled 63 wells. Beginning in 2014, we have also drilled wells in each of the Montney D4 and Montney C intervals. In July 2014, we drilled our first exploration well in the Montney D4 interval in the Pouce Coupe area. As at December 31, 2015, we have drilled a total of seven 100% working interest wells in the Montney D4 interval. Five of these wells are in the Pouce Coupe area and two are in the Elmworth area. During 2014, we drilled our first successful horizontal natural gas well in the Montney C interval.

Drilling activities during 2015 on the Montney/Doig Natural Gas Resource Play consisted of 28 (28.0 net) horizontal natural gas wells drilled in the Pouce Coupe area, 1 (1.0 net) horizontal natural gas well drilled in the Elmworth area and 1 (1.0 net) Belloy vertical well drilled as an acid gas disposal well in the Elmworth area. All horizontal wells drilled in 2015 utilized multi-stage fracture stimulation technology.

In 2015, approximately 92% of our natural gas production, 10% of our light oil production and 88% of our NGL production came from the wells drilled on the Montney/Doig Natural Gas Resource Play. In 2015, production from the Montney/Doig Natural Gas Resource Play averaged 32,890 boe per day and the operating netback for this production was $13.80 per boe. Average operating costs on the Montney/Doig Natural Gas Resource Play were $3.22 per boe. In 2015, we invested $7.7 million to expand and maintain our land position on the Montney/Doig Natural Gas Resource Play.

The vast majority of the production from the Montney/Doig Natural Gas Resource Play is processed at our 100% owned and operated PCS Gas Plant, which currently has a licensed processing capacity of 180 MMcf per day. We also process gas at the Progress gas plant operated by Canadian Natural Resources Northern Alberta Partnership, in which we have a small working interest. Other gas is delivered to the Spectra gathering system, which is processed under firm service contracts at either the Fourth Creek gas plant or the Gordondale East gas plant. We also have a firm service contract with AltaGas for a small volume of gas delivered to and processed at the AltaGas Pouce Coupe gas plant. Clean oil and emulsion from the Progress region is trucked to a terminal located in Gordondale.

THE PCS GAS PLANT

Our 100% owned and operated PCS Gas Plant located in Pouce Coupe South, Alberta is strategically situated in the heart of our Montney/Doig Natural Gas Resource Play, enabling us to process natural gas at a fraction of the costs borne by others who rely on third-party processing. The PCS Gas Plant is the cornerstone of our strategy to develop our Montney/Doig Natural Gas Resource Play, to control and expand our production on the play and to further reduce our operating costs on a per boe basis.

In 2010, we began executing on our "build and fill" strategy with the construction of the PCS Gas Plant. During 2010, we constructed Phases I and II of our PCS Gas Plant with 60 MMcf per day of natural gas processing capacity. In 2012, processing capacity at the PCS Gas Plant was increased to 150 MMcf per day (Phase III) and to 180 MMcf per day in 2014 (Phase IV). Engineering, procurement and fabrication work is underway for the Phase V expansion of the PCS Gas Plant which will increase processing capacity to 260 MMcf per day. Our 2016 Revised Capital Budget includes approximately $24.8 million of capital for the Phase V expansion. We currently expect that the Phase V expansion will be completed in 2017, subject to an improvement in commodity prices and general economic conditions. The completion of Phase V will be timed to coincide with the drilling of additional Montney/Doig horizontal natural gas wells to fill or partially fill the expanded PCS Gas Plant, so that operational momentum will not be lost and ensuring capital is only spent when required. In addition, the design and licensing work is complete for the Phase VI expansion of the PCS Gas Plant which will increase processing capacity to 340 MMcf per day from 260 MMcf per day. We currently expect that the Phase VI expansion will be completed in late 2018 or early 2019, depending primarily on commodity prices and general economic conditions.

Our goal is to continue to expand the processing capacity of the PCS Gas Plant and fill it with natural gas produced from our Montney/Doig horizontal wells.

SIGNIFICANT FUTURE DRILLING OPPORTUNITIES

Our land activities during 2015 on the Montney/Doig Natural Gas Resource Play included the acquisition of 20 sections, all at 100% working interest, 9 sections of which were in the heart of our Pouce Coupe area and 11 sections of which were in our Elmworth area. As at December 31, 2015, we held 333.9 sections of land that have potential for the Montney/Doig Natural Gas Resource Play. Of these lands, 309.9 (293.7 net) sections have potential for the Basal Doig/Upper Montney interval, 317.4 (308.0 net) sections have potential for the Montney D1 interval and 293.4 (287.0 net) sections have potential for the Montney D4 interval. As at December 31, 2015, our total land holdings on these three intervals were 920.8 (888.8 net) sections.

On full development of four horizontal wells per section per drilling interval, we have 3,555.2 net existing horizontal wells and potential net future horizontal drilling locations in respect of the Basal Doig/Upper Montney, Montney D1 and Montney D4 intervals as at December 31, 2015. With 188 (187.9 net) horizontal locations successfully drilled at the end of 2015, there remains 3,367.3 potential net future horizontal drilling locations as at December 31, 2015, up from 3,346.3 net at year end 2014. This does not include any potential net future horizontal drilling locations for the other three prospective Montney intervals, the Montney C, the Montney D2 and the Montney D3.

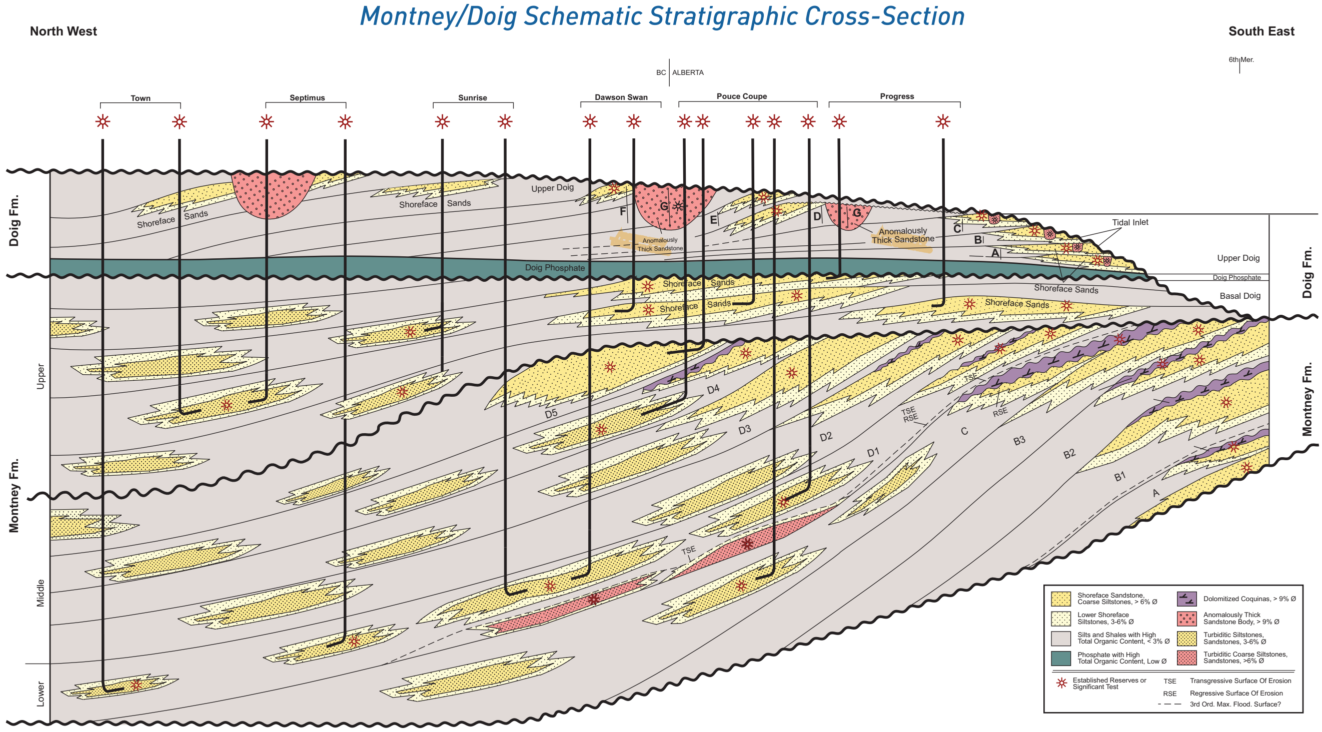
Substantial upside exists with respect to the 3,555.2 net existing horizontal wells and potential net future horizontal drilling locations. The 2015 Reserves Evaluation attributed:

(i) proved reserves to 505.2 net existing wells and potential net future horizontal drilling locations (of which 320.3 net wells are potential future drilling locations); and

(ii) proved plus probable reserves to 698.8 net existing wells and potential net future horizontal drilling locations (of which 513.9 net wells are potential future drilling locations).

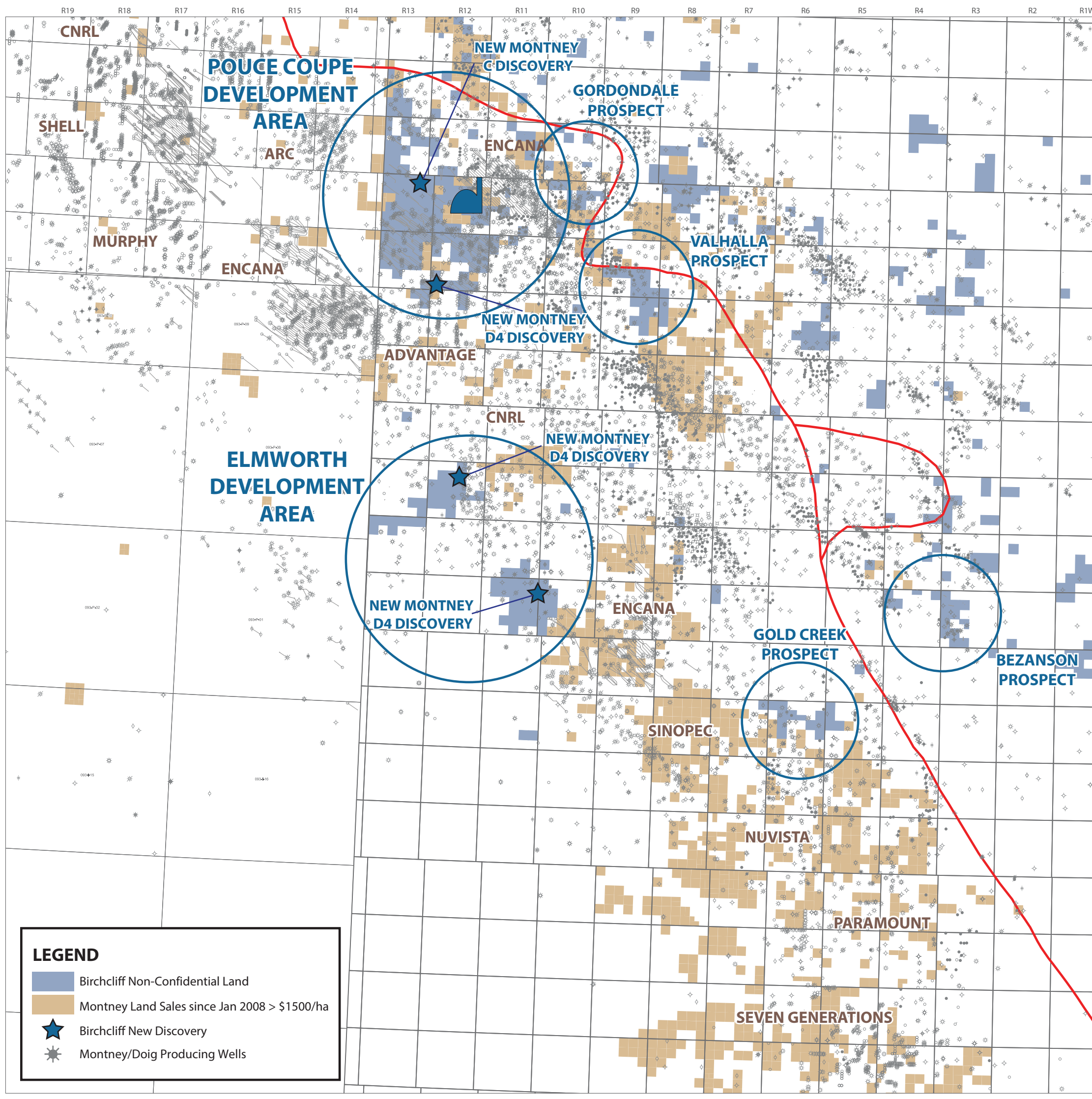
The remaining 2,853.4 potential net future horizontal drilling locations have not yet had any proved or probable reserves attributed to them by Deloitte.

Montney/Doig Schematic Stratigraphic Cross-Section



Source: Davies, Moslow and Sherwin, 1997

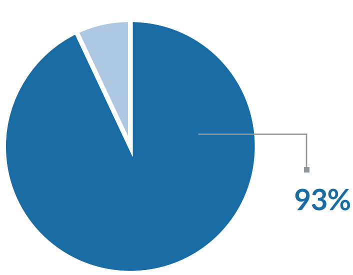
Birchcliff Development Areas and Prospects on the Montney/Doig Natural Gas Resource Play



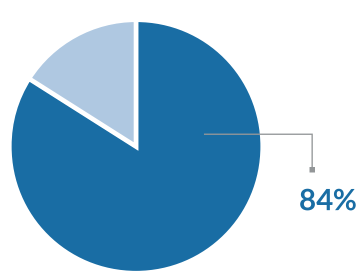
Competitor lands are based on publicly available data.

IN 2015, THE MONTNEY/DOIG NATURAL GAS RESOURCE PLAY ACCOUNTED FOR:

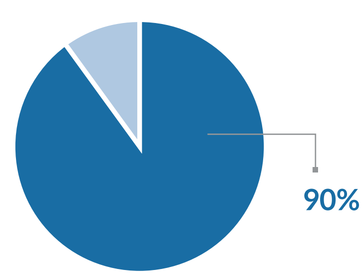
Total Corporate Exploration and Development Expenditures
(including acquisitions and dispositions)



Total Corporate Production Volumes



Total Corporate Proved Plus Probable Reserves



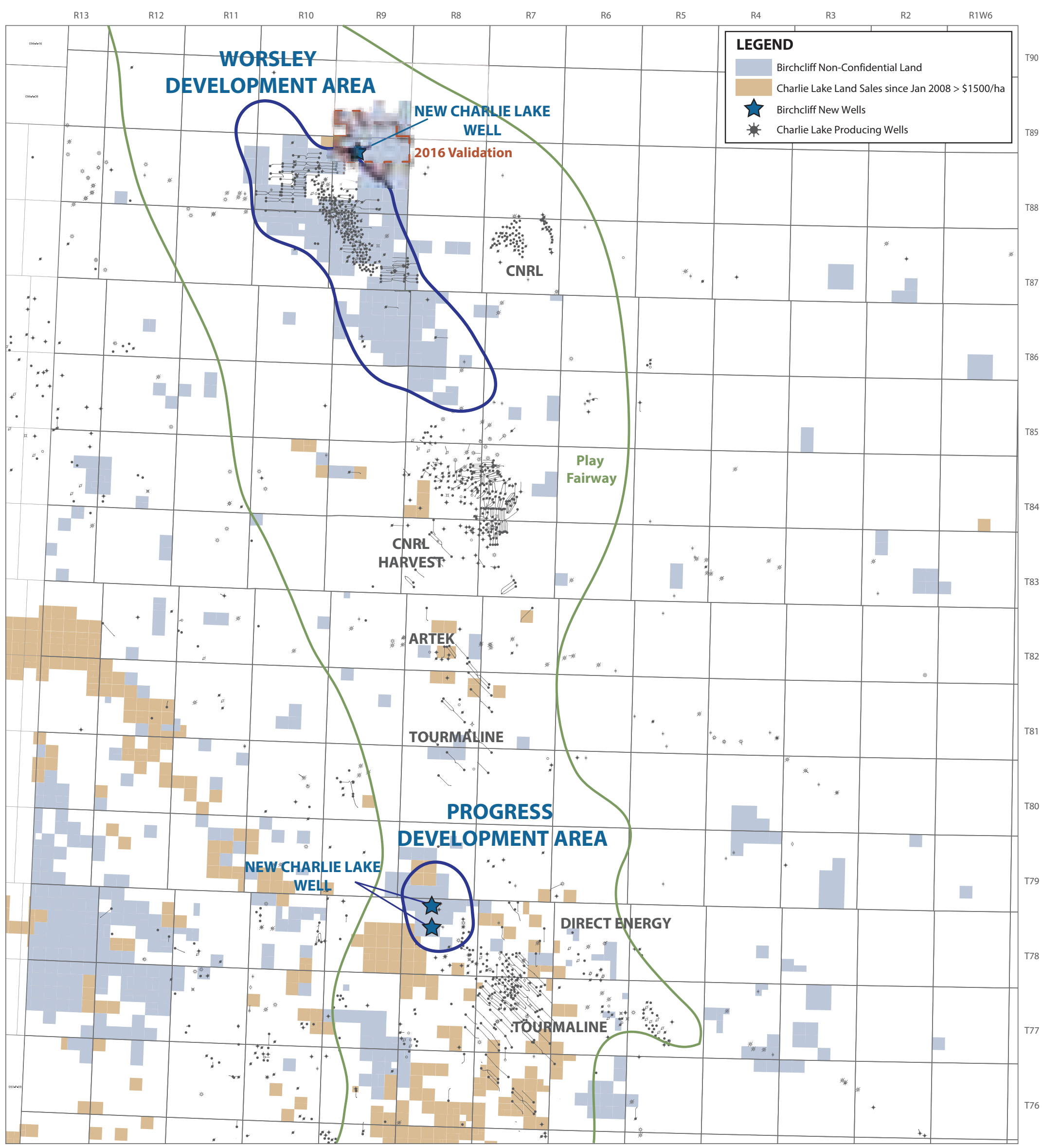
Charlie Lake Light Oil Resource Play

The Charlie Lake Light Oil Resource Play is described by Birchcliff as a regionally extensive variety of restricted to nearshore marine facies. The Charlie Lake reservoirs are heterogeneous and consist of varying quantities of laminated and dolomitic, silty to fine-grained sandstones. The reservoir intervals typically exhibit porosity in the order of 8% to 15% and net reservoir thickness of 3 to 30 metres. A critical component of the play is the main trapping mechanism, comprised of a regional hydrodynamic trap setting up a large regional hydrocarbon column.

The Charlie Lake reservoirs on the Peace River Arch were historically drilled vertically with reasonable economic results. Starting in the 1990s, various companies drilled horizontal wells in the Charlie Lake reservoirs with varying results. In March 2008, we drilled our first horizontal well utilizing multi-stage fracture stimulation technology, being one of the first companies to utilize this technology in the Charlie Lake. As at December 31, 2015, we have successfully drilled 60 (60.0 net) horizontal wells utilizing multi-stage fracture stimulation technology.

Horizontal wells on the Charlie Lake Light Oil Resource Play that utilize multi-stage fracture stimulation technology are generally drilled to a measured depth of 2,500 to 3,500 metres and deliver initial productivity rates of 100 to 750 boe per day.

Birchcliff Development Areas on the Charlie Lake Light Oil Resource Play



CHARLIE LAKE LIGHT OIL RESOURCE PLAY – WORSLEY AREA

We entered the Charlie Lake Light Oil Resource Play through the acquisition of the Worsley Property in September 2007. The Worsley Property is located approximately 150 kilometres north of Grande Prairie, Alberta, which is in close proximity to our other assets. The Worsley Property is characterized by large contiguous blocks of mainly 100% working interest lands containing a very large Charlie Lake light oil pool. Essentially all of the production is operated by Birchcliff and the related infrastructure is owned by Birchcliff.

When we acquired the Worsley Property in September 2007, the previous operator had started a pilot waterflood project. Subsequently, Birchcliff significantly expanded the waterflood and the results have been very positive, adding significant reserves by increasing the recovery factor.

Another important initiative of ours has been to expand and delineate the Worsley pool and we have been very successful. At December 31, 2015, Deloitte estimated that the Worsley Charlie Lake light oil pool had 41.1 MMboe of proved plus probable reserves and 21.9 MMboe of proved reserves. This continues the growth trend for our Worsley Charlie Lake reserves since we acquired the Worsley Property, when reserves were estimated at 15.1 MMboe on a proved plus probable basis and 11.3 MMboe on a proved basis.

Due to low oil prices during 2015, we did not conduct any drilling activities on our Worsley Charlie Lake Light Oil Resource Play. We did, however, spend significant time and effort optimizing the existing wells, waterflood and infrastructure to improve production profiles and reduce decline rates.

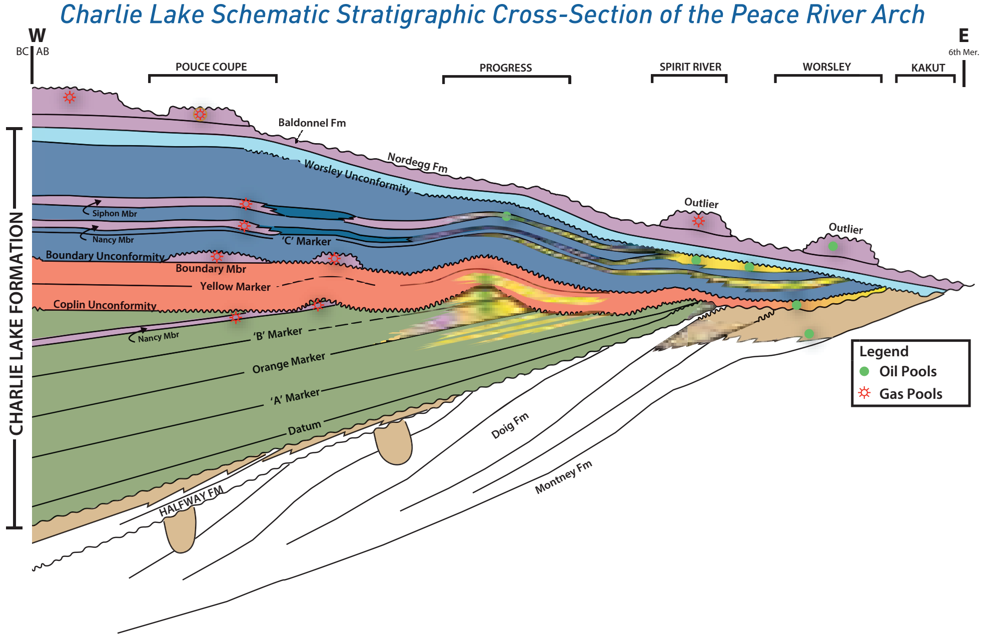
Early in 2016, we drilled a Charlie Lake horizontal light oil well that successfully delineated the pool to the northeast and that will continue 18 sections of land. Additional activities planned for 2016 include the conversion of two wells in the waterflood area to injectors to further optimize the waterflood scheme.

In 2015, 4% of our natural gas production, 73% of our light oil production and 7% of our NGL production came from the wells drilled on the Worsley Charlie Lake Light Oil Resource Play, with production primarily from the oil rich Charlie Lake formation. In 2015, production from the Worsley Charlie Lake Light Oil Resource Play averaged 4,236 boe per day and the operating netback for this production was $21.15 per boe.

The majority of the production from the Worsley Charlie Lake Light Oil Resource Play flows through our 100% owned and operated Worsley oil battery and gas plant, which is located in the core of the Worsley area. Clean oil is trucked from the Worsley facility to truck terminals located in the towns of High Prairie, Valleyview and Gordondale, Alberta and Taylor, British Columbia, to be transported on the Pembina Peace pipeline to Edmonton.

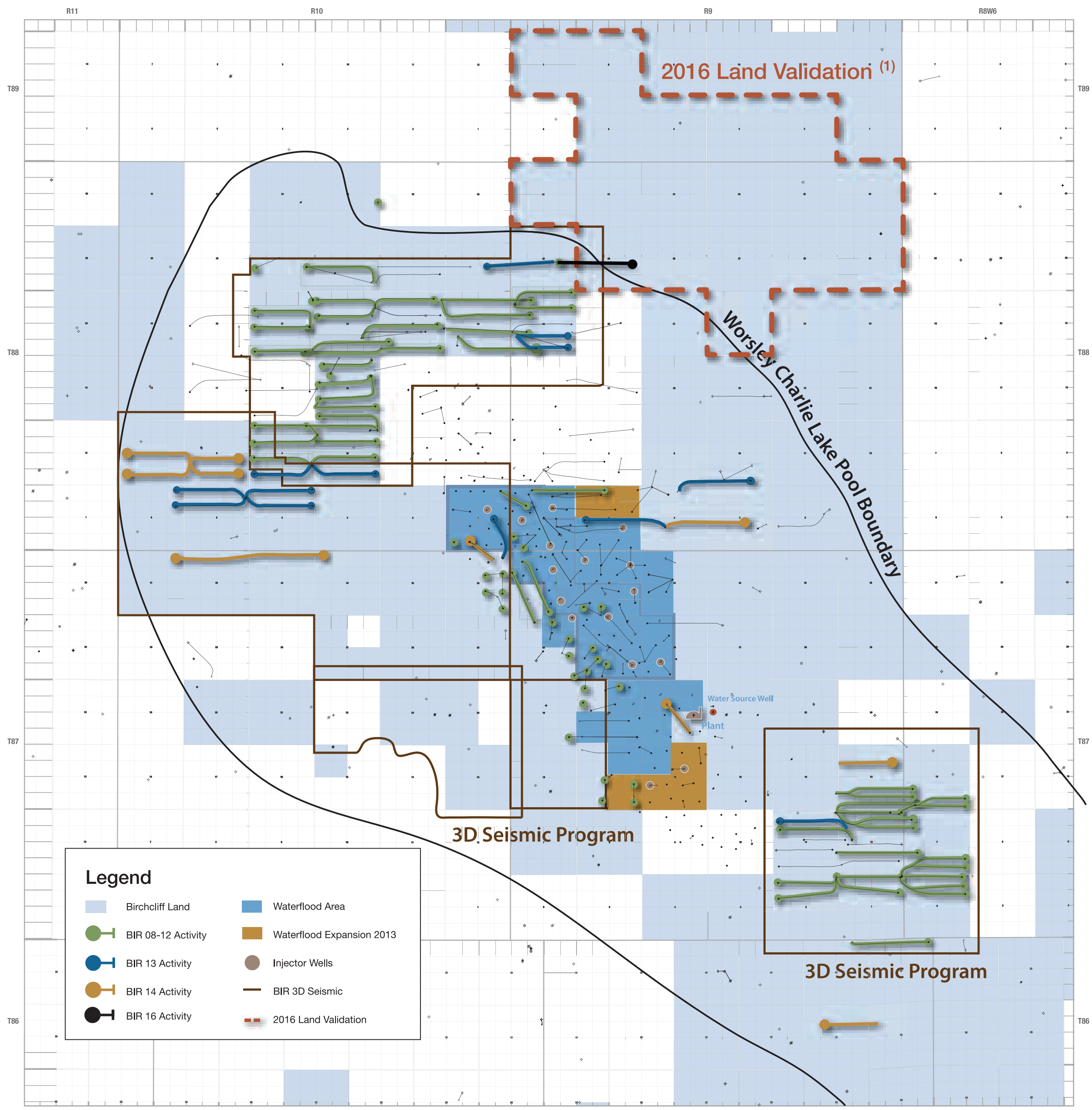
In 2015, we invested $0.4 million to expand and maintain our Worsley Charlie Lake Light Oil Resource Play land position.

Charlie Lake Schematic Stratigraphic Cross-Section of the Peace River Arch



Source: Stoakes Campbell Geoconsulting Ltd., 1989

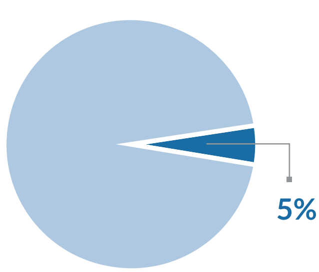
Producing Area of the Worsley Charlie Lake Light Oil Resource Play



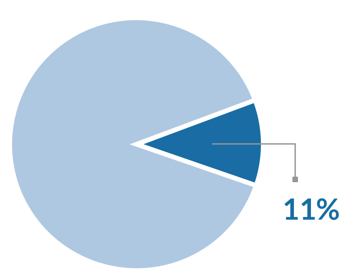
(1) Charlie Lake horizontal light oil well drilled in 2016 to continue 18 sections of land.

IN 2015, THE WORSLEY CHARLIE LAKE LIGHT OIL RESOURCE PLAY ACCOUNTED FOR:

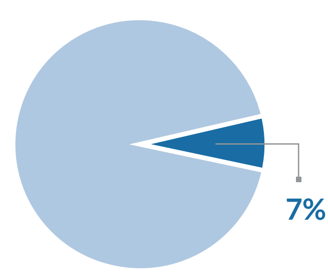
Total Corporate Exploration and Development Expenditures
(including acquisitions and dispositions)



Total Corporate Production Volumes



Total Corporate Proved Plus Probable Reserves



CHARLIE LAKE LIGHT OIL RESOURCE PLAY – PROGRESS AREA

In the fourth quarter of 2014, we drilled our first successful 100% working interest Charlie Lake horizontal exploration well in the Progress area, which was brought on production in December 2014. This well produced at an average rate of 300 bbls per day of light oil and 1.8 MMcf per day of natural gas for a total of 600 boe per day for the first 30 days of production. As at January 31, 2016, this well was producing at an average rate of 45 bbls per day of light oil and 0.7 MMcf per day of natural gas for a total of 165 boe per day with a 39% water cut.

In the second quarter of 2015, we drilled our second successful 100% working interest Charlie Lake horizontal light oil well in our Progress area, which was brought on production in August 2015. This well produced at an average rate of 85 bbls per day of light oil and 2.2 MMcf per day of natural gas for a total of 450 boe per day for the first 30 days of production. As at January 31, 2016, this well was producing at an average rate of 83 bbls per day of light oil and 4.0 MMcf per day of natural gas for a total of 750 boe per day with a 46% water cut.

As at December 31, 2015, we held 28 (27.5 net) sections of land in the Progress area on the Charlie Lake Light Oil Resource Play, compared to 26.5 (25.75 net) sections as at December 31, 2014. In the first quarter of 2015, we acquired a new 3-D seismic program in the Progress area to help delineate our Charlie Lake Light Oil Resource Play exploration success. The results of this seismic program are very encouraging and support our belief that a significant amount of our lands have potential for this play.

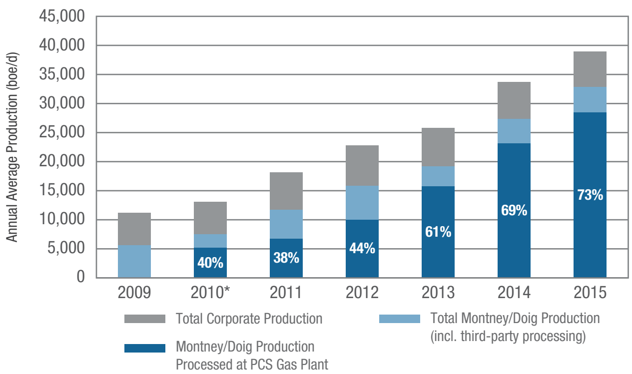
We are currently developing a full scale development plan for our Progress Charlie Lake Light Oil Resource Play.

MONTNEY BY THE NUMBERS

SIGNIFICANT MONTNEY/DOIG PRODUCTION GROWTH

Since 2009, we have delivered significant low-cost production growth from our Montney/Doig Natural Gas Resource Play. The chart below provides a breakdown of our Montney/Doig production as a percentage of total corporate production:

Corporate Production Breakdown



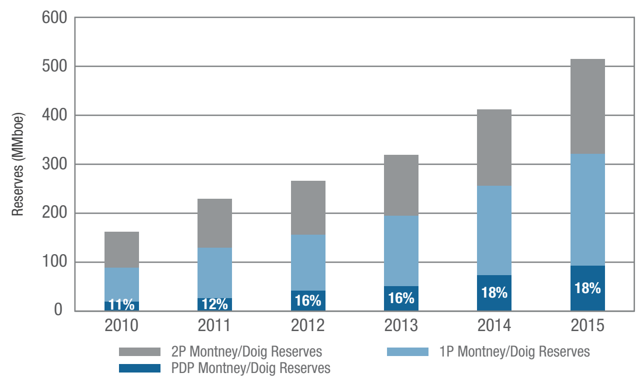
* PCS Gas Plant Online - Began Executing on "Build and Fill" Strategy.

In 2015, our Montney/Doig production processed through the PCS Gas Plant averaged 28,560 boe per day compared to 5,191 boe per day in 2010, which represents a compounded annual growth rate of 41% per year. In 2015, Montney/Doig production processed at the PCS Gas Plant represented approximately 73% of our total corporate production and 81% of our total natural gas production.

SIGNIFICANT MONTNEY/DOIG RESERVES GROWTH

We have added significant low-cost Montney/Doig reserves over the last six years of operations. The chart below provides a breakdown of our Montney/Doig reserves over the last six years, which coincides with the period during which the PCS Gas Plant was operational:

Montney/Doig Reserves Breakdown



Our independent qualified reserves evaluator estimated that as at December 31, 2015, we had 92.4 MMboe of PDP reserves, 321.8 MMboe of 1P reserves and 516.8 MMboe of 2P reserves attributable to our Montney/Doig Natural Gas Resource Play, representing a compounded annual growth rate of 36%, 29% and 26% per year, respectively, during the six year period.

PDP Montney/Doig reserves made up 18% of 2P reserves as at December 31, 2015, leaving significant opportunities for future production growth.

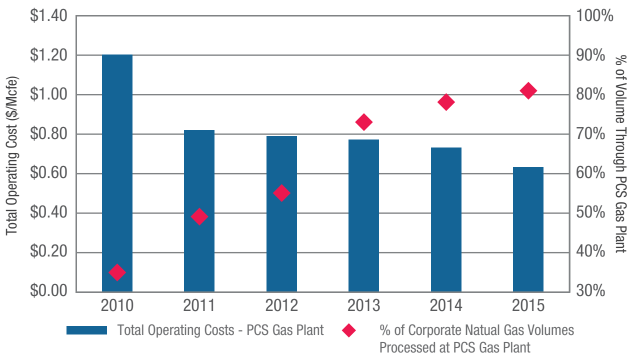
As at December 31, 2015, PDP and 2P Montney/Doig reserves represented 91% and 90% of our total PDP and 2P corporate reserves, respectively.

LOW-COST MONTNEY/DOIG NATURAL GAS PRODUCER

Operating Cost Structure

Our per unit total operating costs at the PCS Gas Plant, which includes operating costs (before processing recoveries), transportation costs and marketing costs ("**total operating costs**"), have come down significantly since 2010 largely due to operational efficiencies associated with economies of scale as we increase the processing capacity at the gas plant. The chart below highlights our total operating costs on a per Mcfe basis at the PCS Gas Plant for the last six years:

Total Operating Costs vs. PCS Gas Plant Sales Volumes*



* Includes operating, transportation and marketing costs and excludes third-party processing recoveries.

In 2015, Birchcliff's total operating costs averaged a record low of $0.62 per Mcfe at the PCS Gas Plant when AECO natural gas spot prices averaged $2.69 per Mcf.

Production Capital Efficiencies

During 2015, our average costs to drill, case, complete, equip and tie-in ("**DCCET**") a Montney/Doig horizontal natural gas well decreased to approximately $4.4 million, primarily due to the application of new technology, operational efficiencies and a reduction in service costs. As a result of lower DCCET costs together with improvements in well performance, we achieved record low production capital efficiencies in 2015. The following table highlights our Montney/Doig production capital efficiencies on a half-cycle DCCET cost basis and on a full-cycle F&D cost basis, in each case calculated by dividing the aggregate capital expended by the initial 90 day restricted (choked) average daily production (IP 90) for the wells drilled in 2015 and 2014:

	2015	2014
DCCET – Capital Efficiencies *($/boe/d)*	$10,400	$13,300
F&D – Capital Efficiencies *($/boe/d)*	$14,800	$16,900
DCCET as a % of F&D Costs	71%	78%

On a half-cycle DCCET cost basis, our Montney/Doig production capital efficiency decreased 22% from 2014 and decreased on average 10% per year in the last five years.

On a full-cycle F&D cost basis, our DCCET Montney/Doig production capital efficiency decreased 12% from 2014 and decreased on average 8% per year in the last five years.

See "*Advisories – Oil and Gas Metrics*" in this Annual Report for a description of the methodology used to calculate production capital efficiencies.

Reserves Capital Efficiencies

We have low FD&A costs relating to our PDP reserves and positive technical revisions accounted for 17% of our proved developed producing reserves additions in 2015. These positive revisions resulted from our independent qualified reserves evaluator's recognition of improved well production performance from our 2015, 2014 and 2013 drilling programs. These technical revisions primarily resulted from the continued advancement of our drilling and completion technologies and improved well production performance on some of our existing wells. Improved well performance, coupled with reduced well costs, resulted in top-tier PDP reserves capital efficiencies.

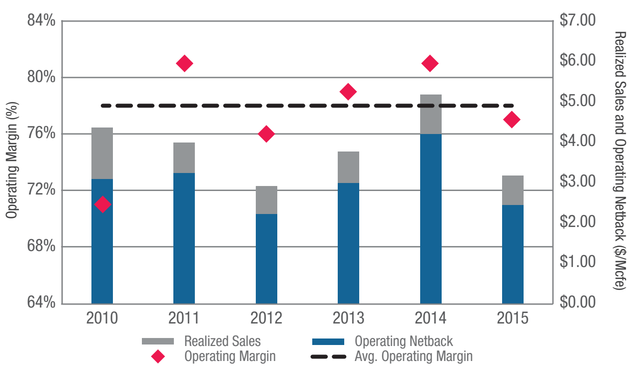
In 2015, we achieved top-tier reserves capital efficiencies on a reserves basis on the Montney/Doig Natural Gas Resource Play. Our Montney/Doig PDP FD&A costs averaged a record low of $1.19 per Mcfe ($7.13 per boe) in 2015, down 36% from $1.86 per Mcfe ($11.16 per boe) in 2014. In the last six years, our Montney/Doig PDP FD&A costs averaged $1.76 per Mcfe ($10.56 per boe), which was well below the average Montney/Doig operating netback of $2.91 per Mcfe ($17.45 per boe) during those years.

A FOCUS ON PROFITABILITY

Operating Margin at the PCS Gas Plant

We are focused on delivering profitable production growth to our shareholders from our Montney/Doig Natural Gas Resource Play. Processing Montney/Doig natural gas at our PCS Gas Plant over the last six years has significantly improved our operating margin. The chart below highlights the operating margin at the PCS Gas Plant for the last six years:

PCS Gas Plant Operating Margin



During the last six years, the estimated annual operating margin at the PCS Gas Plant ranged between 71% and 81%, in a period when the annual AECO natural gas spot price averaged between $2.39 per Mcf and $4.50 per Mcf.

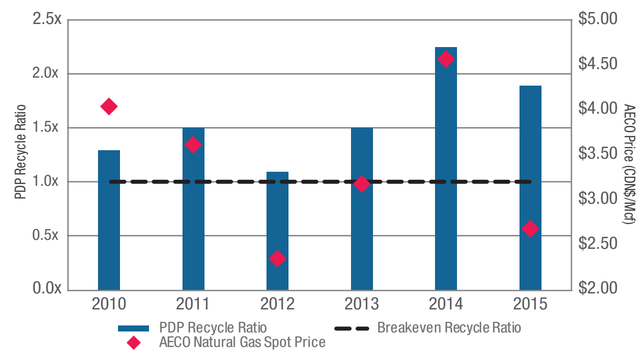
Operating margin is calculated by dividing the operating netback for the period by the realized petroleum and natural gas sales for the period.

On average over the last six years, we recorded an operating margin of $0.78 for every $1.00 in sales revenue received at the PCS Gas Plant.

PDP Operating Netback Recycle Ratio

Over the last six years, we have generated a positive recycle ratio on our Montney/Doig Natural Gas Resource Play, notwithstanding the volatility in commodity prices during that period. The following chart highlights our Montney/Doig PDP operating netback recycle ratio since 2010:

Montney/Doig PDP Operating Netback Recycle Ratio



In 2015, we delivered a top-tier operating netback recycle ratio of 1.9x on our Montney/Doig Natural Gas Resource Play when AECO natural gas prices averaged $2.69 per Mcf ($2.55 per GJ) during the year.

Over the last six years, our Montney/Doig asset generated an operating netback recycle ratio of greater than 1.0x (breakeven), when annual AECO natural gas spot prices averaged as low as $2.39 per Mcf ($2.27 per GJ) during that period.

For a description of the methodology used to calculate recycle ratios, see "*Advisories – Oil and Gas Metrics*" in this Annual Report.

Montney/Doig Profitability Including Finding Costs

The following table highlights our Montney/Doig profit before non-cash items during the last six years, after taking into account the cost to find and develop our proved developed producing reserves and the royalties, operating and transportation and marketing costs to produce our oil and natural gas on the Montney/Doig Natural Gas Resource Play:

	6 Yr. Avg.	2015	2014	2013	2012	2011	2010
WTI Cushing *($US/bbl)*	**$86.28**	$57.90	$92.99	$97.97	$94.21	$95.10	$79.52
AECO – C Daily *($/Mcf)*	**$3.40**	$2.69	$4.50	$3.15	$2.39	$3.63	$4.01
Petroleum and Natural Gas Revenue *($/Mcfe)*	**$3.99**	$3.24	$5.27	$3.82	$3.05	$4.26	$4.59
PDP FD&A *($/Mcfe)*(1)	**($1.76)**	($1.19)	($1.86)	($1.89)	($1.84)	($2.05)	($2.33)
Royalty, Operating & Transportation & Marketing Expenses *($/Mcfe)*	**($1.09)**	($0.94)	($1.17)	($1.02)	($1.04)	($1.18)	($1.54)
Profit Before Non-Cash Items *($/Mcfe)*(2)	**$1.14**	**$1.11**	**$2.24**	**$0.91**	**$0.17**	**$1.03**	**$0.72**
Profit Margin – Montney/Doig *(%)*(2)	**29%**	**34%**	**43%**	**24%**	**6%**	**24%**	**16%**

(1) Cost to find and develop proved developed producing reserves based on FD&A costs.

(2) Profit before non-cash items measures the amount, if any, during the relevant period by which revenues resulting from production exceed the sum of: (i) PDP FD&A (i.e. the costs of replacing production) and (ii) royalty, operating and transportation and marketing expenses. In the case of the Montney/Doig Natural Gas Resource Play, profit before non-cash items does not take into account general and administrative expense or interest expense. This measure is not intended to represent net income or net income to common shareholders as presented in accordance with IFRS. Profit margin is calculated by dividing profit before non-cash items for the period by petroleum and natural gas revenue for the period. See *"Non-GAAP Measures"* in this Annual Report.

In 2015, we realized a profit before non-cash items of $1.11 per Mcfe on our Montney/Doig Natural Gas Resource Play, notwithstanding a 40% decline in AECO spot prices and a 48% decline in WTI oil spot prices during the year.

On average over the last six years, our Montney/Doig asset generated a profit before non-cash items of $1.14 per Mcfe (29% profit margin) when the AECO natural gas spot price averaged $3.40 per Mcf ($3.22 per GJ) during that period.

This measure demonstrates that we can find, develop and produce our reserves for less than what we receive in revenue from our production on the Montney/Doig Natural Gas Resource Play.

TOP-TIER MONTNEY/DOIG NATURAL GAS RESOURCE PLAY

We have added significant Montney/Doig reserves at low FD&A costs and, as a result, we have achieved top-tier industry recycle ratios, reserves replacement ratios and reserves life index. The following table details the key performance metrics of our Montney/Doig Natural Gas Resource Play since 2010:

	6 Year Avg.	2015	2014	2013	2012	2011	2010
Proved Developed Producing							
FD&A *($/Mcfe)*(1)	**$1.76**	$1.19	$1.86	$1.89	$1.84	$2.05	$2.33
Recycle Ratio *(FD&A)*(1)(3)	**1.7**	1.9	2.2	1.5	1.1	1.5	1.3
Reserves Replacement(1)	**298%**	258%	325%	231%	355%	280%	450%
Reserves Life Index *(years)*(1)(4)	**6.2**	7.4	6.5	6.5	5.8	5.7	5.3
Proved							
FD&A *($/Mcfe)*(1)(2)	**$1.32**	$0.28	$1.81	$1.34	$1.61	$1.91	$1.71
Recycle Ratio *(FD&A)*(1)(3)	**2.2**	8.4	2.3	2.1	1.3	1.6	1.8
Reserves Replacement(1)	**715%**	651%	714%	639%	571%	1,039%	996%
Reserves Life Index *(years)*(1)(4)	**24.1**	25.6	22.4	24.6	21.4	27.0	23.9
Proved Plus Probable							
FD&A *($/Mcfe)*(1)(2)	**$1.20**	$0.17	$1.61	$1.30	$1.85	$1.73	$1.29
Recycle Ratio *(FD&A)*(1)(3)	**2.4**	13.3	2.6	2.2	1.1	1.8	2.4
Reserves Replacement(1)	**1,051%**	966%	1,029%	857%	723%	1,684%	1,689%
Reserves Life Index *(years)*(1)(4)	**40.8**	41.0	36.0	40.3	36.2	47.9	43.2

(1) See *"Advisories – Oil and Gas Metrics"* in this Annual Report for a description of the methodology used to calculate FD&A, recycle ratios, reserves replacement and reserves life index.

(2) Includes FDC additions in the respective year.

(3) Based on average annual operating netback in the respective year.

(4) Based on fourth quarter average production in the respective year.

LAND HOLDINGS

Our land base primarily consists of large contiguous blocks of high working interest acreage located near facilities owned and/or operated by Birchcliff or near third party infrastructure.

Our undeveloped land base as at December 31, 2015 was 426,012.6 (398,412.7 net) acres, with a 94% average working interest.

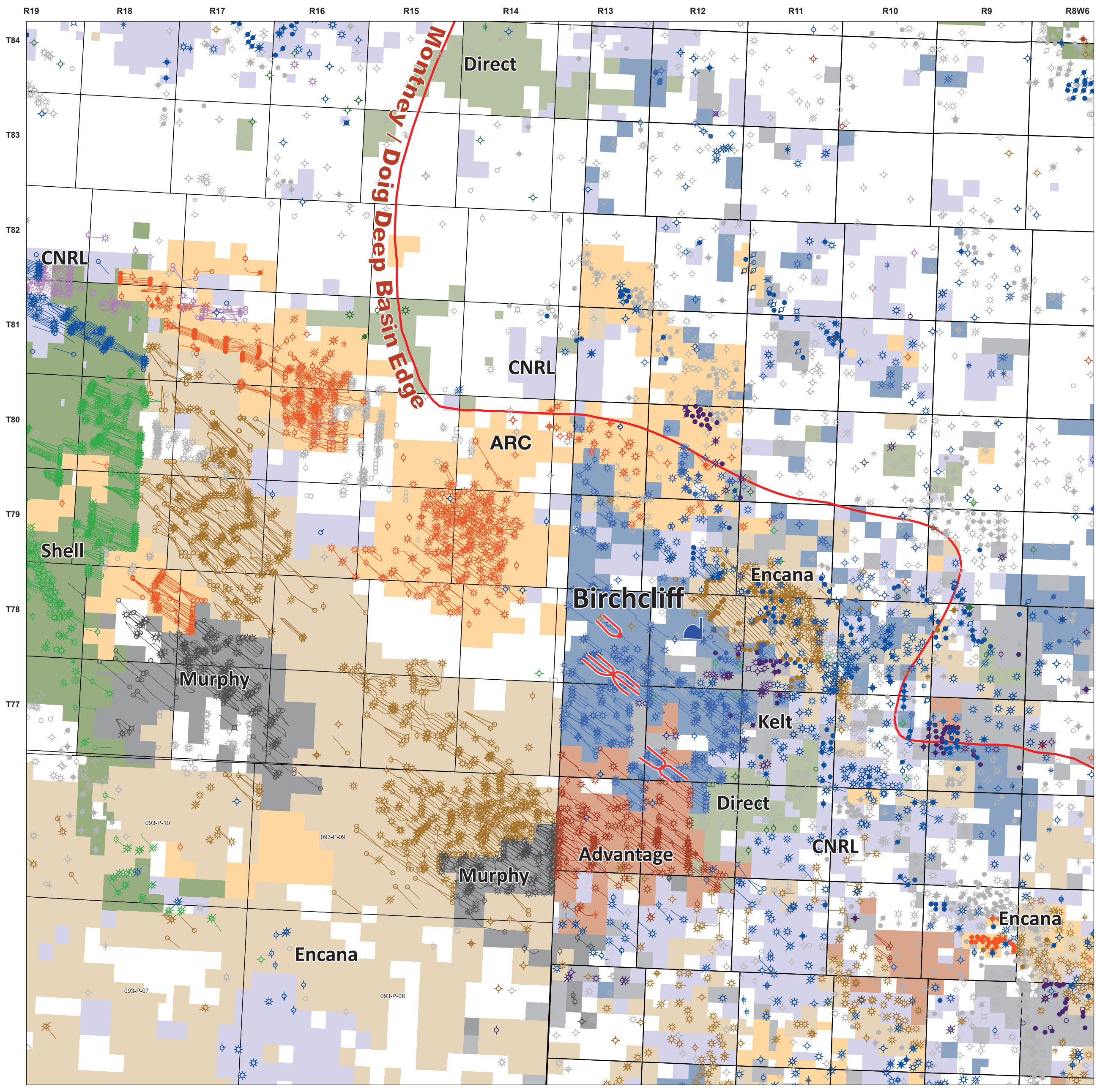
The following table sets forth our land holdings on the following resource plays as at December 31, 2015:

Resource Play Land Holdings as at December 31, 2015

Resource Play	Working Interest	Gross (acres)	Net (acres)
Montney/Doig Natural Gas Resource Play			
Basal Doig/Upper Montney Interval	94.8%	198,336	187,968
Montney D4 Interval	97.8%	187,776	183,680
Montney D1 Interval	97.0%	203,136	197,120
Montney C Interval	97.0%	203,136	197,120
Charlie Lake Light Oil Resource Play	93.3%	146,880	137,133
Duvernay Resource Play	100.0%	73,120	73,120
Nordegg Resource Play	86.0%	405,440	348,528
Banff/Exshaw Resource Play	98.9%	230,400	227,984

Our land holdings on the Montney/Doig Natural Gas Resource Play positions us alongside industry giants. Birchcliff's location allows us to compete directly with key oil and natural gas players. We are constantly evaluating the methods utilized by industry leaders and adopting best practices to increase production growth and reserves, while keeping costs low.

Montney/Doig Natural Gas Resource Play Competitor Activity Map



Competitor lands are based on publicly available data.

Montney Producing Wells

- Birchcliff
- Birchcliff 2016
- Montney Producers
- Montney Horizontal Producers
- Encana
- Murphy
- ARC
- Shell
- CNRL
- Advantage
- Kelt
- Direct

LAND LEGEND

- Birchcliff Non-Confidential
- Encana
- Shell
- Murphy
- CNRL
- ARC
- Advantage
- Kelt
- Direct

DRILLING PROGRAM

Our 2015 drilling program was focused on our Montney/Doig Natural Gas Resource Play and Charlie Lake Light Oil Resource Play. We actively employed the evolving technology utilized by the industry regarding horizontal well drilling and the related multi-stage fracture stimulation technology.

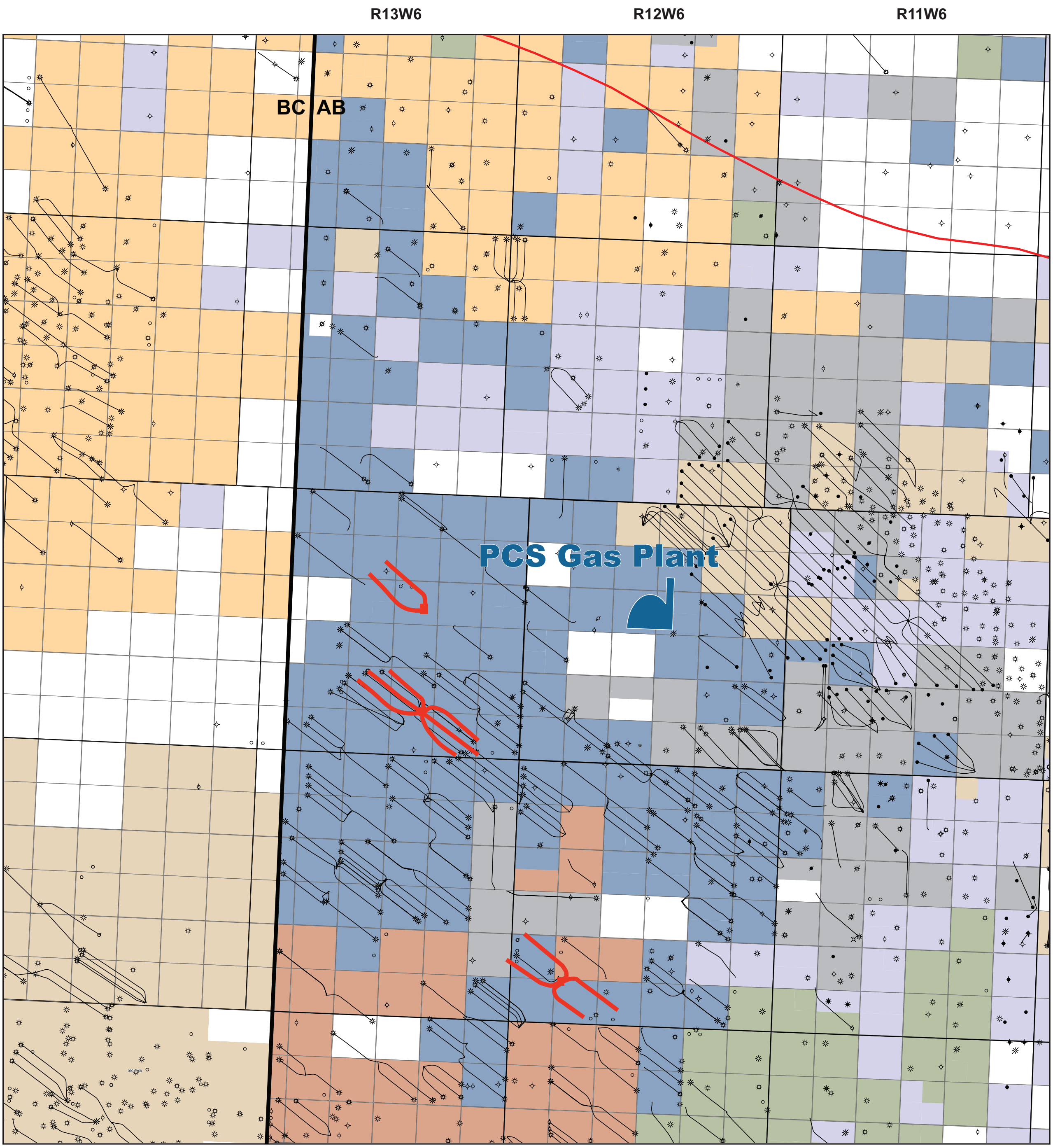
We had an active drilling program during 2015 drilling a total of 32 (31.5 net) wells, consisting of 28 (28.0 net) Montney/Doig horizontal natural gas wells in the Pouce Coupe area, 1 (1.0 net) Montney/Doig horizontal natural gas well in the Elmworth area, 1 (1.0 net) Charlie Lake horizontal light oil well in the Progress area, 1.0 (0.5 net) Halfway horizontal light oil well in the Progress area and 1.0 (1.0 net) Belloy vertical well drilled as an acid gas disposal well in the Elmworth area. All of the horizontal wells drilled in 2015 utilized multi-stage fracture stimulation technology.

Our 2016 Revised Capital Budget is focused on our two proven resource plays. The 2016 Revised Capital Budget contemplates the drilling of 13 (13.0 net) wells, consisting of 12 (12.0 net) Montney/Doig horizontal natural gas wells in the Pouce Coupe area and 1 (1.0 net) Charlie Lake horizontal well in the Worsley area. The 12 Montney/Doig wells will all be drilled on multi-well pads – one 2-well pad, one 4-well pad and one 6-well pad. All three pads are already tied-in to our infrastructure system, minimizing equipping and tie-in costs. Early in 2016, we drilled the Charlie Lake horizontal light oil well that successfully delineated the pool to the northeast and that will continue 18 sections of land.

"I am very proud of our entire Birchcliff Team for their continued efforts to improve our capital and operating cost efficiencies. Strong relationships with our loyal service providers, as well as continued optimization of our operational best practices, have led to top-tier results that speak for themselves."

DAVE HUMPHREYS,
VICE-PRESIDENT, OPERATIONS

2016 Pouce Coupe Montney / Doig Drilling Program



Competitor lands are based on publicly available data.

Montney Producing Wells

- Birchcliff 2016
- Montney Producers
- Montney Horizontal Producers

LAND LEGEND

- Birchcliff Non-Confidential
- Encana
- CNRL
- ARC
- Advantage
- Kelt
- Direct

FACILITIES

As at December 31, 2015, we had a 100% working interest in four gas plants (including the PCS Gas Plant) and one oil battery, as well as various working interests in an additional seven gas plants (one of which is operated by us) and one oil battery.

Our 100% owned and operated PCS Gas Plant, which is currently licensed to process up to 180 MMcf per day of natural gas, is located in the heart of our Montney/Doig Natural Gas Resource Play in the Pouce Coupe South area. The strategically situated site for the PCS Gas Plant enables us to control and operate all essential infrastructure from wellhead to sales point.

The low per unit operating costs of the PCS Gas Plant and related infrastructure give us a strong competitive advantage over others paying for third-party natural gas processing. The PCS Gas Plant is a key component in positioning us as a low-cost finder and producer of natural gas on the Montney/Doig Natural Gas Resource Play.

The PCS Gas Plant is a state-of-the-art facility that meets or exceeds all AER and Alberta Environment requirements. The facility employs energy efficient equipment to optimize performance and keep operating costs low. The PCS Gas Plant uses an amine system to remove sulphur content and refrigeration to meet dew point specification. Acid gas is injected into a high quality reservoir via two wells located at and near the site of the PCS Gas Plant.

Engineering, procurement and fabrication work is underway for the Phase V expansion of the PCS Gas Plant which will increase processing capacity to 260 MMcf per day. In addition, the design and licensing work is complete for the Phase VI expansion which will increase processing capacity to 340 MMcf per day from 260 MMcf per day. For additional information, see *"Resource Plays – Montney/Doig Natural Gas Resource Play"*.

In 2015,

ESTIMATED OPERATING NETBACK AT THE PCS GAS PLANT

$2.44

PER MCFE[1]

PROCESSED AT THE PCS GAS PLANT

81%

OF TOTAL CORPORATE NATURAL GAS PRODUCTION

OPERATING MARGIN AT THE PCS GAS PLANT

77%

1. Realized revenue of $3.17 per Mcfe at the PCS Gas Plant when the AECO natural gas price averaged $2.69 per Mcf.

RESERVES AND RESOURCES

2015 INDEPENDENT RESERVES EVALUATION

Deloitte, our independent qualified reserves evaluator, prepared the 2015 Reserves Evaluation, the 2014 Reserves Evaluation and a reserves estimation and economic evaluation effective December 31, 2013. Reserves data contained herein as at December 31, 2015, 2014 and 2013 are extracted from the relevant evaluation. The 2015 Reserves Evaluation and the prior reserves evaluations were prepared in accordance with the standards contained in the COGE Handbook and NI 51-101 that were in effect at the relevant time.

Numbers presented in the tables below may not total due to rounding. The estimates of reserves and future net revenues contained in this Annual Report were prepared by Deloitte.

The reserves and associated cash flow information set forth herein are estimates only. Birchcliff's actual production and revenues with respect to its reserves will vary from estimates thereof and such variations could be material. For additional information regarding the presentation of our reserves disclosure, please see "*Presentation of Oil and Gas Reserves and Resources*" and "*Advisories*" contained in this Annual Report.

Reserves Summary

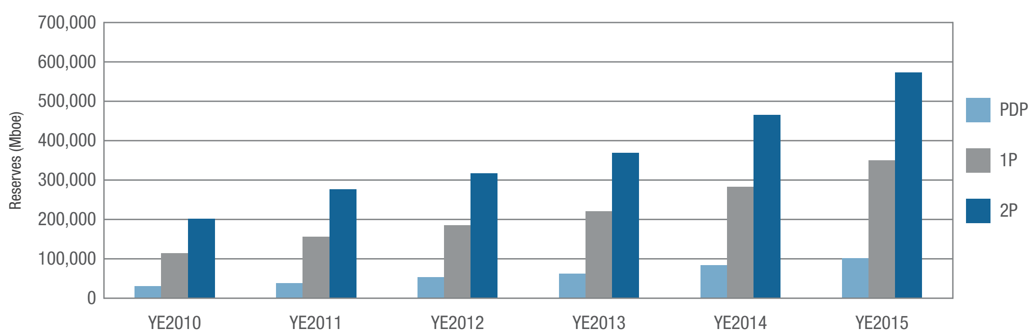
The following table sets forth our gross reserves as at December 31, 2015 and December 31, 2014, using Deloitte's forecast of prices and costs in effect at the applicable reserves evaluation date:

Summary of Reserves

Reserves Category	Dec 31, 2015 *(MMboe)*	Dec 31, 2014 *(MMboe)*	Increase from Dec 31, 2014
Proved Developed Producing	102.1	84.7	21%
Total Proved	351.2	282.3	24%
Probable	221.7	182.7	21%
Total Proved Plus Probable	572.9	465.0	23%

Our proved plus probable reserves are comprised of 85% shale gas, 4% conventional natural gas, 6% light crude oil and medium crude oil (combined) and 5% NGL.

Summary of Company Oil and Natural Gas Reserves



Net Present Values of Future Net Revenue

The following table sets forth the net present values of future net revenue associated with our reserves as at December 31, 2015, before deducting future income tax expense, calculated at various discount rates. The net present values of future net revenue attributable to our reserves are based on Deloitte's December 31, 2015 forecast prices and costs (the "**Deloitte Price Forecast**").

Net Present Values of Future Net Revenue Before Income Taxes[1][2]

	Discounted Rate per Annum				
Reserves Category	*0% (MM$)*	*5% (MM$)*	*10% (MM$)*	*15% (MM$)*	*20% (MM$)*
Proved					
Developed Producing	2,099.5	1,486.5	1,134.6	913.9	765.4
Developed Non-Producing	434.1	230.4	140.5	93.2	65.5
Undeveloped	4,575.0	2,399.3	1,316.1	722.1	372.7
Total Proved	7,108.6	4,116.2	2,591.2	1,729.2	1,203.6
Probable	6,097.7	2,619.1	1,276.2	668.5	361.8
Total Proved Plus Probable	13,206.3	6,735.3	3,867.4	2,397.7	1,565.3

(1) Estimates of future net revenue, whether calculated without discount or using a discount rate, do not represent fair market value.

(2) The net present value of future net revenue attributable to Birchcliff's reserves is based on the Deloitte Price Forecast and is determined before provision for interest, debt servicing and general and administrative expense and after the deduction of royalties, operating costs, development costs and abandonment and reclamation costs. Abandonment and reclamation costs have been estimated by Deloitte in the 2015 Reserves Evaluation, are attributed to all existing and future wells that were assigned reserves in the 2015 Reserves Evaluation and do not include abandonment and reclamation costs for wells and facilities to which no reserves were assigned.

The net present value of the proved plus probable reserves (at a 10% discount rate, before income taxes) was approximately $3.9 billion, a 2% increase from 2014. This increase is a result of the 23% increase in reserves volumes recognized in the 2015 Reserves Evaluation, offset by the significant decrease in oil and natural gas prices contained in the Deloitte Price Forecast as compared to 2014.

The net present value of the proved developed producing reserves (at a 10% discount rate, before income taxes) was approximately $1.1 billion, a 14% decrease compared to 2014. This decrease is a result of the significant decrease in oil and natural gas prices contained in the Deloitte Price Forecast as compared to 2014, notwithstanding the 21% increase in reserves volumes recognized in the 2015 Reserves Evaluation.

The natural gas price forecast and the oil and pentanes plus price forecasts for the years 2016 through 2020 as contained in the Deloitte Price Forecast decreased by 35% and 22%, respectively, compared to the 2014 Deloitte forecast price assumptions. The natural gas price forecast used by Deloitte in the 2015 Reserves Evaluation for the years 2016 through 2020 is approximately $1.64 per MMbtu lower on average than the forecast used by Deloitte for the same period in the 2014 Reserves Evaluation. The Edmonton Par oil price and the pentanes plus price forecasts used by Deloitte in the 2015 Reserves Evaluation for the years 2016 through 2020 are approximately $19.07 per bbl lower than the forecasts used by Deloitte for the same period in the 2014 Reserves Evaluation.

Forecast Prices Used in Estimates

The following table summarizes the crude oil, natural gas and NGL benchmark reference prices and inflation and exchange rate assumptions contained in the Deloitte Price Forecast, which were used by Deloitte for the 2015 Reserves Evaluation:

Deloitte Price Forecast

	Crude Oil		Natural Gas	NGL					
Year	WTI at Cushing Oklahoma *($US/bbl)*	Edmonton City Gate *($CDN/bbl)*	Natural Gas at AECO *($CDN/Mcf)*	Edmonton Ethane *($CDN/bbl)*	Edmonton Propane *($CDN/bbl)*	Edmonton Butane *($CDN/bbl)*	Edmonton Pentanes + Condensate *($CDN/bbl)*	Currency Exchange Rate *($CDN/$US)*	Inflation Rate *(%)*
2016	42.00	51.35	2.45	6.75	5.15	20.55	51.35	0.740	0.0
2017	48.45	57.65	2.85	7.85	11.55	28.80	57.65	0.770	2.0
2018	57.20	66.35	3.10	8.60	19.90	39.80	66.35	0.800	2.0
2019	66.35	77.65	3.45	9.50	23.30	46.60	77.65	0.800	2.0
2020	75.75	89.30	3.75	10.30	26.80	53.60	89.30	0.800	2.0
2021	82.80	98.00	4.15	11.35	29.40	58.80	98.00	0.800	2.0
2022	90.10	107.00	4.40	12.10	32.10	64.20	107.00	0.800	2.0
2023	91.90	109.15	4.65	12.80	32.75	65.50	109.15	0.800	2.0
2024	93.75	111.30	5.00	13.70	33.40	66.80	111.30	0.800	2.0
2025	95.60	113.55	5.15	14.15	34.05	68.10	113.55	0.800	2.0
2026	97.50	115.80	5.50	15.10	34.75	69.50	115.80	0.800	2.0
2027	99.45	118.10	5.80	15.90	35.45	70.85	118.10	0.800	2.0
2028	101.45	120.50	5.90	16.25	36.15	72.30	120.50	0.800	2.0
2029	103.50	122.90	6.00	16.55	36.85	73.75	122.90	0.800	2.0
2030	105.55	125.35	6.15	16.90	37.60	75.20	125.35	0.800	2.0
2031	107.65	127.85	6.25	17.25	38.35	76.70	127.85	0.800	2.0
2032	109.80	130.40	6.40	17.55	39.10	78.25	130.40	0.800	2.0
2033	112.00	133.00	6.50	17.90	39.90	79.80	133.00	0.800	2.0
2034	114.25	135.70	6.65	18.30	40.70	81.40	135.70	0.800	2.0
2035	116.55	138.40	6.75	18.65	41.50	83.05	138.40	0.800	2.0
Thereafter	Escalate at 2% per year								

The Deloitte Price Forecast was determined by Deloitte based on information available from numerous governmental agencies, industry publications, oil refineries, natural gas marketers and industry trends. The Deloitte Price Forecast is subject to the many uncertainties that affect long-term future forecasts. The Deloitte Price Forecast can be found at http://www2.deloitte.com/ca/en/pages/resource-evaluation-and-advisory/topics/resource-evaluation-and-advisory.html.

Reconciliation of Changes in Reserves

The following table sets forth a reconciliation of our gross reserves as at December 31, 2015 set forth in the 2015 Reserves Evaluation, using the Deloitte Price Forecast, to our gross reserves as at December 31, 2014 set forth in the 2014 Reserves Evaluation, using the Deloitte price forecast as at December 31, 2014.

Due to changes in NI 51-101 product type definitions effective July 1, 2015, 1,446,743.8 MMcf of proved reserves, 878,330.1 MMcf of probable reserves and 2,325,073.9 MMcf of proved plus probable reserves were moved from the December 31, 2014 Canadian conventional natural gas opening volumes to the shale gas opening volumes.

Reconciliation of Gross Reserves from December 31, 2014 to December 31, 2015 (Forecast Prices and Costs)

Factors	Light Crude Oil and Medium Crude Oil *(Mbbls)*	Conventional Natural Gas *(MMcf)*	Shale Gas *(MMcf)*	NGL *(Mbbls)*	Oil Equivalent *(Mboe)*
GROSS TOTAL PROVED					
Opening balance December 31, 2014	**18,183.7**	**61,257.0**	**1,446,743.8**	**12,797.7**	**282,314.9**
Discoveries	0.0	0.0	0.0	0.0	0.0
Extensions[1] & Improved Recovery	959.8	9,911.9	332,701.0	2,523.7	60,585.7
Technical Revisions[2]	840.3	(503.3)	139,590.5	1,892.3	25,913.8
Acquisitions	0.0	0.0	0.0	0.0	0.0
Dispositions	0.0	(744.0)	0.0	(6.9)	(130.9)
Economic Factors[3]	(84.7)	(5,053.3)	(11,084.5)	(272.4)	(3,046.7)
Production[4]	(1,365.1)	(5,773.6)	(68,584.1)	(633.2)	(14,314.9)
Closing balance December 31, 2015	**18,534.0**	**59,094.7**	**1,839,366.7**	**16,301.2**	**351,245.4**
GROSS TOTAL PROBABLE					
Opening balance December 31, 2014	**17,765.4**	**58,162.9**	**878,330.1**	**8,875.5**	**182,723.1**
Discoveries	0.0	0.0	0.0	0.0	0.0
Extensions[1] & Improved Recovery	632.0	10,281.2	188,301.7	2,378.8	36,108.0
Technical Revisions[2]	(919.6)	(1,662.1)	60,629.8	464.9	9,373.3
Acquisitions	0.0	0.0	0.0	0.0	0.0
Dispositions	(45.0)	(704.4)	(12,103.6)	(108.2)	(2,287.9)
Economic Factors[3]	35.3	(1,180.6)	(21,408.0)	(493.5)	(4,223.0)
Production[4]	0.0	0.0	0.0	0.0	0.0
Closing balance December 31, 2015	**17,468.1**	**64,897.0**	**1,093,750.0**	**11,117.5**	**221,693.4**
GROSS TOTAL PROVED PLUS PROBABLE					
Opening balance December 31, 2014	**35,949.1**	**119,419.9**	**2,325,073.9**	**21,673.2**	**465,037.9**
Discoveries	0.0	0.0	0.0	0.0	0.0
Extensions[1] & Improved Recovery	1,591.8	20,193.1	521,002.7	4,902.5	96,693.6
Technical Revisions[2]	(79.3)	(2,165.4)	200,220.3	2,357.2	35,287.1
Acquisitions	0.0	0.0	0.0	0.0	0.0
Dispositions	(45.0)	(1,448.4)	(12,103.6)	(115.1)	(2,418.8)
Economic factors[3]	(49.4)	(6,233.9)	(32,492.5)	(765.9)	7,269.7
Production[4]	(1,365.1)	(5,773.6)	(68,584.1)	(633.2)	(14,391.3)
Closing balance December 31, 2015	**36,002.1**	**123,991.7**	**2,933,116.7**	**27,418.7**	**572,938.9**

(1) The majority of conventional natural gas, shale gas and NGL reserves changes comprising *"Extensions"* were the result of drilling activities on the Montney/Doig Natural Gas Resource Play. Wells were drilled extending the resource play beyond lands to which reserves had previously been attributed. The majority of light crude oil and medium crude oil reserves changes comprising *"Extensions"* were the result of drilling activity in the Charlie Lake Light Oil Resource Play in the Progress area. As a result of these successful oil and gas wells, reserves were attributed to future well locations proximal to these wells.

(2) The majority of the *"Technical Revisions"* in the proved and proved plus probable categories are a result of Deloitte's assignment of a new Montney/Doig type curve to the future locations in that area within Pouce Coupe South, which is based on the increased performance of the offsetting Montney/Doig wells.

(3) The change in reserves attributed to "*Economic Factors*" results from the Deloitte Price Forecast used in the 2015 Reserves Evaluation being lower than Deloitte's price forecasts used in the 2014 Reserves Evaluation. This reduction in price resulted in the increase of some wells' economic limits and thereby reduced reserves, or made a future oil or shale gas location uneconomic to develop.

(4) Represents Deloitte's estimate of actual production for the year ended December 31, 2015 before year-end results were available.

Positive Technical Revisions

Positive technical revisions accounted for 17% of the proved developed producing reserves additions, 31% of the proved reserves additions and 29% of the proved plus probable reserves additions in 2015. These positive revisions for proved and proved plus probable reserves, which did not require any increase to FDC, resulted from Deloitte's recognition of improved well production performance from our 2015, 2014 and 2013 drilling programs. These technical revisions primarily resulted from the continued advancement of our drilling and completion technologies and improved well production performance on some of our existing wells. Improved well performance, coupled with reduced well costs, resulted in us having top-tier reserves and production capital efficiencies.

Reserves Replacement

From the 2014 Reserves Evaluation to the 2015 Reserves Evaluation, we had:

- 222% reserves replacement on a proved developed producing basis, including reserves disposed of. We added 2.22 boe of proved developed producing reserves for each boe that was produced during the year (calculated by dividing 2015 proved developed producing reserves additions before production by total production in 2015).
- 585% reserves replacement on a proved basis, including reserves disposed of. We added 5.85 boe of proved reserves for each boe that was produced during the year (calculated by dividing 2015 proved reserves additions before production by total production in 2015).
- 859% reserves replacement on a proved plus probable basis, including reserves disposed of. We added 8.59 boe of proved plus probable reserves for each boe that was produced during the year (calculated by dividing 2015 proved plus probable reserves additions before production by total production in 2015).

See "*Advisories — Oil and Gas Metrics*" for a description of the methodology used to calculate reserves replacement.

Reserves Life Index

Our reserves life index is 6.9 years on a proved developed producing basis, 23.7 years on a proved basis and 38.7 years on a proved plus probable basis, in each case using reserves estimates by Deloitte as at December 31, 2015 and assuming an average daily production rate of 40,500 boe per day, which represents the mid-point of our 2016 annual average production guidance range. See "*Advisories — Oil and Gas Metrics*" for a description of the methodology used to calculate reserves life index.

Reserves on the Montney/Doig Natural Gas Resource Play

Deloitte estimated as at December 31, 2015, that we had 516.8 MMboe of proved plus probable reserves attributed to horizontal wells on the Montney/Doig Natural Gas Resource Play. This is an increase of 25% from 412.3 MMboe proved plus probable reserves attributed to horizontal wells on the Montney/Doig Natural Gas Resource Play as at December 31, 2014.

The following tables sets forth Deloitte's estimates of reserves attributable to our horizontal wells on the Montney/Doig Natural Gas Resource Play, the number of horizontal wells to which reserves were attributed and the future development capital associated with such reserves:

Montney/Doig Natural Gas Resource Play Reserves Data[1]

	Shale Gas (Bcf)[2]		Light Crude Oil and Medium Crude Oil and NGL Combined (Mbbls)[3]		Total (Mboe)		Existing Horizontal Wells and Future Horizontal Well Locations (Gross)		(Net)		Net Future Development Capital (MM$)	
Reserves Category	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**	**2015**[4]	**2014**[5]
Proved Developed Producing	525.8	413.9	4,752.5	4,110.0	92,379.7	73,094.8	185	155	184.9	154.9	0.0	0.0
Total Proved	1,842.0	1,453.6	14,756.4	12,933.9	321,752.4	255,208.2	516	443	505.2	432.2	1,623.7	1,712.1
Total Proved Plus Probable	2,945.7	2,343.2	25,865.7	21,798.2	516,821.4	412,336.2	723	622	698.8	598.8	2,667.7	2,769.4

(1) Estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties due to the effects of aggregation.
(2) With respect to our natural gas reserves attributable to our Montney/Doig Natural Gas Resource Play, such reserves would most closely fit within the category of shale gas as such term is defined in NI 51-101.
(3) Light crude oil and medium crude oil (combined) and NGL have been combined in the table above as the NGL reserves are not material.
(4) Includes approximately $57 million of capital for the Phase V expansion of the PCS Gas Plant to 260 MMcf per day of total throughput, plus $45.8 million of capital for the Phase VI expansion of the PCS Gas Plant to 340 MMcf per day of total throughput, plus $46.5 million of capital for additional pipelines and compression projects during 2016 to 2018, all in the proved category. Also includes approximately $84.3 million of capital for the Phase VII expansion of the PCS Gas Plant to 420 MMcf per day of total throughput, plus $17.9 million of capital for additional pipeline and compression projects during 2018 and 2019, all in the probable category.
(5) Includes approximately $97 million of capital for the Phase V expansion of the PCS Gas Plant to 240 MMcf per day of total throughput, together with the related gathering pipelines, sales pipeline expansion and compression, plus $61 million of capital for the Phase VI expansion of the PCS Gas Plant to 300 MMcf per day of total throughput, plus $56 million of capital for additional pipelines and compression projects during 2016 to 2020, all in the proved category. Also includes approximately $89 million of capital for the Phase VII expansion of the PCS Gas Plant to 360 MMcf per day of total throughput in the probable category.

Montney/Doig Land and Horizontal Natural Gas Well Data

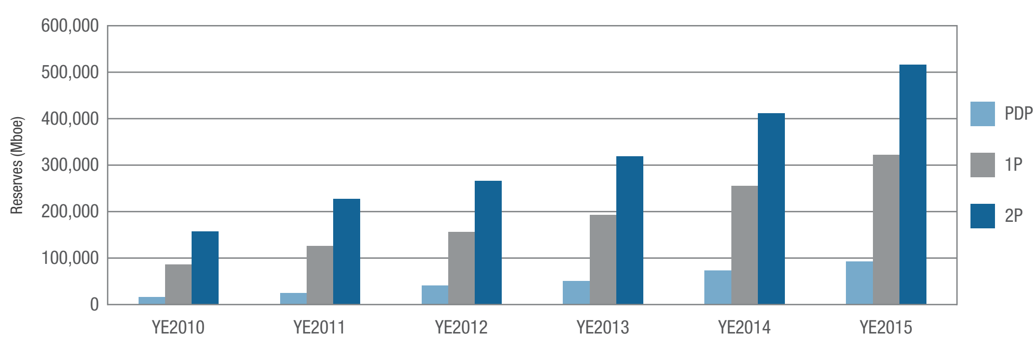
	Dec 31, 2015		Dec 31, 2014		Dec 31, 2013	
	Gross	*Net*	*Gross*	*Net*	*Gross*	*Net*
Number of sections to which Deloitte attributed proved plus probable reserves	150.6	145.9	139.6	133.7	129.6	114.9
For existing and future horizontal wells, number of well locations to which Deloitte attributed proved plus probable reserves	723	698.8	622	598.8	549	470.8
For existing and future horizontal wells, average number of net well locations per net section to which Deloitte attributed proved plus probable reserves	4.8(1)		4.5(2)		4.1(3)	
For existing horizontal wells, average remaining proved plus probable reserves attributed by Deloitte, plus cumulative production	5.3 Bcfe(4)		4.9 Bcfe(4)		4.9 Bcfe	
For future horizontal wells, average remaining proved plus probable reserves attributed by Deloitte	4.7 Bcfe		4.3 Bcfe		4.2 Bcfe	
Average cost per well, forecast by Deloitte	$4.4 million		$5.3 million		$5.2 million	

(1) For existing and future horizontal wells, the average number of net well locations per net section to which Deloitte attributed proved plus probable reserves is 3.1 for the Basal Doig/Upper Montney interval and 3.1 for the Montney D1 interval.
(2) For existing and future horizontal wells, the average number of net well locations per net section to which Deloitte attributed proved plus probable reserves is 3.1 for the Basal Doig/Upper Montney interval and 2.9 for the Montney D1 interval.
(3) For existing and future horizontal wells, the average number of net well locations per net section to which Deloitte attributed proved plus probable reserves is 3.2 for the Basal Doig/Upper Montney interval and 2.9 for the Montney D1 interval.
(4) Does not include the four Montney horizontal light oil wells in Section 17-078-11W6M.

Deloitte has attributed Montney/Doig proved plus probable reserves to 150.6 (145.9 net) sections of land. Deloitte has attributed reserves: (i) in the Montney D1 interval to 131.3 (127.9 net) sections of land, an increase of 12.7 net sections of land from 2014; (ii) in the Montney D4 interval to 22 (22.0 net) sections of land, an increase of 15.0 net sections of land from 2014; (iii) in the Montney C interval to 2 (2.0 net) sections of land, which is unchanged from 2014; and (iv) in the Basal Doig/Upper Montney interval to 94.3 (90.7 net) sections of land, an increase of 10.7 net sections of land from 2014. There are now 84 (82.4 net) sections to which Deloitte has attributed reserves to both the Basal Doig/Upper Montney interval and the Montney D1 interval.

Management believes that the ultimate recovery from our Montney/Doig horizontal natural gas wells will continue to improve year-over-year as production declines continue to flatten. In addition, as drilling and completion technologies continue to improve, recovery factors and production rates in this unconventional reservoir should also improve.

Montney/Doig Reserves



Reserves on the Charlie Lake Light Oil Resource Play – Worsley Area

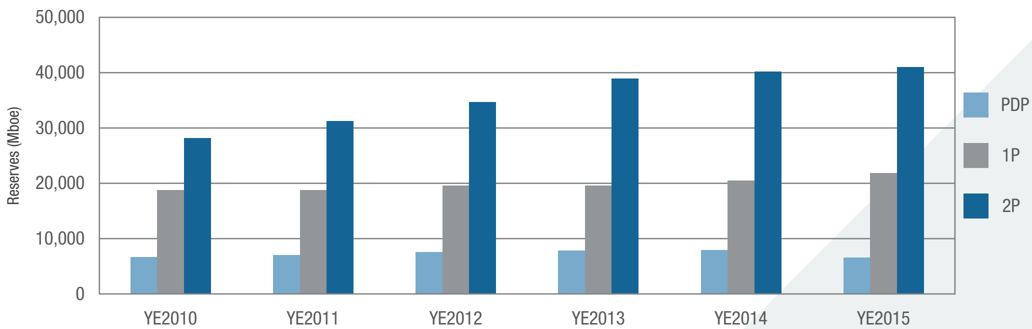
As at December 31, 2015, Deloitte estimated that in the Worsley Charlie Lake light oil pool, we had 41.1 MMboe proved plus probable reserves and 21.9 MMboe of proved reserves. This continues the growth trend for our Worsley Charlie Lake reserves since July 1, 2007 (being the effective date of the acquisition of this property), when reserves were estimated at 15.1 MMboe on a proved plus probable basis and 11.3 MMboe on a proved basis. The reserves continue to increase and we are pleased to report that the Worsley Charlie Lake light oil pool continues to be a top quality asset.

History of Reserves Estimated for the Worsley Charlie Light Oil Lake Pool (MMboe)[1]

Reserves Category	Dec 31, 2015	Dec 31, 2014	Dec 31, 2013	Dec 31, 2012	Dec 31, 2011	Dec 31, 2010	Dec 31, 2009	Dec 31, 2008	Dec 31, 2007	July 1, 2007
Proved	21.9	20.5	19.6	19.6	18.8	18.8	18.3	17.5	15.0	11.3
Proved Plus Probable	41.1	40.2	38.9	34.7	31.3	28.2	26.3	24.6	21.2	15.1

(1) Estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties due to the effects of aggregation.

Worsley Charlie Lake Reserves



"Birchcliff had another strong and successful year in 2015 with reserves growth in all categories. Thanks to our strong technical teams, we have been able to increase our 2P reserves per existing and future well and at the same time reduce our average costs per well."

CHRIS CARLSEN,
VICE-PRESIDENT, ENGINEERING

2015 F&D COSTS

During 2015, our F&D costs were $257 million and our FD&A costs were $246 million. The following table sets forth our estimates of our F&D costs per boe and FD&A costs per boe, excluding FDC and including FDC, on a proved developed producing, proved and proved plus probable basis:

F&D and FD&A Costs ($/boe)[1]

Excluding FDC	2015	2014	2013	Three Year Average
F&D – Proved Developed Producing	$8.11	$13.40	$14.94	$11.64
F&D – Proved	$3.09	$8.29	$5.85	$5.21
F&D – Proved Plus Probable	$2.06	$5.96	$4.11	$3.60
Total FD&A – Proved Developed Producing	$7.79	$12.81	$12.71	$10.89
Total FD&A – Proved	$2.96	$6.03	$4.91	$4.52
Total FD&A – Proved Plus Probable	$2.02	$4.19	$3.46	$3.12
Including FDC[2][3][4]				
F&D – Proved	$2.41	$13.51	$9.39	$7.22
F&D – Proved Plus Probable	$1.55	$12.57	$9.03	$6.32
Total FD&A – Proved	$2.28	$11.56	$8.29	$7.02
Total FD&A – Proved Plus Probable	$1.32	$10.45	$8.60	$6.23

(1) See *"Advisories – Oil and Gas Metrics"* for a description of the methodology used to calculate F&D and FD&A costs.

(2) Includes the 2015 decrease in FDC from 2014 of $56.5 million on a proved basis and $85.4 million on a proved plus probable basis, which decreases are primarily due to the application of new technology, operational efficiencies and a reduction in service costs.

(3) Includes the 2014 increase in FDC from 2013 of $413.0 million on a proved basis and $671.9 million on a proved plus probable basis.

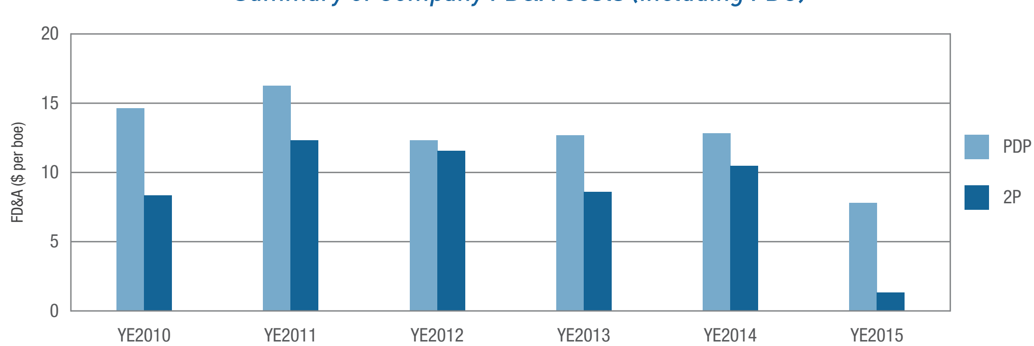
(4) Includes the 2013 increase in FDC from 2012 of $147.1 million on a proved basis and $316.7 million on a proved plus probable basis.

Changes in forecast FDC occur annually as a result of development activities, acquisition and disposition activities and capital cost estimates that reflect Deloitte's best estimate of what it will cost to bring the proved and proved plus probable reserves on production.

Deloitte's estimates of FDC are $1.81 billion on a proved basis, a decrease from $1.87 billion for 2014 and $3.09 billion on a proved plus probable basis, a decrease from $3.18 billion for 2014. These FDC costs are primarily the capital costs required to drill, complete, equip and tie-in undeveloped locations. The estimates also include approximately $252 million on a proved plus probable basis for the expansion of the PCS Gas Plant to 420 MMcf per day of total throughput, together with the related gathering pipelines, sales pipeline expansion and compression, which is down from the $303 million that was included in the 2014 Reserves Evaluation due to the capital that has already been spent and the design efficiencies that have lowered costs for the Phase VI expansion.

Deloitte's estimates of the FDC per Montney/Doig horizontal natural gas well to which reserves were assigned in the 2015 Reserves Evaluation decreased 17% to an average of $4.4 million per well as at December 31, 2015, compared to $5.3 million contained in the 2014 Reserves Evaluation. This decrease is primarily due to the application of new technology, operational efficiencies and a reduction in service costs.

Summary of Company FD&A Costs (including FDC)



2015 RECYCLE RATIOS

The following table sets forth our recycle ratios for operating and funds flow netbacks, which are calculated in each case by dividing the average operating netback per boe or funds flow netback per boe, as the case may be, by each of the F&D costs and the FD&A costs:

Recycle Ratios[1]

	Operating Netback Recycle Ratio		Funds Flow Netback Recycle Ratio	
	2015	2014	2015	2014
Excluding FDC				
F&D – Proved Developed Producing	1.8	2.1	1.4	1.8
FD&A – Proved Developed Producing	1.9	2.2	1.5	1.9
F&D – Proved	4.7	3.3	3.7	2.9
FD&A – Proved	4.9	4.6	3.8	4.0
F&D – Proved Plus Probable	7.0	4.7	5.5	4.1
FD&A – Proved Plus Probable	7.2	6.6	5.6	5.8
Including FDC				
F&D – Proved	6.0	2.1	4.7	1.8
FD&A – Proved	6.4	2.4	5.0	2.1
F&D – Proved Plus Probable	9.3	2.2	7.3	1.9
FD&A – Proved Plus Probable	11.0	2.7	8.6	2.3

(1) See "*Advisories – Oil and Gas Metrics*" for a description of the methodology used to calculate F&D costs, FD&A costs and recycle ratios.

During 2015, the average WTI price of crude oil was US$48.80 per bbl and the average price of natural gas at AECO was CDN$2.69 per Mcf. Operating netback per boe was $14.52 in 2015, compared to $27.77 in 2014. Funds flow netback per boe was $11.31 in 2015, compared to $24.40 in 2014.

2015 INDEPENDENT MONTNEY/DOIG NATURAL GAS RESOURCE ASSESSMENT

Deloitte, our independent qualified reserves evaluator, conducted the 2015 Resource Assessment and the 2014 Resource Assessment. The 2015 Resource Assessment and the 2014 Resource Assessment were prepared in accordance with the standards contained in the COGE Handbook and NI 51-101 in effect at the relevant time.

Resource estimates contained herein as at December 31, 2015 and 2014 are extracted from the relevant resource assessment and reflect only resources on Birchcliff's Montney/Doig lands. The resource assessments did not include our Charlie Lake Light Oil Resource Play or any of our other properties. All anticipated results disclosed herein were prepared by Deloitte, who is an independent qualified reserves evaluator. Deloitte utilized probabilistic methods to generate high, best, and low estimates of reserves and resources volumes.

Certain terms used herein are defined under the headings "*Glossary*" and "*Presentation of Oil and Gas Reserves and Resources*". Certain other terms used herein but not defined are defined in NI 51-101, CSA Staff Notice 51-324 or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101, CSA Staff Notice 51-324 or the COGE Handbook, as applicable.

Unless otherwise indicated, all volumes of our resources presented herein are on an unrisked basis, meaning that they have not been adjusted for the chance of commerciality.

Numbers in the tables presented herein may not total due to rounding.

The product types reasonably expected to be recovered from our resources are shale gas and NGL. See "*Presentation of Oil and Gas Reserves and Resources*" in this Annual Report.

The estimates of our resources provided herein are estimates only and there is no guarantee that the estimated resources will be recovered. Actual resources may be greater than or less than the estimates provided herein and variances could be material. With respect to our discovered resources (including contingent resources), there is uncertainty that it will be commercially viable to produce any portion of the resources. With respect to our undiscovered resources (including prospective resources), there is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. See "*Presentation of Oil and Gas Reserves and Resources*" and "*Advisories*" in this Annual Report.

Additional information concerning our contingent and prospective resources, including a description of our projects, the risks and uncertainties associated with our contingent and prospective resources and the contingencies which prevent the classification of the contingent resources as reserves, is contained in our Annual Information Form for the year ended December 31, 2015 dated March 16, 2016, a copy of which is available on SEDAR at www.sedar.com. For further information regarding the presentation of our resource disclosure, please see "*Presentation of Oil and Gas Reserves and Resources*" and "*Advisories*" in this Annual Report.

Summary of Discovered and Undiscovered Resources

The following table sets forth our total PIIP (discovered and undiscovered), contingent resources and prospective resources as at December 31, 2015 and December 31, 2014 on a best estimate case:

Summary of Discovered and Undiscovered Resources

	Volumes		
Resource Class	**December 31, 2015** *(Bcfe)*	**December 31, 2014** *(Bcfe)*	**Change from December 31, 2014**
Contingent Resources	9,497.0	7,851.7	21%
Total Discovered PIIP	25,589.4	20,726.4	23%
Prospective Resources	12,718.0	13,707.2	(7%)
Total Undiscovered PIIP	27,431.9	29,406.1	(7%)
Total PIIP	53,021.3	50,132.6	6%

As a result of our 2015 exploration successes and offset competitor drilling, a significant amount of resources that were classified as prospective resources as at December 31, 2014 have been re-classified as contingent resources as at December 31, 2015. Comparing the 2015 Resource Assessment to the 2014 Resource Assessment, our contingent resources increased from 7.9 Tcfe as at December 31, 2014 to 9.5 Tcfe as at December 31, 2015 (a 21% increase), accompanied by a 7% decrease in our prospective resources. In addition, a portion of our contingent and prospective resources recognized as at December 31, 2014 were re-classified as reserves as at December 31, 2015. This confirms material success in our strategy for 2015 of promoting prospective resources to contingent resources and contingent resources to reserves.

The following table sets forth our gross volumes for all resources, both discovered and undiscovered, as at December 31, 2015:

Summary of Reserves and Resources

Resource Class			Raw/Sales	Reserves and Resource Volumes *(Bcfe)*[1][2] Low Estimate Case	Best Estimate Case	High Estimate Case
Discovered		Cumulative Production[3]	Sales	286.2	286.2	286.2
		Remaining Reserves[3][4]	Sales	1,938.1	3,114.7	4,474.9
		Total Commercial	Sales	2,224.3	3,400.9	4,761.1
		Surface and Process Loss	Raw	66.5	101.9	146.9
	Total Commercial		Raw	2,290.8	3,502.8	4,908.0
		Contingent Resources[3]	Sales	6,549.3	9,497.0	14,505.4
		Development Pending	Sales	4,334.4	6,348.0	9,952.4
		Development On Hold	Sales	1,140.8	1,719.5	2,605.2
		Development Unclarified	Sales	1,072.0	1,422.0	1,922.2
		Development Not Viable	Sales	2.1	7.6	25.6
		Surface and Process Loss	Raw	311.9	457.7	684.3
		Unrecoverable	Raw	10,685.3	13,165.7	13,833.8
	Total Sub-Commercial		Raw	17,546.5	23,120.4	29,023.6
	TOTAL DISCOVERED PIIP		Raw	19,133.6	25,589.4	32,398.1
Undiscovered		Prospective Resources[3]	Sales	7,954.3	12,718.0	21,026.0
		Prospect[5]	Sales	7,954.3	12,718.0	21,026.0
		Surface and Process Loss	Raw	327.4	526.0	875.6
		Unrecoverable	Raw	11,253.9	15,098.2	16,498.5
	TOTAL UNDISCOVERED PIIP		Raw	18,967.5	27,431.9	36,893.3
TOTAL PIIP			Raw	38,101.1	53,021.3	69,291.4

(1) The volumes presented in the table above, other than cumulative production and reserves, have been presented on an unrisked basis, meaning that they have not been adjusted for the chance of commerciality.
(2) The sum of the total commercial and total sub-commercial resource volumes differs from the total discovered PIIP resource volumes in the table above because the liquid yields included as sales resource volumes were converted to a gas equivalent using a 1:6 bbl/Mcf conversion factor, which is an energy-based conversion factor rather than a volume-based conversion factor. This methodology was also utilized for the components of the undiscovered PIIP volumes and results in a similar discrepancy in volumes.
(3) Sales gas and NGL volumes combined at a ratio of 1 bbl is equivalent to 6 Mcfe.
(4) Includes reserves assigned by Deloitte to both vertical and horizontal Montney/Doig wells. Deloitte prepared the 2015 Reserves Evaluation. Proved, probable and possible reserves evaluated by Deloitte in the 2015 Reserves Evaluation are included in above table for completeness; however, reserves were not the focus of the 2015 Resource Assessment. The low estimate case includes the estimate of proved reserves contained in the 2015 Reserves Evaluation, the best estimate case includes the estimate of proved plus probable reserves contained in the 2015 Reserves Evaluation and the high estimate case includes the estimate of proved plus probable plus possible reserves contained in the 2015 Reserves Evaluation. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
(5) All of Birchcliff's prospective resources were sub-classified into the project maturity sub-class of "prospect".

Interest of Birchcliff in Resources in the Study Area

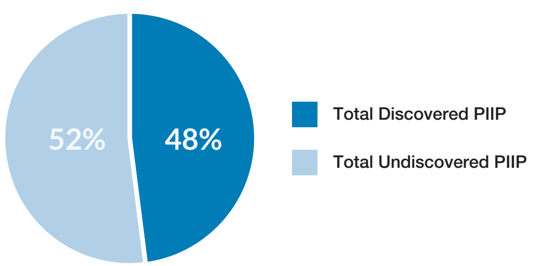
We hold significant high working interest acreage in large contiguous blocks on the Montney/Doig Natural Gas Resource Play in the Peace River Arch area of Alberta. We engaged Deloitte to evaluate the total PIIP and contingent and prospective resources on our lands for the Doig Phosphate, Basal Doig and Montney formations in the Montney/Doig Deep Basin area of northwest Alberta (the "**Study Area**"). In the Study Area, we own an interest in approximately 317.4 gross (308 net) sections of land, which includes Montney rights and 275.1 gross (258.9 net) sections of land which include Doig rights ranging from Townships 69 to 80, Ranges 1 to 13W6. The Study Area is further bounded in a northwest-southeast direction by the Deep Basin edge. The geological section studied was divided into the Doig Phosphate, Basal Doig and Montney stratigraphic units. The Montney was further subdivided into seven intervals, from the top to the base: D5, D4, D3, D2, D1, TSE Valhalla and C.

Deloitte segregated our Montney/Doig resources into development projects based on areal (property/area) and vertical (play interval) boundaries. The Study Area consisted of 13 properties/areas with resources, namely: Pouce Coupe and Pouce Coupe South, Gordondale, Progress North, Progress South, Valhalla, Elmworth, Elmworth North, Elmworth South, Gold Creek, Bezanson, Grande Prairie, Saddle Hills and Teepee. The Montney/Doig Formations are comprised of nine individually mapped stratigraphic units: the Doig Phosphate, Basal Doig and Montney D5, D4, D3, D2, and D1, TSE and C stratigraphic units.

Contingent resources have been attributed to our properties in the Pouce Coupe and Pouce Coupe South, Progress North, Progress South, Gordondale, Elmworth, Elmworth North, Elmworth South, Valhalla and Gold Creek areas in northwestern Alberta. Prospective resources have been attributed to our properties in the Pouce Coupe and Pouce Coupe South, Progress North, Progress South, Gordondale, Elmworth, Elmworth North, Elmworth South, Valhalla, Gold Creek, Bezanson, Grande Prairie, Saddle Hills and Teepee areas in northwestern Alberta. Our resources in the Pouce Coupe and Pouce Coupe South, Gordondale and Progress areas are proximal to our lands to which reserves have been attributed and to the PCS Gas Plant, as well as to third party gathering and processing infrastructure. Our resources in the Elmworth area are proximal to our lands to which reserves have been attributed and to third party gathering and processing infrastructure.

Our average working interest in our best estimate contingent resources is 97% and our average working interest in our best estimate prospective resources is 97%.

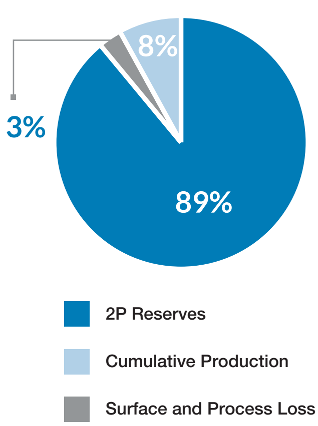
Total PIIP[(1)]



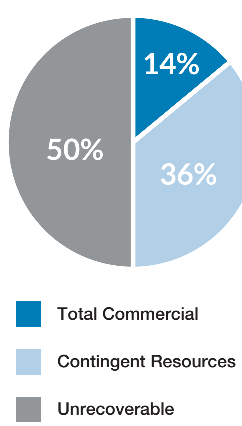
CONTINGENT RESOURCES[(1)]

9.5 TCFE ON A BEST ESTIMATE CASE

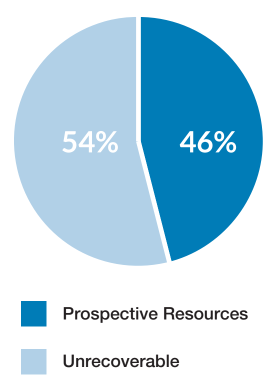
Total Commercial[(1)]



Total Discovered PIIP[(1)]



Total Undiscovered PIIP[(1)]



(1) As at December 31, 2015.

RESPONSIBILITY

HEALTH, SAFETY AND ENVIRONMENT

We have an active program to monitor and comply with health, safety and environmental laws, rules and regulations applicable to our operations. We are committed to constantly evolving and improving our health, safety and environmental management program and conducting our activities in a manner that safeguards our employees, contractors, representatives, the environment and the public at large.

Our corporate policies require operational activities to be conducted in a manner which meets or exceeds regulatory requirements and industry standards to safeguard the environment and protect employees, contractors and the public at large. All employees receive pertinent health, safety and environmental training for their role. Birchcliff conducts operational audits and assessments to identify risks and takes steps to reduce or prevent incidents. We develop emergency response plans in conjunction with local authorities, emergency services and the communities in which we operate in order to be prepared to effectively respond to an environmental incident should it arise. Once such plans are in place, we rigorously conduct exercises and training for our staff.

We participate in Alberta's Certificate of Recognition ("**COR**") Safety Program and have received and maintained a COR certification since 2011. A COR certification evidences that the employer's health and safety management system has been evaluated by a certified auditor and meets provincial standards, which standards are established by Occupational Health and Safety (Alberta). The COR Health and Safety Auditing and the COR Safety Program requires a commitment to continuous improvement in the environment, health and safety management practices, including sound planning and implementation. The program is audited externally every 3 years and internally every other year.

Birchcliff works hard to maintain the safety and integrity of our facilities and infrastructure assets. We have designed and follow a pressure equipment integrity management program and a pipeline operating and maintenance program.

Regulatory requirements relating to the integrity of our pressure vessels is the responsibility of Birchcliff's Alberta Boilers Safety Association ("**ABSA**") Chief Inspector, while the integrity of all other field assets is the responsibility of Birchcliff's field operations personnel. In 2015, we hired a full-time Asset Integrity Coordinator whose responsibility is to assist our ABSA Chief Inspector, as required, and to act as a technical advisor to our field operations personnel on issues relating to the integrity of our facilities and infrastructure and related compliance matters. The main focus of this role is to perform regular inspections, conduct annual risk assessments and proactively monitor the integrity and preventative maintenance operations of all Birchcliff's operated pipelines.

As part of our fundamental values, we recognize the importance of our responsibility for environmental stewardship. We endeavor to maintain excellence in environmental reporting and response and to take proactive steps to eliminate or reduce our environmental impact. As an organization which strives for continuous improvement, we continue to look for and develop new technology, systems and processes that will help improve efficiency, reduce our environmental footprint and create a safer work environment.

Environmental assessments are undertaken for new projects or when acquiring new properties or facilities in order to identify, assess and minimize environmental risks and operational exposures. We conduct audits of operations to confirm compliance with internal standards and to stimulate improvement in practices where needed. Documentation is maintained to support internal accountability and measure operational performance against recognized industry indicators to assist in achieving the objectives of the described policies and programs.

COMMUNITY SUPPORT

Fostering a strong relationship with the community and our stakeholders is as integral to the success of our projects as obtaining the required regulatory approvals. We believe that cooperative, sincere and responsive consultation efforts with stakeholders in the areas in which we operate creates a solid foundation for our business. We have an experienced team working with local stakeholders to learn their values and priorities and to resolve any issues or concerns that arise in the course of our field operations.

We recognize the role that communities play in our success and look for opportunities to "give back". We are a staunch supporter of the community and the business and educational initiatives of the First Nations who live in areas in which we operate. Every year, we participate in a number of community support endeavours in the areas surrounding our field operations and in Calgary.

In 2015, we contributed to a number of local community initiatives that elevate and enhance quality of life at the local level, including minor hockey and other amateur sports, local schools, agricultural societies and fire departments.

STARS Air Ambulance is an important partner in trauma care for the Grande Prairie region of Alberta. To date, we have raised more than $850,000 to support STARS Air Ambulance in the Grande Prairie area.

Each year, we raise funds for the United Way and the YMCA. We make an annual contribution to Home Front Calgary, a community-justice response team dedicated to helping families experiencing domestic violence. We support the Children's Hospital Foundation and Big Brothers, Big Sisters. Through our support of Momentum, Calgarians living in poverty learn how to achieve a sustainable livelihood.

We donate to the OneSight program and support the Canadian Cancer Society daffodil campaign. We volunteer with Feed the Hungry, providing healthy meals in an atmosphere of dignity and respect. During the holiday season, our employees "adopt" a number of families in need and donate gifts, food and decorations to help make the holidays special. We also fill backpacks with living essentials and gifts for the Mustard Seed.

Through these activities and numerous others, we create and maintain long-term, positive partnerships and relationships, while promoting employee engagement in the communities where we live and work.

MANAGEMENT'S DISCUSSION AND ANALYSIS

GENERAL

Birchcliff Energy Ltd. ("**Birchcliff**" or the "**Corporation**") is a Calgary, Alberta based intermediate oil and natural gas company with operations concentrated in its one core area, the Peace River Arch of Alberta. Additional information relating to the Corporation, including its Annual Information Form for the financial year ended December 31, 2015, is available on the SEDAR website at www.sedar.com and on the Corporation's website at www.birchcliffenergy.com. Birchcliff's common shares are listed for trading on the Toronto Stock Exchange (the "**TSX**") under the symbol "BIR" and are included in the S&P/TSX Composite Index.

The following Management's Discussion and Analysis ("**MD&A**") is dated March 16, 2016. The annual financial information with respect to the three and twelve months ended December 31, 2015 (the "**Reporting Periods**") as compared to the three and twelve months ended December 31, 2014 (the "**Comparable Prior Periods**") and this MD&A have been prepared by management and approved by the Corporation's Audit Committee and Board of Directors. This MD&A should be read in conjunction with the audited financial statements of the Corporation and related notes for the year ended December 31, 2015. All dollar amounts are expressed in Canadian currency, unless otherwise stated.

This MD&A uses "funds flow", "funds flow from operations", "funds flow per common share", "adjusted net income (loss) to common shareholders", "netback", "operating netback", "estimated operating netback", "operating margin", "total cash costs" and "total debt", which do not have standardized meanings prescribed by generally accepted accounting principles ("**GAAP**") and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. For further information, see *"Non-GAAP Measures"* in this MD&A.

This MD&A contains forward-looking information within the meaning of applicable Canadian securities laws. For further information, see *"Advisories"* in this MD&A.

All barrel of oil equivalent ("**boe**") amounts have been calculated by using the conversion ratio of six thousand cubic feet (6 Mcf) of natural gas to one barrel of oil (1 bbl). For further information, see *"Advisories"* in this MD&A.

2016 OUTLOOK

On January 21, 2016, Birchcliff announced its capital expenditure program for 2016 of $140 million. With capital expenditures of $140 million, Birchcliff estimated annual average production for 2016 to be 40,000 to 41,000 boe per day. On March 16, 2016, the Corporation reduced its budgeted 2016 capital expenditures by approximately $12 million to approximately $128 million (the "**2016 Revised Capital Budget**"). The 2016 Revised Capital Budget is designed to achieve modest production growth, while further progressing the Corporation's Phase V expansion of its 100% owned Pouce Coupe South gas plant (the "**PCS Gas Plant**") and related infrastructure. The 2016 Revised Capital Budget is projected to be less than Birchcliff's expected funds flow for 2016, assuming an average WTI price of US$40.00 per barrel of oil and an average AECO price of CDN$2.50 per GJ of natural gas during 2016.

Birchcliff is maintaining its annual average production for 2016 at 40,000 to 41,000 boe per day, which represents an increase of 3% to 5% from its 2015 annual average production of 38,950 boe per day.

SELECTED ANNUAL INFORMATION

	2015	2014	2013
Average daily production *(boe at 6 Mcf:1 bbl)*	38,950	33,734	25,829
Petroleum and natural gas revenue *($000s)*(1)	317,304	472,888	316,637
Average sales price *($ CDN)*			
Light oil – *(per barrel)*	53.68	92.39	89.89
Natural gas – *(per thousand cubic feet)*	2.90	4.74	3.41
NGL – *(per barrel)*	50.76	85.13	88.45
Total – barrels of oil equivalent *(6:1)*	22.31	38.39	33.52
Funds flow from operations *($000s)*	160,756	300,498	174,361
Per common share – basic *($)*	1.06	2.03	1.22
Per common share – diluted *($)*	1.04	1.97	1.20
Net income (loss) *($000s)*	(12,160)	114,304	65,417
Net income (loss) to common shareholders *($000s)*	(16,160)	110,304	61,417
Per common share – basic *($)*	(0.11)	0.75	0.43
Per common share – diluted *($)*	(0.11)	0.72	0.42
Capital expenditures, net *($000s)*	247,207	450,932	215,770
Operating costs *($ per boe)*	4.54	5.22	5.68
Total assets *($000s)*	2,025,373	1,918,680	1,586,531
Working capital deficit *($000s)*	21,538	76,712	60,071
Non-revolving term credit facilities *($000s)*	-	129,476	127,144
Revolving term credit facilities *($000s)*	622,074	339,557	266,823
Total debt *($000s)*	643,612	545,745	454,038
Common shares outstanding *(000s)*:			
End of period – basic	152,308	152,214	143,677
End of period – diluted	167,817	166,302	163,548
Weighted average common shares for period – basic	152,286	147,764	142,422
Weighted average common shares for period – diluted	154,078	152,243	145,006
Series A preferred shares outstanding – end of period *(000s)*	2,000	2,000	2,000
Series A – dividend distribution *($000s)*	4,000	4,000	4,000
Per Series A preferred share *($)*	2.00	2.00	2.00
Series C preferred shares outstanding – end of period *(000s)*	2,000	2,000	2,000
Series C – dividend distribution *($000s)*	3,500	3,500	1,913
Per Series C preferred share *($)*	1.75	1.75	0.96

(1) Excludes the effect of hedges using financial instruments.

In 2015, average production was 38,950 boe per day, up 15% from 2014 and up 51% from 2013. These production increases were largely attributed to the success of Birchcliff's capital drilling program, resulting in increased incremental production from new Montney/Doig horizontal natural gas wells producing to the Corporation's 100% owned and operated PCS Gas Plant, which currently has a processing capacity of 180 MMcf per day.

Birchcliff generated lower funds flow in 2015 as compared to the prior two years. These results were largely due to the lower average realized oil and natural gas prices of $22.31 per boe in 2015, down 42% from 2014 and down 33% from 2013 partially offset by increased natural gas production and the continued reduction of total cash costs per boe in the last three years. Birchcliff reduced its total cash costs (comprised of royalty, operating, transportation and marketing, general and administrative and interest expenses) in 2015 to $11.01 per boe, down 21% from 2014 and down 29% from 2013.

Birchcliff recorded a net loss to common shareholders of $16.2 million ($0.11 per basic common share) in 2015 as compared to net income to common shareholders of $110.3 million ($0.75 per basic common share) and $61.4 million ($0.43 per basic common share) in 2014 and 2013, respectively. The net loss to common shareholders in 2015 was largely attributable to lower funds flow and higher aggregate depletion expense resulting from increased natural gas production over the last two years. The net loss in 2015 also included two, one-time, non-cash deferred income tax expense adjustments of $18.0 million, which are non-operational in nature. For more information, see *"Income Taxes"* in this MD&A.

Capital expenditures in the last three years were largely directed towards the expansion of the PCS Gas Plant (including related facilities and gathering systems) to a licensed processing capacity of 180 MMcf per day and the drilling and completion of new Montney/Doig horizontal natural gas wells that have been tied into the PCS Gas Plant.

FUNDS FLOW FROM OPERATIONS

	Three months ended December 31,		Twelve months ended December 31,	
($000s)	**2015**	**2014**	**2015**	**2014**
Funds flow from operations	**33,697**	**61,717**	**160,756**	**300,498**
Per common share – basic *($)*	0.22	0.41	1.06	2.03
Per common share – diluted *($)*	0.22	0.40	1.04	1.97

Funds flow in the three and twelve month Reporting Periods decreased by 45% and 47%, respectively, from the Comparable Prior Periods. Lower funds flow in the Reporting Periods were largely attributed to a significant decrease in the average realized oil and natural gas wellhead prices as compared to the Comparable Prior Periods, offset by a material increase in natural gas production and lower per unit total cash costs. Average realized oil and natural gas prices in the three and twelve month Reporting Periods were down 33% and 42%, respectively, from the Comparable Prior Periods.

The following table provides a breakdown of total cash costs on a per boe basis and the percentage change period-over-period:

	Three months ended December 31,			Twelve months ended December 31,		
	2015	**2014**	**Change**	**2015**	**2014**	**Change**
	($/boe)	*($/boe)*	*(%)*	*($/boe)*	*($/boe)*	*(%)*
Royalty expense	0.94	1.84	(49)	0.81	2.99	(73)
Operating expense	4.16	5.33	(22)	4.54	5.22	(13)
Transportation and marketing expense	2.31	2.39	(3)	2.45	2.43	1
General & administrative expense, net	2.01	2.02	(0)	1.61	1.81	(11)
Interest expense	1.80	1.42	27	1.60	1.57	2
Total Cash Costs	**11.22**	**13.00**	**(14)**	**11.01**	**14.02**	**(21)**

On a per boe basis, total cash costs in the three and twelve month Reporting Periods are down 14% and 21%, respectively, from the Comparable Prior Periods primarily driven by lower royalty and operating costs in the Reporting Periods, partially offset by higher interest costs in the three month Reporting Period. Management believes that total cash costs assists management and investors in assessing Birchcliff's efficiency and overall cash cost structure.

NET INCOME (LOSS) TO COMMON SHAREHOLDERS

	Three months ended December 31,		Twelve months ended December 31,	
($000s)	**2015**	**2014**	**2015**	**2014**
Net income (loss)	(9,322)	17,053	(12,160)	114,304
Net income (loss) to common shareholders[(1)]	**(10,322)**	**16,053**	**(16,160)**	**110,304**
Per common share – basic *($)*	(0.07)	0.11	(0.11)	0.75
Per common share – diluted *($)*	(0.07)	0.10	(0.11)	0.72

(1) Net income (loss) to common shareholders is calculated by adjusting net income (loss) for dividends paid on Series A Preferred Shares during the period. Per common share amounts are calculated by dividing net income (loss) to common shareholders by the weighted average number of basic or diluted common shares outstanding for the period.

Birchcliff recorded a net loss to common shareholders of $10.3 million for the three month Reporting Period and a net loss to common shareholders of $16.2 million for the twelve month Reporting Period as compared to net income to common shareholders of $16.1 million and $110.3 million for the Comparable Prior Periods. The decrease was largely due to lower funds flow from operations, higher aggregate depletion costs resulting from increased production and an increase in deferred income tax expenses in the Reporting Periods.

Adjusted Net Income (Loss) to Common Shareholders

Birchcliff recorded an adjusted net loss to common shareholders of $0.1 million in the three month Reporting Period and adjusted net income to common shareholders of $1.8 million in the twelve month Reporting Period, after excluding: (i) a one-time, non-cash deferred income tax expense in the amount of $7.8 million that was recorded in the second quarter of 2015 as a result of the 2015 change in the Alberta corporate income tax rate from 10% to 12%; and (ii) a one-time, non-cash deferred income tax expense in the amount of $10.2 million that was recorded in the fourth quarter of 2015 as a result of the denial by the Tax Court of Canada (the "**Trial Court**") of Birchcliff's appeal of the reassessment by the Canada Revenue Agency (the "**CRA**") of Birchcliff's income tax filings in 2011 in connection with the tax pools available to Veracel Inc. (the "**Reassessment**"). For more information on the deferred income tax adjustments and the Reassessment, see *"Income Taxes"* in this MD&A.

Management has excluded these non-operational, deferred income tax items from adjusted net income (loss) to common shareholders as management believes that excluding such items better reflects the results generated by Birchcliff's principal business activities. The following table provides a reconciliation of net income (loss) to common shareholders, as determined in accordance with International Financial Reporting Standards ("**IFRS**"), to adjusted net income (loss) to common shareholders:

	Three months ended December 31,		Twelve months ended December 31,	
($000s)	**2015**	**2014**	**2015**	**2014**
Net income (loss) to common shareholders	(10,322)	16,053	(16,160)	110,304
Adjustments:				
Denial by the Trial Court of the Reassessment appeal	10,208	-	10,208	-
Change in Alberta corporate income tax rates	-	-	7,759	-
Adjusted net income (loss) to common shareholders	**(114)**	**16,053**	**1,807**	**110,304**

The deferred income tax adjustments shown in the table above have no impact on the current cash taxes payable by the Corporation.

PCS GAS PLANT NETBACKS

Processing natural gas at the PCS Gas Plant has materially improved Birchcliff's funds flow and net earnings since it first became operational in March 2010. The following table sets forth Birchcliff's annual net production and estimated operating netback for wells producing to the PCS Gas Plant, on a production month basis:

Production Processed through the PCS Gas Plant

	Twelve months ended December 31, 2015		Twelve months ended December 31, 2014	
Average daily production, net to Birchcliff:				
Natural gas *(Mcf)*		163,641		132,808
Oil & NGL *(bbls)*		1,287		1,065
Total boe *(6:1)*		**28,560**		**23,200**
Sales liquids yield (bbls/MMcf)		*7.9*		*8.0*
% of corporate natural gas production		*81%*		*78%*
% of corporate production		*73%*		*69%*
AECO – C daily *($/Mcf)*	$2.69		$4.50	
Netback and cost:	*$/Mcfe*	*$/boe*	*$/Mcfe*	*$/boe*
Petroleum and natural gas revenue	3.17	19.03	5.17	31.02
Royalty expense	(0.11)	(0.63)	(0.24)	(1.42)
Operating expense(1)	(0.31)	(1.90)	(0.42)	(2.52)
Transportation and marketing expense	(0.31)	(1.88)	(0.30)	(1.81)
Estimated operating netback	**$2.44**	**$14.62**	**$4.21**	**$25.27**
Operating margin	**77%**	**77%**	**81%**	**81%**

(1) Represents plant and field operating costs.

MAJOR TRANSACTIONS AFFECTING FINANCIAL RESULTS

On May 11, 2015, the aggregate limit of Birchcliff's credit facilities was increased to $800 million from $750 million primarily as a result of the material increase in the Corporation's proved developed producing reserves at December 31, 2014. In addition to the increase in the credit facilities limit, Birchcliff's syndicate of lenders also approved the consolidation of the Corporation's $750 million credit facilities, which were comprised of a $620 million revolving term credit facility, a $70 million non-revolving five-year term credit facility and a $60 million non-revolving five-year term credit facility, into three-year term extendible revolving credit facilities in the aggregate principal amount of $800 million with maturity dates of May 11, 2018 (the "**Credit Facilities**"). Concurrently, the financial covenants contained in the credit facilities which previously required the Corporation to ensure that on the last day of each quarter the ratio of EBITDA to interest expense, determined on a historical rolling four quarter basis equaled or exceeded 3.5:1.0, and the ratio of debt to EBITDA, determined on a historical rolling four quarter basis did not exceed 4.0:1.0, were removed. As a result, the Credit Facilities do not contain any financial covenants.

The Credit Facilities are comprised of: (i) an extendible revolving syndicated term credit facility of $760 million (the "**Syndicated Credit Facility**"); and (ii) an extendible revolving working capital facility of $40 million (the "**Working Capital Facility**"). Birchcliff may each year, at its option, request an extension to the maturity date of the Syndicated Credit Facility and the Working Capital Facility, or either of them, for an additional period of up to three years from May 11 of the year in which the extension request is made.

See *"Capital Resources and Liquidity – Bank Debt"* and *"Risk Factors and Risk Management – Financial Risks and Risks Relating to Economic Conditions – Credit Facilities"* in this MD&A for further information regarding the Credit Facilities.

DISCUSSION OF OPERATIONS

Petroleum and Natural Gas Revenues

The following table sets forth Birchcliff's petroleum and natural gas ("**P&NG**") revenues, production and percentage of production and sales price by category:

	Three months ended December 31, 2015				Three months ended December 31, 2014			
	Total Revenue *($000s)*	**Average Daily Production**	*(%)*	**Average** *($/unit)*	**Total Revenue**(1) *($000s)*	**Average Daily Production**	*(%)*	**Average**(1) *($/unit)*
Light oil *(bbls)*	16,032	3,530	9	49.36	26,167	3,957	11	71.87
Natural gas *(Mcf)*	51,792	211,127	87	2.67	69,287	192,499	85	3.91
NGL *(bbls)*	7,625	1,727	4	47.98	10,118	1,664	4	66.10
Total P&NG sales *(boe)*	75,449	40,445	100	20.28	105,572	37,704	100	30.43
Royalty revenue	27			-	26			0.01
P&NG revenues	**75,476**			**20.28**	**105,598**			**30.44**

	Twelve months ended December 31, 2015				Twelve months ended December 31, 2014			
	Total Revenue *($000s)*	**Average Daily Production**	*(%)*	**Average** *($/unit)*	**Total Revenue**(1) *($000s)*	**Average Daily Production**	*(%)*	**Average**(1) *($/unit)*
Light oil *(bbls)*	72,636	3,707	10	53.68	133,431	3,957	12	92.39
Natural gas *(Mcf)*	213,494	201,418	86	2.90	293,660	169,852	84	4.74
NGL *(bbls)*	30,991	1,673	4	50.76	45,638	1,469	4	85.13
Total P&NG sales *(boe)*	317,121	38,950	100	22.31	472,729	33,734	100	38.39
Royalty revenue	183			0.01	159			0.02
P&NG revenues	**317,304**			**22.32**	**472,888**			**38.41**

(1) Excludes the effect of hedges using financial instruments.

Production

Production averaged 40,445 boe per day in the three month Reporting Period and 38,950 boe per day in the twelve month Reporting Period, a 7% and 15% increase, respectively, from the Comparable Prior Periods. The increase in production growth from the Comparable Prior Periods was largely due to incremental production added from new Montney/Doig horizontal natural gas wells that were tied into the PCS Gas Plant, notwithstanding natural production declines and the numerous transportation service curtailments on TransCanada's NGTL Pipeline System (the "**TCPL System**") that adversely impacted Birchcliff's production throughout 2015.

The majority of Birchcliff's natural gas production is transported on the TCPL System in Alberta pursuant to both firm and interruptible service agreements. Throughout 2015, interruptible service was suspended and transportable volumes were curtailed from time to time to as low as 85% of Birchcliff's firm service entitlements as a result of National Energy Board ordered pipeline integrity testing procedures and other operational issues with the TCPL System.

Production consisted of approximately 87% natural gas, 9% light oil and 4% natural gas liquids ("**NGL**") in the three month Reporting Period as compared to 85% natural gas, 11% light oil and 4% NGL in the Comparable Prior Period. Production consisted of approximately 86% natural gas, 10% light oil and 4% NGL in the twelve month Reporting Period as compared to 84% natural gas, 12% light oil and 4% NGL in the Comparable Prior Period. The PCS Gas Plant processed approximately 81% of Birchcliff's total corporate natural gas production and 73% of total corporate production in 2015.

Commodity prices

Birchcliff sells the majority of its light crude oil on a spot basis and the majority of its natural gas production for prices based on the AECO natural gas spot price. The average realized price the Corporation receives for its light crude oil and natural gas production depends on a number of factors, including the average benchmark prices for crude oil and natural gas, the US to Canadian dollar exchange rate and transportation and product quality differentials.

The following table sets forth the average benchmark prices and Birchcliff's average realized sales price:

	Three months ended December 31,		Twelve months ended December 31,	
	2015	**2014**	**2015**	**2014**
Average benchmark prices:				
Light oil – WTI Cushing *($USD/bbl)*	42.18	73.15	48.80	92.99
Light oil – Edmonton Par *($/bbl)*	53.78	73.16	57.76	93.38
Natural gas – AECO – C daily *($/MMbtu)*(1)	2.46	3.60	2.69	4.50
Exchange rate – *(USD$/CDN$)*	1.34	1.14	1.29	1.11
Birchcliff's average realized sales price(2):				
Light oil *($/bbl)*	49.36	71.87	53.68	92.39
Natural gas *($/Mcf)*	2.67	3.91	2.90	4.74
NGL *($/bbl)*	47.98	66.10	50.76	85.13
Barrels of oil equivalent *($/boe) (6:1)*	20.28	30.43	22.31	38.39

(1) $1.00/MMbtu = $1.00/Mcf based on a standard heat value Mcf.
(2) Excludes the effect of hedges using financial instruments.

The average benchmark prices for crude oil are impacted by global and regional events that dictate the level of supply and demand for these commodities. The principal benchmark trading exchanges that Birchcliff compares its oil price to are the WTI oil spot price and the Canadian Edmonton Par spot price. The differential between the WTI oil spot price and Canadian Edmonton Par spot price can widen due to a number of factors, including, but not limited to, downtime in North American refineries, rising domestic production, high inventory levels in North America and lack of pipeline infrastructure connecting key consuming oil markets.

Natural gas prices are mainly driven by North American supply and demand fundamentals which can be impacted by a number of factors, including weather-related conditions, changing demographics, economic growth, underground storage levels, net import and export markets, pipeline takeaway capacity, cost of competing fuels, drilling and completion rates and efficiencies in extracting natural gas from North American natural gas basins.

Beginning in the latter half of 2014 and continuing throughout 2015, the WTI oil spot price and AECO natural gas spot price declined significantly due to the global and regional supply/demand imbalance which negatively impacted reported revenues in 2015. The AECO natural gas spot price averaged $2.46 per Mcf for the three month Reporting Period and averaged $2.69 per Mcf for the twelve month Reporting Period, a 32% and 40% decrease, respectively, from the Comparable Prior Periods. The WTI oil spot price in the three and twelve month Reporting Periods were 42% and 48% lower, respectively, than the Comparable Prior Periods.

Birchcliff's realized natural gas sales price at the wellhead averaged $2.67 per Mcf for the three month Reporting Period, a 9% premium from the posted benchmark prices for the period. Birchcliff receives premium pricing for its natural gas production due to its high heat content. The following table sets forth Birchcliff's average realized sales price, heat content premium and other price differentials from its natural gas production:

	Three months ended December 31,		Twelve months ended December 31,	
	2015	**2014**	**2015**	**2014**
AECO – C daily *($/MMbtu)*(1)	2.46	3.60	2.69	4.50
Heat content premium	0.21	0.35	0.21	0.44
Price differential between physical sales contracts and AECO – C daily	-	(0.04)	-	(0.20)
Average realized natural gas sales price *($/Mcf)*	**2.67**	**3.91**	**2.90**	**4.74**

(1) $1.00/MMbtu = $1.00/Mcf based on a standard heat value Mcf.

Risk Management Contracts

Birchcliff had no risk management contracts during the Reporting Periods. During the Comparable Prior Periods, the Corporation did have certain commodity price risk management contracts in place which expired on December 31, 2014. The Corporation actively monitors the market to determine whether any additional commodity price risk management contracts are warranted. There were no risk management contracts entered into subsequent to December 31, 2015.

The following table provides a summary of the realized and unrealized gains on financial derivative contracts:

	Three months ended December 31,				Twelve months ended December 31,			
	2015		**2014**		**2015**		**2014**	
	($000s)	*($/boe)*	*($000s)*	*($/boe)*	*($000s)*	*($/boe)*	*($000s)*	*($/boe)*
Realized gain on derivatives	-	-	1,222	0.35	-	-	291	0.01
Unrealized gain on derivatives	-	-	172	0.05	-	-	379	0.03

Royalties

The following table details the Corporation's royalty expense:

	Three months ended December 31,		Twelve months ended December 31,	
	2015	**2014**	**2015**	**2014**
Oil & natural gas royalties *($000s)*(1)	3,499	6,376	11,548	36,803
Oil & natural gas royalties *($/boe)*	0.94	1.84	0.81	2.99
Effective royalty rate *(%)*(2)	5%	6%	4%	8%

(1) Royalties are paid primarily to the Alberta Government.
(2) The effective royalty rate is calculated by dividing the aggregate royalties into petroleum and natural gas sales for the period.

The decrease in the effective royalty rates from the Comparable Prior Periods was mainly due to production royalty incentives for a number of Montney/Doig horizontal natural gas wells that are receiving a 5% royalty rate and lower oil and natural gas wellhead prices received for Birchcliff's production during the Reporting Periods and the effect these lower prices have on the sliding scale royalty calculation.

Operating Costs

The following table provides a breakdown of operating costs:

	Three months ended December 31,				Twelve months ended December 31,			
	2015		2014		2015		2014	
	($000s)	*($/boe)*	*($000s)*	*($/boe)*	*($000s)*	*($/boe)*	*($000s)*	*($/boe)*
Field operating costs	15,711	4.22	18,737	5.40	65,281	4.59	65,331	5.31
Recoveries	(385)	(0.10)	(340)	(0.10)	(1,500)	(0.10)	(1,284)	(0.10)
Field operating costs, net	15,326	4.12	18,397	5.30	63,781	4.49	64,047	5.21
Expensed workovers and other	143	0.04	89	0.03	730	0.05	170	0.01
Operating costs	**15,469**	**4.16**	**18,486**	**5.33**	**64,511**	**4.54**	**64,217**	**5.22**

Birchcliff continues to focus on controlling the infrastructure it uses to produce its oil and natural gas and on reducing operating costs on a per boe basis.

Corporate operating costs per boe decreased 22% and 13% from the three and twelve month Comparable Prior Periods, respectively, largely due to lower service costs resulting from reduced industry activity, the continued cost benefits achieved from processing incremental volumes of natural gas at the PCS Gas Plant and the implementation of various infrastructure optimization initiatives.

On a production month basis, operating costs averaged $1.90 per boe at the PCS Gas Plant during 2015, down 25% from $2.52 per boe in 2014. Birchcliff processed 81% of its total corporate natural gas production at the PCS Gas Plant during 2015 compared to 78% in 2014.

Transportation and Marketing Expenses

Transportation and marketing expenses were $8.6 million ($2.31 per boe) for the three month Reporting Period and $34.8 million ($2.45 per boe) for the twelve month Reporting Period compared to $8.3 million ($2.39 per boe) and $30.0 million ($2.43 per boe), respectively, for the Comparable Prior Periods. The increased aggregate costs from the Comparable Prior Periods are primarily due to increased firm service commitments on the TCPL System partially offset by reduced costs associated with transporting Birchcliff's condensate from the PCS Gas Plant and lower oil trucking service costs in the Reporting Periods.

Operating Netbacks

The following table details Birchcliff's net production and operating netback for the Montney/Doig Natural Gas Resource Play, the Worsley Charlie Lake Light Oil Resource Play and on a corporate basis:

	Three months ended December 31,		Twelve months ended December 31,	
	2015	2014	2015	2014
Montney/Doig Natural Gas Resource Play[1]				
Average daily production, net:				
Natural gas *(Mcf)*	195,262	177,075	186,260	155,149
Oil & NGL *(bbls)*	1,929	1,804	1,846	1,526
Total boe *(6:1)*	34,473	31,316	32,890	27,384
% of corporate production[2]	85%	83%	84%	81%
Netback and cost *($/boe):*				
Petroleum and natural gas revenue	17.89	25.96	19.43	31.63
Royalty expense	(0.61)	(0.61)	(0.47)	(1.39)
Operating expense, net of recoveries	(2.92)	(4.08)	(3.22)	(3.83)
Transportation and marketing expense	(1.85)	(1.81)	(1.94)	(1.81)
Operating netback	12.51	19.46	13.80	24.60
Worsley Charlie Lake Light Oil Resource Play[1]				
Average daily production, net:				
Natural gas *(Mcf)*	8,054	10,176	8,497	9,684
Oil & NGL *(bbls)*	2,708	3,280	2,819	3,377
Total boe *(6:1)*	4,050	4,976	4,236	4,991
% of corporate production[2]	10%	13%	11%	15%
Netback and cost *($/boe):*				
Petroleum and natural gas revenue	37.41	55.58	40.58	71.73
Royalty expense	(3.12)	(8.67)	(2.89)	(10.68)
Operating expense, net of recoveries	(11.10)	(10.97)	(10.48)	(10.13)
Transportation and marketing expense	(5.99)	(5.65)	(6.06)	(5.69)
Operating netback	17.20	30.29	21.15	45.23
Total Corporate				
Average daily production, net:				
Natural gas *(Mcf)*	211,127	192,499	201,418	169,852
Oil & NGL *(bbls)*	5,257	5,621	5,380	5,426
Total boe *(6:1)*	40,445	37,704	38,950	33,734
Netback and cost *($/boe)*				
Petroleum and natural gas revenue	20.28	30.44	22.32	38.41
Royalty expense	(0.94)	(1.84)	(0.81)	(2.99)
Operating expense, net of recoveries	(4.16)	(5.33)	(4.54)	(5.22)
Transportation and marketing expense	(2.31)	(2.39)	(2.45)	(2.43)
Operating netback	12.87	20.88	14.52	27.77

(1) Most resource plays produce both oil and natural gas; however, a resource play is categorized as either a natural gas resource play or an oil resource play based upon the predominate production or play type in that area.
(2) Production from Birchcliff's other conventional oil and natural gas properties were not individually significant during the Reporting Periods and Comparable Prior Periods.

Montney/Doig Natural Gas Resource Play

Birchcliff's production from the Montney/Doig Natural Gas Resource Play was 34,473 boe per day in the three month Reporting Period and 32,890 boe per day in the twelve month Reporting Period, a 10% and a 20% increase, respectively, from the Comparable Prior Periods. These increases were largely due to higher production of natural gas and liquids from new Montney/Doig horizontal natural gas wells that were tied into the PCS Gas Plant.

Birchcliff's recoveries of liquids from its Montney/Doig natural gas production was 9.9 bbls per MMcf in both the three and twelve month Reporting Periods, a decrease of 3% and an increase of 1%, respectively, from the Comparable Prior Periods. Of the 9.9 bbls per MMcf of liquids produced in the three month Reporting Period, approximately 9.7 bbls per MMcf (98%) are high value oil and condensate (C5+). Of the 9.9 bbls per MMcf of liquids produced in the twelve month Reporting Period, approximately 9.6 bbls per MMcf (97%) are high value oil and condensate (C5+). Any NGL not recovered from the raw natural gas stream (ethane, propane and butane) increases the heat content value of Birchcliff's sales gas and the realized sales price.

Birchcliff's operating netback from the Montney/Doig Natural Gas Resource Play was $12.51 per boe ($2.09 per Mcfe) in the three month Reporting Period and $13.80 per boe ($2.30 per Mcfe) for the twelve month Reporting Period, a decrease of 36% and 44%, respectively, from the Comparable Prior Periods. The decrease was largely due to lower realized prices received for Birchcliff's natural gas and liquids production in the Reporting Periods as compared to the Comparable Prior Periods.

Worsley Charlie Lake Light Oil Resource Play

Birchcliff's production from the Worsley Charlie Lake Light Oil Resource Play was 4,050 boe per day in the three month Reporting Period and 4,236 boe per day in the twelve month Reporting Period, a 19% decrease and a 15% decrease, respectively, from the Comparable Prior Periods. The decrease in production was largely due to natural declines partially offset by production optimization initiatives in the Worsley field that were ongoing throughout 2015.

Operating netback from the Worsley Charlie Lake Light Oil Resource Play was $17.20 per boe in the three month Reporting Period and $21.15 per boe in the twelve month Reporting Period, a 43% decrease and a 53% decrease, respectively, from the Comparable Prior Periods. The decrease was largely due to lower realized prices received for Birchcliff's oil, natural gas and liquids production in the Reporting Periods as compared to the Comparable Prior Periods.

Administrative Expenses

The components of net administrative expenses are detailed in the table below:

	Three months ended December 31,				Twelve months ended December 31,			
	2015		2014		2015		2014	
	($000s)	*(%)*	*($000s)*	*(%)*	*($000s)*	*(%)*	*($000s)*	*(%)*
Cash:								
Salaries and benefits(1)	12,036	80	11,065	80	27,067	69	24,298	66
Other(2)	3,041	20	2,833	20	12,297	31	12,644	34
	15,077	100	13,898	100	39,364	100	36,942	100
Operating overhead recoveries	(47)	(1)	(55)	(1)	(232)	(1)	(247)	(1)
Capitalized overhead(3)	(7,536)	(50)	(6,845)	(49)	(16,308)	(41)	(14,355)	(39)
General & administrative, net	7,494	49	6,998	50	22,824	58	22,340	60
General & administrative, net per boe	$2.01		$2.02		$1.61		$1.81	
Non-cash:								
Stock-based compensation	1,694	100	2,046	100	7,732	100	9,977(4)	100
Capitalized stock-based compensation(3)	(921)	(54)	(1,136)	(56)	(4,526)	(59)	(5,181)	(52)
Stock-based compensation, net	773	46	910	44	3,206	41	4,796	48
Stock-based compensation, net per boe	$0.21		$0.26		$0.23		$0.39	
Administrative expenses, net	**8,267**		**7,908**		**26,030**		**27,136**	
Administrative expenses, net per boe	**$2.22**		**$2.28**		**$1.84**		**$2.20**	

(1) Includes salaries and benefits paid to all officers and employees of the Corporation.
(2) Includes costs such as rent, legal, tax, insurance, minor computer hardware and software and other general business expenses incurred by the Corporation.
(3) Includes a portion of salaries, benefits and stock-based compensation directly attributable to the exploration and development activities of the Corporation which have been capitalized.
(4) In May 2014, the Corporation's outstanding performance warrants were amended to extend the ultimate expiration date to January 31, 2020 from January 31, 2015. The Corporation recorded a non-cash stock-based compensation expense of approximately $1.7 million relating to the extension of the performance warrants in the twelve month Comparable Prior Period.

A summary of the Corporation's outstanding stock options is presented below:

	Twelve months ended December 31, 2015		Twelve months ended December 31, 2014	
	Number	**Exercise price** *($)*(1)	**Number**	**Exercise price** *($)*(1)
Outstanding at beginning of period	11,147,672	8.45	10,931,520	8.31
Granted	3,358,500	6.62	3,112,500	9.08
Exercised	(93,333)	(6.26)	(2,550,846)	(8.55)
Forfeited	(699,201)	(9.70)	(345,502)	(8.96)
Expired	(1,144,400)	(9.66)	-	-
Outstanding, End of Period	**12,569,238**	**7.80**	**11,147,672**	**8.45**

(1) Determined on a weighted average basis.

At December 31, 2015, there were 2,939,732 performance warrants outstanding with an exercise price of $3.00 which expire on January 31, 2020.

Each stock option and performance warrant entitles the holder to purchase one common share at the exercise price.

Depletion and Depreciation Expenses

Depletion and depreciation ("**D&D**") expenses were $35.9 million ($9.66 per boe) for the three month Reporting Period and $147.2 million ($10.35 per boe) for the twelve month Reporting Period as compared to $38.8 million ($11.17 per boe) and $136.3 million ($11.07 per boe), respectively, for the Comparable Prior Periods. D&D expenses were higher on an aggregate basis mainly due to a 7% and 15% increase in production from the three and twelve month Comparable Prior Periods, respectively.

D&D is a function of the estimated proved plus probable reserve additions, the finding and development costs attributable to those reserves, the associated future development capital required to recover those reserves and production in the period. Included in the depletion calculation for 2015 were 572.9 MMboe of proved plus probable reserves and $3.17 billion of future development capital required to recover those reserves. The Corporation determines its D&D expenses on a field area basis.

Asset impairment assessment

The Corporation reviews its petroleum and natural gas assets for impairment in accordance with International Accounting Standards ("**IAS**") 36 under IFRS. Birchcliff's assets are grouped into cash generating units ("**CGUs**") for the purpose of determining impairment. A CGU represents the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. In determining the Corporation's CGUs, the Corporation took into consideration all available information, including, but not limited to, the geographical proximity, geological similarities (i.e. reservoir characteristic, production profiles), degree of shared infrastructure, independent versus interdependent cash flows, operating structure, regulatory environment, management decision-making and overall business strategy.

The Corporation's CGUs are reviewed at each reporting date for both internal and external indicators of potential impairment. Potential CGU impairment indicators include, but are not limited to: changes to Birchcliff's business plan; deterioration in commodity prices; negative changes in technological, economic, legal, capital or operating environment; adverse changes to the physical condition of a CGU; current expectations that a material CGU (or a significant component thereof) is more likely than not to be sold or otherwise disposed of before the end of its previously estimated useful life; non-compliance with the agreements governing the Corporation's credit facilities; deterioration in the financial and operational performance of a CGU; net assets exceeding market capitalization; and significant downward revisions of estimated recoverable proved plus probable reserves of a CGU. If impairment indicators exist, an impairment test is performed by comparing a CGU's carrying value to its recoverable amount.

In light of the current low commodity price environment, Birchcliff performed an impairment test for its petroleum and natural gas assets on a CGU basis to assess for recoverability at December 31, 2015. Management has determined that the recoverable amount of Birchcliff's CGU exceeds the carrying amount at December 31, 2015 and therefore no impairment exists.

Management has determined that the calculation of the recoverable amount is most sensitive to key assumptions regarding discount rates, commodity prices and estimated quantities of proved plus probable reserves and future production profile of those reserves. Each of these underlying key assumptions are reviewed by management and corroborated independently to assess for reasonableness. In determining the recoverable amount, Birchcliff applied a pre-tax discount rate of 10% on cash flows from proved plus probable reserves. The petroleum and natural gas future prices are based on December 31, 2015 commodity price forecast assumptions determined by Deloitte LLP ("**Deloitte**"), the Corporation's independent reserves evaluator.

Finance Expenses

The components of the Corporation's finance expenses are shown in the table below:

	Three months ended December 31,				Twelve months ended December 31,			
	2015		2014		2015		2014	
	($000s)	($/boe)	($000s)	($/boe)	($000s)	($/boe)	($000s)	($/boe)
Cash:								
Interest on credit facilities	6,713	1.80	4,924	1.42	22,861	1.60	19,332	1.57
Non-cash:								
Accretion on decommissioning obligations	570	0.15	547	0.16	2,235	0.16	2,424	0.20
Amortization of deferred financing fees	235	0.06	219	0.06	919	0.06	932	0.08
Finance expenses	**7,518**	**2.01**	**5,690**	**1.64**	**26,015**	**1.82**	**22,688**	**1.85**

The aggregate interest expense is impacted by pricing margins established under Birchcliff's bank credit agreements which are used to determine Birchcliff's average effective interest rate and the average balance outstanding under its bank credit facilities during the period.

The following table details the Corporation's effective interest rates under its credit facilities:

	Three months ended December 31,		Twelve months ended December 31,	
	2015	2014	2015	2014
Revolving working capital facility	4.7%	4.5%	4.7%	4.5%
Revolving syndicated term credit facility	4.0%	4.4%	4.0%	4.2%
Non-revolving term credit facility(1)	-	4.3%	4.0%	4.5%

(1) During the three month Reporting Period, the Corporation did not have an outstanding non-revolving term credit facility.

Birchcliff's average outstanding total credit facilities balance was approximately $625 million and $655 million in the three and twelve month Reporting Periods, respectively, as compared to $447 million and $445 million in the Comparable Prior Periods, calculated as the simple average of the month end amounts.

Gain on Sale of Assets

Birchcliff recorded a gain on sale of assets of approximately $6.7 million ($1.80 per boe) and $7.3 million ($0.52 per boe) in the three and twelve month Reporting Periods, respectively, as compared to $3.2 million ($0.91 per boe) and $3.2 million ($0.26 per boe) in the Comparable Prior Periods.

In February 2015, Birchcliff completed two transactions whereby it disposed of minor non-reserve assets in the Gold Creek and Sturgeon Lake areas of Alberta in exchange for $0.7 million in cash. As a result of the disposition, Birchcliff recorded a gain of $0.6 million in the first quarter of 2015.

In November 2015, Birchcliff completed a transaction whereby it disposed of non-core reserve assets in the Mirage area of Alberta in exchange for strategic assets acquired in the Pouce Coupe area of Alberta. The fair value of the swap transaction was estimated to be $1.3 million. As a result of the disposition, Birchcliff recorded a gain of $1.4 million in the fourth quarter of 2015.

In December 2015, Birchcliff completed a transaction whereby it disposed of non-core reserve assets in the Dawson and Pouce Coupe areas of Alberta for $9.1 million in cash. As a result of the disposition, Birchcliff recorded a gain of $5.3 million in the fourth quarter of 2015.

All 2015 dispositions noted above are considered non-core asset dispositions as they collectively represent less than 1% of both Birchcliff's 2015 production and proved plus probable reserves at December 31, 2015 and therefore are not significant to the Corporation's financial results and operational performance.

Income Taxes

The components of income tax expense are shown in the table below:

	Three months ended December 31,		Twelve months ended December 31,	
($000s)	2015	2014	2015	2014
Deferred income tax expense	10,552	5,941	20,232	38,814
Dividend tax expense on preferred shares	750	750	3,000	3,000
Income tax expense	**11,302**	**6,691**	**23,232**	**41,814**
Income tax expense per boe	**$3.05**	**$1.93**	**$1.64**	**$3.39**

The income tax expense for the Reporting Periods included: (i) a one-time, non-cash, deferred income tax expense in the amount of $7.8 million that was recorded in the second quarter of 2015 as a result of the 2015 change in the Alberta corporate income tax rate from 10% to 12%; and (ii) a one-time, non-cash deferred income tax expense in the amount of $10.2 million that was recorded in the fourth quarter of 2015 as a result of the denial by the Trial Court of Birchcliff's appeal of the Reassessment.

After excluding these deferred income tax adjustments note above, the income tax expense for the three and twelve month Reporting Periods was $1.1 million and $5.3 million, respectively, compared to $6.7 million and $41.8 million in the Comparable Prior Periods. The decrease in income tax expense was a result of lower net income before tax recorded in the Reporting Periods.

The Corporation's estimated income tax pools were $1.5 billion at December 31, 2015 (2014 – $1.4 billion). Management expects that future taxable income will be available to utilize the accumulated tax pools. The components of the Corporation's estimated income tax pools are shown in the table below:

($000s)	Tax pools as at December 31, 2015
Canadian oil and gas property expense	221,883
Canadian development expense	303,076
Canadian exploration expense	257,199
Undepreciated capital costs	244,229
Non-capital losses	426,480
Financing costs	1,925
Estimated income tax pools	**1,454,792**

Veracel tax pools

Birchcliff's 2006 income tax filings were reassessed by the CRA in 2011. The Reassessment was based on the CRA's position that the tax pools available to Veracel Inc. ("**Veracel**"), prior to its amalgamation with Birchcliff, ceased to be available to Birchcliff after Birchcliff and Veracel amalgamated on May 31, 2005 (the "**Veracel Transaction**"). The Veracel tax pools in dispute totaled $39.3 million which includes approximately $16.2 million in non-capital losses, $15.6 million in scientific research and experimental development expenditures and $7.5 million in investment tax credits.

Birchcliff appealed the Reassessment to the Trial Court and the trial of that appeal occurred in November 2013. On October 1, 2015, the Trial Court issued its decision (the "**Trial Decision**") and dismissed Birchcliff's appeal on the basis of the general anti-avoidance rule contained in the *Income Tax Act* (Canada).

Birchcliff has appealed the Trial Decision to the Federal Court of Appeal (the "**Court of Appeal**") and expects that appeal to be heard in 2016. While management continues to believe that its tax position is supportable, Birchcliff has recognized a deferred income tax liability of $10.2 million in the fourth quarter of 2015 as a result of the Trial Decision being rendered. The Trial Decision does not result in any current cash taxes payable by Birchcliff.

CAPITAL EXPENDITURES

The following table sets forth a summary of the Corporation's capital expenditures:

	Three months ended December 31,		Twelve months ended December 31,	
($000s)	2015	2014	2015	2014
Land	3,468	4,650	9,261	17,694
Seismic	355	814	3,542	7,176
Workovers	1,213	1,321	6,015	7,889
Drilling and completions	32,024	80,097	160,091	271,455
Well equipment and facilities	6,346	25,761	78,146	92,342
Finding and development capital	43,406	112,643	257,055	396,556
Acquisitions	-	-	-	56,677
Dispositions	(10,281)	(3,692)	(10,947)	(3,823)
Finding, development and acquisition capital	33,125	108,951	246,108	449,410
Administrative assets	408	731	1,099	1,522
Capital expenditures, net	**33,533**	**109,682**	**247,207**	**450,932**

Capital expenditures of $33.5 million in the three month Reporting Period included approximately $26.7 million (80%) on drilling and completing new Montney/Doig horizontal natural gas wells that produced to the PCS Gas Plant during the year and the remaining $6.8 million (20%) on other infrastructure, expansion of the Montney/Doig Natural Gas Resource Play and the Charley Lake Light Oil Resource Play, the acquisition of land and other oil and gas exploration and development projects in the Peace River Arch. Drilling activities during the fourth quarter of 2015 resulted in 4 (4.0 net) Montney/Doig horizontal natural gas wells in the Pouce Coupe area.

Capital expenditures of $247.2 million in the twelve month Reporting Period included $32.7 million (13%) spent on Phase V expansion of the PCS Gas Plant and related infrastructure, approximately $144.9 million (59%) on drilling and completing new Montney/Doig horizontal natural gas wells that produced to the PCS Gas Plant during the year and the remaining $69.6 million (28%) on other infrastructure, expansion of the Montney/Doig Natural Gas Resource Play and the Charley Lake Light Oil Resource Play, the acquisition of land and other oil and gas exploration and development projects in the Peace River Arch.

Birchcliff drilled 32 (31.5 net) wells in 2015, consisting of 30 (30.0 net) natural gas wells and 2 (1.5 net) oil wells. The natural gas wells included 28 (28.0 net) Montney/Doig horizontal wells in the Pouce Coupe area, 1 (1.0 net) Montney Doig horizontal well in the Elmworth area and 1 (1.0 net) Belloy vertical well drilled as an acid gas disposal well in the Elmworth area. The oil wells included 1 (1.0 net) Charlie Lake horizontal light oil well in the Progress area and 1 (0.5 net) Halfway horizontal light oil well in the Progress area.

CAPITAL RESOURCES AND LIQUIDITY

In response to low commodity prices in 2015, the Corporation initiated proactive measures with a view to ensuring financial flexibility in a low commodity price environment, including establishing a revised capital expenditure program for 2015 of approximately $250 million (decreased from the original capital expenditure program of $266.7 million, with actual capital expenditures of $247.2 million in 2015), negotiating reductions in both capital and operating service costs and implementing various cost optimization initiatives.

The 2016 Revised Capital Budget is projected to be less than Birchcliff's expected funds flow for 2016, assuming an average WTI price of US$40.00 per barrel of oil and an average AECO price of CDN$2.50 per GJ of natural gas during 2016. Birchcliff will continue to monitor economic conditions and commodity prices and, where deemed prudent, will adjust the 2016 Revised Capital Budget to respond to changes in commodity prices and other material changes in the assumptions underlying the 2016 Revised Capital Budget. In addition, the Corporation may make adjustments to its other activities as appropriate. Actual spending may vary due to a variety of factors, including commodity prices, economic conditions, results of operations and costs of labour, services and material.

Management does not foresee any liquidity issues with respect to the operation of Birchcliff's oil and natural gas business in 2016 and expects that the Corporation will be able to meet its future obligations as they become due. Should commodity prices deteriorate materially, Birchcliff may adjust the 2016 Revised Capital Budget accordingly and/or consider the potential sale of its non-core assets to fund planned growth. See "*Advisories*".

Capital Resources

Birchcliff's capital resources consist primarily of funds flow from operations and available credit under its Credit Facilities. Management believes that its funds flow from operations and available credit under its Credit Facilities will be sufficient to fund the Corporation's planned growth and to meet its current and future working capital requirements in 2016. Birchcliff's funds flow from operations depends on a number of factors, including commodity prices, production and sales volumes, operating expenses, royalties and foreign exchange rates.

The following table sets forth a summary of the Corporation's capital resources:

	Three months ended December 31,		Twelve months ended December 31,	
($000s)	**2015**	**2014**	**2015**	**2014**
Funds flow from operations	33,697	61,717	160,756	300,498
Changes in non-cash working capital from operations	11,336	16,059	(11,066)	11,066
Decommissioning expenditures	(247)	(263)	(893)	(1,663)
Exercise of stock options	-	558	585	21,820
Exercise of preferred warrants(1)	-	-	-	49,690
Financing fees paid on credit facilities	-	-	(940)	(1,018)
Dividends paid on preferred shares	(1,875)	(1,875)	(7,500)	(7,500)
Net change in non-revolving term credit facilities	-	(30)	(129,970)	703
Net change in revolving term credit facilities	(4,923)	33,378	283,340	73,362
Changes in non-cash working capital from investing	(4,455)	138	(47,102)	3,932
Capital resources	**33,533**	**109,682**	**247,210**	**450,890**

(1) For details regarding the preferred warrants, see Note 11 – *Capital Stock* to the Corporation's audited financial statements for the year ended December 31, 2015.

Working Capital

The Corporation's working capital deficit (current assets minus current liabilities) decreased to $21.5 million at December 31, 2015 from $76.7 million at December 31, 2014. The deficit at the end of the Reporting Period is largely comprised of costs incurred from the drilling and completion of new wells.

At December 31, 2015, the major component of Birchcliff's current assets was revenue to be received from its marketers in respect of December 2015 production (85%), which was subsequently received in January 2016. In contrast, current liabilities largely consisted of trade and joint venture payables (55%) and accrued capital and operating costs (43%). Birchcliff routinely assesses the financial strength of its marketers and joint venture partners in accordance with the Corporation's credit risk guidelines. At this time, Birchcliff expects that such counterparties will be able to meet their financial obligations.

Birchcliff manages its working capital deficit using funds flow from operations and advances under the Credit Facilities. The Corporation's working capital deficit does not reduce the amount available under the Credit Facilities. The Corporation did not identify any liquidity issues with respect to the operation of its petroleum and natural gas business during the Reporting Periods.

Bank Debt

Management of debt levels continues to be a priority for Birchcliff given its long-term growth plans and the current low commodity price environment. Birchcliff believes a phased and flexible approach to existing and future growth plans should assist management in maintaining its ability to manage capital expenditures and debt levels. Management is able to quickly respond to changing commodity prices by increasing or decreasing its capital spending programs in an effort to protect the Corporation's balance sheet.

Total debt, including the working capital deficit, was $643.6 million at December 31, 2015 as compared to $545.7 million at December 31, 2014. A significant portion of the funds drawn under Birchcliff's bank credit facilities in 2015 was to pay costs relating to the drilling and completion of new Montney/Doig horizontal natural gas wells that were tied into the PCS Gas Plant, the Phase V expansion of the PCS Gas Plant and the exploration and development of the Montney/Doig Resource Natural Gas Play and the Worsley Charlie Lake Light Oil Resource Play.

In May 2015, Birchcliff's credit facilities were consolidated and increased into the Credit Facilities in the aggregate principal amount of $800 million from credit facilities previously in the aggregate amount of $750 million. See *"Major Transactions Affecting Financial Results"* in this MD&A. The Credit Facilities are no longer subject to the quarterly financial covenants review (interest coverage & debt to EBITDA), which further improves Birchcliff's financial flexibility.

The following table sets forth the Corporation's unused bank credit facilities:

As at, *($000s)*	**December 31, 2015**	**December 31, 2014**
Maximum borrowing base limit(1):		
Non-revolving term credit facilities	-	130,000
Revolving term credit facilities	800,000	620,000
	800,000	750,000
Principal amount utilized:		
Drawn non-revolving term credit facilities(2)	-	(130,000)
Drawn revolving term credit facilities(2)	(630,037)	(342,433)
Outstanding letters of credit(3)	(242)	(184)
	(630,279)	(472,617)
Unused credit	**169,721**	**277,383**
% unused credit	**21%**	**37%**

(1) The Credit Facilities are subject to an annual review of the borrowing base limit, which is directly impacted by the value of Birchcliff's petroleum and natural gas reserves.
(2) The drawn amounts are not reduced for unamortized costs and fees associated with each credit facility.
(3) Letters of credit are issued to various service providers. There were no amounts drawn on the letters of credit during the periods ended December 31, 2014 and December 31, 2015.

The aggregate limit of the Credit Facilities was $800 million at December 31, 2015, leaving $169.7 million (21%) undrawn at the end of 2015.

The Credit Facilities are subject to a semi-annual review of the borrowing base limit by Birchcliff's syndicate of lenders, which limit is directly impacted by the value of Birchcliff's oil and natural gas reserves. In addition, pursuant to the terms of the credit agreement governing the Credit Facilities, the borrowing base of the Credit Facilities may be adjusted in certain other circumstances. The Corporation's lenders use the Corporation's reserves, commodity prices, applicable discount rate and other factors to determine the Corporation's borrowing base. A material decline in commodity prices could result in a reduction in the Corporation's borrowing base, thereby reducing the funds available to the Corporation under the Credit Facilities. Notwithstanding the significant increase in proved developed producing reserve volumes at the end of 2015, Birchcliff currently expects that as a result of the continued deterioration in commodity prices, the aggregate borrowing base limit of the Credit Facilities will remain at $800 million during the normal credit review in May 2016.

The maturity date of the Credit Facilities is May 11, 2018. The Corporation may each year, at its option, request an extension to the maturity date of the Syndicated Credit Facility and the Working Capital Facility, or either of them, for an additional period of up to three years from May 11 of the year in which the extension request is made. On March 8, 2016, Birchcliff requested an extension to the maturity dates of the Credit Facilities from May 11, 2018 to May 11, 2019.

See "*Risk Factors and Risk Management – Financial Risks and Risks Relating to Economic Conditions – Credit Facilities*" in this MD&A.

Contractual Obligations

The Corporation enters into contractual obligations in the ordinary course of conducting its day-to-day business. The following table lists Birchcliff's estimated material contractual obligations at December 31, 2015:

($000s)	**2016**	**2017**	**2018 – 2020**	**Thereafter**
Accounts payable and accrued liabilities	47,584	-	-	-
Drawn revolving term credit facilities	-	-	630,037	-
Office lease(1)	3,616	3,315	12,862	33,344
Purchase obligations(2)	20,807	-	-	-
Transportation and processing	38,611	35,028	75,724	65,644
Estimated contractual obligations(3)	**110,618**	**38,343**	**718,623**	**98,988**

(1) The Corporation is committed under an existing operating lease relating to its office premises, beginning December 1, 2007 and expiring on November 30, 2017. Effective December 1, 2012, Birchcliff has not sublet any excess space to an arm's length party under the existing lease.
On December 2, 2015, the Corporation entered into a new operating lease commitment relating to an office premises beginning February 1, 2018 and expiring on January 31, 2028. The commitment amount under the new 10 year office lease is estimated to be $46.2 million, which includes costs allocated to base rent, parking and building operating expenses.
(2) The Corporation is committed to spend approximately $20.8 million in 2016 under a purchasing agreement relating to the construction of Phase V of the PCS Gas Plant.
(3) Contractual commitments that are routine in nature and form part of the normal course of operations for Birchcliff are not included. The Corporation's decommissioning obligations are excluded from the table as these obligations arose from a regulatory requirement rather than from a contractual arrangement. Birchcliff estimates the total undiscounted cash flow to settle its decommissioning obligations on its wells and facilities at December 31, 2015 to be approximately $159.9 million and will be incurred as follows: 2017 – $1.6 million, 2018 – $1.8 million and $156.5 million thereafter. The estimate for determining the undiscounted decommissioning obligations requires significant assumptions on both the abandonment cost and timing of the decommissioning and therefore the actual obligation may differ materially.
Birchcliff's Series C Preferred Shares, which are redeemable by their holders after June 30, 2020, have not been included in this table as they are not contractual obligations of the Corporation at the end of the Reporting Periods. Upon receipt of a notice of redemption, the Corporation has an obligation to redeem the Series C Preferred Shares, at its option, in cash or common shares.

OFF-BALANCE SHEET TRANSACTIONS

Birchcliff was not involved in any off-balance sheet transactions that would result in a material change to its financial position, performance or cash flows during the Reporting Periods and Comparable Prior Periods.

OUTSTANDING SHARE INFORMATION

At December 31, 2015, Birchcliff had outstanding common shares, Series A Preferred Shares and Series C Preferred Shares. Birchcliff's common shares began trading on the TSX on July 21, 2005 under the symbol "**BIR**" and were at the same time de-listed from the TSX Venture Exchange where they were trading under the same symbol prior to such time. Birchcliff's common shares are included in the S&P/TSX Composite Index. Birchcliff's Series A Preferred Shares and Series C Preferred Shares are individually listed on the TSX under the symbols "**BIR.PR.A**" and "**BIR.PR.C**", respectively.

The following table summarizes the common shares issued by the Corporation:

	Common shares
Balance at December 31, 2013	143,676,661
Exercise of options	2,550,846
Exercise of preferred warrants	5,986,699
Balance at December 31, 2014	152,214,206
Exercise of options	93,333
Balance at December 31, 2015	**152,307,539**

As of March 16, 2016, the Corporation had outstanding: 152,307,539 common shares; 2,000,000 Series A Preferred Shares; 2,000,000 Series C Preferred Shares; 13,973,705 stock options to purchase an equivalent number of common shares; and 2,939,732 performance warrants to purchase an equivalent number of common shares.

On December 2, 2015, the Board of Directors declared a quarterly cash dividend of $1.0 million or $0.50 per Series A Preferred Share and $0.875 million or $0.4375 per Series C Preferred Share for the calendar quarter ending December 31, 2015. Both dividends are designated as an eligible dividend for purposes of the *Income Tax Act* (Canada).

In 2015, cash dividends totalled $4.0 million or $2.00 per Series A Preferred Share (2014 – $4.0 million or $2.00 per Series A) and $3.5 million or $1.75 per Series C Preferred Share (2014 – $3.5 million or $1.75 per Series C).

SUMMARY OF QUARTERLY RESULTS

The following are the quarterly results of the Corporation for the eight most recently completed quarters:

Quarter ending,	Dec. 31, 2015	Sep. 30, 2015	Jun. 30, 2015	Mar. 31, 2015	Dec. 31, 2014	Sep. 30, 2014	Jun. 30, 2014	Mar. 31, 2014
Average daily production *(boe 6:1)*	40,445	38,433	38,489	38,416	37,704	34,235	31,178	31,749
Realized natural gas price *($/Mcf)*	2.67	3.12	2.86	2.98	3.91	4.37	4.81	6.10
Realized oil price *($/bbl)*[(1)]	49.36	52.91	64.93	47.66	71.87	95.94	104.72	97.30
Total revenues *($000s)*[(1)]	75,476	82,011	82,791	77,026	105,598	116,424	117,308	133,558
Operating costs *($/boe)*	4.16	4.39	4.53	5.11	5.33	5.06	5.25	5.21
Capital expenditures, net *($000s)*	33,533	50,013	65,122	98,539	109,682	104,363	75,484	161,403
Funds flow from operations *($000s)*	33,697	44,587	45,752	36,720	61,717	75,030	75,382	88,369
Per common share – basic *($)*	0.22	0.29	0.30	0.24	0.41	0.50	0.52	0.61
Per common share – diluted *($)*	0.22	0.29	0.30	0.24	0.40	0.48	0.49	0.60
Net income (loss) *($000s)*	(9,322)	4,815	(4,174)	(3,479)	17,053	29,665	28,087	39,499
Net income (loss) to common shareholders *($000s)*[(2)]	(10,322)	3,815	(5,174)	(4,479)	16,053	28,665	27,087	38,499
Per common share – basic *($)*	(0.07)	0.03	(0.03)	(0.03)	0.11	0.19	0.19	0.27
Per common share – diluted *($)*	(0.07)	0.02	(0.03)	(0.03)	0.10	0.19	0.18	0.26
Total assets *($ million)*	2,025	2,022	2,009	1,983	1,919	1,846	1,771	1,730
Long-term bank debt *($000s)*	622,074	626,839	599,998	536,570	469,033	435,545	452,183	453,772
Total debt *($000s)*	643,612	640,751	632,306	610,170	545,745	495,307	514,637	524,720
Dividends on pref. shares – Series A *($000s)*	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Dividends on pref. shares – Series C *($000s)*	875	875	875	875	875	875	875	875
Pref. shares outstanding – Series A *(000s)*	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Pref. shares outstanding – Series C *(000s)*	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Common shares outstanding *(000s)*								
Basic	152,308	152,308	152,294	152,284	152,214	152,154	145,912	144,504
Diluted	167,817	168,112	168,181	168,108	166,302	166,190	166,285	166,085
Wtd. average common shares outstanding *(000s)*								
Basic	152,308	152,303	152,289	152,243	152,183	149,594	145,145	144,026
Diluted	153,627	153,916	154,650	154,215	155,304	154,800	152,623	147,090

(1) Excludes the effect of hedges using financial instruments.
(2) Reduced for Series A Preferred Share dividends paid in the period.

Average daily production volumes have generally increased over the past eight quarters, which can be attributed primarily to the Corporation's exploration and development activities on the Montney/Doig Natural Gas Resource Play.

Over the past eight quarters, the Corporation's successful drilling program along with fluctuations in commodity prices have contributed to the fluctuations in oil and gas revenues and funds flow from operations.

Net income has fluctuated primarily due to changes in funds flow from operations (attributed generally to fluctuating oil and natural gas spot prices over the last eight quarters).

Capital expenditures have fluctuated over the past eight quarters as a result of the timing of the Corporation's development capital expenditures as well as a significant asset acquisition that occurred during the first quarter of 2014.

POTENTIAL TRANSACTIONS

Within its focus area, the Corporation is continually reviewing potential property acquisitions and corporate mergers and acquisitions for the purpose of determining whether any such potential transaction is of interest to the Corporation, as well as the terms on which such a potential transaction would be available. As a result, the Corporation may from time to time be involved in discussions or negotiations with other parties or their agents in respect of potential property acquisitions and corporate merger and acquisition opportunities. The Corporation is not committed to any such potential transaction and cannot be reasonably confident that it can complete any such potential transaction until appropriate legal documentation has been signed by the relevant parties.

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

The Corporation's Chief Executive Officer and Chief Financial Officer (the "**Certifying Officers**") have designed, or caused to be designed under their supervision, disclosure controls and procedures ("**DC&P**"), as defined in National Instrument 52-109 – *Certification of Disclosure in Issuer's Annual and Interim Filings* ("**NI 52-109**"), to provide reasonable assurance that: (i) material information relating to the Corporation is made known to the Certifying Officers by others, particularly during the period in which the annual filings are being prepared; and (ii) information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by the Corporation under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation. The Certifying Officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Corporation's DC&P at December 31, 2015 and have concluded that the Corporation's DC&P were effective at December 31, 2015.

While the Certifying Officers believe that the Corporation's DC&P provide a reasonable level of assurance and are effective, they do not expect that the DC&P will prevent all errors and fraud. A control system, no matter how well conceived, maintained and operated, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met.

Internal Control over Financial Reporting

The Certifying Officers have designed, or caused to be designed under their supervision, internal control over financial reporting ("**ICFR**"), as defined in NI 52-109, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the generally accepted accounting principles applicable to the Corporation. The control framework the Certifying Officers used to design the Corporation's ICFR is *"Internal Control – Integrated Framework (May 2013)"* published by The Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Certifying Officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Corporation's ICFR at December 31, 2015 and have concluded that the Corporation's ICFR were effective at December 31, 2015. There were no changes in the Corporation's ICFR that occurred during the period beginning on October 1, 2015 and ended on December 31, 2015 that have materially affected, or are reasonably likely to materially affect, the Corporation's ICFR.

While the Certifying Officers believe that the Corporation's ICFR provide a reasonable level of assurance and are effective, they do not expect that the ICFR will prevent all errors and fraud. A control system, no matter how well conceived, maintained and operated, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the financial statements requires management to make judgments, estimates and assumptions that affect the application of IFRS accounting policies; reported amounts of assets and liabilities; and income and expenses. Accordingly, actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected.

Critical Judgments in Applying Accounting Policies

The following are critical judgments that management has made in the process of applying the Corporation's IFRS accounting policies and that have the most significant effect on the amounts recognized in the audited financial statements for the Reporting Periods.

Identification of cash-generating units

Birchcliff's assets are aggregated into CGUs for the purpose of calculating impairment based on their ability to generate largely independent cash inflows. CGUs have been determined based on similar geological structure, shared infrastructure, geographical proximity, operating structure, commodity type and similar exposures to market risks. By their nature, these assumptions are subject to management's judgment and may impact the carrying value of the Corporation's assets in future periods.

Identification of impairment indicators

IFRS requires Birchcliff to assess, at each reporting date, whether there are any indicators that its assets may be impaired. Birchcliff is required to consider information from both external sources (such as negative downturn in commodity prices, significant adverse changes in the technological, market, economic or legal environment in which the entity operates) and internal sources (such as downward revisions in reserves, significant adverse effect on the financial and operational performance of a CGU, evidence of obsolescence or physical damage to the asset). By their nature, these assumptions are subject to management's judgment and may impact the carrying value of the Corporation's assets in future periods.

Tax uncertainties

IFRS requires Birchcliff, at each reporting date, to make certain judgments on uncertain tax positions by relevant tax authorities. Judgments include determining whether the Corporation will "more likely than not" be successful in defending its tax positions by considering information from relevant tax interpretations and tax laws in Canada. As such, this recognition threshold is subject to management's judgment and may impact the carrying value of the Corporation's deferred tax assets and liabilities at the end of the reporting period.

Key Sources of Estimation Uncertainty

The following are the key assumptions concerning the sources of estimation uncertainty at the end of the reporting period, that have a significant risk of causing adjustments to the carrying amounts of assets and liabilities within the next financial year.

Reserves

Reported recoverable quantities of proved and probable reserves requires estimation regarding production profile, commodity prices, exchange rates, remediation costs, timing and amount of future development costs, and production, transportation and marketing costs for future cash flows. It also requires interpretation of geological and geophysical models in order to make an assessment of the size, shape, depth and quality of reservoirs, and their anticipated recoveries. The economical, geological and technical factors used to estimate reserves may change from period to period. Changes in reported reserves can impact the carrying values of the Corporation's petroleum and natural gas properties and equipment, the calculation of depletion and depreciation, the provision for decommissioning obligations and the recognition of deferred tax assets due to changes in expected future cash flows. The recoverable quantities of reserves and estimated cash flows from Birchcliff's petroleum and natural gas interests are independently evaluated by reserve engineers at least annually.

The Corporation's petroleum and natural gas reserves represent the estimated quantities of petroleum, natural gas and NGL which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be economically recoverable in future years from known reservoirs and which are considered commercially producible. Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon: (i) a reasonable assessment of the future economics of such production; (ii) a reasonable expectation that there is a market for all or substantially all the expected petroleum and natural gas production; and (iii) evidence that the necessary production, transmission and transportation facilities are available or can be made available. Reserves may only be considered proven and probable if producibility is supported by either production or conclusive formation tests. Birchcliff's oil and gas reserves are determined in accordance with the standards contained in National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**") and the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**").

Share-based payments

All equity-settled, share-based awards issued by the Corporation are fair valued using the Black-Scholes option-pricing model. In assessing the fair value of equity-based compensation, estimates have to be made regarding the expected volatility in share price, option life, dividend yield, risk-free rate and estimated forfeitures at the initial grant date.

Decommissioning obligations

The Corporation estimates future remediation costs of production facilities, wells and pipelines at different stages of development and construction of assets or facilities. In most instances, removal of assets occurs many years into the future. This requires an estimate regarding abandonment date, future environmental and regulatory legislation, the extent of reclamation activities, the engineering methodology for estimating cost, future removal technologies in determining the removal cost and liability-specific discount rates to determine the present value of these cash flows.

Impairment of non-financial assets

For the purposes of determining the extent of any impairment or its reversal, estimates must be made regarding future cash flows taking into account key assumptions, including future petroleum and natural gas prices, expected forecasted production volumes and anticipated recoverable quantities of proved and probable reserves. These assumptions are subject to change as new information becomes available. Changes in economic conditions can also affect the rate used to discount future cash flow estimates. Changes in the aforementioned assumptions could affect the carrying amount of the Corporation's assets, and impairment charges and reversal will affect profit or loss.

Income taxes

Birchcliff files corporate income tax, goods and services tax and other tax returns with various provincial and federal taxation authorities in Canada. There can be differing interpretations of applicable tax laws and regulations. The resolution of these tax positions through negotiations or litigation with tax authorities can take several years to complete. The Corporation does not anticipate that there will be any material impact upon the results of its operations, financial position or liquidity.

Tax provisions are based on enacted or substantively enacted laws. Changes in those laws could affect amounts recognized in profit or loss both in the period of change, which would include any impact on cumulative provisions, and in future periods.

Deferred tax assets (if any) are recognized only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse and a judgment as to whether or not there will be sufficient taxable profits available to offset the tax assets when they do reverse. This requires assumptions regarding future profitability and is therefore inherently uncertain. Estimates of future taxable income are based on forecasted cash flows from operations. To the extent that any interpretation of tax law is challenged by the tax authorities or future cash flows and taxable income differ significantly from estimates, the ability of Birchcliff to realize the deferred tax assets recorded at the balance sheet date could be impacted.

FUTURE ACCOUNTING PRONOUNCEMENTS

In January 2016, the International Accounting Standards Board (the "**IASB**") issued IFRS 16 *Leases*. The standard will be effective for annual periods beginning on or after January 1, 2019. Early adoption is permitted, provided IFRS 15 *Revenue from Contracts with Customers*, has been applied, or is applied at the same date as IFRS 16. Birchcliff is currently evaluating the impact of adopting IFRS 16 on the financial statements.

On May 28, 2014, the IASB issued IFRS 15 *Revenue From Contracts With Customers* replacing IAS 11 *Construction Contracts*, IAS 18 *Revenue* and several revenue-related interpretations. IFRS 15 contains a single model that applies to contracts with customers and two approaches to recognizing revenue: at a point in time or over time. The model features a contract-based five-step analysis of transactions to determine whether, how much and when revenue is recognized. IFRS 15 is effective for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. Birchcliff is currently assessing the impact of adopting IFRS 15; however, it anticipates that this standard will not have a material impact on the Corporation's financial statements.

On July 24, 2014, the IASB issued the final version of IFRS 9 *Financial Instruments* to replace IAS 39 *Financial Instruments: Recognition and Measurement*. IFRS 9 aligns hedge accounting more closely with risk management. The new standard does not fundamentally change the types of hedging relationships or the requirement to measure and recognize ineffectiveness. However, under the new standard, more hedging strategies that are used for risk management will qualify for hedge accounting. IFRS 9 is effective for years beginning on or after January 1, 2018. As the Corporation does not currently apply hedge accounting it anticipates that this standard will not have a material impact on the Corporation's financial statements.

RISK FACTORS AND RISK MANAGEMENT

The Corporation's operations are exposed to a number of risks, some that impact the oil and natural gas industry as a whole and others that are unique to the Corporation. The impact of any risk or a combination of risks may adversely affect the Corporation's business, financial condition, results of operations, prospects, cash flow and reputation, which may reduce or restrict the Corporation's ability to pay preferred share dividends and may materially affect the market price of the Corporation's securities. The Corporation's approach to risk management includes an annual review of principal and emerging risks, an analysis of the severity and likelihood of each risk and an evaluation of the effectiveness of current mitigation procedures.

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision. The risks set out below are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with the Corporation's business and the oil and natural gas business generally.

Financial Risks and Risks Relating to Economic Conditions

Commodity Price Volatility and Weakness in the Oil and Gas Industry

The Corporation's revenues, operating results and financial condition are substantially dependent upon the prices that it receives for oil, natural gas and NGL and the prices that it receives for such products is closely correlated to the price of crude oil and natural gas. Historically, crude oil and natural gas markets have been volatile and are likely to continue to be volatile in the future. Crude oil and natural gas prices have fluctuated widely during recent years and are subject to fluctuations in response to changes in supply, demand, market uncertainty and other factors that are beyond the Corporation's control. These factors include, but are not limited to:

- global energy policy, including (without limitation) the ability of the Organization of the Petroleum Exporting Countries ("**OPEC**") to set and maintain production levels and influence prices for crude oil;
- political instability and hostilities;
- domestic and foreign supplies of crude oil;
- the overall level of energy demand;
- weather conditions;
- government regulations;
- taxes;
- currency exchange rates;
- the availability of refining capacity and transportation infrastructure;
- the effect of worldwide environmental and/or energy conservation measures;
- the price and availability of alternative energy supplies; and
- the overall economic environment.

Through the latter half of 2014 and into 2016, the price for crude oil has declined significantly. In addition, recent prices for natural gas have declined substantially from 2015 levels. Recent market events and conditions, including global excess oil and natural gas supply, recent actions taken by OPEC, slowing growth in China and other emerging economies, market volatility and disruptions in Asia, and sovereign debt levels in various countries, have caused significant weakness and volatility in commodity prices. These events and conditions have caused a significant decrease in the valuation of oil and natural gas companies and a decrease in confidence in the oil and natural gas industry. These difficulties have been exacerbated in Canada by the recent changes in government at a federal level and, in case of Alberta, the provincial level and the resultant uncertainty surrounding regulatory, tax and royalty changes that may be implemented by the new governments. In addition, the inability to get the necessary approvals to build pipelines and other facilities to provide better access to markets for the oil and natural gas industry in western Canada has led to additional uncertainty and reduced confidence in the oil and natural gas industry in western Canada.

Any prolonged period of low crude oil or natural gas prices could result in a decision by the Corporation to suspend or slow exploration and development activities, the construction or expansion of new or existing facilities or reduce production levels. Any such actions could have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects and ultimately on the market price of the Corporation's securities, the Corporation's ability to pay dividends on its Series A Preferred Shares and Series C Preferred Shares and on the value of the Corporation's reserves.

Volatility in oil and natural gas prices makes it difficult to estimate the value of producing properties for acquisitions and often causes disruption in the market for oil and natural gas producing properties, as buyers and sellers may have difficultly agreeing on the value of such properties. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

The Corporation's financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. Of particular importance are the price differentials between the Corporation's light/medium oil and natural gas and quoted market prices. Not only are these discounts influenced by regional supply and demand factors, they are also influenced by other factors such as transportation costs, capacity and interruptions and the quality of the oil and natural gas produced, all of which are beyond the Corporation's control.

The Corporation's reserves as at December 31, 2015 are estimated using forecast prices and costs. These prices are substantially above current crude oil and natural gas prices. If crude oil and natural gas prices stay at current levels, the Corporation's reserves may be substantially reduced as economic limits of developed reserves are reached earlier and undeveloped reserves become uneconomic at such prices. Even if some reserves remain economic at lower price levels, sustained low prices may compel the Corporation to re-evaluate its development plans and reduce or eliminate various projects with marginal economics. In addition, lower commodity prices have restricted, and are anticipated to continue to restrict, the Corporation's cash flow. The Corporation's capital expenditure plans are impacted by the Corporation's cash flow. If commodity prices continue to deteriorate and the Corporation reduces its capital expenditures, the Corporation may not be able to replace its production with additional reserves and both its production and reserves could be reduced on a year-over-year basis.

Birchcliff conducts an assessment of the carrying value of its assets to the extent required by IFRS. If forecasted oil or natural gas prices decline, the carrying value of the Corporation's assets could be subject to downward revision, and the Corporation's earnings could be adversely affected by any reduction in such carrying value.

Additional Funding Requirements and Access to Credit Markets

Due to the nature of the Corporation's business, it is necessary from time to time for the Corporation to access other sources of capital beyond its internally generated cash flow in order to fund its acquisition, exploration and development activities. As part of this strategy, the Corporation obtains some of this necessary capital by incurring debt; therefore, the Corporation is dependent to a certain extent on continued availability of the credit markets. The continued availability of the credit markets for the Corporation is primarily dependent on the state of the economy and the health of the banking industry in Canada and the United States. There is a risk that if the economy and banking industry experienced unexpected or prolonged deterioration, the Corporation's access to credit markets may contract or disappear altogether. The Corporation tries to mitigate this risk by dealing with reputable lenders and tries to structure its lending agreements to give it the most flexibility possible should these situations arise. However, situations that give rise to credit markets tightening or disappearing are largely beyond the Corporation's control.

Due to the conditions in the oil and natural gas industry and/or global economic volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. The current conditions in the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies to access additional financing. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. Continued depressed oil and natural gas prices have caused decreases, and may cause further decreases, in the Corporation's revenues from its reserves, which may affect its ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Corporation's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of the Corporation's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties.

The Corporation is also dependent, to a certain extent, on continued access to equity capital markets. The Common Shares are listed on the TSX and management maintains an active investor relations program. In addition to the other factors outlined herein, continued access to capital is dependent on the Corporation's ability to continue to perform at a level that meets market expectations.

Issuance of Debt

From time to time, the Corporation may enter into transactions to acquire assets or shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Credit Facilities

The amount authorized under the Credit Facilities is dependent on the borrowing base determined by the Corporation's lenders. As at December 31, 2015, the borrowing base limit under the Credit Facilities is $800 million and long-term bank debt is $622.1 million. The Credit Facilities are subject to a semi-annual review of the borrowing base limit by Birchcliff's syndicate of lenders, which limit is directly impacted by the value of Birchcliff's oil and natural gas reserves. The Corporation's lenders use the Corporation's reserves, commodity prices, applicable discount rate and other factors to determine the Corporation's borrowing base. A material decline in commodity prices could result in a reduction in the Corporation's borrowing base, thereby reducing the funds available to the Corporation under the Credit Facilities. As the borrowing base is determined based on the lender's interpretation of the Corporation's reserves and future commodity prices, there can be no assurance as to the amount of the borrowing base determined at each review. In addition, the lenders are able to request one additional borrowing base redetermination in between scheduled redeterminations and the borrowing base may be reduced in connection with asset dispositions. If, at the time of a borrowing base redetermination, the outstanding borrowings under the Credit Facilities were to exceed the borrowing base as a result of any such recalculation, the Corporation would be required to eliminate this excess. If the Corporation is forced to repay a portion of its indebtedness under the Credit Facilities, it may not have sufficient funds to make such repayments. If it does not have sufficient funds and is otherwise unable to negotiate renewals of its borrowings or arrange new financing, it may have to sell significant assets. Any such sale could have a material adverse effect on the Corporation's business and financial results.

The maturity date of the Credit Facilities is May 11, 2018. The Corporation may each year, at its option, request an extension to the maturity date of the Syndicated Credit Facility and the Working Capital Facility, or either of them, for an additional period of up to three years from May 11 of the year in which the extension request is made. In the event that either of the Credit Facilities is not extended before the maturity date, all outstanding indebtedness under such Credit Facility will be repayable at the maturity date. There is also a risk that the Credit Facilities will not be renewed for the same principal amount or on the same terms. Any of these events could adversely affect the Corporation's ability to fund its ongoing operations and to pay dividends on its Series A Preferred Shares and Series C Preferred Shares.

The Corporation is required to comply with covenants under the Credit Facilities. In the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond the Corporation's control may contribute to the failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in default under the Credit Facilities, which could result in the Corporation being required to repay amounts owing thereunder. Even if the Corporation is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to the Corporation. If the Corporation is unable to repay amounts owing under the Credit Facilities, the lenders under the Credit Facilities could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of the Corporation's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Credit Facilities impose certain restrictions on the Corporation, including, but not limited to, restrictions on the payment of dividends, incurring of additional indebtedness, dispositions of properties and the entering into of amalgamations, mergers, plans of arrangements, reorganizations or consolidations with any person.

Dividends

Dividends on the Corporation's Series A Preferred Shares and Series C Preferred Shares are payable at the discretion of the Board. The Corporation may not declare or pay a dividend if there are reasonable grounds for believing that: (i) the Corporation is, or would after the payment be, unable to pay its liabilities as they become due; or (ii) the realizable value of the Corporation's assets would thereby be less than the aggregate of its liabilities and stated capital of its outstanding shares. Additionally, pursuant to the Credit Facilities, Birchcliff is not permitted to make any distribution (which includes dividends) at any time when an event of default exists or would reasonably be expected to exist upon making such distribution, unless such event of default arose subsequent to the ordinary course declaration of the applicable distribution.

The Corporation has never paid any dividends on its Common Shares or made distributions to holders of Common Shares. Any decision to declare and pay dividends will be made at the discretion of the Board and will depend on, among other things, the cash flow, results of operations and financial condition of the Corporation, current and future capital requirements, working capital requirements, commodity prices and the Corporation's outlook for commodity prices, contractual restrictions, financing agreement covenants, liquidity and solvency tests imposed by corporate law and other factors that the Board may deem relevant.

Hedging

From time to time, the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Corporation engages in price risk management activities to protect it from commodity price declines, the Corporation may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Corporation's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes or prices fall significantly lower than projected;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;
- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar. However, if the Canadian dollar declines in value compared to the United States dollar, the Corporation will not benefit from the fluctuating exchange rate.

During the year ended December 31, 2015, the Corporation had no financial derivatives in place.

Counterparty Credit Risk

The Corporation may be exposed to third-party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In addition, the Corporation may be exposed to third party credit risk from operators of properties in which the Corporation has a working or royalty interest. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may affect a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in the Corporation being unable to collect all or portion of any money owing from such parties. Any of these factors could materially adversely affect the Corporation's financial and operational results.

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in United States dollars. The Canadian/United States dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar relative to the United States dollar may negatively affect the Corporation's production revenues. Future Canadian/United States exchange rates could also impact the future value of the Corporation's reserves as determined by independent evaluators. Although a low value of the Canadian dollar relative to the United States dollar may positively affect the price the Corporation receives for its oil and natural gas production, it could also result in an increase in the price for certain goods used for the Corporation's operations, which may have a negative impact on the Corporation's financial results.

To the extent that the Corporation engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Corporation may contract. The Corporation has not hedged any of its foreign exchange risk at the date hereof. See "– *Hedging*".

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, resulting in a reduced amount available to fund its exploration and development activities, and if applicable, the cash available for dividends and could negatively impact the market price of the Corporation's securities.

Business and Operational Risks

Exploration, Development and Production

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Corporation may have at any particular time and the production therefrom, will decline over time as such existing reserves are exploited. A future increase in the Corporation's reserves will depend on both the ability of the Corporation to explore and develop its existing properties and its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Corporation will be able continue to find satisfactory properties to acquire or participate in. Moreover, management of the Corporation may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participations uneconomic. There is also no assurance that the Corporation will discover or acquire further commercial quantities of oil and natural gas. In addition, the success of the Corporation's business is highly dependent on its ability to acquire or discover new reserves in a cost efficient manner as substantially all of the Corporation's cash flow is derived from the sale of the petroleum and natural gas reserves that it accumulates and develops. In order to remain financially viable, the Corporation must be able to replace reserves over time at a lesser cost on a per unit basis than its cash flow on a per unit basis.

The Corporation remains subject to the risk that the production rate of a significant well may decrease in an unpredictable and uncontrollable manner, which could result in a decrease in the Corporation's overall production and associated cash flows. The Corporation mitigates this risk by having a large number of wells on production, reducing the ability of any one well to materially affect overall production and associated cash flow.

Future oil and natural gas exploration may involve unprofitable efforts from dry wells as well as from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, and shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury. Particularly, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation.

Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

As is standard industry practice, the Corporation is not fully insured against all risks, nor are all risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event, the Corporation could incur significant costs. See *"– Other Risks – Insurance"*.

Project Risks

The Corporation manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. The Corporation's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling and hydraulic fracturing, or the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation could be unable to execute projects on time, on budget, or at all, and may be unable to effectively market the oil and natural gas that it produces.

Gathering and Processing Facilities and Pipeline Systems

The Corporation delivers its products through gathering and processing facilities and pipeline systems, some of which it does not own. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities and pipeline systems. The lack of availability of capacity in any of the gathering and processing facilities and pipeline systems could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Corporations production, operations and financial results. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, results of operations and cash flows. The federal government has signaled that it plans to review the National Energy Board approval process for large projects. This may cause the timeframe for project approvals to increase for current and future applications.

The majority of the Corporation's production passes through Birchcliff owned or third party infrastructure prior to it being ready for transfer at designated commodity sales points. There is a risk that should this infrastructure fail and cause a significant portion of the Corporation's production to be shut-in and be unable to be sold, this could have a material adverse effect on the Corporation's available cash flow. With respect to facilities owned by third parties and over which the Corporation has no control, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a material adverse effect on the Corporation's ability to process its production and deliver the same for sale.

Hydraulic Fracturing

Hydraulic fracturing is the process of pumping a fluid or a gas under pressure down a well, which causes the surrounding rock to crack or fracture. The fluid, typically consisting of water, sand, chemicals and other additives, flows into the cracks where the sand remains to keep the cracks open and allow natural gas or liquids to be recovered. Fracturing fluids are produced back to the surface through the wellbore and are stored for reuse or future disposal in accordance with applicable regulations, which may include injection into underground wells.

While hydraulic fracturing has been in use and improved upon for many years, there has been increased focus on environmental aspects of hydraulic fracturing practices in recent years. In the United States, the process is regulated by state and local governments, but the United States Environmental Protection Agency is considering undertaking a broad study as it pertains to the national *Clean Water Act* (United States). Any U.S. rules on hydraulic fracturing could influence other jurisdictions' regulations and force oil and natural gas companies, including the Corporation, to cease using the process or to add pollution control technology to their operations. Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and natural gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil, natural gas, and NGL or could make it more difficult to perform hydraulic fracturing. The adoption of additional federal, provincial or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and natural gas wells, increased compliance costs and time, which could adversely affect the Corporation's financial position, results of operations and cash flows.

Effective December 2012, AER rules require that licensees comply with enhanced requirements to report amounts and sources of water and chemicals used in every hydraulic fracturing job. The AER requires that any hydraulic fracturing fluids used above the base of groundwater protection be non-toxic and that the operator reveal the contents of the fluids to the AER upon request. The AER also requires that the type and volume of all additives used in fracturing fluids be recorded in the daily record of operations for any well and such information must be submitted to the AER.

Uncertainty of Reserves Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and the future cash flows attributed to such reserves, including many factors beyond the control of the Corporation. In general, estimates of economically recoverable oil, natural gas and NGL reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, initial production rates, production decline rates, ultimate reserve recovery, the timing and amount of capital expenditures, the success of future development activities, future commodity prices, marketability of oil, natural gas and NGL, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable oil, natural gas and NGL reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers or by the same engineer at different times, may vary substantially. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Estimates with respect to reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations in the estimated reserves, which may be substantial.

In accordance with applicable securities laws in Canada, the Corporation's independent qualified reserves evaluator has used forecast prices and costs in estimating the Corporation's reserves and future net cash flows. Actual future net cash flows also will be affected by other factors such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulations or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Corporation's reserves will vary from the estimates contained in the reserves estimation and economic evaluation effective December 31, 2015 in respect of the Corporation's oil and gas properties prepared by Deloitte (the "**2015 Reserves Evaluation**"), and such variations could be material. The 2015 Reserves Evaluation is based in part on the expected success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom and contained in the 2015 Reserves Evaluation may be reduced to the extent that such activities do not achieve the expected level of success.

Costs and Availability of Equipment and Services

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Corporation and may delay exploration and development activities. During times of high commodity prices for oil and natural gas, there is a risk of substantially increased cost of operation, which impacts both the amount of capital required to perform operations and the netback the Corporation achieves from its production sales. Although the Corporation strives for continuous improvement in its planning, operations and procurement of materials, unexpected changes in the market for such equipment and services could negatively affect the Corporation's business, financial condition, results of operations and prospects.

Potential Future Drilling Locations

The Corporation's identified potential future drilling locations represent a significant part of the Corporation's growth strategy. The Corporation's ability to drill and develop these locations depends on a number of uncertainties and factors, including, but not limited to, the availability of capital, equipment and personnel, oil and natural gas prices, capital and operating costs, inclement weather, seasonal restrictions, drilling results, additional geological, geophysical and reservoir information that is obtained production rate recovery, gathering system and transportation constraints, net price received for commodities produced, regulatory approvals, regulatory changes. As a result of these uncertainties, there can be no assurance that the potential future drilling locations the Corporation has identified will ever be drilled or if the Corporation will be able to produce oil, NGL or natural gas from these or any other potential future drilling locations. As such, the Corporation's actual drilling activities may materially differ from those presently identified, which could adversely affect the Corporation's business.

Operational Dependence

Other companies operate some of the assets in which the Corporation has an interest. The Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's business, financial condition, results of operations and prospects. The Corporation's return on assets operated by others depends upon a number of factors that may be outside of the Corporation's control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

In addition, due to the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which the Corporation has an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which the Corporation has an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations, the Corporation may be required to satisfy such obligations and to seek recourse from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, the Corporation potentially becoming subject to additional liabilities relating to such assets and the Corporation having difficulty collecting revenue due from such operators. Any of these factors could materially adversely affect the Corporation's financial and operational results.

Cost of New Technologies

The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil and natural gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before the Corporation. There can be no assurance that the Corporation will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilized by the Corporation or implemented in the future may become obsolete. In such case, the Corporation's business, financial condition, results of operations and prospects could be affected adversely and materially. If the Corporation is unable to utilize the most advanced commercially available technology, its business, financial condition, results of operations and prospects could also be adversely affected in a material way.

Alternatives to and Changing Demand for Petroleum Products

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

Health, Safety and Environment

Health, safety and environmental risks influence the workforce, operating costs and the establishment of regulatory standards. These risks include, but are not limited to, encountering unexpected formations or pressures; premature declines of reservoirs; blow-outs; equipment failures; human error or wilful misconduct by field workers; other accidents such as, cratering, sour gas releases, uncontrollable flows of oil, natural gas or well fluid spills; adverse weather conditions, pollution, fires and other environmental risks. The Corporation provides staff with the training and resources they need to complete work safely and effectively; incorporates hazard assessment and risk management as an integral part of everyday operations; monitors performance to ensure its operations comply with legal obligations and internal standards; and identifies and manages environmental liabilities associated with its existing asset base. The Corporation has a site inspection program and a corrosion risk management program designed to ensure compliance with environmental laws and regulations. The Corporation carries insurance to cover a portion of property losses, liability to third parties and business interruption resulting from unusual events.

The Corporation is subject to the risk that the unexpected failure of its equipment used in drilling, completing or producing wells or in transporting production could result in release of fluid substances that pollute or contaminate lands at or near its facilities, which could result in significant liability to the Corporation for costs of clean up, remediation and reclamation of contaminated lands. The Corporation conducts its operations with due regard for the potential impact on the environment. This includes hiring skilled personnel, providing adequate training to all staff involved with operations, and by retaining expert advice and assistance to deal with environmental remediation and reclamation work where such expertise is needed.

Seasonality

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

Expiration of Licences and Leases

The Corporation's properties are held in the form of licences and leases and working interests in licences or leases held by others. If the Corporation or the holder of the licence or lease fails to meet specific requirements of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of licences or leases may have a material adverse effect on the business, financial condition, results of operations and prospects of the Corporation. To mitigate this risk, the Corporation carefully monitors its undeveloped land position and plans operations in order to keep key licences and leases from terminating or expiring.

Competition

The oil and natural gas industry is highly competitive, particularly as it pertains to the exploration for and development of new sources of oil and natural gas reserves. The industry also competes with other industries in supplying non-petroleum energy products. The Corporation actively competes for land, production and reserves acquisitions, exploration leases, licences and concessions and skilled technical and operating personnel with a substantial number of other oil and natural gas companies, many of which have greater financial resources, staff and facilities than the Corporation. Competitive factors in the distribution and marketing of oil and natural gas include price, methods, and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

All Assets in One Area

All of the Corporation's producing properties are geographically concentrated in the Peace River Arch area of Alberta. As a result of this concentration, the Corporation may be disproportionately exposed to the impact of delays or interruptions of production from that area caused by significant governmental regulation in Alberta, transportation capacity constraints, curtailment of production, natural disasters, availability of equipment, facilities or services, adverse weather conditions or other events which impact that area. Due to the concentrated nature of the Corporation's portfolio of properties, a number of the Corporation's properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on the Corporation's results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on the Corporation's financial condition and results of operations.

Expansion into New Activities

The operations and expertise of the Corporation's management are currently focused primarily on oil and natural gas production, exploration and development in Peace River Arch area of Alberta. In the future, the Corporation may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase the Corporations exposure to one or more existing risk factors, which may in turn result in the Corporation's future operational and financial conditions being adversely affected.

Environmental and Regulatory Risks

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and natural gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material, as well as the responsibility to remedy environmental problems caused by the Corporation's operations. A serious breach could result in the Corporation being required to suspend operations or enter into an interim compliance measure which may restrict the Corporation's ability to conduct operations.

Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental legislation, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. See also *"– Changes in Legislation".*

Political and economic events may significantly affect the scope and timing of climate change measures that are put in place. Some of the Corporation's facilities may be subject to future provincial or federal climate change regulations to manage emissions and there can be no assurance that the compliance costs will be immaterial. The implementation of new environmental regulations or the modification of existing environmental regulations affecting the oil and natural gas industry generally could reduce demand for oil and natural gas and increase costs. See also *"– Changes in Legislation"* and *"– Climate Change".*

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, the Corporation will require regulatory permits, licences, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the permits, licences, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, the Corporation's business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

Changes in Legislation

Government royalties, income tax laws, environmental laws and regulatory requirements can have a significant financial and operational impact on the Corporation. As an oil and natural gas producer, the Corporation is subject to a broad range of regulatory requirements. Negative consequences which could arise as a result of changes to the current regulatory environment include, but are not limited to, extraordinary environmental and emissions regulation of current and future projects by governmental authorities, which could result in changes to facility design and operating requirements, thereby potentially increasing the cost of construction, operation and abandonment. The Corporation hires and retains skilled personnel that are knowledgeable regarding changes to the regulatory regime under which it operates.

There can be no assurance that the federal government and the provincial government of Alberta will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Corporation's projects and could adversely affect the Corporation's results of operations, financial condition or prospects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic. On January 29, 2016, the Government of Alberta released its Royalty Review Advisory Panel

Report (the "**Royalty Review**"). The Royalty Review recommends new rules coming into effect in 2017, but also recommends grandfathering, under the current rules, all wells drilled before 2017 for a ten year period. The Royalty Review also recommends modernization of Alberta's royalty framework for crude oil, liquids and natural gas. The Government of Alberta has accepted the recommendations set out in the Royalty Review and additional details regarding the royalty framework, including the applicable royalty rates and formulas, are expected to be released by March 31, 2016. It is not anticipated that the new rules will materially impact the Corporation's financial condition; however, the specific nature in which the new rules will be applied has not yet been determined and may alter this view.

Climate Change

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases ("**GHG**"). Various federal and provincial governments have announced intentions to regulate GHG emissions and other air pollutants. Some of these regulations are in effect while others remain in various phases of review, discussion or implementation in the U.S. and Canada. Uncertainties exist relating to the timing and effects of these regulations. Additionally, lack of certainty regarding how any future federal legislation will harmonize with provincial regulations makes it difficult to accurately determine the cost estimate of climate change legislation compliance with certainty.

The *Specified Gas Emitters Regulation* (Alberta) (the "**SGER**"), which imposes GHG emissions intensity limits and reduction requirements for owners of facilities that emit 100,000 tonnes per year or more of GHG, was recently amended. Previously, an owner of such a facility was required to reduce the emissions intensity of that facility by a minimum of 12%. The amendments have increased the minimum emission intensity reduction requirement for facility owners to 15% in 2016 and 20% starting in 2017. One of the options for complying with the SGER is for facility owners to purchase technology fund credits. The amendments have increased the price for such credits from $15/tonne to $20/tonne for 2016 and $30/tonne beginning in 2017. The Corporation is not currently subject to the SGER as Birchcliff does not currently emit more than 100,000 tonnes per year; however, should the Corporation emit more than 100,000 tonnes per year, it would be subject to such requirements.

The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Corporation's business, financial results of operations and prospects. Any such regulations could also increase the cost of consumption and thereby reduce the demand for the oil, natural gas and NGL that the Corporation produces. Given the evolving nature of the debate related to climate change and the control of GHG, it is not possible to predict with certainty the impact on the Corporation and its operations and financial condition.

Alberta Climate Leadership Plan

In November 2015, the Alberta government announced its climate leadership plan (the "**CLP**") and released to the public the climate leadership report to the Minister of Environment and Parks (the "**Report**") that it commissioned from the Climate Change Advisory Panel and on which the CLP is based. The CLP includes four strategies that the government will implement to address climate change: (i) the complete phase-out of coal-fired sources of electricity by 2030; (ii) implementing an Alberta economy-wide price on GHG emissions of $30 per tonne; (iii) reducing oil sands emissions to a province-wide total of 100 megatonnes per year (compared to current industry emissions levels of approximately 70 megatonnes per year), with certain exceptions for cogeneration power sources and new upgrading capacity; and (iv) reducing methane emissions from oil and gas activities by 45% by 2025. Uncertainties exist with respect to the implementation of the CLP and the effects that the CLP, including the overall emissions limit, may have on the industry.

Adverse impacts to the Corporation's business as a result of comprehensive GHG legislation or regulation, including legislation to implement the CLP and the amendments to the SGER, to be enacted and applied to the Corporation's business in Alberta or any jurisdiction in which the Corporation operates, may include, but are not limited to: increased compliance costs; permitting delays; substantial costs to generate or purchase emission credits or allowances adding costs to the products the Corporation produces; and reduced demand for crude oil and certain refined products. Emission allowances or offset credits may not be available for acquisition or may not be available on an economic basis. Required emission reductions may not be technically or economically feasible to implement, in whole or in part, and failure to meet such emission reduction requirements or other compliance mechanisms may have a material adverse effect on the Corporation's business resulting in, among other things, fines, permitting delays, penalties and the suspension of operations. Consequently, no assurances can be given that the effect of future climate change regulations will not be significant to the Corporation.

Beyond existing legal requirements, the extent and magnitude of any adverse impacts of any additional programs or additional regulations cannot be reliably or accurately estimated at this time because specific legislative and regulatory requirements have not been finalized and uncertainty exists with respect to the additional measures being considered and the time frames for compliance.

The Paris Agreement

Canada and 195 other countries that are members of the United Nations Framework Convention on Climate Change met in Paris, France in December, 2015, and signed the Paris Agreement on climate change. The stated objective of the Paris Agreement is to hold "the increase in global average temperature to well below 2 degrees Celcius above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5 degrees Celcius". Signatory countries agreed to meet every five years to review their individual progress on GHG emissions reductions and to consider amendments to individual country targets, which are not legally binding. Canada is required to report and monitor its GHG emissions, though details of how such reporting and monitoring will take place have yet to be determined. Additionally, the Paris Agreement contemplates that, by 2020, the parties will develop a new market-based mechanism related to carbon trading. It is expected that this mechanism will largely be based on the best practices and lessons learned from the Kyoto Protocol. The government of Canada has stated that it will develop and announce a Canada-wide approach to implementing the Paris Agreement in early 2016.

Mandatory emissions reduction requirements may result in increased operating costs and capital expenditures for oil and gas producers. The Corporation is unable to predict the impact of emissions reduction legislation on the Corporation and it is possible that such legislation may have a material adverse effect on the Corporation's financial condition, results of operations and prospects.

Liability Management Programs

The Alberta government has developed a liability management program designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. The program generally involves an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Although the Corporation does not currently have to post security under the existing program, changes to the ratio of the Corporation's deemed assets to deemed liabilities or changes to the requirements of the liability management program may result in the requirement for security to be posted in the future. In addition, the liability management program may prevent or interfere with the Corporation's ability to acquire or dispose of assets as both the vendor and the purchaser of oil and natural gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets.

Other Risks

Volatility of Market Price of Securities

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. The market price of the Corporation's securities may be volatile, which may affect the ability of holders to sell such securities at an advantageous price. Market price fluctuations in the Corporation's securities may be due to the Corporation's operating results failing to meet the expectations of securities analysts or investors in any quarter, downward revision in securities analysts' estimates, governmental regulatory action, adverse change in general market conditions or economic trends, acquisitions, dispositions or other material public announcements by the Corporation or its competitors, along with a variety of additional factors, including, without limitation, those set forth under "Advisories – Forward-Looking Information". In addition, the market price for securities in the stock markets, including the TSX, has recently experienced significant price and trading fluctuations. These fluctuations have resulted in volatility in the market prices of securities that are often unrelated or disproportionate to changes in operating performance. Factors unrelated to the Corporation's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices or current perceptions of the oil and natural gas market. These broad market fluctuations may adversely affect the market prices of the Corporation's securities, and, as such, the price at which the Corporation's securities will trade cannot be accurately predicted.

Insurance

The Corporation obtains insurance in accordance with industry standards to address business risks. However, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, certain risks may not in all circumstances be insurable or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on its business, financial condition, results of operations or prospects.

Management of Growth

The Corporation may be subject to growth-related risks. including capacity constraints and pressure on its internal systems and controls. An inability of the Corporation to effectively deal with this growth could have a material adverse impact on its business, financial condition, results of operations and prospects. Management mitigates this risk by continually implementing appropriate procedures and policies for its size, upgrading its systems, training its employees and providing effective supervision and management of its staff.

Reliance on Key Personnel

The Corporation's success depends, in large measure, on certain key personnel. The loss of the services of such key personnel could have a material adverse effect on the Corporation. The Corporation does not have "key person" insurance in effect for management and the contributions of these individuals to the Corporation's immediate operations is of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Shareholders must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the Corporation's management.

Litigation

In the normal course of the Corporation's operations, it may become involved in, be named as a party to, or be the subject of various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation and as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations. Even if the Corporation prevails in any such legal proceeding, the proceeding could be costly and time-consuming and may divert the attention of management and key personnel from the Corporation's business operations. For specific disclosure of current legal proceedings, see *"Legal Proceedings and Regulatory Actions"* in the Annual Information Form for the financial year ended December 31, 2015.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Corporation's ownership claims. If a title defect does exist, this could result in the Corporation losing all or a portion of its right title and interest in and to the properties to which the title defects relate which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect the Corporation's title to the oil and natural gas properties the Corporation controls that could impair the Corporation's activities on them and result in a reduction of the revenue received by the Corporation.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights in portions of Western Canada. The Corporation is not aware that any claims have been made in respect of its properties or assets; however, the legal basis of an aboriginal land claim and aboriginal rights is a matter of considerable legal complexity and the impact of the assertion of such a claim, or the possible effect of a settlement of such claim, upon the Corporation cannot be predicted with any degree of certainty at this time. In addition, no assurance can be given that any recognition of aboriginal rights or claims whether by way of a negotiated settlement or by judicial pronouncement (or through the grant of an injunction prohibiting exploration or development pending resolution of any such claim) would not delay or even prevent the Corporation's exploration and development activities. If a claim arose and was successful, such claim may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation makes acquisitions and dispositions of properties and other assets in the ordinary course of business. Typically, once an opportunity is identified, a review of available information relating to the assets is conducted with most of the review effort being focused on the most significant assets. There is a risk that even a detailed review of records and assets may not necessarily reveal every existing or potential problem, nor will it permit the Corporation to become sufficiently familiar with the assets to fully assess their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the Corporation may assume certain environmental and other risk liabilities in connection with acquired assets. There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and actual future production rates and associated costs with respect to acquired properties, and actual results may vary substantially from those assumed in estimates.

Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses may require substantial management effort, time and resources, diverting management's focus from other strategic opportunities and operational matters.

Management continually assesses the value of the Corporation's assets and may dispose of non-core assets so that the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market, there is a risk that certain non-core assets could realize less than their carrying value in the Corporation's financial statements.

Internal Controls

Effective internal controls are necessary for the Corporation to provide reliable financial reports and to help prevent fraud. Although the Corporation undertakes a number of procedures in order to help ensure the reliability of its financial reports, including those imposed on it under Canadian securities laws, the Corporation cannot be certain that such measures will ensure that the Corporation will maintain adequate control over financial processes and reporting. Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm the Corporation's results of operations or cause it to fail to meet its reporting obligations. If the Corporation or its independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in the Corporation's financial statements and harm the trading price of the Corporation's securities.

Income Taxes

The Corporation files all required income tax returns and believes that it is in full compliance with the provisions of the *Income Tax Act* (Canada) and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Corporation, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects the Corporation. Furthermore, tax authorities having jurisdiction over the Corporation may disagree with how the Corporation calculates its income for tax purposes or could change administrative practices to the Corporation's detriment.

Breaches of Confidentiality

While discussing potential business relationships or other transactions with third parties, the Corporation may disclose confidential information relating to the business, operations or affairs of the Corporation. Although confidentiality agreements are signed by third parties prior to the disclosure of confidential information, a breach could put the Corporation at competitive risk and may cause significant damage to its business. The harm to the Corporation's business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, the Corporation will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Dilution

The Corporation may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Corporation which may be dilutive.

Forward-Looking Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate. Additional information on the risks, assumptions and uncertainties regarding forward-looking information are found under the heading *"Advisories – Forward-Looking Information"* in this MD&A.

NON-GAAP MEASURES

This MD&A uses "funds flow", "funds flow from operations", "funds flow per common share", "adjusted net income to common shareholders", "adjusted net loss to common shareholders", "netback", "operating netback", "estimated operating netback", "operating margin", "total cash costs" and "total debt". These measures do not have standardized meanings prescribed by GAAP and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. Management believes that these non-GAAP measures assist management and investors in assessing Birchcliff's profitability, efficiency, liquidity and overall performance. Each of these measures is discussed in further detail below.

"Funds flow" and "funds flow from operations" denote cash flow from operating activities before the effects of decommissioning expenditures and changes in non-cash working capital. "Funds flow per common share" denotes funds flow divided by the basic or diluted weighted average number of common shares outstanding for the period. Management believes that funds flow, funds flow from operations and funds flow per common share assists management and investors in assessing Birchcliff's profitability, as well as its ability to generate the cash necessary to fund future growth through capital investments, pay dividends on preferred shares and repay debt. The following table provides a reconciliation of cash flow from operating activities, as determined in accordance with IFRS, to funds flow from operations:

	Three months ended December 31,		**Twelve months ended December 31,**	
($000s)	**2015**	**2014**	**2015**	**2014**
Cash flow from operating activities	44,786	77,513	148,797	309,901
Adjustments:				
Decommissioning expenditures	247	263	893	1,663
Change in non-cash working capital	(11,336)	(16,059)	11,066	(11,066)
Funds flow from operations	**33,697**	**61,717**	**160,756**	**300,498**

"Adjusted net income (loss) to common shareholders" is calculated as net income (loss) to common shareholders, as determined in accordance with IFRS, after excluding: (i) a one-time, non-cash deferred income tax expense in the amount of $7.8 million that was recorded in the second quarter of 2015 as a result of the 2015 change in the Alberta corporate income tax rate from 10% to 12%; and (ii) a one-time, non-cash deferred income tax expense in the amount of $10.2 million that was recorded in the fourth quarter of 2015 as a result of the denial by the Trial Court of Birchcliff's appeal of the Reassessment in connection with the tax pools available to Veracel. See "*Income Taxes*" in this MD&A for further information. Management has excluded these non-operational, deferred income tax items from adjusted net income to common shareholders as management believes that excluding such items better reflects the results generated by Birchcliff's principal business activities. The following table provides a reconciliation of net income (loss) to common shareholders, as determined in accordance with IFRS, to adjusted net income (loss) to common shareholders:

	Three months ended December 31,		Twelve months ended December 31,	
($000s)	**2015**	**2014**	**2015**	**2014**
Net income (loss) to common shareholders	(10,322)	16,053	(16,160)	110,304
Adjustments:				
Denial by the Trial Court of the Reassessment Appeal	10,208	-	10,208	-
Change in Alberta corporate income tax rates	-	-	7,759	-
Adjusted net income (loss) to common shareholders	**(114)**	**16,053**	**1,807**	**110,304**

"Netback" and "operating netback" denote petroleum and natural gas revenue less royalties, less operating expenses and less transportation and marketing expenses. "Estimated operating netback" of the PCS Gas Plant (and the components thereof) is based upon certain cost allocations and accruals directly attributable to the PCS Gas Plant and related wells and infrastructure on a production month basis. All netbacks are calculated on a per unit basis. Management believes that netback, operating netback and estimated operating netback assists management and investors in assessing Birchcliff's profitability and its operating results on a per unit basis to better analyze its performance against prior periods on a comparable basis.

"Operating margin" for the PCS Gas Plant is calculated by dividing the estimated operating netback for the period by the petroleum and natural gas revenue for the period. Management believes that operating margin assists management and investors in assessing the profitability and efficiency of the PCS Gas Plant and Birchcliff's ability to generate operating cash flows (equal to petroleum and natural gas revenue less royalties, less operating expenses and less transportation and marketing expenses).

"Total cash costs" are comprised of royalty, operating, transportation and marketing, general and administrative and interest expenses. Total cash costs are calculated on a per boe basis. Management believes that total cash costs assists management and investors in assessing Birchcliff's efficiency and overall cash cost structure.

"Total debt" is calculated as the revolving term credit facilities plus non-revolving term credit facilities plus working capital deficit. Management believes that total debt assists management and investors in assessing Birchcliff's liquidity. The following table provides a reconciliation of the non-revolving term credit facilities plus the revolving term credit facilities, as determined in accordance with IFRS, to total debt:

As at, *($000s)*	**December 31, 2015**	**December 31, 2014**
Non-revolving term credit facilities	-	129,476
Revolving term credit facilities	622,074	339,557
Long-term bank debt	622,074	469,033
Working capital deficit	21,538	76,712
Total debt	**643,612**	**545,745**

PRESENTATION OF OIL AND GAS RESERVES

Deloitte, independent qualified reserves evaluators of Calgary, Alberta, prepared the 2015 Reserves Evaluation. Reserves estimates stated herein are effective as at December 31, 2015 and are extracted from the 2015 Reserves Evaluation. There are numerous uncertainties inherent in estimating the quantities of reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserves estimates of Birchcliff's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein and variances could be material.

Reserves Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable.

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

- "**Proved reserves**" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
- "**Probable reserves**" are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.
- "**Possible reserves**" are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

Development and Production Status of Reserves

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

- "**Developed reserves**" are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.
    - "**Developed producing reserves**" are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
    - "**Developed non-producing reserves**" are those reserves that either have not been on production, or have previously been on production but are shut-in and the date of resumption of production is unknown.
- "**Undeveloped reserves**" are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (proved, probable, possible) to which they are assigned.

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

Interest in Reserves, Production, Wells and Properties

"**Gross**" means:

(a) in relation to Birchcliff's interest in production or reserves, Birchcliff's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of Birchcliff;

(b) in relation to wells, the total number of wells in which Birchcliff has an interest; and

(c) in relation to properties, the total area of properties in which Birchcliff has an interest.

"**Net**" means:

(a) in relation to Birchcliff's interest in production or reserves, Birchcliff's working interest (operating or non-operating) share after deduction of royalty obligations, plus Birchcliff's royalty interests in production or reserves;

(b) in relation to Birchcliff's interest in wells, the number of wells obtained by aggregating Birchcliff's working interest in each of its gross wells; and

(c) in relation to Birchcliff's interest in a property, the total area in which Birchcliff has an interest multiplied by the working interest owned by Birchcliff.

Forecast Prices and Costs

"**Forecast prices and costs**" means future prices and costs that are:

(a) generally accepted as being a reasonable outlook of the future;

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which Birchcliff is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

Gross Volumes of Reserves

Unless otherwise indicated, all volumes of Birchcliff's reserves presented herein are on a "gross" basis.

ADVISORIES

Boe Conversions

Boe amounts have been calculated by using the conversion ratio of 6 Mcf of natural gas to 1 bbl of oil. Boe amounts may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Mcfe Conversions

Thousands of cubic feet of gas equivalent ("**Mcfe**") amounts have been calculated by using the conversion ratio of 1 bbl of oil to 6 Mcf of natural gas. Mcfe amounts may be misleading, particularly if used in isolation. A conversion ratio of 1 bbl to 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

MMbtu Pricing Conversions

$1.00 per MMbtu equals $1.00 per Mcf based on a standard heat value Mcf.

Operating Costs

References in this MD&A to "operating costs" exclude transportation and marketing costs.

Forward-Looking Information

This MD&A contains forward-looking information within the meaning of applicable Canadian securities laws. Forward-looking information relates to future events or future performance and is based upon Birchcliff's current internal expectations, estimates, projections, assumptions and beliefs. All information other than historical fact is forward-looking information. Information relating to reserves is forward-looking as it involves the implied assessment, based on certain estimates and assumptions, that the reserves exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future. Words such as "plan", "expect", "project", "intend", "believe", "anticipate", "estimate", "estimated", "forecast", "may", "will", "potential", "proposed" and other similar words that convey certain events or conditions "may" or "will" occur are intended to identify forward-looking information.

In particular, this MD&A contains forward-looking information relating to: Birchcliff's plans and other aspects of its anticipated future operations, management focus, strategies and priorities; the 2016 Revised Capital Budget, including planned capital expenditures, the objectives of and anticipated results from the 2016 Revised Capital Budget and Birchcliff's expectation that the 2016 Revised Capital Budget will be less than expected funds flow for 2016; proposed expansions of the PCS Gas Plant; Birchcliff's production guidance for 2016, including its estimates of its annual average production for 2016 and 2016 annual average production growth; the Corporation's estimated income tax pools and management's expectation that future taxable income will be available to utilize the accumulated tax pools; statements with respect to the Reassessment, including Birchcliff's expectation that its appeal to the Court of Appeal will be heard in 2016 and management's belief that its tax position is supportable; the Corporation's liquidity, including statements that should commodity prices deteriorate materially, the Corporation may adjust the 2016 Revised Capital Budget and/or consider the potential sale of its non-core assets, management's expectation that the Corporation will be able to meet its future obligations as they become due, management's belief that its funds flow from operations and available credit facilities will be sufficient to fund the Corporation's planned growth and to meet its working capital requirements in 2016 and the Corporation's expectation that counterparties will be able to meet their financial obligations; management's ability to manage capital expenditures and debt levels and its ability to respond to changing commodity prices by increasing or decreasing its capital spending programs; the Corporation's expectation that the aggregate borrowing base of the Credit Facilities will remain at $800 million during the normal credit review in 2016; estimates of contractual and decommissioning obligations; Birchcliff's financial flexibility; estimates of reserves; and future development capital.

The forward-looking information contained in this MD&A is based upon certain expectations and assumptions, including: prevailing and future commodity prices, currency exchange rates, interest rates, inflation rates, royalty rates and tax rates; the state of the economy and the exploration and production business; the economic and political environment in which Birchcliff operates; the regulatory framework regarding royalties, taxes and environmental laws; anticipated timing and results of capital expenditures; the sufficiency of budgeted capital expenditures to carry out planned operations; results of operations; operating, transportation, marketing and general and administrative costs; the performance of existing and future wells, well production rates and well decline rates; well drainage areas; success rates for future drilling; reserves and resource volumes and Birchcliff's ability to replace and expand oil and gas reserves through acquisition, development or exploration; the impact of competition; the availability of, demand for and cost of labour, services and materials; Birchcliff's ability to access capital; the ability to obtain financing on acceptable terms; the ability to obtain any necessary regulatory approvals in a timely manner; the ability of Birchcliff to secure adequate transportation for its products; and Birchcliff's ability to market oil and gas. In addition, Birchcliff has made the following key assumptions with respect to certain forward-looking information contained in this MD&A:

- With respect to statements regarding the 2016 Revised Capital Budget, including Birchcliff's expectation that the 2016 Revised Capital Budget will be less than expected funds flow for 2016, the key assumption is that Birchcliff realizes the annual average production target of 40,000 to 41,000 boe per day and the commodity prices upon which the 2016 Revised Capital Budget is based, being an expected annual average WTI price of US$40.00 per barrel of oil and an AECO price of CDN$2.50 per GJ of natural gas during 2016 with an exchange rate of $CDN/$US of 1.40. Birchcliff will continue to monitor economic conditions and commodity prices and, where deemed prudent, will adjust the 2016 Revised Capital Budget to respond to changes in commodity prices and other material changes in the assumptions underlying the 2016 Revised Capital Budget.
- With respect to statements regarding proposed expansions of the PCS Gas Plant, the key assumptions are that: future drilling is successful; there is sufficient labour, services and equipment available; Birchcliff will have access to sufficient capital to fund those projects; and commodity prices and general economic conditions warrant proceeding with the construction of such facilities and the drilling of associated wells.
- With respect to estimates as to Birchcliff's annual average production for 2016 and 2016 annual average production growth, the key assumptions are that: the 2016 Revised Capital Budget will be carried out as currently contemplated; no unexpected outages occur in the infrastructure that Birchcliff relies on to produce its wells and that any transportation service curtailments or unplanned outages that occur will be short in duration or otherwise insignificant; the construction of new infrastructure meets timing

expectations; existing wells continue to meet production expectations; and future wells scheduled to come on production meet timing, production and capital expenditure expectations.

- With respect to statements regarding management's belief that its tax position with respect to the Veracel Transaction is supportable, the key assumption is the validity of Birchcliff's interpretation of how the *Income Tax Act* (Canada) applies to the Veracel Transaction.
- With respect to statements that the Credit Facilities will remain at $800 million during Birchcliff's normal credit review in May 2016, the key assumptions are that: commodity prices do not further deteriorate from current levels; the criteria applied by Birchcliff's syndicate of bank lenders remains consistent with historical practice; and the bank syndicate's forecast of commodity prices are consistent with the forecast used by Deloitte in the preparation of the 2015 Reserves Evaluation.
- With respect to estimates of reserves, the key assumption is the validity of the data used by Deloitte in their independent evaluations, which includes technical information and forecast commodity prices.

Undue reliance should not be placed on forward-looking information, as there can be no assurance that the plans, intentions, expectations or assumptions upon which they are based will occur. Although Birchcliff believes that the expectations and assumptions reflected in the forward-looking information are reasonable, there can be no assurance that such expectations will prove to be correct. As a consequence, actual results may differ materially from those anticipated.

Forward-looking information necessarily involves both known and unknown risks and uncertainties that could cause actual results to differ materially from those anticipated, including, but not limited to: general economic, market and business conditions which will, among other things, impact the demand for and market prices of Birchcliff's products and Birchcliff's access to capital; volatility of crude oil and natural gas prices; fluctuations in currency and interest rates; operational risks and liabilities inherent in oil and natural gas operations; uncertainties associated with estimating oil and natural gas reserves and resources; the accuracy of oil and natural gas reserves estimates and estimated production levels as they are affected by exploration and development drilling and estimated decline rates; geological, technical, drilling, construction and processing problems; uncertainty of geological and technical data; changes in tax laws, crown royalty rates, environmental laws and incentive programs relating to the oil and natural gas industry and other actions by government authorities, including changes to the royalty and carbon tax regimes and the imposition or reassessment of taxes; the cost of compliance with current and future environmental laws; political uncertainty and uncertainty associated with government policy changes; uncertainties and risks associated with pipeline restrictions and outages to third-party infrastructure that could cause disruptions to production; the inability to secure adequate production transportation for Birchcliff's products; the occurrence of unexpected events such as fires, equipment failures and other similar events affecting Birchcliff or other parties whose operations or assets directly or indirectly affect Birchcliff; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; stock market volatility; loss of market demand; environmental risks, claims and liabilities; incorrect assessments of the value of acquisitions and exploration and development programs; shortages in equipment and skilled personnel; uncertainties associated with the outcome of litigation or other proceedings involving Birchcliff; competition for, among other things, capital, acquisitions of reserves, undeveloped lands, equipment and skilled personnel; and uncertainties associated with credit facilities and counterparty credit risk.

The foregoing list of risk factors is not exhaustive. Additional information on these and other risk factors that could affect operations or financial results are included in Birchcliff's most recent Annual Information Form and in other reports filed with Canadian securities regulatory authorities. Forward-looking information is based on estimates and opinions of management at the time the information is presented. Birchcliff is not under any duty to update the forward-looking information after the date of this MD&A to conform such information to actual results or to changes in Birchcliff's plans or expectations, except as otherwise required by applicable securities laws.

Any "financial outlook" contained in this MD&A, as such term is defined by applicable securities laws, is provided for the purpose of providing information about management's current expectations and plans relating to the future. Readers are cautioned that reliance on such information may not be appropriate for other purposes.

MANAGEMENT'S REPORT

To the Shareholders of Birchcliff Energy Ltd.

The annual financial statements of Birchcliff Energy Ltd. for the year ended December 31, 2015 were prepared by management within the acceptable limits of materiality and are in accordance with International Financial Reporting Standards. Management is responsible for ensuring that the financial and operating information presented in the annual report is consistent with that shown in the financial statements.

The financial statements have been prepared by management in accordance with the accounting policies as described in the notes to the financial statements. Timely release of financial information sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. When necessary, such estimates are based on informed judgments made by management.

Management has designed and maintains an appropriate system of internal controls to provide reasonable assurance that all assets are safeguarded and financial records properly maintained to facilitate the preparation of financial statements for reporting purposes.

KPMG LLP, an independent firm of Chartered Professional Accountants appointed by shareholders, have conducted an examination of the corporate and accounting records in order to express their opinion on the financial statements.

The Audit Committee, consisting of non-management directors, has met with representatives of KPMG LLP and management in order to determine if management has fulfilled its responsibilities in the preparation of the financial statements. The Board of Directors has approved the financial statements on the recommendation of the Audit Committee.

Respectfully,

(signed) *"Bruno P. Geremia"*

Bruno P. Geremia,

Vice-President and Chief Financial Officer

(signed) *"A. Jeffery Tonken"*

A. Jeffery Tonken,

President and Chief Executive Officer

Calgary, Canada
March 16, 2016

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Birchcliff Energy Ltd.

We have audited the accompanying financial statements of Birchcliff Energy Ltd., which comprise the statements of financial position as at December 31, 2015 and December 31, 2014 and the statements of net income (loss) and comprehensive income (loss), changes in shareholders' equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

MANAGEMENT'S RESPONSIBILITY FOR THE FINANCIAL STATEMENTS

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

AUDITORS' RESPONSIBILITY

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

OPINION

In our opinion, the financial statements present fairly, in all material respects, the financial position of Birchcliff Energy Ltd. as at December 31, 2015 and December 31, 2014, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

(signed) *"KPMG LLP"*

Chartered Professional Accountants

March 16, 2016
Calgary, Canada

BIRCHCLIFF ENERGY LTD.
STATEMENTS OF FINANCIAL POSITION

(Expressed in thousands of Canadian dollars)

As at December 31,	2015	2014
ASSETS		
Current assets:		
Cash	57	54
Accounts receivable *(Note 17)*	23,410	34,931
Prepaid expenses and deposits	2,579	1,612
	26,046	36,597
Non-current assets:		
Exploration and evaluation *(Note 5)*	247	2,235
Petroleum and natural gas properties and equipment *(Note 6)*	1,999,080	1,879,848
	1,999,327	1,882,083
Total assets	**2,025,373**	**1,918,680**
LIABILITIES		
Current liabilities:		
Accounts payable and accrued liabilities *(Note 17)*	47,584	113,309
	47,584	113,309
Non-current liabilities:		
Revolving term credit facilities *(Note 7)*	622,074	339,557
Non-revolving term credit facilities *(Note 8)*	-	129,476
Decommissioning obligations *(Note 9)*	92,504	85,824
Deferred income taxes *(Note 10)*	116,171	95,941
Capital securities *(Note 11)*	48,606	48,296
	879,355	699,094
Total liabilities	**926,939**	**812,403**
SHAREHOLDERS' EQUITY		
Share capital *(Note 11)*		
Common shares	783,481	782,671
Preferred shares *(perpetual)*	41,434	41,434
Contributed surplus	60,625	53,118
Retained earnings	212,894	229,054
	1,098,434	1,106,277
Total shareholders' equity and liabilities	**2,025,373**	**1,918,680**

Commitments *(Note 18)*

The accompanying notes are an integral part of these financial statements.

Approved by the Board

(signed) *"Larry A. Shaw"*
Larry A. Shaw
Director

(signed) *"A. Jeffery Tonken"*
A. Jeffery Tonken
Director

BIRCHCLIFF ENERGY LTD.
STATEMENTS OF NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

(Expressed in thousands of Canadian dollars, except per share information)

Years Ended December 31,	**2015**	**2014**
REVENUE		
Petroleum and natural gas sales	317,304	472,888
Royalties	(11,548)	(36,803)
Net revenue from oil and natural gas sales	305,756	436,085
Realized gain on financial instruments *(Note 17)*	-	291
Unrealized gain on financial instruments *(Note 17)*	-	379
	305,756	436,755
EXPENSES		
Operating *(Note 12)*	64,511	64,217
Transportation and marketing	34,804	29,989
Administrative, net *(Note 13)*	26,030	27,136
Depletion and depreciation *(Note 6)*	147,163	136,278
Finance *(Note 14)*	26,015	22,688
Dividends on capital securities *(Note 11)*	3,500	3,500
(Gain) on sale of assets *(Note 6)*	(7,339)	(3,171)
	294,684	280,637
INCOME BEFORE TAXES	11,072	156,118
Income tax expense *(Note 10)*	23,232	41,814
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)	**(12,160)**	**114,304**
Net income (loss) per common share *(Note 11)*		
Basic	($0.11)	$0.75
Diluted	($0.11)	$0.72

The accompanying notes are an integral part of these financial statements.

BIRCHCLIFF ENERGY LTD.
STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(Expressed in thousands of Canadian dollars)

	Share Capital				
	Common Shares	**Preferred Shares**	**Contributed Surplus**	**Retained Earnings**	**Total**
As at December 31, 2013	694,183	41,434	60,119	118,750	914,486
Dividends on perpetual preferred shares *(Note 11)*	-	-	-	(4,000)	(4,000)
Exercise of stock options *(Notes 11 and 15)*	31,705	-	(9,885)	-	21,820
Exercise of preferred warrants *(Note 11)*	56,783	-	(7,093)	-	49,690
Stock-based compensation *(Notes 13 and 15)*	-	-	9,977	-	9,977
Net income and comprehensive income	-	-	-	114,304	114,304
As at December 31, 2014	782,671	41,434	53,118	229,054	1,106,277
Dividends on perpetual preferred shares *(Note 11)*	-	-	-	(4,000)	(4,000)
Exercise of stock options *(Notes 11 and 15)*	810	-	(225)	-	585
Stock-based compensation *(Notes 13 and 15)*	-	-	7,732	-	7,732
Net loss and comprehensive loss	-	-	-	(12,160)	(12,160)
As at December 31, 2015	**783,481**	**41,434**	**60,625**	**212,894**	**1,098,434**

The accompanying notes are an integral part of these financial statements.

BIRCHCLIFF ENERGY LTD.
STATEMENTS OF CASH FLOWS

(Expressed in thousands of Canadian dollars)

Years ended December 31,	**2015**	**2014**
Cash provided by (used in):		
OPERATING		
Net income (loss) and comprehensive income (loss)	(12,160)	114,304
Adjustments for items not affecting operating cash:		
Unrealized (gain) on financial instruments	-	(379)
Depletion and depreciation	147,163	136,278
Stock-based compensation	3,206	4,796
Finance	26,015	22,688
(Gain) on sale of assets	(7,339)	(3,171)
Income taxes	23,232	41,814
Interest paid *(Note 14)*	(22,861)	(19,332)
Dividends on capital securities	3,500	3,500
Decommissioning expenditures *(Note 9)*	(893)	(1,663)
Changes in non-cash working capital *(Note 19)*	(11,066)	11,066
	148,797	309,901
FINANCING		
Exercise of stock options	585	21,820
Exercise of preferred warrants	-	49,690
Financing fees paid on credit facilities	(940)	(1,018)
Dividends on perpetual preferred shares *(Note 11)*	(4,000)	(4,000)
Dividends on capital securities *(Note 11)*	(3,500)	(3,500)
Net change in non-revolving term credit facilities	(129,970)	703
Net change in revolving term credit facilities	283,340	73,362
	145,515	137,057
INVESTING		
Petroleum and natural gas properties and equipment	(258,041)	(397,976)
Exploration and evaluation assets	(113)	(102)
Acquisition of petroleum and natural gas properties	-	(56,677)
Sale of petroleum and natural gas properties and equipment	10,887	3,692
Sale of exploration and evaluation assets	60	131
Changes in non-cash working capital *(Note 19)*	(47,102)	3,932
	(294,309)	(447,000)
NET CHANGE IN CASH	3	(42)
CASH, BEGINNING OF YEAR	54	96
CASH, END OF YEAR	**57**	**54**

The accompanying notes are an integral part of these financial statements.

BIRCHCLIFF ENERGY LTD.
NOTES TO THE FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2015 AND 2014

(Expressed In Thousands Of Canadian Dollars, Unless Otherwise Stated)

1. NATURE OF OPERATIONS

Birchcliff Energy Ltd. ("**Birchcliff**" or the "**Corporation**") is domiciled and incorporated in Canada. Birchcliff is engaged in the exploration for and the development, production and acquisition of petroleum and natural gas reserves in Western Canada. The Corporation's financial year end is December 31. The address of the Corporation's registered office is 500, 630 – 4th Avenue S.W., Calgary, Alberta, Canada T2P 0J9. Birchcliff's common shares, Series A Preferred Shares and Series C Preferred Shares are listed for trading on the Toronto Stock Exchange under the symbols "**BIR**", "**BIR.PR.A**" and "**BIR.PR.C**", respectively.

These financial statements were approved and authorized for issuance by the Board of Directors on March 16, 2016.

2. BASIS OF PREPARATION

These financial statements present Birchcliff's financial results of operations and financial position under International Financial Reporting Standards ("**IFRS**") as issued by IASB as at and for the years ended December 31, 2015 and December 31, 2014. The financial statements have been prepared in accordance with IFRS accounting policies and methods of computation as set forth in Note 3.

Operating, transportation and marketing expenses in profit or loss are presented as a combination of function and nature in conformity with industry practices. Depletion and depreciation, finance expenses, dividends on capital securities and gain on sale of assets are presented in a separate line by their nature, while net administrative expenses are presented on a functional basis. Significant expenses such as salaries and benefits and stock-based compensation are presented by their nature in the notes to the financial statements.

Birchcliff's financial statements are prepared on a historical cost basis, except for certain financial and non-financial assets and liabilities which have been measured at fair value. The Corporation's financial statements include the accounts of Birchcliff only and are expressed in Canadian dollars, unless otherwise stated. There are no subsidiary companies.

3. SIGNIFICANT ACCOUNTING POLICIES

(a) Revenue Recognition

Revenue from the sale of petroleum and natural gas is recognized when volumes are delivered and title passes to an external party at contractual delivery points and are recorded gross of transportation charges incurred by the Corporation. The costs associated with the delivery, including transportation and production-based royalty expenses, are recognized in the same period in which the related revenue is earned and recorded.

(b) Cash and Cash Equivalents

Cash may consist of cash on hand, deposits and term investments held with a financial institution, with an original maturity of three months or less. Restricted cash is not considered part of cash and cash equivalents.

(c) Jointly Owned Assets

Certain activities of the Corporation are conducted jointly with others where the participants have a direct ownership interest in the related assets. Accordingly, the accounts of Birchcliff reflect only its working interest share of revenues, expenses and capital expenditures related to these jointly owned assets. The relationship with jointly owned asset partners have been referred to as joint venture in the remainder of the financial statements as this is common terminology in the Canadian oil and natural gas industry.

(d) Exploration and Evaluation Assets

Costs incurred prior to obtaining the right to explore a mineral resource are recognized as an expense in the period incurred.

Intangible exploration and evaluation expenditures are initially capitalized and may include mineral license acquisitions, geological and geophysical evaluations, technical studies, exploration drilling and testing and other directly attributable administrative costs. Tangible assets acquired which are consumed in developing an intangible exploration asset are recorded as part of the cost of the exploration asset. These costs are accumulated in cost centres by exploration area pending the determination of technical feasibility and commercial viability.

The technical feasibility and commercial viability of extracting a mineral resource in an exploration area is considered to be determinable when economic quantities of proven reserves are determined to exist. A review of each exploration project by area is carried out at each reporting date to ascertain whether such reserves have been discovered. Upon determination of commercial proven reserves, associated exploration costs are transferred from exploration and evaluation to developing and producing petroleum and natural gas properties and equipment as reported on the statements of financial position. Exploration and evaluation assets are reviewed for impairment prior to any such transfer. Assets classified as exploration and evaluation are not subject to depletion and depreciation until they are reclassified to petroleum and natural gas properties and equipment.

(e) Petroleum and Natural Gas Properties and Equipment

(i) Recognition and measurement

Petroleum and natural gas properties and equipment are measured at cost less accumulated depletion and depreciation and accumulated impairment losses, if any.

Petroleum and natural gas properties and equipment consists of the purchase price and costs directly attributable to bringing the asset to the location and condition necessary for its intended use. Petroleum and natural gas assets include developing and producing interests such as mineral lease acquisitions, geological and geophysical costs, facility and production equipment and associated turnarounds, other directly attributable administrative costs and the initial estimate of the costs of dismantling and removing an asset and restoring the site on which it was located.

(ii) Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability are recognized as developing and producing petroleum and natural gas interests when they increase the future economic benefits embodied in the specific asset to which they relate. Such capitalized petroleum and natural gas interests generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves, and are accumulated on an area basis. The cost of day-to-day servicing of an item of petroleum and natural gas properties and equipment is expensed in profit or loss as incurred.

Petroleum and natural gas properties and equipment are de-recognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising from the disposal of an asset, determined as the difference between the net disposal proceeds and the carrying amount of the asset, is recognized in profit or loss.

(iii) Asset exchanges

For exchanges or parts of exchanges that involve only exploration and evaluation assets, the exchange is accounted for at carrying value. Exchanges of development and production assets are measured at fair value, unless the exchange transaction lacks commercial substance or the fair value of the assets given up or the assets received cannot be reliably estimated. The cost of the acquired asset is measured at the fair value of the asset given up, unless the fair value of the asset received is more reliable. Where fair value is not used, the cost of the acquired asset is measured at the carrying amount of the asset given up. Any gain or loss on the de-recognition of the asset given up is recognized in profit and loss.

(iv) Depletion and depreciation

The net carrying value of developing and producing petroleum and natural gas assets, net of estimated residual value, is depleted on an area basis using the unit of production method. This depletion calculation includes actual production in the period and total estimated proved plus probable reserves attributable to the assets being depreciated, taking into account total capitalized costs plus estimated future development costs necessary to bring those reserves into production. Relative volumes of reserves and production (before royalties) are converted at the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of oil. These estimates are reviewed by the Corporation's independent reserves evaluator at least annually.

Capitalized plant turnaround costs are depreciated on a straight-line basis over the estimated time until the next turnaround is completed. Corporate assets, which include office furniture and equipment, software, computer equipment and leasehold improvements, are depreciated on a straight-line basis over the estimated useful lives of the assets, which are estimated to be four years.

When significant parts of property and equipment, including petroleum and natural gas interests, have different useful lives, they are accounted for as separate items (major components). Depreciation methods, useful lives and residual values for petroleum and natural gas properties and equipment are reviewed at each reporting date.

(f) Provisions

Provisions are recognized when the Corporation has a present obligation (legal or constructive), as a result of a past event, if it is probable that the Corporation will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation.

The amount recognized as a provision is the best estimate of the consideration required to settle the present obligation at the end of the reporting period, taking into account the risks and uncertainties surrounding the obligation. When a provision is measured using the cash flows estimated to settle the present obligation, its carrying amount is the present value of those cash flows (where the effect of the time value of money is significant).

When some or all of the economic benefits required to settle a provision are expected to be recovered from a third party, a receivable is recognized as an asset if it is virtually certain that reimbursement will be received and the amount of the receivable can be measured reliably.

Provisions are not recognized for future operating losses.

(g) Decommissioning Obligations

The Corporation's activities give rise to dismantling, restoration and site disturbance remediation activities. Costs related to abandonment activities are estimated by management in consultation with the Corporation's independent reserves evaluators based on risk-adjusted current costs which take into consideration current technology in accordance with existing legislation and industry practices.

Decommissioning obligations are measured at the present value of the best estimate of expenditures required to settle the present obligations at the reporting date. When the best estimate of the liability is initially measured, the estimated cost, discounted using a pre-tax risk-free discount rate, is capitalized by increasing the carrying amount of the related petroleum and natural gas properties and equipment. The increase in the provision due to the passage of time, which is referred to as accretion, is recognized as a finance expense. Actual costs incurred upon settlement of the liability are charged against the obligation to the extent that the obligation was previously established. The carrying amount capitalized in petroleum and natural gas properties and equipment is depleted in accordance with the Corporation's depletion and depreciation policy. The Corporation reviews the obligation at each reporting date and revisions to the estimated timing of cash flows, discount rates and estimated costs result in an increase or decrease to the obligations and the related petroleum and natural gas properties and equipment. Any difference between the actual costs incurred upon settlement of the obligation and the recorded liability is recognized as a gain or loss in profit or loss.

(h) Share-Based Payments

Equity-settled share-based awards granted by the Corporation include stock options and performance warrants granted to officers, directors and employees. The fair value determined at the grant date of an award is expensed on a graded basis over the vesting period of each respective tranche of an award with a corresponding increase to contributed surplus. In calculating the expense of share-based awards, the Corporation revises its estimate of the number of equity instruments expected to vest by applying an estimated forfeiture rate for each vesting tranche and subsequently revising this estimate throughout the vesting period, as necessary, with a final adjustment to reflect the actual number of awards that vest. Upon the exercise of share-based awards, consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase to share capital. In the event that vested share-based awards expire without being exercised, previously recognized compensation costs associated with such awards are not reversed. The expense related to share-based awards is included within administrative expenses in profit or loss.

The fair value of equity-settled share-based awards is measured using the Black-Scholes option-pricing model taking into account the terms and conditions upon which the awards were granted. Measurement inputs as at the grant date include: share price, exercise price, expected volatility (based on weighted average historical traded daily volatility), 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) applicable to the term of the award.

A portion of share-based compensation expense directly attributable to the exploration and development of the Corporation's assets are capitalized.

(i) Finance Income and Expenses

Finance expenses include interest expense on borrowings, accretion of the discount on decommissioning obligations, amortization of deferred charges and impairment losses (if any) recognized on financial assets. Interest income is recognized as it is earned.

(j) Borrowing Costs

Borrowing costs incurred for the acquisition, construction or production of qualifying assets are capitalized during the period of time that is required to complete and prepare the asset for its intended use or sale. Assets are considered to be qualifying assets when this period of time is substantial. The capitalization rate, used to determine the amount of borrowing costs to be capitalized, is the weighted average interest rate applicable to the Corporation's outstanding borrowings during the period. All other borrowing costs are charged to profit or loss using the effective interest method.

(k) Financial Instruments

(i) Non-derivative financial instruments

Non-derivative financial instruments are comprised of cash, accounts receivable, accounts payable and accrued liabilities, outstanding credit facilities and capital securities. Non-derivative financial instruments are recognized initially at fair value plus any directly attributable transaction costs. Subsequent to initial recognition, non-derivative financial instruments are measured based on their classification. The Corporation has made the following classifications:

- Cash and accounts receivable are classified as loans and receivables and are measured at amortized cost using the effective interest method. Typically, the fair value of these balances approximates their carrying value due to their short term to maturity.

- Accounts payable and accrued liabilities and outstanding credit facilities are classified as other financial liabilities and are measured at amortized cost using the effective interest method. Due to the short term nature of accounts payable and accrued liabilities, their carrying values approximate their fair values. The Corporation's outstanding credit facilities bear interest at a floating rate and accordingly the fair market value approximates the carrying value before the carrying value is reduced for any remaining unamortized costs. The interest costs and financing fees associated with the Corporation's credit facilities have been deferred and netted against the amounts drawn, and are being amortized to profit or loss using the effective interest method over the applicable term.
- The proceeds from the issuance of Series C Preferred Shares, which are presented as "capital securities" on the statement of financial position, are classified as "other financial liabilities" under IFRS. The incremental costs directly attributable to the issuance of Series C Preferred Shares are initially recognized as a reduction to capital securities and subsequently amortized to profit and loss, using the effective interest rate method, as a finance expense. Dividend distributions on capital securities are recorded as an expense directly to profit and loss and presented as a financing activity on the statements of cash flows.

(ii) Derivative financial instruments

Derivatives may be used by the Corporation to manage economic exposure to market risk relating to commodity prices. Birchcliff's policy is not to utilize derivative financial instruments for speculative purposes. The Corporation does not designate its financial derivative contracts as hedges, and as such does not apply hedge accounting. As a result, financial derivatives are classified at fair value through profit or loss and are recorded on the statements of financial position at fair value.

The fair value of commodity price risk management contracts is determined by discounting the difference between the contracted prices and published forward price curves as at the balance sheet date, using the remaining contracted oil and natural gas volumes and a risk-free interest rate (based on published government rates). The fair value of options and costless collars is based on option models that use published information with respect to volatility, prices and interest rates.

The Corporation accounts for any forward physical delivery sales contracts, which were entered into and continue to be held for the purpose of receipt or delivery of non-financial items, in accordance with its expected purchase, sale or usage requirements as executory contracts. As such, these contracts are not considered to be derivative financial instruments and have not been recorded at fair value on the statements of financial position. Settlements on physical sales contracts are recognized in petroleum and natural gas sales in profit and loss.

(iii) Share capital

Common shares and perpetual preferred shares are classified as equity. Incremental costs directly attributable to the issuance of shares are recognized as a reduction in share capital, net of any tax effects.

(l) Impairment

(i) Impairment of financial assets

Financial assets are assessed at each reporting date to determine whether there is any objective evidence that they are impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset. An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

Impairment losses are recognized in profit or loss. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized.

(ii) Impairment of non-financial assets

The Corporation's petroleum and natural gas properties and equipment are grouped into Cash Generating Units ("**CGUs**") for the purpose of assessing impairment. A CGU represents the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets.

CGUs are reviewed at each reporting date for indicators of potential impairment. Such indicators may include, but are not limited to, changes in the Corporation's business plan, deterioration in commodity prices or a significant downward revision of estimated recoverable reserves. If indicators of asset impairment exist, an impairment test is performed by comparing a CGU's carrying value to its recoverable amount. A CGU's recoverable amount is the greater of its fair value less cost to sell and its current value in use. The calculation of the recoverable amount is sensitive to the assumptions regarding production volumes, discount rates and commodity prices. Any excess of carrying value over recoverable amount is recognized as impairment loss in profit or loss.

In assessing the value in use, the estimated future cash flows from proved and probable reserves are discounted to their present value using a pre-tax discount rate that reflects current market assessment of the time value of money. Fair value is determined as the amount that would be obtained from the sale of the asset in an arm's length transaction between knowledgeable and willing parties. The petroleum and natural gas future prices used in the impairment test are based on period-end commodity price forecasts estimated by the Corporation's independent reserves evaluator and are adjusted for petroleum and natural gas differentials and transportation and marketing costs specific to the Corporation.

Where circumstances change such that an impairment no longer exists or is less than the amount previously recognized, the carrying amount of the CGU is increased to the revised estimate of its recoverable amount as long as the revised estimate does not exceed the carrying amount that would have been determined, net of depletion and depreciation, had no impairment loss been recognized for the CGU in prior periods. A reversal of an impairment loss is recognized immediately through profit or loss.

Exploration and evaluation assets are assessed for impairment if: (i) sufficient data exists to determine technical feasibility and commercial viability of an exploration area, or (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, exploration and evaluation assets are allocated to CGUs.

(m) Income Taxes

Birchcliff is a corporation as defined under the *Income Tax Act* (Canada) and is subject to Canadian Federal and provincial taxes. Birchcliff is subject to provincial taxes in Alberta as the Corporation operates in this jurisdiction. The Corporation's income tax expenses include current and/or deferred tax. Income tax expense is recognized through profit or loss except to the extent that it relates to items recognized directly in equity, in which case the related income taxes are also recognized in equity.

Current tax is the expected tax payable on taxable income and Part VI.I dividend tax payable on taxable preferred shares for the period, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized on temporary differences between the carrying amounts of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income. Deferred tax liabilities are generally recognized for all taxable temporary differences. Deferred tax assets are generally recognized for all deductible temporary differences to the extent that it is probable that taxable income will be available against which those deductible temporary differences can be utilized. The carrying amount of deferred tax assets is reviewed at the end of each reporting period and reduced to the extent that it is no longer probable that sufficient taxable income will be available to allow all or part of the asset to be recovered.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the period in which the liability is expected to be settled or the asset realized, based on tax rates (and tax laws) that have been enacted or substantively enacted by the end of the reporting period. The measurement of deferred tax liabilities and assets reflects the tax consequences that would follow from the manner in which Birchcliff expects, at the end of the reporting period, to recover or settle the carrying amount of its assets and liabilities.

(n) Capital Securities

The issuance of Series C Preferred Shares, which are presented as "capital securities" on the statements of financial position, are classified as "other financial liabilities" under IFRS. The incremental costs directly attributable to the issuance of Series C Preferred Shares are initially recognized as a reduction to capital securities and subsequently amortized to profit and loss, using the effective interest rate method, as a finance expense. Dividend distributions on capital securities are recorded as an expense directly to profit and loss and presented as a financing activity on the statements of cash flows.

(o) Flow-Through Shares

The Corporation may issue flow-through shares to finance a portion of its capital expenditure program. Pursuant to the terms of the flow-through share agreements, the tax deductions associated with the expenditures are renounced to the subscribers. The difference between the value ascribed to flow-through shares issued and the value that would have been received for common shares at the date of announcements of the flow-through shares is initially recognized as a liability on the statements of financial position. When the expenditures are incurred, the liability is drawn down, a deferred tax liability is recorded equal to the estimated amount of deferred income tax payable by the Corporation as a result of the renunciation and the difference is recognized as a deferred tax expense.

(p) Per Common Share

The Corporation calculates per common share amounts using net income available to Birchcliff's shareholders, reduced for perpetual preferred share dividends and divided by the weighted average number of common shares outstanding. Basic per share information is computed using the weighted average number of basic common shares outstanding during the period. Diluted per share information is calculated using the treasury stock method, which assumes that any proceeds from the exercise of "in-the-money" stock options, performance warrants or warrants (the "**Securities**"), plus the unamortized stock-based compensation expense amounts, would be used to purchase common shares at the average market price during the period. No adjustment to diluted earnings per share is made if the result of these calculations is anti-dilutive. The average market value of the Corporation's shares for the purpose of calculating the dilutive effect is based on average quoted market prices for the time that the Securities were outstanding during the period.

(q) Critical Accounting Judgments and Key Sources of Estimation Uncertainty

The timely preparation of the financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected.

Critical judgments in applying accounting policies:

The following are the critical judgments that management has made in the process of applying the Corporation's accounting policies and that have the most significant effect on the amounts recognized in these financial statements:

(i) Identification of cash-generating units

Birchcliff's assets are required to be aggregated into CGUs for the purpose of calculating impairment based on their ability to generate largely independent cash inflows. CGUs have been determined based on similar geological structure, shared infrastructure, geographical proximity, operating structure, commodity type and similar exposures to market risks. By their nature, these assumptions are subject to management's judgment and may impact the carrying value of the Corporation's assets in future periods.

(ii) Identification of impairment indicators

IFRS requires Birchcliff to assess, at each reporting date, whether there are any indicators that its petroleum and natural gas assets may be impaired. Birchcliff is required to consider information from both external sources (such as negative downturn in commodity prices, significant adverse changes in the technological, market, economic or legal environment in which the entity operates) and internal sources (such as downward revisions in reserves, significant adverse effect on the financial and operational performance of a CGU, evidence of obsolescence or physical damage to the asset). By their nature, these assumptions are subject to management's judgment.

(iii) Tax uncertainties

IFRS requires Birchcliff, at each reporting date, to make certain judgments on uncertain tax positions by relevant tax authorities. Judgments include determining whether the Corporation will "more likely than not" be successful in defending its tax positions by considering information from relevant tax interpretations and tax laws in Canada. As such, this recognition threshold is subject to management's judgment and may impact the carrying value of the Corporation's deferred tax assets and liabilities at the end of the reporting period.

Key sources of estimation uncertainty:

The following are the key assumptions concerning the sources of estimation uncertainty at the end of the reporting period, that have a significant risk of causing adjustments to the carrying amounts of assets and liabilities within the next financial year:

(i) Reserves

Reported recoverable quantities of proved and probable reserves requires estimation regarding production profile, commodity prices, exchange rates, remediation costs, timing and amount of future development costs, and production, transportation and marketing costs for future cash flows. It also requires interpretation of geological and geophysical models in order to make an assessment of the size, shape, depth and quality of reservoirs, and their anticipated recoveries. The economical, geological and technical factors used to estimate reserves may change from period to period. Changes in reported reserves can impact the carrying values of the Corporation's petroleum and natural gas properties and equipment, the calculation of depletion and depreciation, the provision for decommissioning obligations, and the recognition of deferred tax assets due to changes in expected future cash flows. The recoverable quantities of reserves and estimated cash flows from Birchcliff's petroleum and natural gas interests are independently evaluated by reserve engineers at least annually.

The Corporation's petroleum and natural gas reserves represent the estimated quantities of petroleum, natural gas and NGL which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be economically recoverable in future years from known reservoirs and which are considered commercially producible. Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon (i) a reasonable assessment of the future economics of such production; (ii) a reasonable expectation that there is a market for all or substantially all the expected petroleum and natural gas production; and (iii) evidence that the necessary production, transmission and transportation facilities are available or can be made available. Reserves may only be considered proven and probable if producibility is supported by either production or conclusive formation tests. Birchcliff's oil and gas reserves are determined in accordance with the standards contained in National Instrument 51-101 – *Standards of Disclosures for Oil and Gas Activities* and the *Canadian Oil and Gas Evaluation Handbook*.

(ii) Share-based payments

All equity-settled, share-based awards issued by the Corporation are fair valued using the Black-Scholes option-pricing model. In assessing the fair value of equity-based compensation, estimates have to be made regarding the expected volatility in share price, option life, dividend yield, risk-free rate and estimated forfeitures at the initial grant date.

(iii) Decommissioning obligations

The Corporation estimates future remediation costs of production facilities, wells and pipelines at different stages of development and construction of assets or facilities. In most instances, removal of assets occurs many years into the future. This requires an estimate regarding abandonment date, future environmental and regulatory legislation, the extent of reclamation activities, the engineering methodology for estimating cost, future removal technologies in determining the removal cost and liability-specific discount rates to determine the present value of these cash flows.

(iv) Impairment of non-financial assets

For the purposes of determining the extent of any impairment or its reversal, estimates must be made regarding future cash flows taking into account key assumptions including future petroleum and natural gas prices, expected forecasted production volumes and anticipated recoverable quantities of proved and probable reserves. These assumptions are subject to change as new information becomes available. Changes in economic conditions can also affect the rate used to discount future cash flow estimates. Changes in the aforementioned assumptions could affect the carrying amount of the Corporation's assets, and impairment charges and reversal will affect profit or loss.

(v) Income taxes

Birchcliff files corporate income tax, goods and service tax and other tax returns with various provincial and federal taxation authorities in Canada. There can be differing interpretations of applicable tax laws and regulations. The resolution of these tax positions through negotiations or litigation with tax authorities can take several years to complete. The Corporation does not anticipate that there will be any material impact upon the results of its operations, financial position or liquidity.

Tax provisions are based on enacted or substantively enacted laws. Changes in those laws could affect amounts recognized in profit or loss both in the period of change, which would include any impact on cumulative provisions, and in future periods.

Deferred tax assets (if any) are recognized only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse and a judgment as to whether or not there will be sufficient taxable profits available to offset the tax assets when they do reverse. This requires assumptions regarding future profitability and is therefore inherently uncertain. Estimates of future taxable income are based on forecasted cash flows from operations. To the extent that any interpretation of tax law is challenged by the tax authorities or future cash flows and taxable income differ significantly from estimates, the ability of Birchcliff to realize the deferred tax assets recorded at the balance sheet date could be impacted.

4. CHANGES IN ACCOUNTING POLICIES

Future Accounting Pronouncements

In January 2016, the IASB issued IFRS 16 *Leases*. The standard will be effective for annual periods beginning on or after January 1, 2019. Early adoption is permitted, provided IFRS 15 *Revenue from Contracts with Customers*, has been applied, or is applied at the same date as IFRS 16. Birchcliff is currently evaluating the impact of adopting IFRS 16 on the financial statements.

On May 28, 2014, the IASB issued IFRS 15 *Revenue From Contracts With Customers* replacing IAS 11 *Construction Contracts*, IAS 18 *Revenue* and several revenue-related interpretations. IFRS 15 contains a single model that applies to contracts with customers and two approaches to recognizing revenue: at a point in time or over time. The model features a contract-based five-step analysis of transactions to determine whether, how much and when revenue is recognized. IFRS 15 is effective for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. Birchcliff is currently assessing the impact of adopting IFRS 15; however, it anticipates that this standard will not have a material impact on the Corporation's financial statements.

On July 24, 2014, the IASB issued the final version of IFRS 9 *Financial Instruments* to replace IAS 39 *Financial Instruments: Recognition and Measurement*. IFRS 9 aligns hedge accounting more closely with risk management. The new standard does not fundamentally change the types of hedging relationships or the requirement to measure and recognize ineffectiveness. However, under the new standard, more hedging strategies that are used for risk management will qualify for hedge accounting. IFRS 9 is effective for years beginning on or after January 1, 2018. As the Corporation does not currently apply hedge accounting it anticipates that this standard will not have a material impact on the Corporation's financial statements.

5. EXPLORATION AND EVALUATION ASSETS

The continuity for Exploration and Evaluation ("**E&E**") assets are as follows:

($000s)	**E&E(1)**
As at December 31, 2013	2,264
Additions	102
Disposals	(131)
As at December 31, 2014	2,235
Additions	117
Disposals	(1)
Lease expiries(2)	(2,104)
As at December 31, 2015	**247**

(1) E&E assets consist of the Corporation's exploration activities which are pending the determination of economic quantities of commercially producible proven reserves. Additions represent the Corporation's net share of costs incurred on E&E activities during the period. A review of each exploration project by area is carried out at each reporting date to ascertain whether economical quantities of proven reserves have been discovered and whether such costs should be transferred to depletable petroleum and natural gas components. There were no exploration costs reclassified from the E&E category to petroleum and natural gas properties and equipment category during 2015 and 2014.

(2) For the year ending December 31, 2015, the Corporation incurred an expense of approximately $2.1 million related to lease expiries on undeveloped land that has been included in depletion and depreciation expense.

6. PETROLEUM AND NATURAL GAS PROPERTIES AND EQUIPMENT

The continuity for Petroleum and Natural Gas ("**P&NG**") Properties and Equipment are as follows:

($000s)	P&NG Assets	Corporate Assets	Total
Cost:			
As at December 31, 2013	1,855,992	8,802	1,864,794
Additions	411,579	1,418	412,997
Acquisitions(1)	58,465	-	58,465
Dispositions(2)	(535)	-	(535)
As at December 31, 2014	2,325,501	10,220	2,335,721
Additions	267,711	749	268,460
Dispositions(3)	(4,862)	-	(4,862)
As at December 31, 2015(4)	2,588,350	10,969	2,599,319
Accumulated depletion and depreciation:			
As at December 31, 2013	(314,325)	(5,284)	(319,609)
Depletion and depreciation expense	(135,098)	(1,180)	(136,278)
Dispositions(2)	14	-	14
As at December 31, 2014	(449,409)	(6,464)	(455,873)
Depletion and depreciation expense(5)	(143,181)	(1,185)	(144,366)
As at December 31, 2015	(592,590)	(7,649)	(600,239)
Net book value:			
As at December 31, 2014	1,876,092	3,756	1,879,848
As at December 31, 2015(6)	**1,995,760**	**3,320**	**1,999,080**

(1) Mainly consists of Birchcliff acquiring a partner's 30% working interest in land and production for cash proceeds of approximately $56.0 million.
(2) Mainly consists of asset dispositions in the Mulligan and Gold Creek areas with a net book value of $0.5 million for net proceeds of $3.7 million.
(3) Mainly consists of several non-core asset dispositions with an aggregate net book value of $4.9 million for net proceeds of $10.9 million.
(4) The Corporation's P&NG properties and equipment were pledged as security for its credit facilities. Although the Corporation believes that it has title to its petroleum and natural gas properties, it cannot control or completely protect itself against the risk of title disputes and challenges. There were no borrowing costs capitalized to P&NG properties and equipment.
(5) Future capital costs required to develop and produce proved plus probable reserves totalled $3.1 billion at the end of 2015 (2014 – $3.2 billion) and are included in the depletion expense calculation.
(6) In light of low commodity prices, the Corporation performed an asset impairment test to ensure that the carrying value of its P&NG properties and equipment was recoverable at the end of the reporting period. Birchcliff's P&NG properties and equipment were not impaired at December 31, 2015. In determining the recoverable amount, Birchcliff applied a pre-tax discount rate of 10% on cash flows from proved plus probable reserves. The petroleum and natural gas future prices are based on period-end commodity price forecasts determined by the Corporation's independent reserves evaluator.

7. REVOLVING TERM CREDIT FACILITIES

The components of the Corporation's revolving credit facilities include:

As at December 31, *($000s)*	2015	2014
Syndicated credit facility	607,000	319,000
Working capital facility	23,037	23,433
Drawn revolving term credit facilities	630,037	342,433
Unamortized prepaid interest on bankers' acceptances	(6,347)	(2,084)
Unamortized deferred financing fees	(1,616)	(792)
Revolving term credit facilities	**622,074**	**339,557**

On May 11, 2015, the aggregate limit of Birchcliff's credit facilities was increased to $800 million from $750 million. In addition to the increase in the credit facilities limit, Birchcliff's syndicate of lenders also approved the consolidation of the Corporation's $750 million credit facilities, which were comprised of a $620 million revolving term credit facility, a $70 million non-revolving five-year term credit facility and a $60 million non-revolving five-year term credit facility, into three-year term extendible revolving credit facilities in the aggregate principal amount of $800 million with maturity dates of May 11, 2018 (the "**Credit Facilities**"). Concurrently, the financial covenants contained in the credit facilities which previously required the Corporation to ensure that on the last day of each quarter the ratio of EBITDA to interest expense, determined on a historical rolling four quarter basis equaled or exceeded 3.5:1.0, and the ratio of debt to EBITDA, determined on a historical rolling four quarter basis did not exceed 4.0:1.0, were removed. As a result, the Credit Facilities do not contain any financial covenants.

The Credit Facilities are comprised of: (i) an extendible revolving syndicated term credit facility of $760 million (the "**Syndicated Credit Facility**"); and (ii) an extendible revolving working capital facility of $40 million (the "**Working Capital Facility**"). Birchcliff may each year, at its option, request an extension to the maturity date of the Syndicated Credit Facility and the Working Capital Facility, or either of them, for an additional period of up to three years from May 11 of the year in which the extension request is made.

The Credit Facilities allow for prime rate loans, LIBOR loans, U.S. base rate loans, bankers' acceptances and, in the case of the Working Capital Facility only, letters of credit. The interest rates applicable to the drawn loans are based on a pricing grid and will change as a result of the ratio of outstanding indebtedness to EBITDA. EBITDA is defined as earnings before interest and non-cash items including income taxes, stock-based compensation, gains and losses on sale of assets, unrealized gains and losses on financial instruments and depletion, depreciation and amortization.

The Credit Facilities are subject to a semi-annual review of the borrowing base limit by Birchcliff's syndicate of lenders, which limit is directly impacted by the value of Birchcliff's oil and natural gas reserves. In addition, pursuant to the terms of the credit agreement governing the Credit Facilities, the borrowing base of the Credit Facilities may be adjusted in certain other circumstances. Upon any change in or redetermination of the borrowing base limit which results in a borrowing base shortfall, Birchcliff must eliminate the borrowing base shortfall amount. The Credit Facilities are secured by a fixed and floating charge debenture, an instrument of pledge and a general security agreement encompassing all of the Corporation's assets.

8. NON-REVOLVING TERM CREDIT FACILITIES

The components of the Corporation's non-revolving term credit facilities include:

As at December 31, *($000s)*	**2015**	**2014**
$70 million non-revolving five-year term credit facility(1)	-	70,000
$60 million non-revolving five-year term credit facility(1)	-	60,000
Drawn non-revolving term credit facilities	-	130,000
Unamortized prepaid interest on bankers' acceptances	-	(30)
Unamortized deferred financing fees	-	(494)
Non-revolving term credit facilities	**-**	**129,476**

(1) On May 11, 2015, Birchcliff's non-revolving term credit facilities were consolidated and included in the $800 million three-year term revolving credit facility as described in Note 7 to these financial statements.

9. DECOMMISSIONING OBLIGATIONS

The Corporation's decommissioning obligations result from net ownership interests in its petroleum and natural gas properties and equipment including well sites, processing facilities and gathering systems. The total estimated inflated undiscounted cash flows required to settle the Corporation's decommissioning obligations at December 31, 2015 was $159.9 million (2014 – $155.8 million) and is expected to be incurred between 2017 and 2063.

A reconciliation of the decommissioning obligations is provided below:

As at December 31, *($000s)*	**2015**	**2014**
Balance, beginning	85,824	73,433
Obligations incurred	2,086	5,751
Obligations acquired	-	1,788
Obligations divested	(1,170)	-
Changes in estimated future cash flows[1]	4,422	4,091
Accretion expense	2,235	2,424
Actual expenditures	(893)	(1,663)
Balance, ending	**92,504**	**85,824**

(1) Changes in estimated future cash flows largely due to the revision in both the risk-free discount rate and abandonment and reclamation cost and date estimates for Birchcliff's oil and natural gas wells and facilities. A risk-free rate of 2.26% and an inflation rate of 2.0% were used to calculate the discounted fair value of decommissioning liabilities at December 31, 2015 (December 31, 2014 – 2.43% and 2.0%, respectively).

10. INCOME TAXES

Included in income tax expense for the year ended December 31, 2015 is a provision for deferred income tax expense totalling $20.2 million (2014 – $38.8 million) and a Part VI.I dividend tax totalling $3.0 million (2014 – $3.0 million) resulting from preferred share dividends paid during the period. Effective July 1, 2015, the Alberta government increased the corporate general income tax rate from 10% to 12%. For the purposes of determining the current income tax, the Corporation applied a combined Canadian federal and provincial income tax rate of 26% in 2015 (2014 – 25%). For the purposes of determining the deferred income tax, the Corporation applied a combined Canadian federal and provincial effective income tax rate of 27% in 2015 (2014 – 25%).

The components of income tax expense include:

Years ended December 31, *($000s)*	**2015**	**2014**
Net income before taxes	11,072	156,118
Computed expected income tax expense	2,879	39,030
Increase (decrease) in taxes resulting from:		
Non-deductible stock-based compensation	1,025	1,360
Non-deductible expenses	93	122
Non-deductible dividends on capital securities	910	875
Increase in Alberta corporate income tax rates	7,759	-
Denial of the Veracel tax pools reassessment[1]	10,208	-
Other	358	427
Income tax expense	**23,232**	**41,814**

(1) Refer to Note 20.

The components of deferred income tax liabilities include:

As at December 31, *($000s)*	**2015**	**2014**
Deferred income tax liabilities:		
P&NG properties and equipment and E&E assets	256,004	185,007
Deferred financing fees	436	321
Capital securities	376	426
Deferred income tax assets:		
Decommissioning obligations	(24,976)	(21,456)
Share issue costs	(520)	(885)
Non-capital losses	(115,149)	(67,472)
Deferred income tax liabilities	**116,171**	**95,941**

A continuity of the net deferred income tax liabilities is provided below:

($000s)	Balance Jan. 1, 2015	Recognized in Profit or Loss	Balance Dec. 31, 2015
P&NG and E&E assets	185,007	70,997	256,004
Deferred financing fees	321	115	436
Capital securities	426	(50)	376
Decommissioning obligations	(21,456)	(3,520)	(24,976)
Share issue costs	(885)	365	(520)
Non-capital losses	(67,472)	(47,677)	(115,149)
	95,941	20,230	116,171

($000s)	Balance Jan. 1, 2014	Recognized in Profit or Loss	Balance Dec. 31, 2014
P&NG and E&E assets	155,022	29,985	185,007
Deferred financing fees	222	99	321
Risk management contracts – asset	207	(207)	-
Capital securities	503	(77)	426
Decommissioning obligations	(18,358)	(3,098)	(21,456)
Risk management contracts – liability	(301)	301	-
Share issue costs	(1,300)	415	(885)
Non-capital losses	(78,868)	11,396	(67,472)
	57,127	38,814	95,941

As at December 31, 2015, the Corporation had approximately $1.5 billion (2014 – $1.4 billion) in tax pools available for deduction against future taxable income. Included in this tax basis are estimated non-capital loss carry forwards of approximately $426 million that expire between 2026 and 2035 (2014 – $272.5 million that expire between 2026 and 2034). Discretionary tax deductions, including Canadian Development Expenses, Canadian Oil and Gas Property Expense and Capital Cost Allowance, were maximized in the respective tax years in order to reduce Birchcliff's accounting profits into a loss position for tax purposes.

11. CAPITAL STOCK

Share Capital

(a) Authorized:

Unlimited number of voting common shares, with no par value

Unlimited number of preferred shares, with no par value

The preferred shares may be issued in one or more series and the directors are authorized to fix the number of shares in each series and to determine the designation, rights, privileges, restrictions and conditions attached to the shares of each series.

(b) Number of common shares and perpetual preferred shares issued:

Common shares and perpetual preferred shares are classified as equity and recorded to share capital. Incremental costs directly attributable to the issuance of common and perpetual preferred shares are recognized as a reduction to share capital, net of any tax effects. Dividend distributions on perpetual preferred shares are recorded directly to equity.

As at December 31,	2015	2014
Common Shares:		
Outstanding at beginning of period – Jan 1	152,214,206	143,676,661
Exercise of stock options	93,333	2,550,846
Exercise of preferred warrants	-	5,986,699
Outstanding at end of period	152,307,539	152,214,206
Series A Preferred Shares (perpetual)[(1)]:		
Outstanding at beginning of period – Jan 1	2,000,000	2,000,000
Outstanding at end of period	2,000,000	2,000,000

(1) In August 2012, Birchcliff completed a bought deal equity financing for gross proceeds of $50 million. The Corporation issued 2,000,000 preferred units at a price of $25.00 per preferred unit for gross proceeds of $50 million. Each preferred unit was comprised of one cumulative redeemable five year rate reset Series A Preferred Share of Birchcliff, to yield initially 8% per annum; and three common share purchase warrants of Birchcliff (the "**preferred warrants**"). Each preferred warrant provided the right to purchase one common share until August 8, 2014, at an exercise price of $8.30 per common share.
The Series A Preferred Shares pay cumulative dividends of $2.00 per Series A Preferred Share per annum, payable quarterly if, as and when declared by Birchcliff's Board of Directors, with the first quarterly dividend paid on September 30, 2012, for the initial five year period ending September 30, 2017. Thereafter, the dividend rate will be reset every five years at a rate equal to the then current five year Government of Canada bond yield plus 6.83%. The Series A Preferred Shares are redeemable at $25.00 per preferred share at the option of the Corporation on or after September 30, 2017, and on September 30 in every fifth year thereafter. Holders of the Series A Preferred Shares have the right, at their option, to convert their Series A Preferred Shares into cumulative redeemable floating rate Series B Preferred Shares, subject to certain conditions, on September 30, 2017 and on September 30 in every fifth year thereafter. The holders of the Series B Preferred Shares will be entitled to receive quarterly floating rate cumulative preferential cash dividends, if declared by Birchcliff's Board of Directors, at a rate equal to the sum of the then current 90 day Government of Canada Treasury Bill rate plus 6.83%. In the event of liquidation, dissolution or winding-up of Birchcliff, the holders of the Series A Preferred Shares and Series B Preferred Shares will be entitled to receive $25.00 per share as well as all accrued unpaid dividends before any amounts will be paid or any assets will be distributed to the holders of any other shares ranking junior to the Series A Preferred Shares and the Series B Preferred Shares. The holders of the Series A Preferred Shares and the Series B Preferred Shares will not be entitled to share in any further distribution of the assets of the Corporation.

Capital Securities

The Series C Preferred Shares are not redeemable by the Corporation prior to June 30, 2018. On and after June 30, 2018, the Corporation may, at its option, redeem for cash, all or any number of the outstanding Series C Preferred Shares at $25.75 per share if redeemed before June 30, 2019, at $25.50 per share if redeemed on or after June 30, 2019 but before June 30, 2020 and at $25.00 per share if redeemed on or after June 30, 2020 in each case together with all accrued and unpaid dividends to but excluding the date fixed for redemption.

The Series C Preferred Shares are not redeemable by the holders of the preferred shares prior to June 30, 2020. On and after June 30, 2020, a holder of Series C Preferred Shares may, at its option, redeem for cash, all or any number of Series C Preferred Shares held by such holder on the last day of March, June, September and December of each year at $25.00 per share, together with all accrued and unpaid dividends to but excluding the date fixed for redemption. Upon receipt of the Notice of Redemption, the Corporation may, at its option elect to convert such Series C Preferred Shares into common shares of the Corporation.

On and after June 30, 2018, the Corporation may, at its option, convert all or any number of the outstanding Series C Preferred Shares into common shares.

The Corporation has outstanding 2,000,000 Series C Preferred Shares at December 31, 2015 (2014 – 2,000,000).

Dividends

On December 2, 2015, the Board of Directors declared a quarterly cash dividend of $1.0 million or $0.50 per Series A Preferred Share and $0.875 million or $0.4375 per Series C Preferred Share for the calendar quarter ending December 31, 2015.

In 2015, cash dividends totalled $4.0 million or $2.00 per Series A Preferred Share (2014 – $4.0 million or $2.00 per Series A) and $3.5 million or $1.75 per Series C Preferred Share (2014 – $3.5 million or $1.75 per Series C).

Both dividends are designated as an eligible dividend for purposes of the *Income Tax Act* (Canada).

Preferred Warrants

Birchcliff issued 6,000,000 preferred warrants in conjunction with the offering of Series A Preferred Shares in August 2012. Each preferred warrant was exercisable until August 8, 2014 at a price of $8.30 to purchase one common share of Birchcliff. During 2014 there were 5,986,699 preferred warrants exercised for total proceeds of approximately $49.7 million. The remaining 13,301 preferred warrants that were not exercised expired on August 8, 2014.

Per Common Share

The Corporation calculates basic and diluted per common share amounts by dividing net income, which has been reduced for any dividends paid on Series A perpetual preferred shares, by the weighted average number of basic or diluted common shares outstanding.

The following table presents the computation of net income per common share:

Years Ended December 31,	**2015**	**2014**
Net income (loss) *($000s)*	(12,160)	114,304
Dividends on Series A Preferred Shares *($000s)*	(4,000)	(4,000)
Net income (loss) to common shareholders *($000s)*	(16,160)	110,304
Weighted average common shares *(000s)*:		
Weighted average basic common shares outstanding	152,286	147,764
Effects of dilutive securities	-	4,479
Weighted average diluted common shares outstanding[1]	152,286	152,243
Net income (loss) per common share *($/share)*		
Basic	**($0.11)**	**$0.75**
Diluted	**($0.11)**	**$0.72**

(1) As the Corporation reported a loss for the twelve months ended December 31, 2015 the basic and diluted weighted average shares outstanding are the same for the period. The weighted average diluted common shares outstanding excludes 15,508,970 stock options and performance warrants that are anti-dilutive in the twelve month reporting period (December 31, 2014 – 2,273,700).

12. OPERATING EXPENSES

The Corporation's operating expenses include all costs with respect to day-to-day well and facility operations. Processing recoveries related to joint ventures reduces operating expenses. The components of operating expenses are as follows:

Years ended December 31, *($000s)*	**2015**	**2014**
Field operating costs	65,281	65,331
Recoveries	(1,500)	(1,284)
Field operating costs, net	63,781	64,047
Expensed workovers and other	730	170
Operating expenses	**64,511**	**64,217**

13. ADMINISTRATIVE EXPENSES

The components of administrative expenses are as follows:

Years ended December 31, *($000s)*	2015	2014
Cash:		
Salaries and benefits[1]	27,067	24,298
Other[2]	12,297	12,644
	39,364	36,942
Operating overhead recoveries	(232)	(247)
Capitalized overhead[3]	(16,308)	(14,355)
General and administrative, net	22,824	22,340
Non-cash:		
Stock-based compensation	7,732	9,977
Capitalized stock-based compensation[3]	(4,526)	(5,181)
Stock-based compensation, net	3,206	4,796
Administrative expenses, net	**26,030**	**27,136**

(1) Includes salaries and benefits paid to all Officers and employees of the Corporation.
(2) Includes costs such as rent, legal, tax, insurance, minor computer hardware and software and other business expenses incurred by the Corporation.
(3) Includes a portion of salaries, benefits and stock-based compensation directly attributable to the exploration and development activities of the Corporation which have been capitalized.

Compensation for Executive Officers and Directors are comprised of the following:

Years ended December 31, *($000s)*	2015	2014
Salaries and benefits[1]	6,175	5,468
Stock-based compensation[2]	2,284	2,534
Executive Officers and Directors compensation	**8,459**	**8,002**

(1) Includes salaries and benefit earned by Executive Officers and Directors comprising of: Chairman of the Board, President & Chief Executive Officer, Vice-President of Exploration & Chief Operating Officer, Vice-President & Chief Financial Officer, Vice-President of Operations, Vice-President of Engineering, Vice-President of Corporate Development and other independent Directors.
(2) Represents the amortization of stock-based compensation expense in the year associated with options granted to Executive Officers and Directors participating in the Corporation's Amended and Restated Stock Option Plan.

14. FINANCE EXPENSES

The components of finance expenses are as follows:

Years ended December 31, *($000s)*	2015	2014
Cash:		
Interest on credit facilities	22,861	19,332
Non-cash:		
Accretion on decommissioning obligations	2,235	2,424
Amortization of deferred financing fees	919	932
Finance expenses	**26,015**	**22,688**

15. SHARE-BASED PAYMENTS

Stock Options

At December 31, 2015, the Corporation's Amended and Restated Stock Option Plan permitted the grant of options in respect of a maximum of 15,230,754 (December 31, 2014 – 15,221,421) common shares. At December 31, 2015, there remained available for issuance options in respect of 2,661,516 (December 31, 2014 – 4,073,749) common shares. For stock options exercised during 2015, the weighted average share trading price was $6.42 (December 31, 2014 – $10.69) per common share.

A summary of the outstanding stock options is presented below:

	Number	Weighted Average Exercise Price *($)*
Outstanding, December 31, 2013	10,931,520	8.31
Granted	3,112,500	9.08
Exercised	(2,550,846)	(8.55)
Forfeited	(345,502)	(8.96)
Outstanding, December 31, 2014	11,147,672	8.45
Granted	3,358,500	6.62
Exercised	(93,333)	(6.26)
Forfeited	(699,201)	(9.70)
Expired	(1,144,400)	(9.66)
Outstanding, December 31, 2015	**12,569,238**	**7.80**

The weighted average fair value per option granted during 2015 was $2.14 (December 31, 2014 – $2.92). In determining the stock-based compensation expense for options issued during 2015, the Corporation applied a weighted average estimated forfeiture rate of 13% (December 31, 2014 – 14%).

The weighted average assumptions used in calculating the Black-Scholes fair values are set forth below:

Years Ended December 31,	**2015**	**2014**
Risk-free interest rate	0.7%	1.4%
Expected life *(years)*	4.0	3.9
Expected volatility	40.8%	39.3%

A summary of the stock options outstanding and exercisable under the plan at December 31, 2015 is presented below:

Exercise Price		Awards Outstanding			Awards Exercisable		
Low	High	Quantity	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Quantity	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price
$5.88	$6.00	2,157,735	1.33	$5.96	2,147,735	1.3	$5.96
$6.01	$9.00	8,518,803	3.19	$7.48	2,799,464	2.5	$7.83
$9.01	$12.00	1,777,700	0.46	$11.21	1,648,365	0.2	$11.31
$12.01	$13.26	115,000	0.47	$12.79	113,000	0.4	$12.80
		12,569,238	**2.46**	**$7.80**	**6,708,564**	**1.5**	**$8.17**

Performance Warrants

On January 14, 2005, Birchcliff issued 4,049,665 performance warrants as part of the Corporation's initial restructuring to become a public entity. Each performance warrant is exercisable at a price of $3.00 to purchase one common share of Birchcliff. There are 2,939,732 performance warrants outstanding and exercisable at December 31, 2015 (December 31, 2014 – 2,939,732).

In May 2014, the Corporation's outstanding performance warrants were amended to extend the ultimate expiration date of January 31, 2015 to January 31, 2020 (the "**Extension**"). The Corporation recorded non-cash stock-based compensation expense of approximately $1.7 million relating to the Extension of the performance warrants in 2014.

16. CAPITAL MANAGEMENT

The Corporation's general policy is to maintain a sufficient capital base in order to manage its business in the most effective manner with the goal of increasing the value of its assets and thus its underlying share value. The Corporation's objectives when managing capital are to maintain financial flexibility in order to preserve its ability to meet financial obligations, including potential obligations arising from additional acquisitions; to maintain a capital structure that allows Birchcliff to finance its growth strategy using primarily internally-generated cash flow and its available debt capacity; and to optimize the use of its capital to provide an appropriate investment return to its shareholders. There were no changes in the Corporation's approach to capital management in 2015.

The following table shows the Corporation's total available credit:

As at December 31, *($000s)*	**2015**	**2014**
Maximum borrowing base limit[(1)]*:*		
Non-revolving term credit facilities	-	130,000
Revolving term credit facilities	800,000	620,000
	800,000	750,000
Principal amount utilized:		
Drawn non-revolving term credit facilities	-	(130,000)
Drawn revolving term credit facilities	(630,037)	(342,433)
Outstanding letters of credit[(2)]	(242)	(184)
	(630,279)	(472,617)
Unused credit	**169,721**	**277,383**

(1) The Corporation's credit facilities are subject to an annual review of the borrowing base limit, which is directly impacted by the value of Birchcliff's petroleum and natural gas reserves. On May 11, 2015, the aggregate limit of Birchcliff's credit facilities was increased to $800 million from $750 million.
(2) Letters of credit are issued to various service providers. There were no amounts drawn on the letters of credit during 2015 and 2014.

The capital structure of the Corporation is as follows:

As at December 31, *($000s)*	**2015**	**2014**	**Change**
Shareholders' equity[(1)]	1,098,434	1,106,277	
Capital securities	48,606	48,296	
Shareholders' equity & capital securities	1,147,040	1,154,573	(1%)
Shareholders' equity & capital securities as a % of total capital[(2)]	64%	68%	
Working capital deficit	21,538	76,712	
Drawn non-revolving term credit facilities	-	130,000	
Drawn revolving term credit facilities	630,037	342,433	
Drawn debt	651,575	549,145	19%
Drawn debt as a % of total capital	36%	32%	
Capital	**1,798,615**	**1,703,718**	**6%**

(1) Shareholders' equity is defined as share capital plus contributed surplus plus retained earnings, less any deficit.
(2) Of the 64%, approximately 56% relates to common capital stock and 8% relates to preferred capital stock.

17. FINANCIAL RISK MANAGEMENT

Birchcliff is exposed to credit risk, liquidity risk and market risk as part of its normal course of business. The Board of Directors has overall responsibility for the establishment and oversight of the Corporation's financial risk management framework and periodically reviews the results of all risk management activities and all outstanding positions. Management has implemented and monitors compliance with risk management guidelines as outlined by the Board of Directors. The Corporation's risk management guidelines are established to identify and analyze the risks faced by the Corporation, to set appropriate risk limits and controls and to monitor risks and adherence to market conditions and the Corporation's activities.

Credit Risk

Credit risk is the risk of financial loss to the Corporation if a customer or counterparty to a financial instrument fails to meet its contractual obligation, and arises principally from Birchcliff's receivables from joint venture partners and oil and natural gas marketers. Cash is comprised of bank balances. Historically, the Corporation has not carried short term investments. Should this change in the future, counterparties will be selected based on credit ratings, management will monitor all investments to ensure a stable return and complex investment vehicles with higher risk will be avoided. The Corporation's exposure to cash credit risk at the balance sheet date is low.

The carrying amount of accounts receivable reflects management's assessment of the credit risk associated with these customers. The following table illustrates the Corporation's maximum exposure for accounts receivable:

As at December 31, *($000s)*	**2015**	**2014**
Marketers(1)	22,181	29,943
Joint venture partners and other	1,229	4,988
Accounts receivable	**23,410**	**34,931**

(1) At December 31, 2015, approximately 24% was due from one marketer (2014 – 26%, one marketer). During 2015, the Corporation received 20%, 18%, 15%, 15%, 13% and 12% of its revenue, respectively, from six core marketers (2014 – 31%, 18%, 17%, 15% and 13% of its revenue, respectively, from five core marketers).

Typically, Birchcliff's maximum credit exposure from its marketers is revenue from two months of commodity sales. Receivables from marketers are normally collected on the 25th day of the month following production. Birchcliff mitigates the credit risk associated with these receivables by establishing marketing relationships with credit worthy purchasers, obtaining guarantees from their ultimate parent companies and obtaining letters of credit as appropriate. The Corporation historically has not experienced any material collection issues with its marketers.

Birchcliff's accounts receivables are aged as follows:

As at December 31, *($000s)*	**2015**	**2014**
Current (less than 30 days)	22,569	33,762
30 to 60 days	289	570
61 to 90 days	332	237
91 to 120 days	91	103
Over 120 days	129	259
Accounts receivable	**23,410**	**34,931**

At December 31, 2015, approximately $0.1 million or 0.6% (2014 – $0.3 million or 1%) of Birchcliff's total accounts receivable are aged over 120 days and considered past due. The majority of these accounts are due from various joint venture partners. Birchcliff attempts to mitigate the credit risk from joint venture receivables by obtaining pre-approval of significant capital expenditures. However, the receivables are from participants in the oil and natural gas sector, and collection of the outstanding balances is dependent on industry factors such as commodity price fluctuations, escalating costs and the risk of unsuccessful drilling. In addition, further risk exists with joint venture partners as disagreements occasionally arise that increases the potential for non-collection. The Corporation does not typically obtain collateral from petroleum and natural gas marketers or joint venture partners; however, the Corporation does have the ability to withhold production from joint venture partners in the event of non-payment.

The carrying amount of accounts receivable and cash and cash equivalents and commodity price risk management contracts represents the maximum credit exposure. Should Birchcliff determine that the ultimate collection of a financial instrument is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to profit or loss. If the Corporation subsequently determines an account is uncollectible, the account is written off with a corresponding charge to the allowance for doubtful accounts. Birchcliff did not have an allowance for doubtful accounts balance at December 31, 2015 and December 31, 2014.

Liquidity Risk

Liquidity risk is the risk that the Corporation will not be able to meet its obligations associated with financial liabilities that are settled by cash as they become due. Birchcliff's approach to managing liquidity is to ensure, as much as possible, that it will have sufficient liquidity to meet its short-term and long-term financial obligations when due, under both normal and unusual conditions without incurring unacceptable losses or risking harm to the Corporation's reputation.

All of the Corporation's contractual financial liabilities can be settled in cash. Typically, the Corporation ensures that it has sufficient cash on demand to meet expected operational expenses, including the servicing of financial obligations. To achieve this objective, the Corporation prepares annual capital expenditure budgets, which are approved by the Board of Directors and are regularly reviewed and updated as considered necessary. Petroleum and natural gas production is monitored daily and is used to provide monthly cash flow estimates. Further, the Corporation utilizes authorizations for expenditures on both operated and non-operated projects to manage capital expenditure. The Corporation also attempts to match its payment cycle with collection of petroleum and natural gas revenue on the 25th of each month. Should commodity prices deteriorate materially, Birchcliff may adjust its capital spending accordingly to ensure that it is able to service its short-term financial obligations.

To facilitate the capital expenditure program, the Corporation has an aggregate $800 million reserve-based bank credit facilities at the end of 2015 (2014 – $750 million) which are reviewed annually by its lenders (see Note 7). The principal amount utilized under the Corporation's total credit facilities at December 31, 2015 was $630.3 million (2014 – $472.6 million) and $169.7 million in unused credit was available at the end of 2015 (2014 – $277.4 million) to fund future obligations.

The following table lists the contractual obligations of the Corporation's financial liabilities at December 31, 2015:

($000s)	**2016**	**2017**	**2018 – 2020**
Non-derivative financial liabilities:			
Accounts payable and accrued liabilities	47,584	-	-
Drawn revolving credit facilities	-	-	630,037
Financial liabilities	**47,584**	**-**	**630,037**

Market Risk

Market risk is the risk that changes in market conditions, such as commodity prices, exchange rates and interest rates, will affect the Corporation's net income or the value of its financial instruments, if any. The objective of market risk management is to manage and control exposures within acceptable limits, while maximizing returns. These risks are consistent with prior years. All risk management transactions are conducted within risk management tolerances that are reviewed by the Board of Directors.

Commodity Price Risk

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. Significant changes in commodity prices can materially impact cash flows and the Corporation's borrowing base limit. Lower commodity prices can also reduce the Corporation's ability to raise capital. Commodity prices for petroleum and natural gas are not only influenced by Canadian ("**CDN**") and United States ("**US**") demand, but also by world events that dictate the levels of supply and demand.

As at December 31, 2015, the Corporation had no financial derivatives in place as all 2014 contracts expired on December 31, 2014. The Corporation actively monitors the market to determine whether any additional commodity price risk management contracts are warranted.

The following table provides a summary of the realized and unrealized gains on financial derivatives contracts:

Years ended December 31, *($000s)*	**2015**	**2014**
Realized gain on financial instruments	-	291
Unrealized gain on financial instruments	-	379

There were no financial derivative contracts entered into subsequent to December 31, 2015.

Physical Sales Contracts

As at December 31, 2015, the Corporation had no physical delivery sales contracts in place as all 2014 sales contracts expired on October 31, 2014. There were no physical sales contracts entered into subsequent to December 31, 2015.

Foreign Currency Risk

Foreign currency risk is the risk that future cash flows will fluctuate as a result of changes in foreign currency exchange rates. The exchange rate effect cannot be quantified but generally an increase in the value of the CDN dollar as compared to the US dollar will reduce the prices received by Birchcliff for its petroleum and natural gas sales. The Corporation had no forward exchange rate contracts in place as at or during the years ended December 31, 2015 and 2014.

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Corporation's credit facilities are exposed to interest rate cash flow risk on a floating interest rate due to fluctuations in market interest rates. The remainder of Birchcliff's financial assets and liabilities are not exposed directly to interest rate risk.

A 1% change in the CDN prime interest rate in 2015 would have changed after-tax net income by approximately $4.3 million (2014 – $3.3 million), assuming that all other variables remain constant. A sensitivity of 1% is considered reasonable given the current level of the bank prime rate and market expectations for future movements. The Corporation considers this risk to be limited and thus does not enter into contracts to mitigate its interest rate risk. The Corporation had no interest rate swap contracts in place as at or during the years ended December 31, 2015 and 2014.

Fair Value of Financial Instruments

Birchcliff's financial instruments include cash, accounts receivable, accounts payable and accrued liabilities, outstanding credit facilities and capital securities. All of Birchcliff's financial instruments are transacted in active markets. Financial instruments carried at fair value are assessed using the following hierarchy based on the amount of observable inputs used to value the instrument:

- Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.
- Level 3 – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy level. The carrying value and fair value of the Corporation's financial assets and liabilities at December 31, 2015 as presented below have been assessed based on the fair value hierarchy described above and classified as Level 1.

($000s)	**Carrying Value**	**Fair Value**
Loans and receivables:		
Cash	57	57
Accounts receivable	23,410	23,410
Other liabilities:		
Accounts payable and accrued liabilities	47,584	47,584
Capital Securities	48,606	40,480
Drawn revolving credit facilities	630,037	630,037

18. COMMITMENTS

The Corporation enters into contracts and commitments in the ordinary course of conducting its day to day business. The following table lists Birchcliff's commitments at December 31, 2015:

($000s)	2016	2017	2018 – 2020	Thereafter
Office lease(1)	3,616	3,315	12,862	33,344
Purchase obligations(2)	20,807	-	-	-
Transportation and processing	38,611	35,028	75,724	65,644
Commitments	**63,034**	**38,343**	**88,586**	**98,988**

(1) The Corporation is committed under its existing operating lease relating to its office premises beginning December 1, 2007 which expires on November 30, 2017. Effective December 1, 2012, Birchcliff has not sublet any excess space to an arm's length party under the existing lease.
On December 2, 2015, the Corporation entered into a new operating lease commitment relating to an office premises beginning February 1, 2018 and expiring on January 31, 2028. The commitment amount under the new 10 year office lease is estimated to be $46.2 million, which includes costs allocated to base rent, parking and building operating expenses.
(2) The Corporation is committed to spend approximately $20.8 million in 2016 under a purchasing agreement relating to the construction of Phase V of the PCS Gas Plant.

19. SUPPLEMENTARY CASH FLOW INFORMATION

Years ended December 31, *($000s)*	2015	2014
Provided by (used in):		
Accounts receivable	11,521	2,091
Prepaid expenses and deposits	(967)	(474)
Accounts payable and accrued liabilities	(65,556)	17,165
Dividend tax	(3,166)	(3,784)
	(58,168)	14,998
Provided by (used in):		
Operating	(11,066)	11,066
Investing	(47,102)	3,932
	(58,168)	14,998

20. CONTINGENT LIABILITY

Birchcliff's 2006 income tax filings were reassessed by the Canada Revenue Agency (the "**CRA**") in 2011 (the "**Reassessment**"). The Reassessment was based on the CRA's position that the tax pools available to Veracel Inc. ("**Veracel**"), prior to its amalgamation with Birchcliff, ceased to be available to Birchcliff after Birchcliff and Veracel amalgamated on May 31, 2005. The Veracel tax pools in dispute totaled $39.3 million, which includes approximately $16.2 million in non-capital losses, $15.6 million in scientific research and experimental development expenditures and $7.5 million in investment tax credits.

Birchcliff appealed the Reassessment to the Tax Court of Canada (the "**Trial Court**") and the trial of that appeal occurred in November 2013. On October 1, 2015, the Trial Court issued its decision (the "**Trial Decision**") and dismissed Birchcliff's appeal on the basis of the general anti-avoidance rule contained in the *Income Tax Act* (Canada).

Birchcliff has appealed the Trial Decision to the Federal Court of Appeal and expects that appeal to be heard in 2016. While management continues to believe that its tax position is supportable, Birchcliff has recorded a deferred income tax expense in the amount of $10.2 million in the fourth quarter of 2015 as a result of the Trial Decision being rendered. This Trial Decision does not result in any current cash taxes payable by Birchcliff.

GLOSSARY

DEFINITIONS

Capitalized terms not otherwise defined in this Annual Report shall have the following meanings:

"2014 Reserves Evaluation"	means the reserves estimation and economic evaluation prepared by Deloitte in respect of Birchcliff's oil and natural gas properties effective December 31, 2014, which is contained in a report dated January 30, 2015.
"2014 Resource Assessment"	means the evaluation of resources prepared by Deloitte in respect of Birchcliff's lands that have potential for the Montney/Doig Natural Gas Resource Play effective December 31, 2014, which is contained in a report dated January 30, 2015.
"2015 Reserves Evaluation"	means the reserves estimation and economic evaluation in respect of Birchcliff's oil and natural gas properties effective December 31, 2015, which is contained in a report dated February 5, 2016.
"2015 Resource Assessment"	means the evaluation of resources prepared by Deloitte in respect of Birchcliff's lands that have potential for the Montney/Doig Natural Gas Resource Play effective December 31, 2015, which is contained in a report dated March 14, 2016.
"AER"	means the Alberta Energy Regulator.
"Birchcliff", the "Corporation", "its", "us" or "we"	means Birchcliff Energy Ltd.
"Charlie Lake Light Oil Resource Play"	means Birchcliff's Charlie Lake formation light oil resource play located northwest of Grande Prairie, Alberta.
"COGE Handbook"	means the Canadian Oil and Gas Evaluation Handbook maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter), as amended from time to time.
"CSA Staff Notice 51-324"	means the Canadian Securities Administrators Staff Notice 51-324 – *Revised Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities.*
"DCCET"	means drill, case, complete, equip and tie-in.
"IFRS"	means International Financial Reporting Standards.
"Montney/Doig Natural Gas Resource Play"	means Birchcliff's Montney and Doig formations natural gas resource play located northwest of Grande Prairie, Alberta.
"NI 51-101"	means National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities.*
"Peace River Arch"	means the Peace River Arch area of Alberta, a geological area centred northwest of Grande Prairie, Alberta, adjacent to the British Columbia border.
"TSX"	means the Toronto Stock Exchange.
"Western Canadian Sedimentary Basin"	means the vast sedimentary basin underlying Western Canada that is the source of most of Western Canada's current oil and gas production.
"working interest"	means the percentage of ownership in an oil and gas property.
"Worsley Charlie Lake Light Oil Resource Play"	means Birchcliff's Charlie Lake Light Oil Resource Play located near Worsley, Alberta.
"Worsley Property"	means the oil and natural gas assets in the Peace River Arch acquired by Birchcliff in September 2007.

ABBREVIATIONS

Oil and Natural Gas Liquids

bbl	barrel
bbls	barrels
Mbbls	thousand barrels
NGL	natural gas liquids

Natural Gas

Bcf	billion cubic feet
GJ	gigajoule
Mcf	thousand cubic feet
MMbtu	million British Thermal Units
MMcf	million cubic feet

Other

1P	proved
2P	proved plus probable
AECO	physical storage and trading hub for natural gas on the TransCanada Alberta transmission system which is the delivery point for various benchmark Alberta index prices
Bcfe	billion cubic feet of gas equivalent
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
F&D	finding and development
FD&A	finding, development and acquisition
FDC	future development capital
Mboe	thousand barrels of oil equivalent
Mcfe	thousand cubic feet of gas equivalent
MMboe	million barrels of oil equivalent
PDP	proved developed producing
PIIP	petroleum initially-in-place
Tcfe	trillion cubic feet of gas equivalent
WTI	West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing
000s	thousands
$000s	thousands of dollars
MM$	millions of dollars

CONVERSIONS

The following table sets forth certain Standard Imperial Units and International System of Units conversions:

From	To	Multiply By
Mcf	cubic metres	28.174
Mcf	GJ	1.055
GJ	MMbtu	0.950
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
feet	metres	0.305
miles	kilometres	1.609
acres	hectares	0.405
sections	acres	640
sections	hectares	256

CONVENTIONS

Certain terms used herein are defined in NI 51-101, CSA Staff Notice 51-324 and the COGE Handbook and, unless the context otherwise requires, shall have the same meanings in this Annual Report as in NI 51-101, CSA Staff Notice 51-324 or the COGE Handbook, as the case may be.

Unless otherwise indicated, references in this Annual Report to "$", "CDN$" or "dollars" are to Canadian dollars and references to "US$" are to United States dollars. All financial information contained in this Annual Report has been presented in accordance with Canadian GAAP.

PRESENTATION OF OIL AND GAS RESERVES AND RESOURCES

Deloitte prepared the 2015 Reserves Evaluation, the 2014 Reserves Evaluation, a reserves estimation and economic evaluation effective December 31, 2013, the 2015 Resource Assessment and the 2014 Resource Assessment. In addition, Deloitte or its predecessors, AJM Deloitte and AJM Petroleum Consultants, prepared reserves evaluations in respect of Birchcliff's oil and natural gas properties effective December 31, 2012, 2011, 2010, 2009, 2008 and 2007. Such evaluations were prepared in accordance with the standards contained in NI 51-101 and the COGE Handbook that were in effect at the relevant time. Reserves and resource estimates stated herein are extracted from the relevant evaluation.

There are numerous uncertainties inherent in estimating quantities of reserves, resources and the future cash flows attributed to those reserves, including many factors beyond the control of Birchcliff. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery, reserves and resource estimates of Birchcliff's reserves and resources provided herein are estimates only and there is no guarantee that the estimated reserves or resources will be recovered. Actual reserves and resources may be greater than or less than the estimates provided herein and variances could be material. For further information regarding the risks and uncertainties associated with Birchcliff's reserves and resources, please see Birchcliff's Annual Information Form for the year ended December 31, 2015, a copy of which is available on SEDAR at www.sedar.com, and *"Risk Factors and Risk Management"* in the MD&A.

RESERVES CATEGORIES

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable.

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

- "**Proved reserves**" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
- "**Probable reserves**" are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.
- "**Possible reserves**" are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

DEVELOPMENT AND PRODUCTION STATUS OF RESERVES

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

- "**Developed reserves**" are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.
    - "**Developed producing reserves**" are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
    - "**Developed non-producing reserves**" are those reserves that either have not been on production, or have previously been on production but are shut-in and the date of resumption of production is unknown.

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

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

LEVELS OF CERTAINTY FOR REPORTED RESERVES

The qualitative certainty levels referred to in the definitions above are applicable to "individual reserves entities", which refers to the lowest level at which reserves calculations are performed, and to "reported reserves", which refers to the highest level sum of individual entity estimates for which reserves estimates are presented. Reported reserves should target the following levels of certainty under a specific set of economic conditions:

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

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

RESOURCES AND PRODUCTION

Resources encompass all petroleum quantities that originally existed on or within the earth's crust in naturally occurring accumulations, including discovered and undiscovered (recoverable and unrecoverable) plus quantities already produced. Resources are classified as follows:

- **Total PIIP** is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered. "Total resources" is equivalent to "total PIIP".
- **Discovered PIIP** is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered PIIP includes production, reserves and contingent resources; the remainder is unrecoverable.
- **Contingent resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies.
- **Undiscovered PIIP** is that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. The recoverable portion of undiscovered PIIP is referred to as prospective resources; the remainder is unrecoverable.
- **Prospective resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.
- **Unrecoverable** is that portion of discovered and undiscovered PIIP quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to the physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.
- **Production** is the cumulative quantity of petroleum that has been recovered at a given date.

UNCERTAINTY RANGES FOR RESOURCES

Estimates of resource volumes can be categorized according to the range of uncertainty associated with the estimates. Uncertainty ranges are described in the COGE Handbook as low, best and high estimates as follows:

- A "low estimate" (1C) is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
- A "best estimate" (2C) is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- A "high estimate" (3C) is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

PROJECT MATURITY SUB-CLASSES FOR RESOURCES

The project maturity sub-classes for contingent resources are "development pending", "development on hold", "development unclarified" or "development not viable", all as defined in the COGE Handbook. "Development pending" is when resolution of the final conditions for development is being actively pursued (high chance of development). "Development on hold" is when there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator. "Development unclarified" is when the evaluation is incomplete and there is ongoing activity to resolve any risks or uncertainties. "Development not viable" is when no further data acquisition or evaluation is currently planned and hence there is a low chance of development.

The project maturity sub-classes for prospective resources are "prospect", "lead" and "play", all as defined in the COGE Handbook. A "prospect" is defined as a potential accumulation within a play that is sufficiently well defined to represent a viable drilling target. A "lead" is defined as a potential accumulation within a play that requires more data acquisition and/or evaluation in order to be classified as a prospect. A "play" is defined as a family of geologically similar fields, discoveries, prospects and leads.

PRODUCT TYPES

NI 51-101 requires a reporting issuer to disclose its reserves and resources in accordance with the product types contained in NI 51-101, which product types include light crude oil and medium crude oil (combined), conventional natural gas, shale gas and NGL. "Shale gas" as defined in NI 51-101 means natural gas: (i) contained in dense organic-rich rocks, including low-permeability shales, siltstones and carbonates, in which the natural gas is primarily adsorbed on the kerogen or clay minerals; and (ii) that usually requires the use of hydraulic fracturing to achieve economic production rates. With respect to Birchcliff's natural gas reserves and resources attributable to its Montney/Doig Natural Gas Resource Play, such reserves and resources would most closely fit within the category of shale gas as opposed to conventional natural gas; however, the primary storage mechanism is gas stored in the pore space with contributions from gas adsorbed to kerogen, clay minerals and bitumen. Birchcliff considers that its natural gas reserves and resources attributable to the Montney/Doig Natural Gas Resource Play to be low permeability gas resources or "tight gas" (as such term is defined in the COGE Handbook), a generic term that includes "basin-centred", "deep gas" and "shale gas". Although Montney/Doig reservoirs usually consist of low permeability sandstones, siltstones, or shales, they may also contain carbonates. While a small amount of gas may also be present in natural fractures, extensive hydraulic fracturing is invariably required to produce the "tight gas". The trapping mechanisms may be the same as for conventional reservoirs, adsorption on kerogen or clays, or relative permeability effects. "Shale gas" is the NI 51-101 product type that most closely matches the natural gas from Birchcliff's Montney/Doig Natural Gas Resource Play.

INTEREST IN RESERVES, RESOURCES, PRODUCTION, WELLS AND PROPERTIES

"**Gross**" means:

(a) in relation to Birchcliff's interest in production, reserves or resources, Birchcliff's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of Birchcliff;

(b) in relation to wells, the total number of wells in which Birchcliff has an interest; and

(c) in relation to properties, the total area of properties in which Birchcliff has an interest.

"**Net**" means:

(a) in relation to Birchcliff's interest in production, reserves or resources, Birchcliff's working interest (operating or non-operating) share after deduction of royalty obligations, plus Birchcliff's royalty interests in production or reserves;

(b) in relation to Birchcliff's interest in wells, the number of wells obtained by aggregating Birchcliff's working interest in each of its gross wells; and

(c) in relation to Birchcliff's interest in a property, the total area in which Birchcliff has an interest multiplied by the working interest owned by Birchcliff.

FORECAST PRICES AND COSTS

"**Forecast prices and costs**" means future prices and costs that are:

(a) generally accepted as being a reasonable outlook of the future;

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which Birchcliff is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

GROSS VOLUMES OF RESERVES AND RESOURCES

Unless otherwise indicated, all volumes of Birchcliff's reserves and resources presented herein are on a "gross" basis.

UNRISKED VOLUMES

Unless otherwise indicated, all volumes of Birchcliff's resources presented herein are on an unrisked basis, meaning that they have not been adjusted for the chance of commerciality.

NON-GAAP MEASURES

This Annual Report uses "funds flow", "funds flow from operations", "funds flow per common share", "adjusted net income to common shareholders", "netback", "operating netback", "estimated operating netback", "operating margin", "total cash costs" and "total debt". These measures do not have standardized meanings prescribed by GAAP and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. Management believes that these non-GAAP measures assist management and investors in assessing Birchcliff's profitability, efficiency, liquidity and overall performance. For further details on these non-GAAP measures, please see "*Non-GAAP Measures*" in the MD&A.

In addition, this Annual Report uses "profit before non-cash items", "profit margin", "funds flow netback" and "total operating costs".

"Profit before non-cash items" measures the amount, if any, during the relevant period by which revenues resulting from production exceed the sum of: (i) PDP FD&A (i.e. the costs of replacing production), (ii) royalty, operating and transportation and marketing expenses and, in the case of Birchcliff at the business-entity level, (iii) general and administrative expense, (iv) interest expense and (v) preferred share dividends. This measure is not intended to represent net income or net income to common shareholders as presented in accordance with IFRS. "Profit margin" is calculated by dividing profit before non-cash items for the period by petroleum and natural gas revenue for the period. Birchcliff believes that profit before non-cash items and profit margin are useful measures as they assist management and investors in assessing Birchcliff's ability during a period of declining commodity prices to bear all of its total cash costs and the costs of replacing its production during the relevant period. Birchcliff does not believe that this measure can be properly reconciled to any GAAP measure.

"Funds flow netback" denotes petroleum and natural gas revenue less royalties, less operating expenses, less transportation and marketing expenses, less net general and administrative expenses, less interest expenses and less any realized losses (plus realized gains) on financial instruments and plus any other cash income sources. Funds flow netback has been calculated on a per unit basis. Management believes that funds flow netback assists management and investors in assessing Birchcliff's profitability and its operating results on a per unit basis to better analyze its performance against prior periods on a comparable basis.

"Total operating costs" denotes operating costs (before processing recoveries), transportation costs and marketing costs. Management believes that total operating costs assists management and investors in assessing Birchcliff's cost structure as it relates to the PCS Gas Plant.

ADVISORIES

BOE CONVERSIONS

Boe amounts have been calculated by using the conversion ratio of 6 Mcf of natural gas to 1 bbl of oil. Boe amounts may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

MCFE, BCFE AND TCFE CONVERSIONS

Mcfe, Bcfe and Tcfe amounts have been calculated by using the conversion ratio of 1 bbl of oil to 6 Mcf of natural gas. Mcfe, Bcfe and Tcfe amounts may be misleading, particularly if used in isolation. A conversion ratio of 1 bbl to 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

MMBTU PRICING CONVERSION

$1.00 per MMbtu equals $1.00 per Mcf based on a standard heat value Mcf.

RESERVES FOR PORTION OF PROPERTIES

With respect to the disclosure of reserves contained herein relating to portions of Birchcliff's properties, the estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties due to the effects of aggregation.

FUTURE NET REVENUE

Estimates of future net revenue, whether calculated without discount or using a discount rate, do not represent fair market value.

POSSIBLE RESERVES

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

DISCOVERED RESOURCES

With respect to the discovered resources (including contingent resources) disclosed in this Annual Report, there is uncertainty that it will be commercially viable to produce any portion of the resources.

UNDISCOVERED RESOURCES

With respect to the undiscovered resources (including prospective resources) disclosed in this Annual Report, there is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

OIL AND GAS METRICS

This Annual Report contains metrics commonly used in the oil and natural gas industry, including netbacks, production and reserves capital efficiencies, reserves life index, recycle ratio, reserves replacement, F&D costs and FD&A costs. These oil and gas metrics do not have do not have any standardized meanings and may not be comparable to similar measures presented by other companies where similar terminology is used and should not be used to make comparisons. As a result, readers are cautioned as to the reliability of such metrics.

- Production capital efficiency is calculated by dividing the aggregate capital expended (DCCET or F&D, as the case may be) by the initial 90 day restricted (choked) average daily production (IP 90) for the wells drilled. In this Annual Report, production capital efficiency for Birchcliff has been presented on a half-cycle and full-cycle basis. Half-cycle economics are based on Birchcliff's DCCET costs. Full-cycle economics are based on F&D costs and incorporate half-cycle costs, as well as Birchcliff's facilities, land, seismic and related costs. There is no certainty that Birchcliff's future capital programs will generate results to match historic production capital efficiencies presented in this Annual Report.
- Reserves life index is calculated by dividing reserves estimated by Deloitte as at December 31 of the year indicated by the specified production rate. Reserves life index may be used as a measure of a company's sustainability.
- Recycle ratios are calculated by dividing the average operating netback per boe or funds flow netback per boe, as the case may be, by F&D costs or FD&A costs, as the case may be. A breakeven recycle ratio of 1.0x exists when the operating netback per boe or funds flow netback per boe, as the case may be, equals the F&D costs and FD&A costs, as the case may be. Recycle ratios may be used as a measure of a company's profitability.
- Reserves replacement is calculated by dividing proved developed producing reserves, proved reserves or proved plus probable reserves additions, as the case may be, before production by total production in the applicable period. Reserves replacement may be used as a measure of a company's sustainability and its ability to replace its proved developed producing reserves, proved reserves or proved plus probable reserves, as the case may be.

- With respect to F&D and FD&A costs (which are also referred to herein as "reserves capital efficiencies") disclosed in this Annual Report:
    - F&D costs both including and excluding FDC have been presented herein. F&D costs for each reserves category in a particular period are calculated by taking the sum of: (i) exploration and development costs incurred in the period; and (ii) where FDC has been included, the change during the period in FDC for the reserves category; divided by the additions to the reserves category before production during the period. F&D costs exclude the effects of acquisitions and dispositions. FD&A costs are calculated in the same manner as F&D costs but include the effect of acquisitions and dispositions.
    - In calculating the amounts of F&D and FD&A costs for a year, the changes during the year in estimated reserves and estimated FDC are based upon the evaluations of Birchcliff's reserves prepared by Deloitte, Birchcliff's independent qualified reserves evaluator, effective December 31 of such year.
    - The aggregate of the exploration and development costs incurred in the most recent financial year and any change during that year in estimated FDC generally will not reflect total F&D costs related to reserves additions for that year.
    - F&D and FD&A costs may be used as a measure of a company's efficiency with respect to finding and developing its reserves.
- For information regarding netbacks, please see "*Non-GAAP Measures*".

DRILLING LOCATIONS

This Annual Report discloses potential future drilling locations in three categories: (i) proved locations; (ii) probable locations; and (iii) unbooked locations. Proved locations and probable locations are proposed drilling locations identified in the 2015 Reserves Evaluation that have proved and/or probable reserves, as applicable, attributed to them in the 2015 Reserves Evaluation. Unbooked locations are internal estimates based on Birchcliff's prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal technical analysis review. Unbooked locations do not have proved or probable reserves attributed to them in the 2015 Reserves Evaluation. Of the 3,555.2 net existing horizontal wells and potential net future horizontal drilling locations identified herein, 505.2 are proved locations, 698.8 are proved plus probable locations and 2,853.4 are unbooked locations. Unbooked locations have been identified by management based on evaluation of applicable geologic, seismic, engineering, production and reserves information.

Birchcliff's ability to drill and develop these locations and the drilling locations on which Birchcliff actually drills wells depends on a number of uncertainties and factors, including, but not limited to, the availability of capital, equipment and personnel, oil and natural gas prices, capital and operating costs, inclement weather, seasonal restrictions, drilling results, additional geological, geophysical and reservoir information that is obtained, production rate recovery, gathering system and transportation constraints, net price received for commodities produced, regulatory approvals and regulatory changes. As a result of these uncertainties, there can be no assurance that the potential future drilling locations Birchcliff has identified will ever be drilled or if Birchcliff will be able to produce oil, NGL or natural gas from these or any other potential drilling locations. As such, Birchcliff's actual drilling activities may materially differ from those presently identified, which could adversely affect Birchcliff's business. While certain of the unbooked drilling locations have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, some of the other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional proved or probable reserves, resources or production.

INITIAL PRODUCTION RATES

Any references in this Annual Report to initial production rates and other short-term production rates for any wells are not determinative of the rates at which such wells will continue to produce and decline thereafter and are not necessarily indicative of the long-term performance or the ultimate recovery of such wells. Such rates may be based on field estimates and may be based on limited data available at the time. Readers are cautioned not to place reliance on such rates in calculating aggregate production for Birchcliff or the assets for which such rates are provided.

OPERATING COSTS

References in this Annual Report to "operating costs" exclude transportation and marketing costs.

FORWARD-LOOKING INFORMATION

This Annual Report contains forward-looking information within the meaning of applicable Canadian securities laws. Forward-looking information relates to future events or future performance and is based upon Birchcliff's current internal expectations, estimates, projections, assumptions and beliefs. All information other than historical fact is forward-looking information. Information relating to reserves is forward-looking as it involves the implied assessment, based on certain estimates and assumptions, that the reserves exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future. Words such as "plan", "expect", "project", "intend", "believe", "anticipate", "estimate", "estimated", "forecast", "may", "will", "potential", "proposed" and other similar words that convey certain events or conditions "may" or "will" occur are intended to identify forward-looking information.

In particular, this Annual Report contains forward-looking information relating to: Birchcliff's plans and other aspects of its anticipated future operations, management focus, strategies, priorities and goals, including Birchcliff's goal of self-funded capital expenditure programs, a strong balance sheet and strong production; performance characteristics of Birchcliff's oil and natural gas assets; the potential of Birchcliff's resource plays and estimated ultimate recoveries; estimates of future drilling locations and opportunities and Birchcliff's expectation that its inventory of drilling opportunities will provide significant upside and production and reserves growth for many years; Birchcliff's competitive position; Birchcliff's ability to maximize funds flow in a low commodity price environment; Birchcliff's expectation that it will continue to seek opportunities to reduce its costs further; decline rates and Birchcliff's forecast base production decline rate for 2016, which decline rate is expected to give Birchcliff the ability to spend less to keep production flat; Birchcliff's ability to withstand the low commodity price environment; Birchcliff's expectation that it can continue to unlock value for shareholders by developing its resource plays; estimates of reserves, resources and the net present values of future net revenue associated with Birchcliff's reserves; opportunities for future production growth; price forecasts; FDC; reserves life index; Birchcliff's expectation that its business is economically viable in the current commodity price environment; the 2016 Revised Capital Budget, including planned capital expenditures, Birchcliff's plan to drill a total of 13 (13.0 net) wells, the anticipated results from the 2016 Revised Capital Budget and Birchcliff's expectation that the 2016 Revised Capital Budget will be less than its expected funds flow for 2016; Birchcliff's flexibility to adjust the level of its capital expenditures and Birchcliff's financial flexibility; Birchcliff's proposed exploration and development activities and the timing thereof, including wells to be drilled; Birchcliff's production guidance for 2016, including its estimates of its annual average production for 2016 and 2016 annual average production growth; Birchcliff's costs to drill, case, complete, equip and tie-in its Montney/Doig horizontal natural gas wells are expected to average approximately $4.0 million per well during 2016; the combination of decreased capital costs and the improved well performance that Birchcliff is now realizing is expected to have a positive effect on its reserves and production capital efficiencies and internal rates of return; Birchcliff's belief that if in 2017 commodity prices remain low, it could spend approximately $90 million of capital and run flat between 40,000 to 41,000 boe per day; Birchcliff's ability to find, develop and produce from its reserves for less than what it receives in revenue from its production; proposed expansions of the PCS Gas Plant, including the anticipated processing capacities of the PCS Gas Plant after such expansions, the anticipated timing of such expansions and the estimated cost to achieve such expansions; management's belief that the ultimate recovery from Birchcliff's Montney/Doig horizontal natural gas wells will continue to improve year-over-year as production declines continue to flatten; and expectations that as drilling and completion technologies continue to improve, recovery factors and production rates in the Montney/Doig Natural Gas Resource Play should also improve. In addition, forward-looking information in this Annual Report includes the forward-looking information identified in the MD&A under the heading "*Advisories – Forward-Looking Information*".

The forward-looking information contained in this Annual Report is based upon certain expectations and assumptions, including: prevailing and future commodity prices, currency exchange rates, interest rates, inflation rates, royalty rates and tax rates; the state of the economy and the exploration and production business; the economic and political environment in which Birchcliff operates; the regulatory framework regarding royalties, taxes and environmental laws; anticipated timing and results of capital expenditures; the sufficiency of budgeted capital expenditures to carry out planned operations; results of operations; operating, transportation, marketing and general and administrative costs; the performance of existing and future wells, well production rates and well decline rates; well drainage areas; success rates for future drilling; reserves and resource volumes and Birchcliff's ability to replace and expand oil and gas reserves through acquisition, development or exploration; the impact of competition; the availability of, demand for and cost of labour, services and materials; Birchcliff's ability to access capital; the ability to obtain financing on acceptable terms; the ability to obtain any necessary regulatory approvals in a timely manner; the ability of Birchcliff to secure adequate transportation for its products; and Birchcliff's ability to market oil and gas. In addition, Birchcliff has made the following key assumptions with respect to certain forward-looking information contained in this Annual Report:

- With respect to statements regarding decline rates, the key assumption is the validity of the geological and other technical interpretations performed by Birchcliff's technical staff.
- With respect to estimates of reserves, resources and the net present values of future net revenue associated with Birchcliff's reserves, the key assumption is the validity of the data used by Deloitte in their independent evaluations, which includes technical information and forecast commodity prices.
- With respect to statements regarding the 2016 Revised Capital Budget, including Birchcliff's expectation that the 2016 Revised Capital Budget will be less than its expected funds flow for 2016, the key assumption is that Birchcliff realizes the annual average production target of 40,000 to 41,000 boe per day and the commodity prices upon which the 2016 Revised Capital Budget is based, being an expected annual average WTI price of US$40.00 per barrel of oil and an AECO price of CDN$2.50 per GJ of natural gas during 2016 with an exchange rate of $CDN/$US of 1.40. Birchcliff will continue to monitor economic conditions and commodity prices and, where deemed prudent, will adjust the 2016 Revised Capital Budget to respond to changes in commodity prices and other material changes in the assumptions underlying the 2016 Revised Capital Budget.
- With respect to statements of future wells to be drilled and estimates of future drilling locations and opportunities, the key assumptions are: the validity of the geological and other technical interpretations performed by Birchcliff's technical staff, which indicate that commercially economic volumes can be recovered from Birchcliff's lands as a result of drilling future wells; and that commodity prices and general economic conditions warrant proceeding with the drilling of such wells.
- With respect to estimates as to Birchcliff's annual average production for 2016 and 2016 annual average production growth, the key assumptions are that: the 2016 Revised Capital Budget will be carried out as currently contemplated; no unexpected outages occur in the infrastructure that Birchcliff relies on to produce its wells and that any transportation service curtailments or unplanned outages that occur will be short in duration or otherwise insignificant; the construction of new infrastructure meets timing expectations; existing wells continue to meet production expectations; and future wells scheduled to come on production meet timing, production and capital expenditure expectations.
- With respect to statements regarding proposed expansions of the PCS Gas Plant, including the anticipated processing capacities of the PCS Gas Plant after such expansions and the anticipated timing of such expansions, the key assumptions are that: future drilling is successful; there is sufficient labour, services and equipment available; Birchcliff will have access to sufficient capital to fund those projects; and commodity prices and general economic conditions warrant proceeding with the construction of such facilities and the drilling of associated wells.
- With respect to Birchcliff's belief that if in 2017 commodity prices remain low, it could spend approximately $90 million of capital and run flat between 40,000 to 41,000 boe per day, the key assumptions are that: drilling results in 2017 will be consistent with historical drilling results; and drilling, completion, equipping and tie-in costs do not exceed current levels.

Undue reliance should not be placed on forward-looking information, as there can be no assurance that the plans, intentions, expectations or assumptions upon which they are based will occur. Although Birchcliff believes that the expectations and assumptions reflected in the forward-looking information are reasonable, there can be no assurance that such expectations will prove to be correct. As a consequence, actual results may differ materially from those anticipated.

Forward-looking information necessarily involves both known and unknown risks and uncertainties that could cause actual results to differ materially from those anticipated, including, but not limited to: general economic, market and business conditions which will, among other things, impact the demand for and market prices of Birchcliff's products and Birchcliff's access to capital; volatility of crude oil and natural gas prices; fluctuations in currency and interest rates; operational risks and liabilities inherent in oil and natural gas operations; uncertainties associated with estimating oil and natural gas reserves and resources; the accuracy of oil and natural gas reserves estimates and estimated production levels as they are affected by exploration and development drilling and estimated decline rates; geological, technical, drilling, construction and processing problems; uncertainty of geological and technical data; changes in tax laws, crown royalty rates, environmental laws and incentive programs relating to the oil and natural gas industry and other actions by government authorities, including changes to the royalty and carbon tax regimes and the imposition or reassessment of taxes; the cost of compliance with current and future environmental laws; political uncertainty and uncertainty associated with government policy changes; uncertainties and risks associated with pipeline restrictions and outages to third-party infrastructure that could cause disruptions to production; the inability to secure adequate production transportation for Birchcliff's products; the occurrence of unexpected events such as fires, equipment failures and other similar events affecting Birchcliff or other parties whose operations or assets directly or indirectly affect Birchcliff; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; stock market volatility; loss of market demand; environmental risks, claims and liabilities; incorrect assessments of the value of acquisitions and exploration and development programs; shortages in equipment and skilled personnel; uncertainties associated with the outcome of litigation or other proceedings involving Birchcliff; competition for, among other things, capital, acquisitions of reserves, undeveloped lands, equipment and skilled personnel; and uncertainties associated with credit facilities and counterparty credit risk.

The foregoing list of risk factors is not exhaustive. Additional information on these and other risk factors that could affect operations or financial results are included in Birchcliff's most recent Annual Information Form and in other reports filed with Canadian securities regulatory authorities. Forward-looking information is based on estimates and opinions of management at the time the information is presented. Birchcliff is not under any duty to update the forward-looking information after the date of this Annual Report to conform such information to actual results or to changes in Birchcliff's plans or expectations, except as otherwise required by applicable securities laws.

Any "financial outlook" contained in this Annual Report, as such term is defined by applicable securities laws, is provided for the purpose of providing information about management's current expectations and plans relating to the future. Readers are cautioned that reliance on such information may not be appropriate for other purposes.

THANK YOU TEAM BIRCHCLIFF

Jeffrey Akeroyd, Bradley Alexander, Karen Allen, Camille Ashton, Rainer Augsten, Gates Aurigemma, Al Basnett, Angela Belbeck, Charmaine Belley, Tyrus Bender, Tim Berg, Perry Billard, Deborah Borthwick, Myles Bosman, Jeff Boswell, Robyn Bourgeois, David Boyle, Wayne Brown, James Burke, Madison Burns, David Campbell, Chris Carlsen, Alex Carlson, Caitlin Carrigy, Robert Charchuk, David Christensen, Bob Clark, Owen Clarke, Wendy Clay, Mike Cordingley, Ken Cullen, Krystal Dafoe, Dennis Dawson, Allan Dixon, Jesse Doenz, Joe Doenz, Keifer Dolen, Kelly Dolen, Emily Ebbels, Tim Etcheverry, Laura Ferguson, Jaryn Flower, Grant Friesen, Marshall Fritz, George Fukushima, Andy Fulford, Carrie Fyfe, Alexandra Gatza, Bruno Geremia, Melina Geremia, Melodie Gilker, Chad Goddard, Jolanda Goertzen, David Graham, Lee Grant, Bob Grisack, Tania Haberlack-Dolan, Sam Hampton, Theresa Hannouche, Richard Harris, Wanda Hiebert, Lorna Hildebrand, Paul Hirsekorn, Janet Hogan, Jasen Holmstrom, Daryl Hudak, Dave Humphreys, Derek Jamieson, Anna Johnson, Dave Johnson, Julie Johnson, Stacy Johnson, Dustin Kelm, Ryan Kennedy, Phyllis Kinzner, Diane Knoblauch, Heather Kwiatkowski, Dani Laird, Kristen Lewicki, Michael Lillejord, Thomas Lundquist, Joe Lyste, Scott MacDermott, John MacGillivray, Dallas MacLean, Darcy MacLeod, Mary MacNeill, Janice Malainey, Maggie Malapad, Valerie Martin, Jeff McAndrews, Deb McFee, Angie McGonigal, Marc McIntosh, Ryan McIntosh, Darin McLarty, Jerilyn McLeod, Danielle McPhee, Richard Melling, Paul Messer, Melissa Meyers, Al Michetti, Emelyia Moghaddami, Tyler Montpellier, Ron Morgan, Stephen Morton, Shaun Moskalyk, Steve Mueller, McKenzie Murdoch, Ed Murphy, Tyler Murray, Sarah Nance, Michael Ng, Marcel Njongwe, Christopher Olson, Laura O'Neill, Philomena Paisley, Bruce Palmer, Bill Partridge, Dean Paterson, Brenda Pearson, Paul Picco, Allan Pickel, Landon Poffenroth, Lindsay Postma, Shoni Proctor, Dale Richardson, Brian Ritchie, Michelle Rodgerson, Jeff Rogers, Sherri Rosia, Randy Rousson, Todd Sajtovich, Lee Sallenbach, Victor Sandhawalia, Andreas Scheel, Seymour Schulich, Wade Schultz, Daniel Sharp, Larry Shaw, Amy Short, Nick Sizer, Ryan Sloan, Dwayne Spelay, Ben Stevenson, Darby Stolk, Lindsay Sturrock, Tracey Suchlandt, Jim Surbey, Jeff Tonken, Gillian Topping, Hue Tran, Tammy Tran, Trevor Trudeau, Becky Van De Reit, Theo van der Werken, Kara Vance, Greg Vreim, Linda Wang, Matthew Weiss, David Wetta, Jonathan White, Chris Wurz, John Yeo, Deirdre Yuzwa, Steve Zylinski

CORPORATE INFORMATION

OFFICERS

A. Jeffery Tonken
President & Chief Executive Officer

Myles R. Bosman
Vice-President, Exploration &
Chief Operating Officer

Chris A. Carlsen
Vice-President, Engineering

Bruno P. Geremia
Vice-President &
Chief Financial Officer

David M. Humphreys
Vice-President, Operations

James W. Surbey
Vice-President,
Corporate Development

DIRECTORS

Larry A. Shaw (Chairman)
Calgary, Alberta

Kenneth N. Cullen
Calgary, Alberta

Dennis A. Dawson
Calgary, Alberta

A. Jeffery Tonken
President & Chief Executive Officer
Calgary, Alberta

MANAGEMENT TEAM

Gates Aurigemma
Manager, General Accounting

Perry Billard
Asset Team Lead – North

Robyn Bourgeois
General Counsel

Wayne Brown
Production Manager

Jesse Doenz
Controller &
Investor Relations Manager

George Fukushima
Manager of Engineering

Andrew Fulford
Surface Land Manager

Robert (Bob) Grisack
Land Manager

Paul Messer
Manager of Information Technology

MANAGEMENT TEAM (con't)

Bruce Palmer
Manager of Geology

Bill Partridge
Asset Team Lead – East

Michelle Rodgerson
Office Manager

Jeff Rogers
Facilities Manager

Randy Rousson
Drilling & Completions Manager

Ryan Sloan
Health, Safety & Environment
Manager

Hue Tran
Joint Venture & Marketing Manager

Theo van der Werken
Asset Team Lead – West

SOLICITORS

Borden Ladner Gervais LLP
Calgary, Alberta

AUDITORS

KPMG LLP
Chartered Professional Accountants
Calgary, Alberta

RESERVES EVALUATOR

Deloitte LLP
Calgary, Alberta

BANK SYNDICATE

The Bank of Nova Scotia

HSBC Bank Canada

Union Bank, Canada Branch

Alberta Treasury Branches

National Bank of Canada

Canadian Imperial Bank of Commerce

The Toronto-Dominion Bank

Business Development Bank of Canada

United Overseas Bank Limited

ICICI Bank Canada

Wells Fargo Bank, N.A., Canadian Branch

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SPIRIT RIVER OFFICE

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TRANSFER AGENT

Computershare Trust Company
of Canada
Calgary, Alberta and Toronto, Ontario

STOCK EXCHANGE LISTING

The Toronto Stock Exchange
Trading Symbols: BIR, BIR.PR.A, BIR.PR.C

ANNUAL GENERAL MEETING

The Annual General Meeting of
Shareholders will be held at
3:00 p.m. on Thursday, May 12, 2016,
in the Strand/Tivoli Room of the
Metropolitan Conference Centre,
333 - 4th Avenue S.W., Calgary, Alberta

Birchcliff Energy Ltd.

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