Crescent Point Energy

Corporate Presentation

December 2016

15 YEARS OF SUCCESS

Crescent Point Energy is one of Canada's largest light and medium oil producers, based in Calgary, Alberta.
The Company is focused on growing its significant resource base in the Williston Basin, Southwest Saskatchewan and the Uinta Basin in Utah.

FORWARD-LOOKING STATEMENTS

This presentation contains "forward-looking statements" within the meaning of applicable securities legislation, such as section 27A of the Securities Act of 1933 and section 21E of the Securities Exchange Act of 1934, including estimates of future production, cash flows and reserves, business plans for drilling and exploration, the estimated amounts and timing of capital expenditures, the assumptions upon which estimates are based and related sensitivity analyses, and other expectations, beliefs, plans, objectives, assumptions or statements about future events or performance (often, but not always, using words or phrases such as "expects" or "does not expect", "is expected", "anticipates" or "does not anticipate", "plans", "estimated" or "intends", or stating that certain actions, events or results “may", "could", "would", "might" or "will" be taken, occur or be achieved). In particular, this presentation contains forward-looking statements pertaining, to the following: estimates of 2017 average and exit production and capital expenditures (including the percentage expected to be spent on drilling and development and the percentage expected to be spent on facilities and seismic), reserves, drilling inventory (including broken down by key focus area) and expected 2017 decline rates; the Corporation’s business strategy to develop and enhance, acquire and manage risk; the expected impact of the Corporation’s hedging program on funds flow volatility and dividend and capital spending stability; expected 2017 drilling capital efficiency, funds flow from operations netbacks, net debt to funds flow from operations (Q4 annualized) and the number of wells in the 2017 drilling plan; the basis for opportunities for additional production upside in 2017 due to conservative risked production; expected exit production per share growth; planned 2017 capital allocation (including drilling plans) and exit production growth by core area; plans to increase spending in Flat Lake and Uinta; expectations that waterflood efficiencies will be realized in 2017; the Corporation’s flexibility to increase its capital budget and growth targets, including expected increase in funds flow for every WTI US$1/bbl increase in prices; expected well payouts; the opportunity for secondary waterflood development in Flat Lake; 2017 horizontal drilling plans for the Unita Basin; targeted recovery rate on primary in Viewfield Bakken; secondary waterflood development plans for Viewfield Bakken, including targeted recovery rate and F&D and the expected implementation of waterflood technology to enhance production and recovery rates; confirmation of no material near-term debt maturities along with 2019 renewal date for bank credit facilities; continued capital cost improvements; and expected operating expense reductions for 2016 compared to original budget; plans to create long-term value by using waterflood expansion to lower decline rates and future capital requirements, while also increasing ultimate recoveries over primary development; using technology to increase recoveries and capital efficiencies, expand programs from vertical to larger horizontal opportunities and help discover new plays; the Corporation’s opportunity to lever its technical expertise in the future; plans to continue growing on a per share basis; and the opportunity for increased recovery associated with the Corporation’s new resource plays with attractive mobility.

Statements relating to "reserves" are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future. There are numerous uncertainties inherent in estimating crude oil, natural gas and NGL reserves and the future cash flow attributed to such reserves. The reserve and associated cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating expenses, all of which may vary materially. Actual reserve values may be greater than or less than the estimates provided herein. Unless otherwise noted, reserves referenced herein are given as at December 31, 2015. Also, estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates and future net revenue for all properties due to the effect of aggregation. With respect to disclosure contained herein regarding resources other than reserves, there is uncertainty that it will be commercially viable to produce any portion of the resources. All required reserve information for the Company is contained in its Annual Information Form for the year ended December 31, 2015, which is accessible at www.sedar.com.

All forward-looking statements are based on Crescent Point’s beliefs and assumptions based on information available at the time the assumption was made. The material assumptions are disclosed in the presentation, in the Management’s Discussion and Analysis for the year ended December 31, 2015 under the headings “Marketing and Prices”, “Dividends”, “Capital Expenditures”, “Decommissioning Liability”, “Liquidity and Capital Resources”, “Critical Accounting Estimates”, “Changes in Accounting Policies” and “Outlook”. Crescent Point believes that the expectations reflected in these forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this presentation should not be unduly relied upon. By their nature, such forward-looking statements are subject to a number of risks, uncertainties and assumptions, which could cause actual results or other expectations to differ materially from those anticipated, expressed or implied by such statements, including those material risks discussed in the Company’s Annual Information Form and Form 40-F under “Risk Factors” and our Management’s Discussion and Analysis for the year ended December 31, 2015, under the headings “Risk Factors” and “Forward-Looking Information”, and risk factors described in other documents we file from time to time with securities regulatory authorities, all of which are available on SEDAR or sedar.com , EDGAR or www.sec.gov and Crescent Point Energy’s website as www.crescentpointenergy.com. In addition, risk factors include: financial risk of marketing reserves at an acceptable price given market conditions; volatility in market prices for oil and natural gas; delays in business operations; pipeline restrictions; blowouts; the risk of carrying out operations with minimal environmental impact; industry conditions including changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; uncertainties associated with estimating oil and natural gas reserves; economic risk of finding and producing reserves at a reasonable cost; uncertainties associated with partner plans and approvals; operational matters related to non-operated properties; increased competition for, among other things, capital, acquisitions of reserves and undeveloped lands; competition for and availability of qualified personnel or management; incorrect assessments of the value of acquisitions and exploration and development programs; unexpected geological, technical, drilling, construction and processing problems; availability of insurance; fluctuations in foreign exchange and interest rates; stock market volatility; failure to realize the anticipated benefits of acquisitions; general economic, market and business conditions; uncertainties associated with regulatory approvals; uncertainty of government policy changes; uncertainties associated with credit facilities and counterparty credit risk; and changes in income tax laws, tax laws, crown royalty rates and incentive programs relating to the oil and gas industry.

These risks and uncertainties could cause actual results or other expectations to differ materially from those anticipated, expressed or implied by such statements. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent. Crescent Point assumes no obligation to update forward-looking statements should circumstances or management's estimates or opinions change. Certain information contained herein have been prepared by third-party sources. The information provided herein has not been independently audited or verified by the Company.

HIGH-QUALITY, LOW-COST PRODUCER: CPG (TSX AND NYSE)

Crescent Point

2017 Average Production	172,000 boe/d (~89% liquids)
2017 Exit Production	183,000 boe/d (~89% liquids)
2017 Capital Expenditures	$1.45 billion
Market Capitalization	$9.4 billion[1]
Net Debt	$3.6 billion
Enterprise Value	$13.0 billion
Dividend (Yield)	$0.03 per month (2.1%)
Proved + Probable Reserves	935.7 mmboe (~15 years RLI)[2,3]
Drilling Inventory	~8,085 locations (~12 years)[3,4]
Expected 2017 Decline Rate	28%

Strategic Asset Base
Largest Canadian producer in Williston Basin (Top 5 including US producers)

Experienced Operator
#1 driller in Canada (Based on meters drilled)

Scalability in High-Netback Plays
Top quartile netbacks supported by drilling program with quick payouts

Operational Execution
~580 million boe of organic reserves additions and never missed a production target

Pioneers in Tight Rock Waterflood
Bakken waterflood is the largest tight oil pool under commercial waterflood in North America

2017 production, capital expenditures, and expected decline rate are based on guidance as of December 2016.
Remains on-track to meet or exceed 2016 average production guidance of 167,000 boe/d.
Net debt as of September 30, 2016.

FOOTNOTES INCLUDED IN THE BACK AS ENDNOTES

BUSINESS STRATEGY: PRINCIPALS OF SUCCESS

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Develop and Enhance Assets

- Increase recovery factors through step-out and infill drilling, waterflood optimization and improved technology

Acquire

- Focus on high-quality, large resource-in-place pools with production and reserves upside

Manage Risk

- Maintain excellent balance sheet, significant unutilized bank line capacity and 3 ½-year hedging program

• Proven Management Team • Excellent Balance Sheet • High-Quality Asset Base

FOCUSED GROWTH:
>23 BILLION BARRELS OF OOIP

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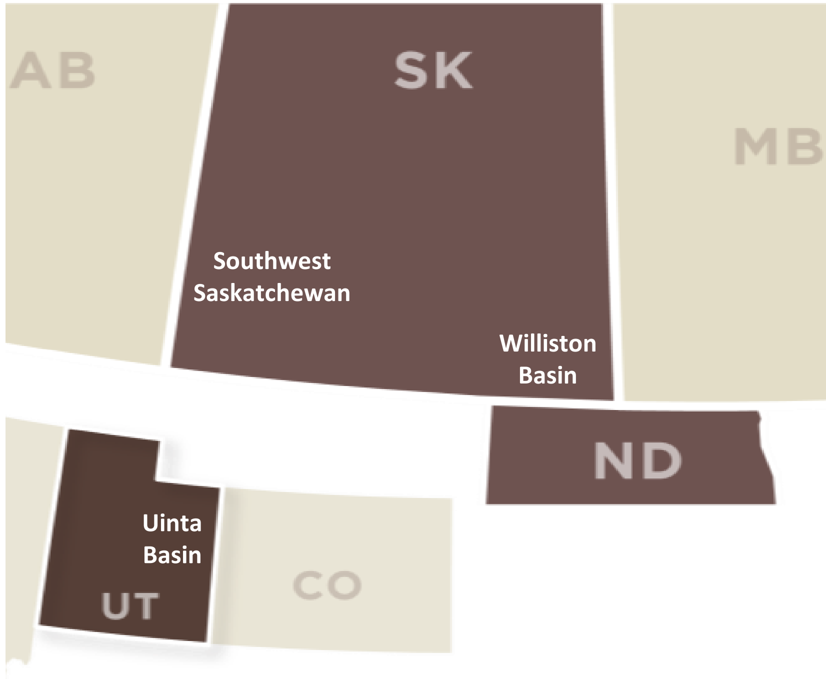
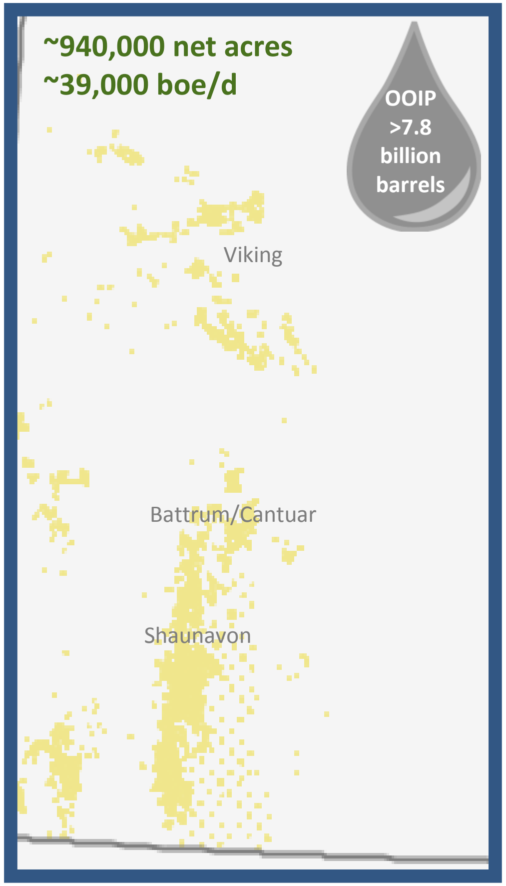
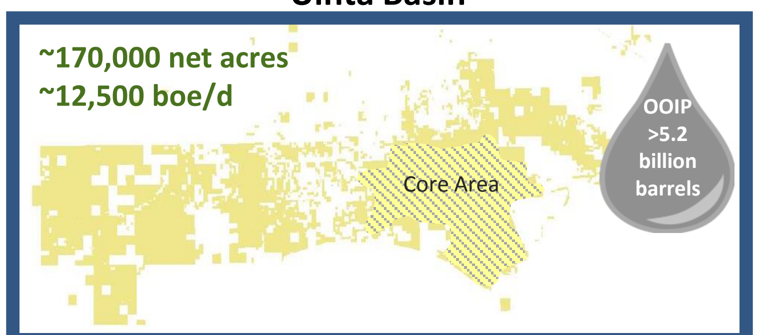


Southwest Saskatchewan



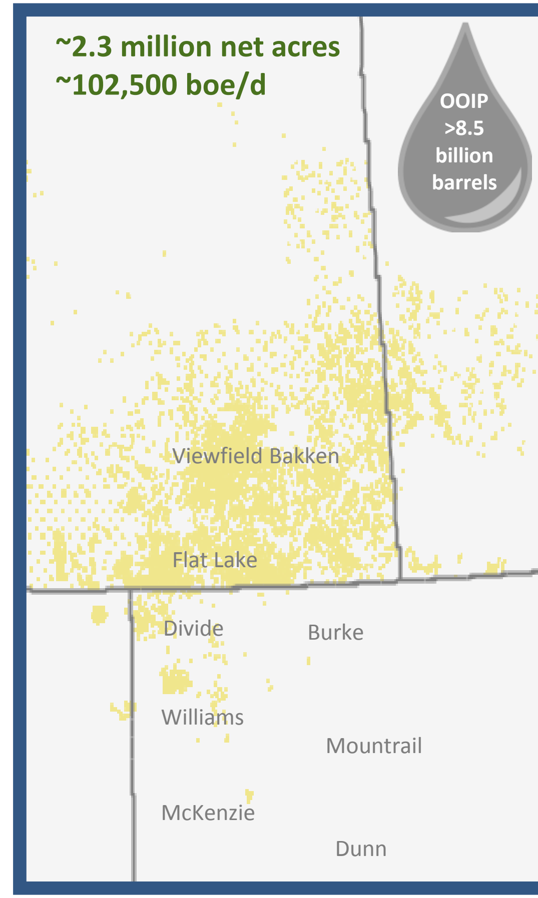
- Largest producer in the Shaunavon resource play
- Operating largest waterflood program

Uinta Basin



- Third largest producer and most active driller in 2016
- Highest number of zones tested to date horizontally

Williston Basin



- Largest Canadian producer and among top 5 within the Williston basin
- Operating largest waterflood program

Production as at December 2016.

CPG lands

COMMODITY HEDGING STRATEGY

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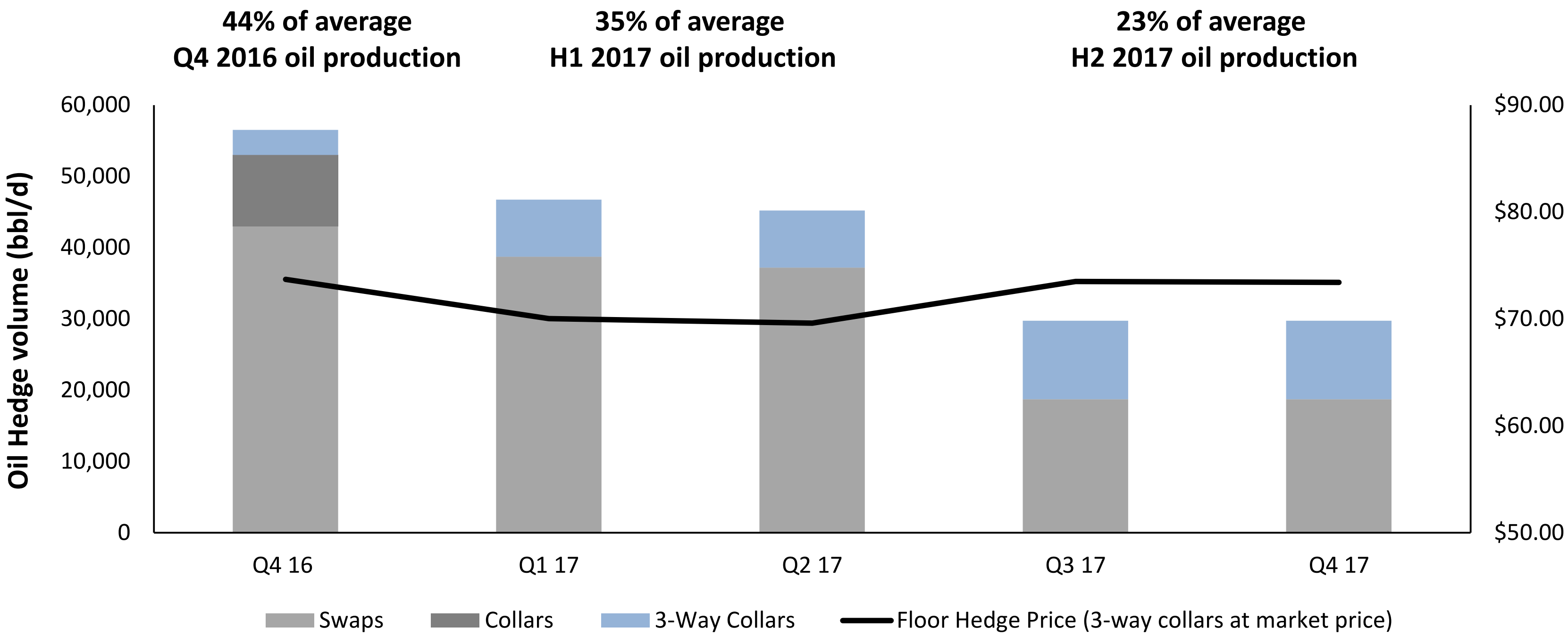

- Added approximately 4.9 million barrels of oil to hedging program since Q2 2016
- Active hedging program reduces funds flow volatility, provides greater stability to dividends and capital spending

As of Dec.5, 2016. Floor hedge price is calculated using the forward strip for the 3-way collar hedges. Floor hedge price of 3-way collar hedges are subject to change based on forward market prices. Percentages based on 2017 guidance.

2016 EXECUTION AND 2017 FOCUS

- **Ahead of 2016 production targets. Expect 2017 exit production of 183,000 boe/d (+10% growth)**
  - Production growth within each core area in 2017

- **Increased corporate drilling inventory in 2016 to >8,000 locations (~12 years)**
  - Added approximately ~1,000 net locations, more than replacing annual drilling program
  - Reduced capital costs during 2016 resulting in strong capital efficiencies of ~$21,000/boe in 2017

- **New play development during 2016 with plans to follow up and expand on this success during 2017**
  - Discovered new horizontal play in the Uinta Basin with productive capacity of ~80,000 boe/d[5]
  - Expanded Flat Lake resource play including the discovery of a new conventional Ratcliffe zone

- **Implementing new completions and waterflood technology to enhance recoveries and efficiencies**
  - Increasing testing of multiple-stage segmented strings waterflood technology during 2017

SEE "DEFINITIONS / NON-GAAP FINANCIAL MEASURES" FOR DETAILS ON OOIP DEFINITION.
SEE FOOTNOTES INCLUDED IN THE BACK AS ENDNOTES.

2017 CAPITAL BUDGET AND PRODUCTION GROWTH

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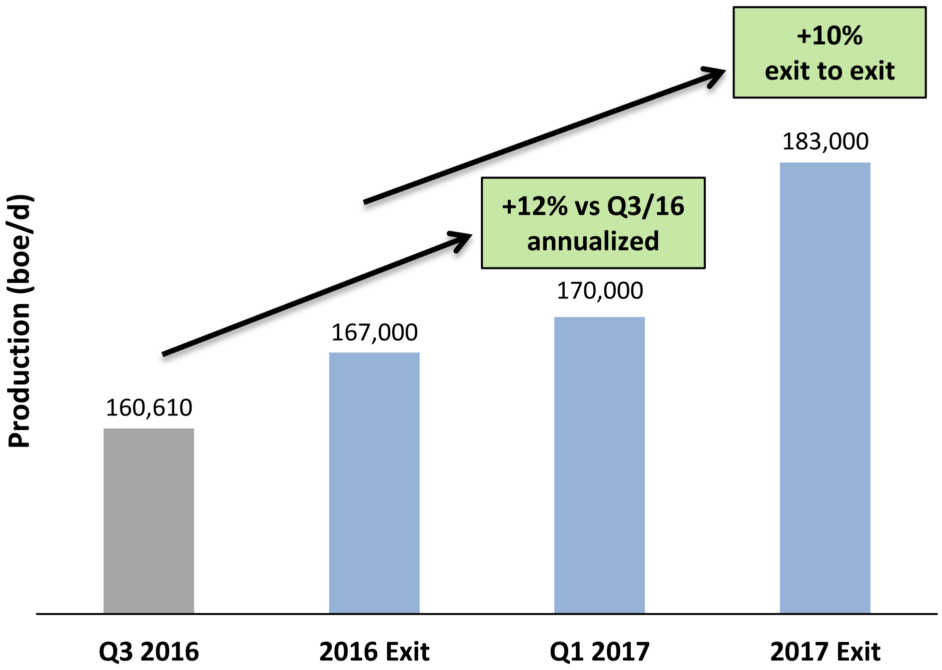
2017 Guidance	
Capital Expenditures ($ million)*	$1,450
Drilling and Development (%)	89%
Facilities and Seismic (%)	11%
Annual Average Production (boe/d)	172,000
Exit Production (boe/d)	183,000
Annual Decline Rate (%)	28%
Drilling Capital Efficiency ($ per boe/d)	$21,000
Funds Flow from Operations Netback ($/boe)	$26.50
Total Payout Ratio (%)	100%
Net debt to Funds Flow from Operations (Q4 Annualized)	2.0x
Number of Net Wells in Drilling Plan	670

* Excludes any net land and property acquisitions.
Netbacks and payout ratio based on US$52/bbl WTI and 0.75 CAD/USD exchange.

2017 Production Growth



- 6% growth from Q3/16 to Q1/17 (12% annualized) and 10% budgeted 2016 exit to 2017 exit growth
- Opportunity for additional upside as 2017 production guidance assumes conservative risking in new play developments (i.e. Flat lake step-out drilling, Uinta horizontals, etc.)

All figures are approximate.

2017 CAPITAL ALLOCATION AND PRODUCTION GROWTH BY CORE AREA

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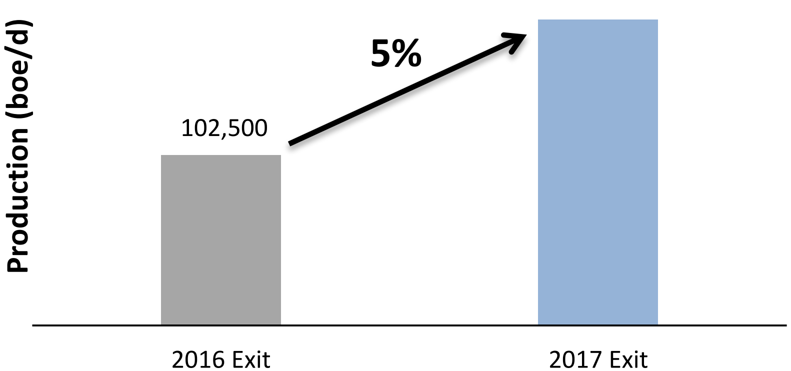
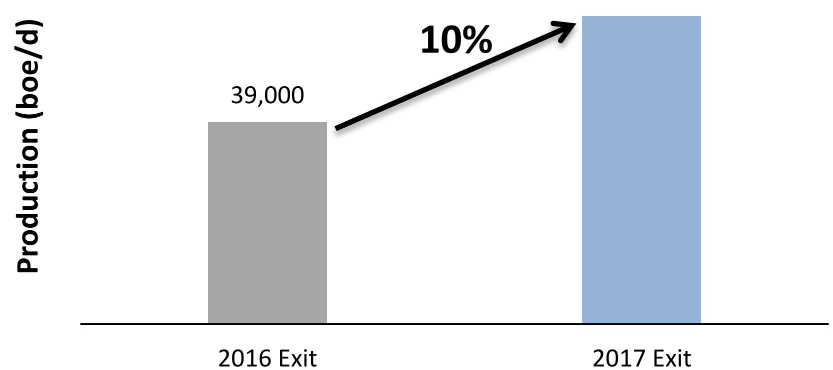
Williston Basin



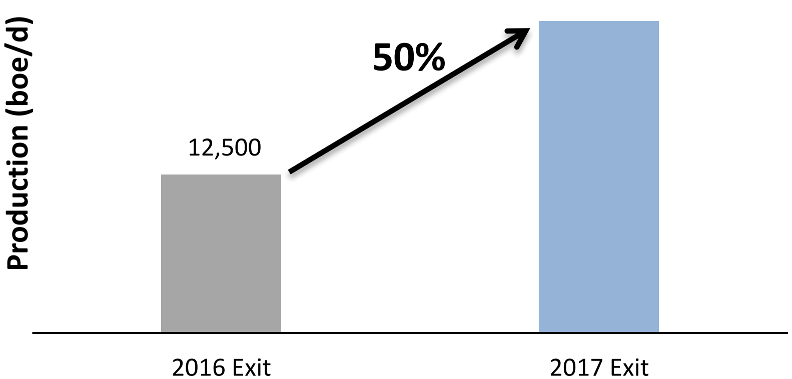
51% of 2017 total capital expenditures: 350 net wells

SW Saskatchewan



25% of 2017 total capital expenditures: 270 net wells

Uinta Basin



18% of 2017 total capital expenditures: 30 net wells

- **Increased spending in Flat Lake and Uinta Resource Plays**
  - Top quartile economics driving strong rates of return
  - Expanding on new play development success in 2016
- **Increasing efficiency of waterflood** during 2017
  - Testing new multi-stage segregated strings technology for field-wide implementation
- **Flexibility to increase capital budget and growth targets**
  - ~$50 million in funds flow for every WTI US$1/bbl increase

All figures are approximate.

SIGNIFICANT GROWTH POTENTIAL SUPPORTED BY STRONG WELL ECONOMICS

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Large Drilling Inventory and Significant OOIP with Low Recovery to Date

Key Focus Areas	Net locations[4]	Years of Inventory	OOIP (mmbbls)	Recovery to Date
Williston Basin	3,470	10	8,500	3.3%
SW Saskatchewan	3,375	13	7,800	2.5%
Uinta Basin[6]	830	26	5,200	0.6%
Other	410	17	1,600	11.4%
TOTAL	**8,085**	**12**	**23,100**	**3.0%**

- **Updated drilling inventory highlights success from new play developments**:
  - Added ~1,000 net internally identified locations during 2016 more than replacing annual drilling program

Drilling Program Supported by Quick Payouts

Well Payouts

~1 year or less

Williston Basin: Viewfield Bakken
Williston Basin: Flat Lake
Uinta Basin: Recent horizontal wells

~1 to 2 years

Williston Basin: SE SK Conventional
SW Saskatchewan: Shaunavon
SW Saskatchewan: Viking
Uinta Basin: Verticals
Other: Swan Hills

>2 years

Williston Basin: North Dakota

Pricing assumption:
2017 – US $52.00 WTI / 0.75 CAD/USD fx
2018 – US $57.50 WTI / 0.76 CAD/USD fx

All figures are rounded to approximate values.
OOIP and recovery to date as of December 31, 2015.

FOOTNOTES INCLUDED IN THE BACK AS ENDNOTES

WILLISTON BASIN: EXPANSION OF THE FLAT LAKE AREA

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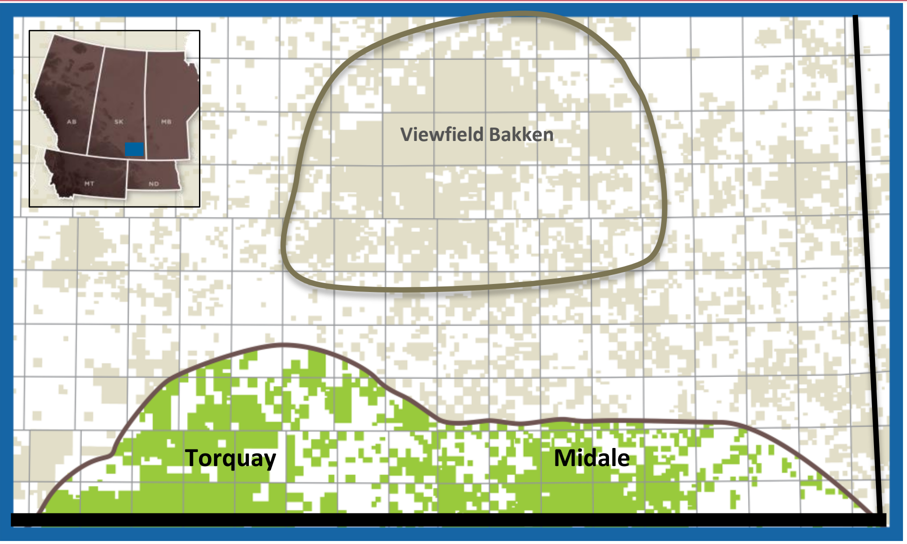
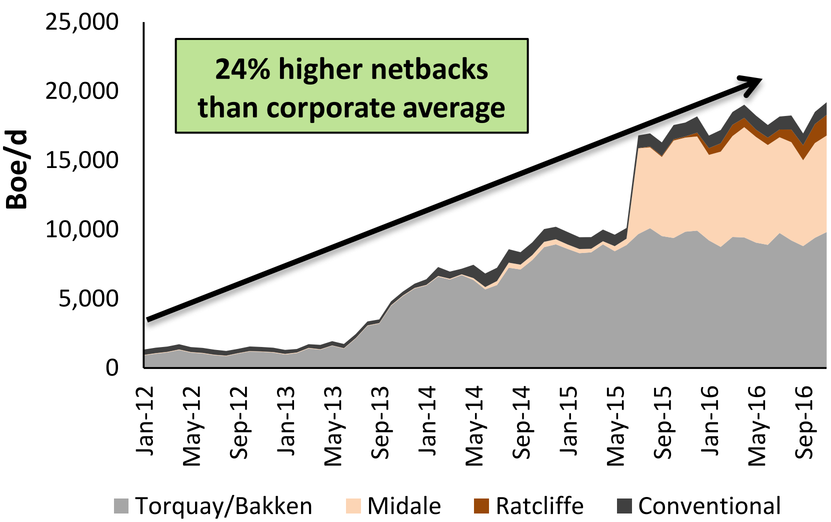


Flat Lake lands
Flat Lake edge
USA border
Crescent Point Energy lands

- **~23 % of 2017 capital expenditures budget (up from 19% in 2016)**
  - ~150 net wells planned for 2017 (up from ~105 in 2016)
- **Increased drilling locations and strategic land position during 2016:**
  - **Step-out program**: generated over 220 new net locations in the Torquay, Midale and Ratcliffe zones[7]
  - **Land Sales and acquisition**: consolidated ~67 net sections of land and ~300 net drilling locations[7]
- **Scalability across multiple zones**
  - ~1,300 net drilling locations and ~544,000 net acres of land[8]
  - ~2.9 billion barrels of OOIP (recovery to date of ~0.9%)
- **Strong economics and netbacks** that are top-quartile within company
- **Opportunity for secondary waterflood** development in each zone

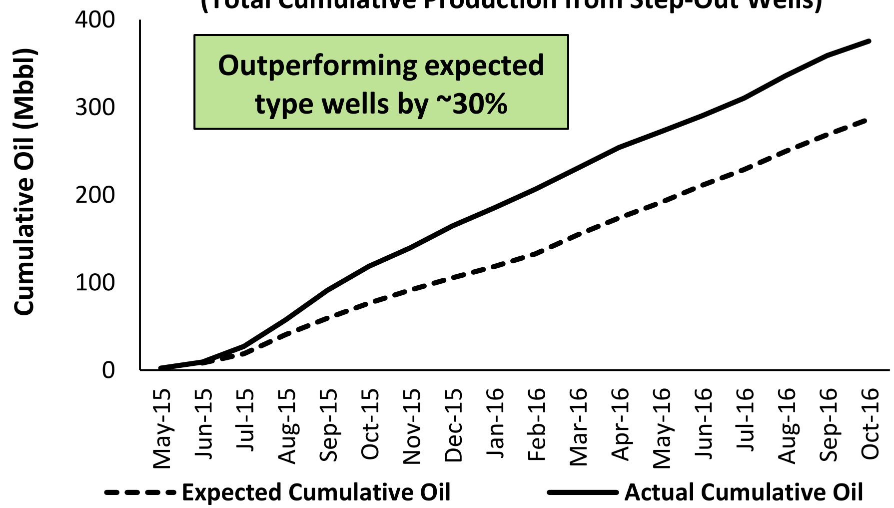
Flat Lake Production Growth



Netback comparison versus corporate average as at Q3 2016.

Step-Out Well Success Since 2015

(Total Cumulative Production from Step-Out Wells)



UINTA BASIN
ADVANCING NEW HORIZONTAL PLAY

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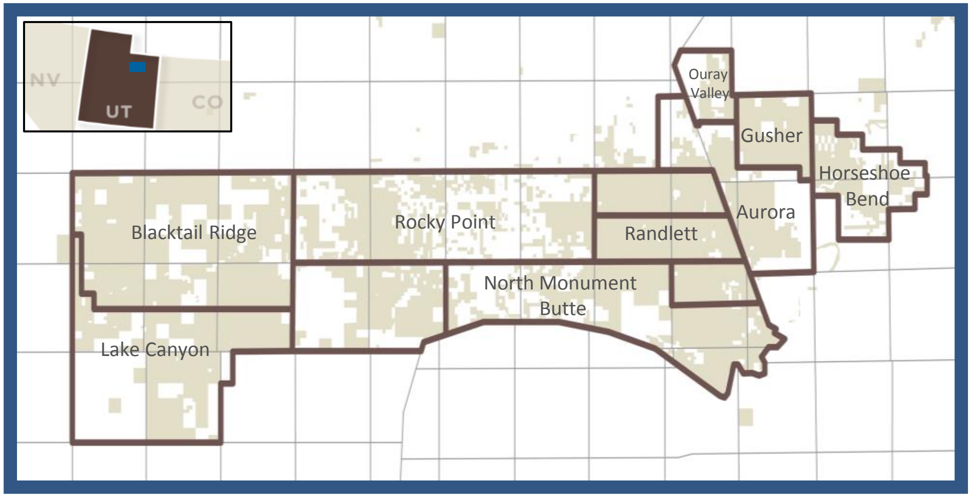


Crescent Point Energy lands

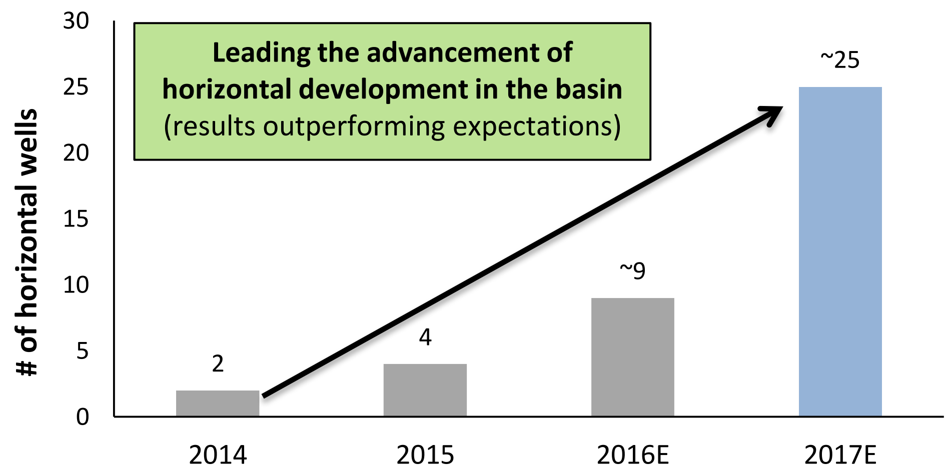
- **~18 % of 2017 capital expenditures budget (up from 8% in 2016)**
  - ~25 horizontal wells planned for 2017 (up from ~9 in 2016)
- **Most active horizontal driller during 2016**
  - Increased basin knowledge (seismic, core samples, well logs)
- **Scalability across multiple zones**
  - **~5.2 billion barrels of OOIP** (recovery to date ~0.6%)
  - Delineating six zones across ~170,000 net acres
  - Internally identified **~120 horizontal drilling locations** to date **in Castle Peak zone** (assuming 4 wells per section)[7]
    - ~80,000 boe/d of productive capacity[5]
  - **~700 vertical drilling** locations in addition to the early stage horizontal inventory[7]
- **Continually optimizing fluids and completion methods**

Multi-Zone Potential

	HZ wells drilled to date
Mahogany	
Garden Gulch	
Douglas Creek	3
Upper Black Shale	1
Lower Black Shale	1
Castle Peak	8
Uteland Butte	1
Wasatch	1
Horizontal Wells Drilled	**15**

5,000 ft
10,000 ft

Horizontal Drills Per Year



CASTLE PEAK ZONE:
HORIZONTAL DEVELOPMENT AND ECONOMICS

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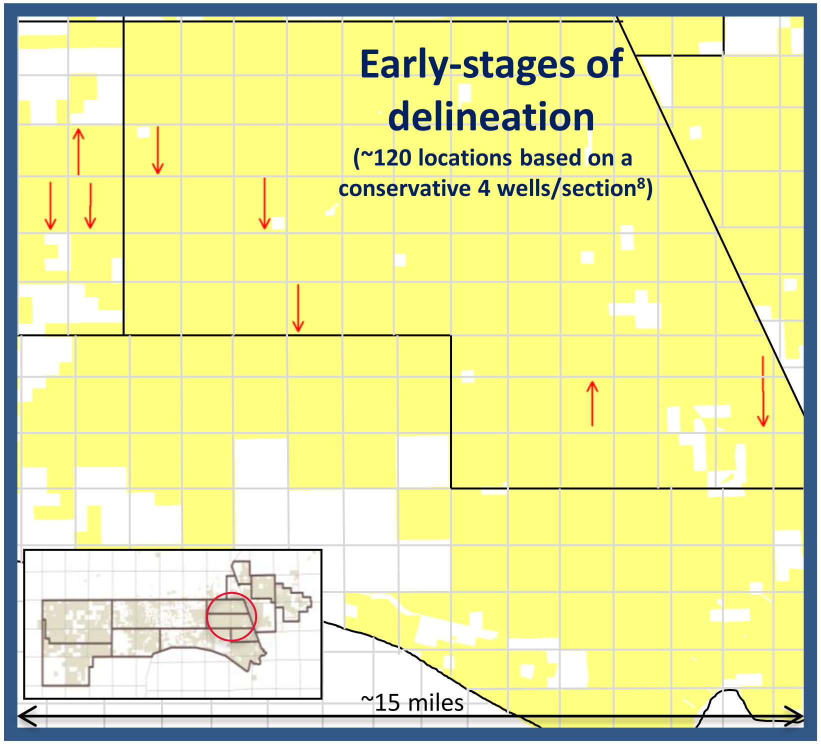


Castle Peak HZ drills to date in Randlett

Castle Peak Horizontal Type Curve Information

Depth (ft)	6,000 to 9,000
Lateral Length	Currently one-mile
Down-hole pressure (psi per foot)	0.5 to 0.7
Max flowing pressure (psi)	>1,600
Peak flowing rate (boe/d)*	>1,300
Proppant loading (lbs/foot)	Currently ~1,750
Differential to US WTI	~90%
Liquids Percentage	~80%

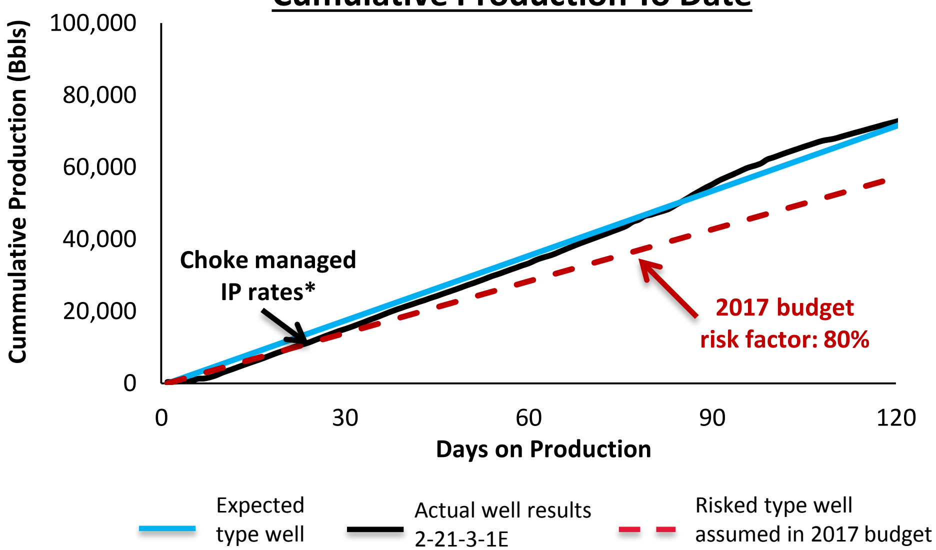
Castle Peak Horizontal Type Curve Economics

	Type Well (mboe)	IP 30 Rate* (boe/d)	IP 90 Rate (boe/d)	Well Cost ($M)	NPV @ 10% ($M)	IRR (%)	Payout (months)
Castle Peak	380	620	650	$5.0	$2.9	87	10

Well cost and NPV are in USD.

Pricing assumption:
2017 – US $52.00 WTI / 0.75 CAD/USD fx 2018 – US $57.50 WTI / 0.76 CAD/USD fx

Cumulative Production To Date



* Choke management to optimize current infrastructure

NEW WATERFLOOD TECHNOLOGY: MULTIPLE-STAGE SEGMENTED STRINGS

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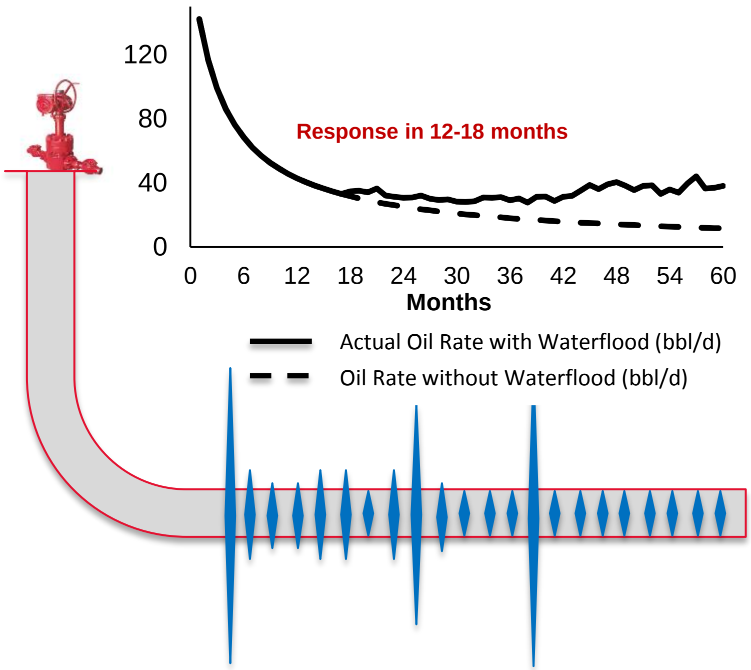
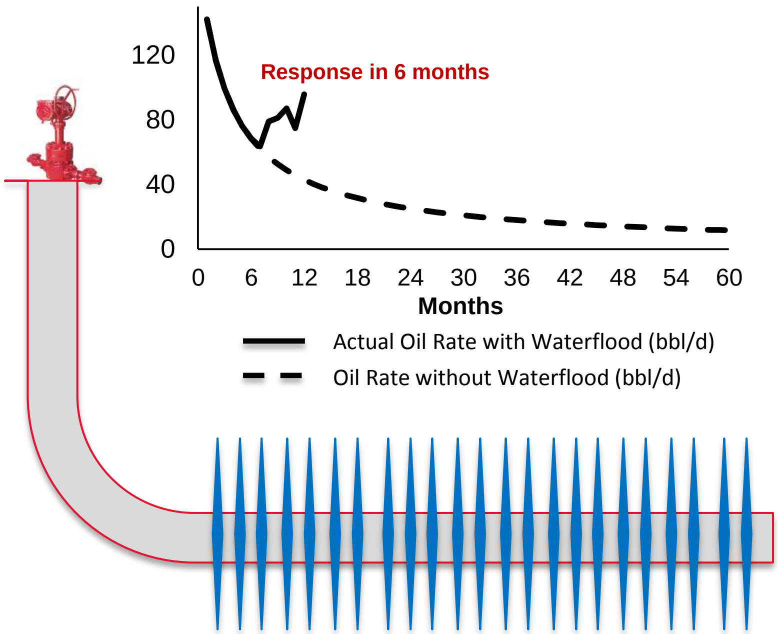
Previous Waterflood Technology



New Multiple-Stage Segmented Strings Technology

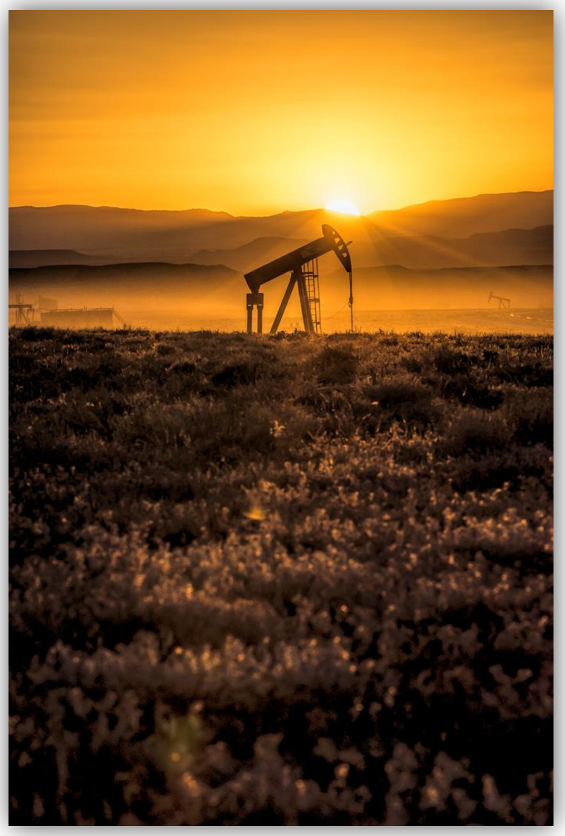


- **Benefits of multiple-stage segmented strings:**
  - **Water injectivity**: 3x increase without any corresponding change in the percentage of water produced
  - **Improved sweep efficiency**: Increased water distribution and more uniform sweep is analogous to what happened in the progression of completions technology (comparable to moving from surgi-frac to multi-stage fracture stimulation technology)
  - **Faster response time and higher economic recoveries**: Doubled production in offset wells after six months of injection versus predecessor technology, which stabilized production after one year
- **Focusing on increasing efficiency of waterflood during 2017**
  - Continue testing new multiple-stage segregated strings technology for field-wide implementation

FOOTNOTES INCLUDED IN THE BACK AS ENDNOTES

Proven Management Team

- Proven track record of per share reserves, production and cash flow growth and have never missed a production target
- 5-year weighted average F&D of $20.39 per 2P boe of reserves (2.2 times recycle ratio)[9]
- 6% production per share CAGR plus 7% average dividend yield (2010-2015)
- Paid out >$7 billion of dividends to shareholders, or $31.35 per share, since 2003
- Leaders in advancing new completions and waterflood technology



Excellent Balance Sheet

- Flexible capital budget to maintain balance sheet strength
- 3½-year hedging program provides cash flow stability and balance sheet protection
- Significant unutilized credit capacity of ~$1.9 billion

High-Quality Reserve Base

- Efficiently allocating capital across high-netback asset base
- ~8,085 net locations in drilling inventory within low cost, high-return basins (~12 years)[3,4]
- Large OOIP of >23 billion barrels with only ~3.0% recovered to date

FOOTNOTES INCLUDED IN THE BACK AS ENDNOTES

APPENDIX

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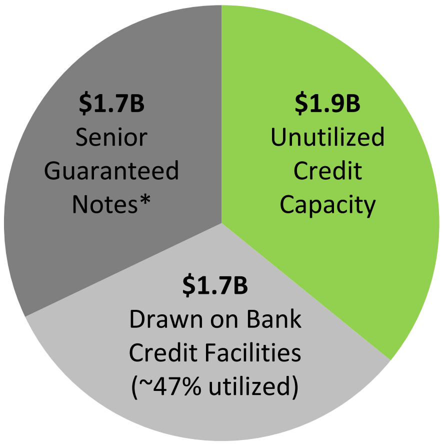
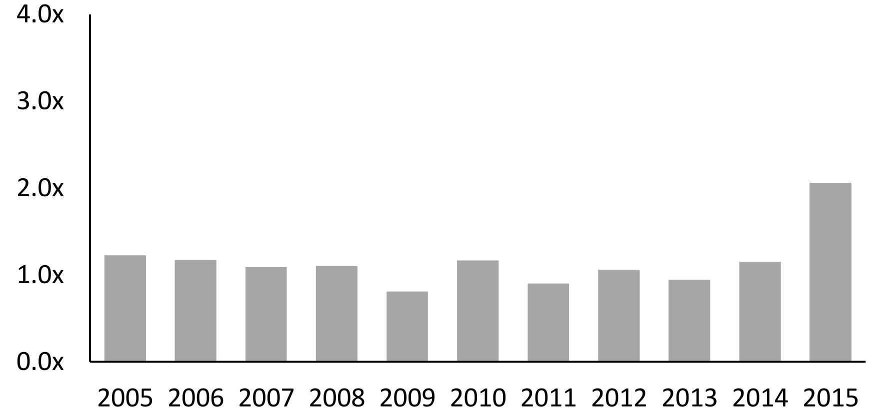
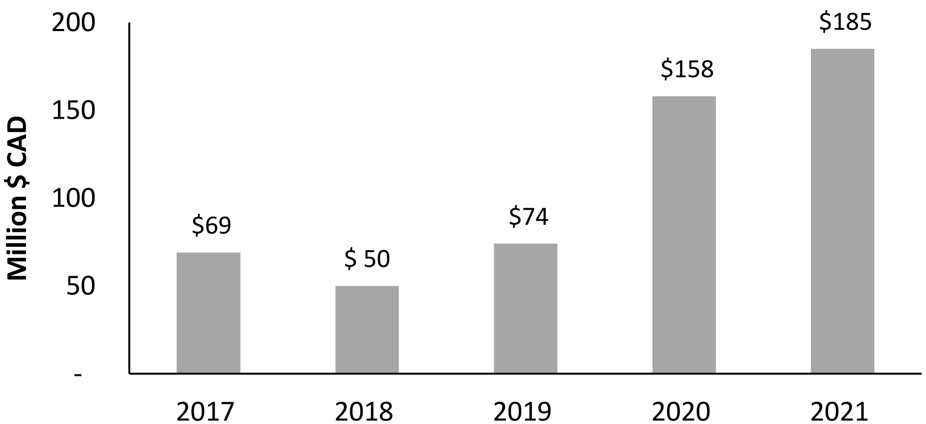
Debt Composition ($CAD) as of September 30, 2016



Net Debt to Funds Flow from Operations



Senior Guaranteed Notes Maturity Schedule*



- No material near-term debt maturities, significant unutilized credit capacity of ~$1.9 billion
- Bank credit facilities and senior guaranteed notes rank equal and are unsecured and covenant-based. Bank credit facilities have a June 2019 renewal date
- US$ denominated senior guaranteed notes fully hedged with cross currency swaps

Significant amount of liquidity and financial flexibility

*Includes underlying currency swaps.

LONG-TERM STRATEGY OF DEVELOPING A RESOURCE PLAY: VIEWFIELD BAKKEN EXAMPLE

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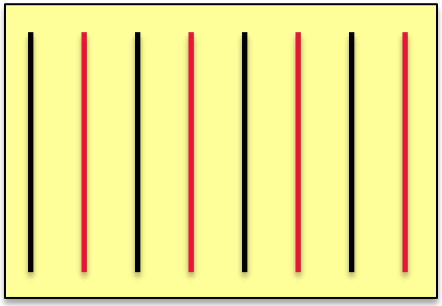
Primary and Infill Development

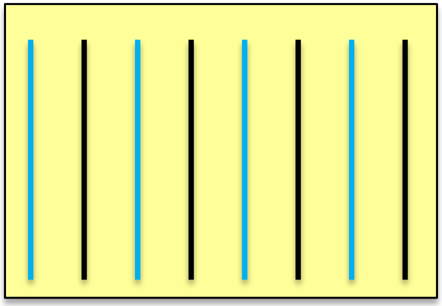


Primary well — Infill well

200-metre spacing (8 wells per section)

- Initiated drilling program in 2007 with over 2,100 horizontal wells drilled to date in the play
- ~1,200 net drilling locations remaining within current inventory in the play (~11 years)[10]
- Targeting 19% recovery rate on primary basis (well payouts of approximately one year or less)
- Continually implementing new technology to increase EURs and NPVs (~3x since entering the play)

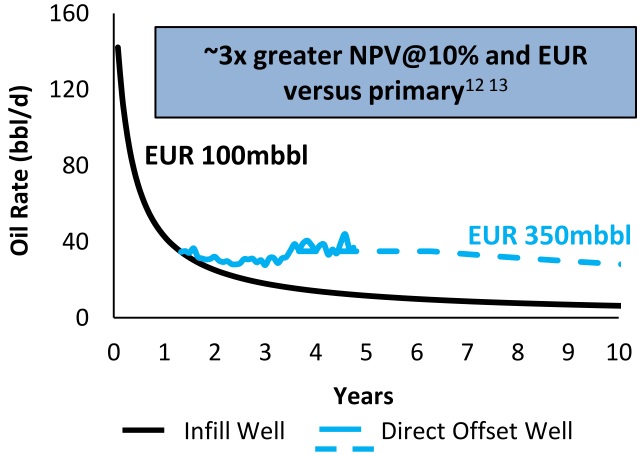
Secondary Waterflood Development



Primary well — Converted water injection well

200-metre spacing (8 wells per section)

- Convert primary well to water injection well to increase reservoir pressure, lower decline rates and increase ultimate oil recovery rates
- Infill wells under waterflood are recovering greater than ~3x the EURs versus primary
- Targeting 30% to 40% recovery rate and F&D of ~$2 per bbl on waterflood reserves[11]
- Implementing waterflood technology to enhance production and recovery rates (i.e. multiple-stage segmented strings)



Secondary development strategy resulting in higher EUR wells versus primary

IMPROVING CAPITAL AND OPERATING COSTS

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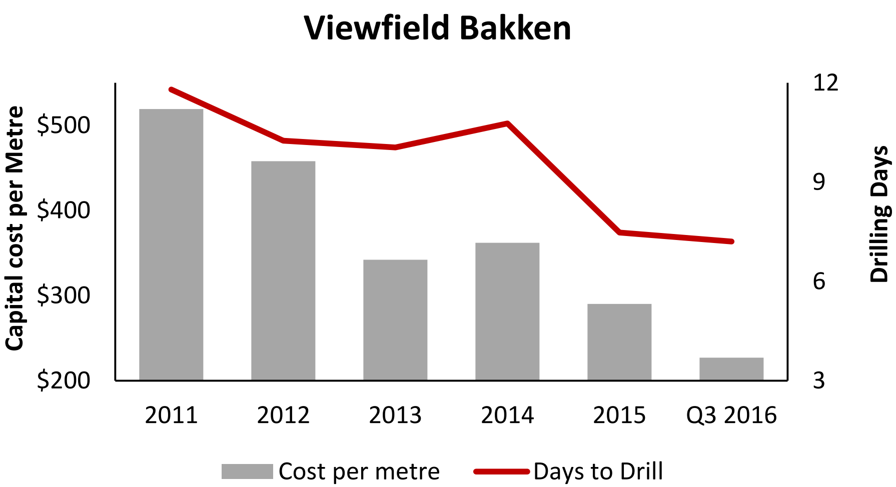
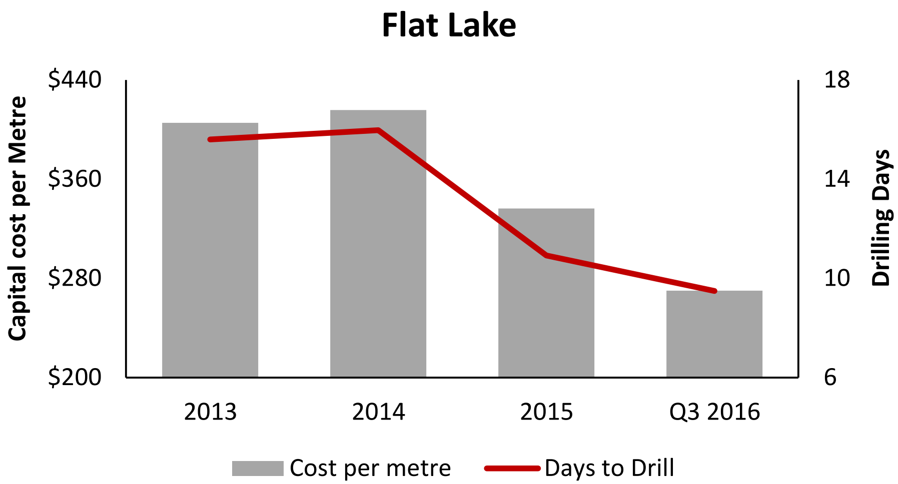
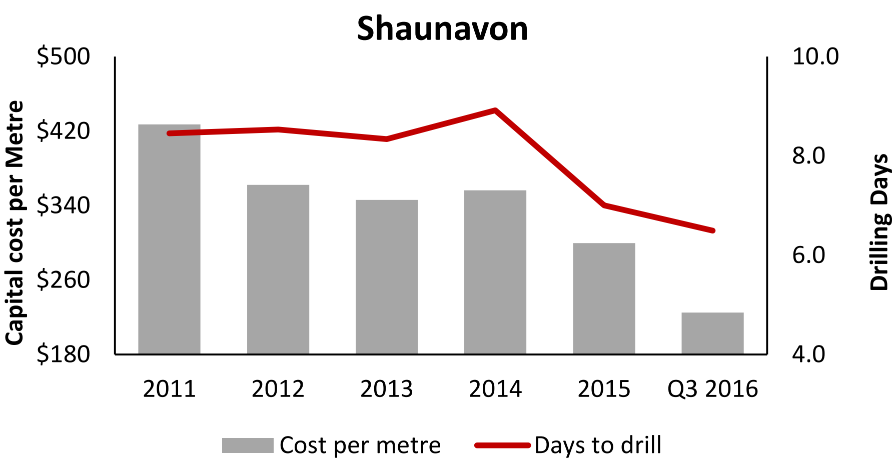


~60% reduction in capital cost per metre



~30% reduction in capital cost per metre



~50% reduction in capital cost per metre

- Achieved a milestone in both the Viewfield Bakken and Shaunavon resource plays by drilling wells in ~5 days
- Capital costs continue to improve through internal efficiencies and lower service rates
- ~$50 million of operating expense reductions expected in comparison to original 2016 budget

2016 days to drill based on Q3 2016 results.

HISTORY OF SUCCESS

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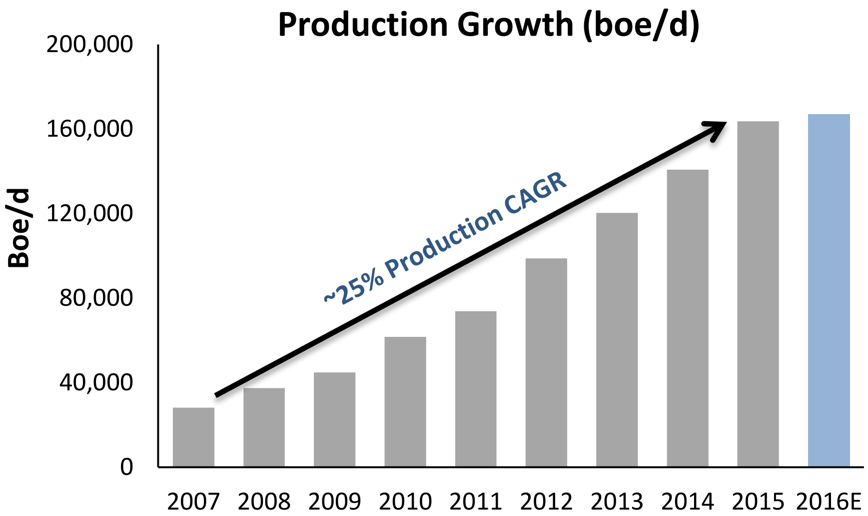

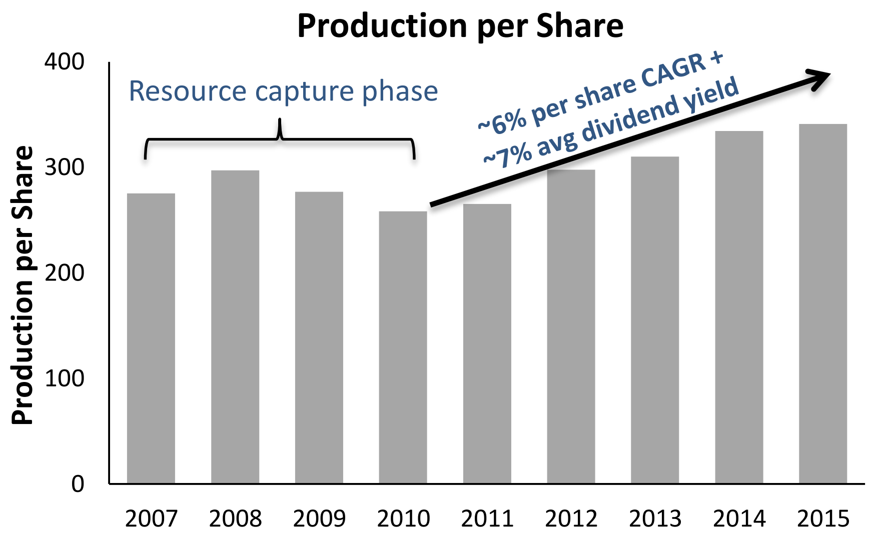

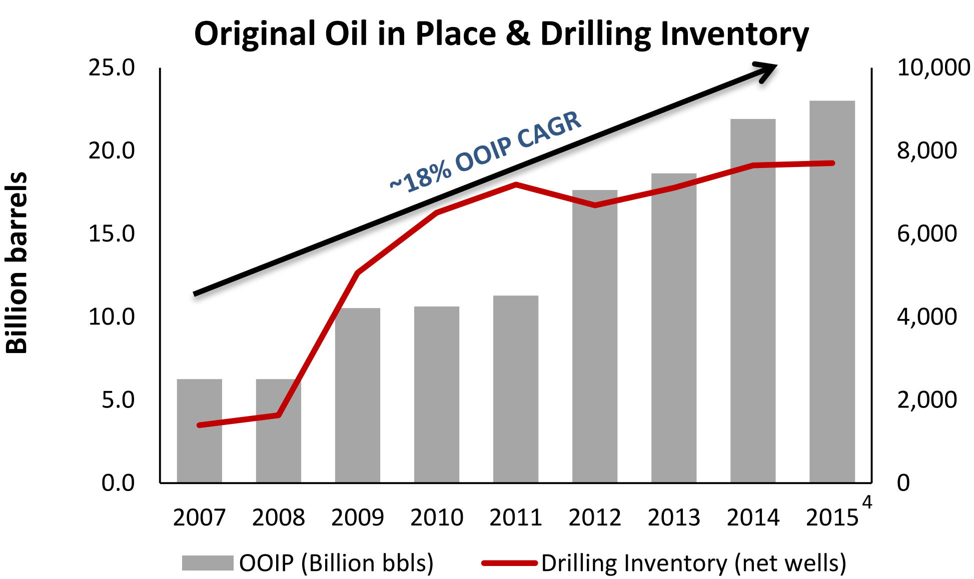

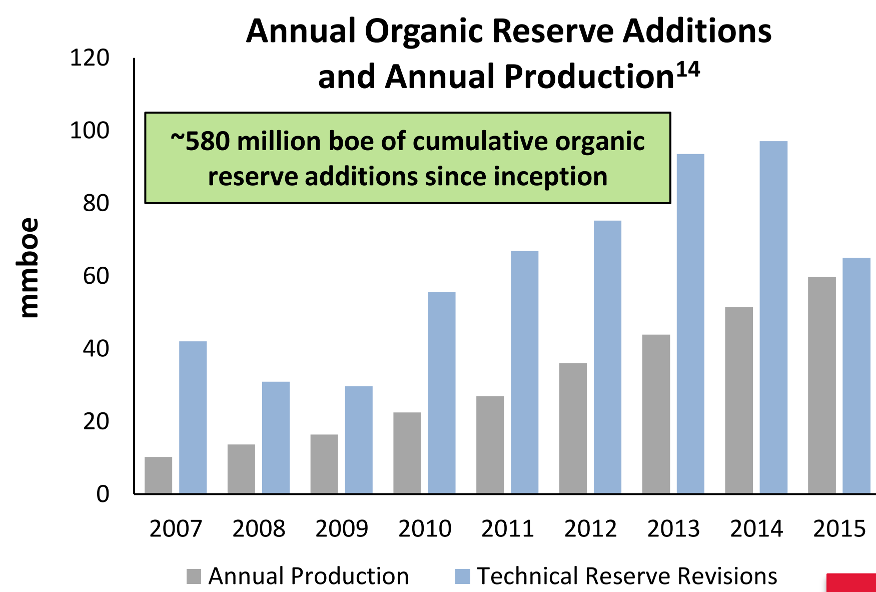

ECONOMICS BY PLAY

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Area	Type Well (mbbl EUR)	Cost per well ($M)	NPV @ 10% ($M)	IRR (%)	Payout (months)
Williston Basin (Viewfield)	75 - 125	$1.3	$1.4 to $3.4	113 to 433	6 to 12
Williston Basin (Flat Lake – Torquay)	150 - 225	$2.3	$2.8 to $5.6	84 to 267	8 to 15
Williston Basin (Flat Lake – Midale)	100 - 150	$1.7	$0.5 to $1.3	33 to 96	12 to 25
Williston Basin (Flat Lake – Ratcliffe)	75 - 100	$1.1	$1.4 to $2.2	125 to 246	8 to 12
Williston Basin (North Dakota)	430 - 500	$4.2 to $4.7	$1.5 to $1.8	17 to 22	44 to 59
Williston Basin (SE Saskatchewan Conventional)	60	$1.0	$1.0	67	19
SW Saskatchewan Resource Play (Shaunavon)	84 - 150	$1.4	$0.7 to $1.7	30 to 84	14 to 34
SW Saskatchewan Resource Play (Viking)	41 - 51	$0.6	$0.9 to $1.1	95 to 134	11 to 14
Uinta (Castle Peak Horizontals)	380	$5.0	$2.9	87	10
Uinta (Vertical)	125 - 175	$1.4	$0.9 to $1.9	34 to 76	17 to 30

All figures are approximate. Uinta and North Dakota figures are in USD.
Shaunavon economics based on upper and lower Shaunavon type wells.
Midale and Uinta Castle Peak horizontal type well EUR is mboe.
Uinta vertical economics based on fee title land locations.
Capital costs per well include drilling, completion, equip, and tie-in expenses.

Pricing assumption:
2017 – US WTI $52.00 / 0.75 CAD/USD fx
2018 – US WTI $57.50 / 0.76 CAD/USD fx

CREATING LONG-TERM VALUE FOR SHAREHOLDERS

Crescent Point

Growth + Dividend Strategy

=

CPG Base Business

- Large OOIP resources with low recovery to date
- High-return asset base
- Control of infrastructure
- Manage risk (i.e. hedging and strong balance sheet)
- Dividend provides capital discipline

+

Waterflood Expansion

- Lower decline rates and future capital requirements
- Increase ultimate recoveries over primary development

+

Technology Initiatives

- Increase recoveries and capital efficiencies
- Expand programs from vertical into larger horizontal opportunities
- Allows for discovery of new plays

+

M&A

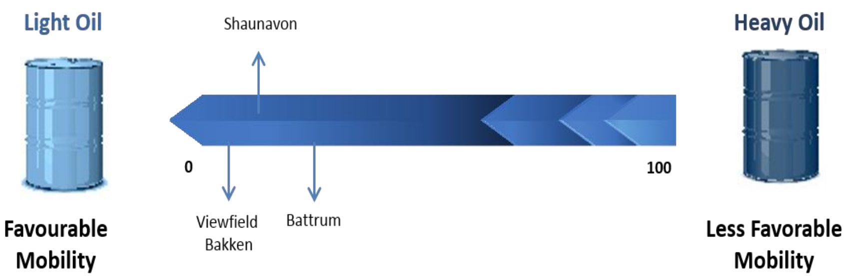
- History of creating value on a per share basis - reserves, cash flow and production - while also adding quality drilling locations
- Opportunity to lever technical expertise

Unlocking value irrespective of commodity prices

FAVOURABLE WATERFLOOD RESERVOIRS

Crescent Point

Low Mobility Ratios Enhance Waterflood Oil Recovery



	Viewfield Bakken	Shaunavon	Battrum
Mobility Ratio	0.4	2.5	20
Recovery to Date	3.4%	1.2%	26.9%

New resource plays with attractive mobility provide opportunity for increased recovery

- Crescent Point benefits from shallow, low-cost reservoirs with characteristics attractive for waterflood development
- Majority Crown ownership and unitization accelerates waterflood implementation and efficiency

Mobility ratio is defined as the oil's ability to move within the rock; determined by permeability and viscosity

Horizontal Waterflood Comparison

Tight Oil Unconventional Resource Plays	Province	E&P Companies	Total Affected Waterflood Production (bbl/d)	Pilot Initiated
Viewfield Bakken	**SK**	**CPG**	**~22,000**	**2006**
Shaunavon	**SK**	**CPG**	**~11,000**	**2008**
Shaunavon	SK	1 E&P	~300	2012
Cardium	AB	4 E&Ps	~6,000	2008
Slave Point	AB	4 E&Ps	~5,000	2012
Viking	SK	3 E&Ps	~4,000	2009
Montney	AB	5 E&Ps	~4,000	2009
Swan Hills	AB	2 E&Ps	~2,000	2012
Swan Hills	**AB**	**CPG**	**~1,000**	**2013**
Viking	AB	2 E&Ps	~700	2013
Viking	**AB**	**CPG**	**~300**	**2014**
TOTAL			**~56,300**	

Source: Accumap Canada. Waterflood production based on horizontal injection wells. Based on 2015 production data.

- Viewfield Bakken is the largest unconventional oil pool in North America currently under commercial waterflood, with plans for expansion (Wood Mackenzie Canada Ltd.)

ACQUISITION HISTORY: RESERVES MORE THAN DOUBLED

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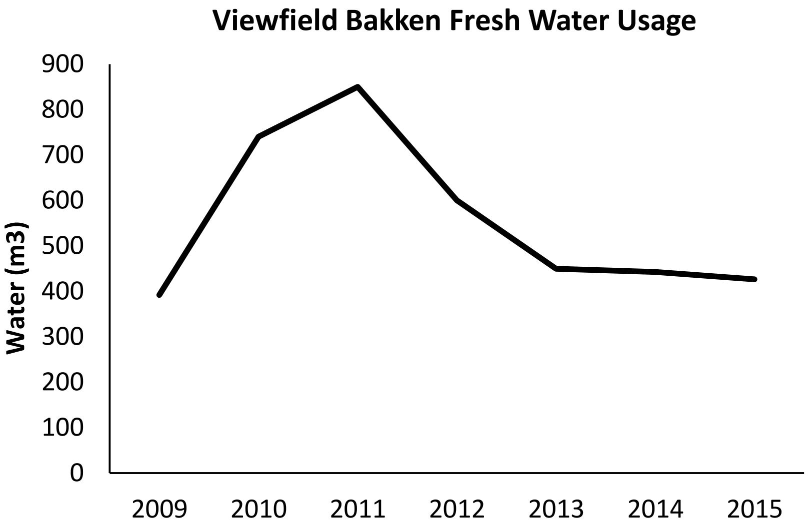
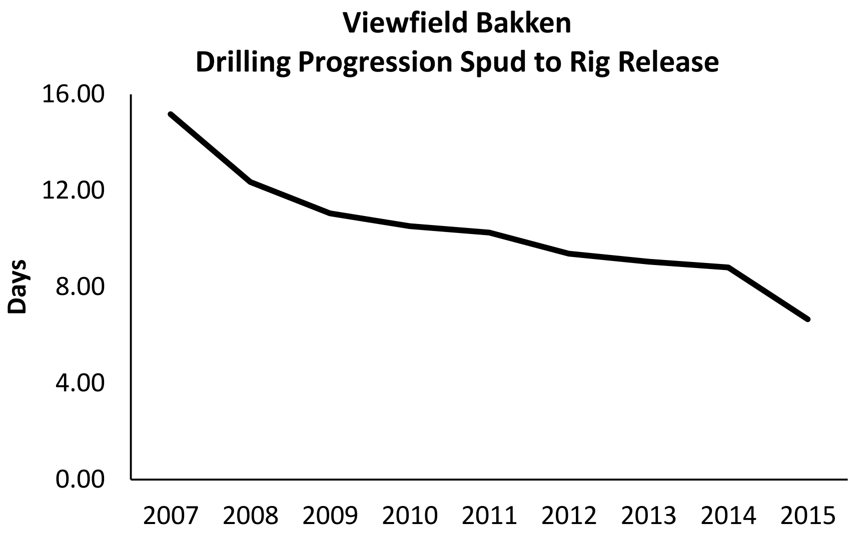
Property	Initial 2P Reserves (Mboe)	Estimated Production (Mboe)	Current 2P Reserves (Mboe)	Total 2P Reserves (Mboe)	Increase in 2P Reserves (Mboe)	% Increase in Reserves
Sounding Lake	2,437	4,402	3,383	7,785	5,348	219%
Manor/Tatagwa Unit	13,641	17,072	25,571	42,643	29,002	213%
Little Bow	2,872	2,992	1,683	4,675	1,803	63%
Subtotal	**18,950**	**24,466**	**30,637**	**55,103**	**36,153**	**191%**
SW Sask	132,285	55,740	193,655	249,395	117,110	89%
Viewfield Resource	106,630	116,393	231,121	347,514	240,884	226%
Flat Lake Resource	3,178	7,767	69,796	77,563	74,385	2,341%
Canada Subtotal	**261,043**	**204,366**	**525,209**	**729,575**	**468,532**	**179%**
Utah	61,858	14,747	89,358	104,105	42,247	68%
North Dakota	13,511	6,909	64,352	71,261	57,750	427%
CPG TOTAL	**336,412**	**226,022**	**678,919**	**904,941**	**568,529**	**169%**

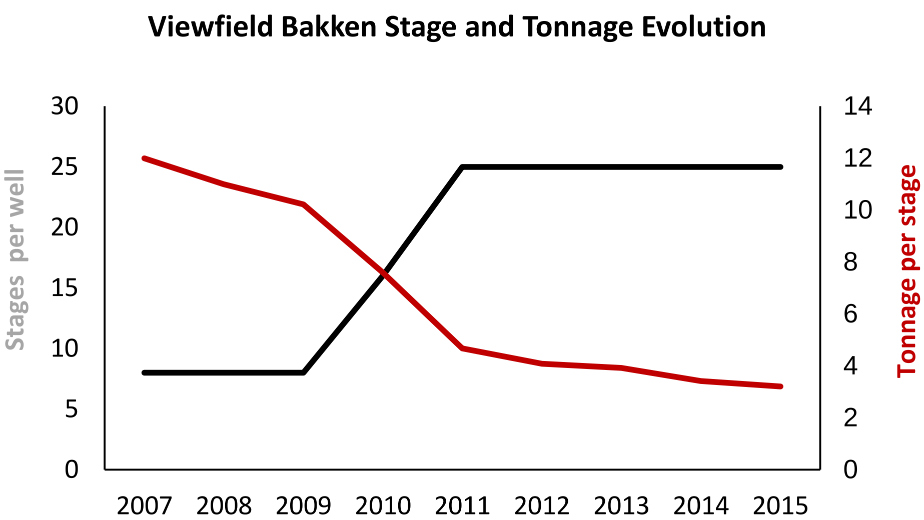
As of December 31, 2015 as evaluated by GLJ Petroleum Consultants Ltd. and Sproule Associates Limited.
Total 2P reserves = estimated production plus current 2P reserves.

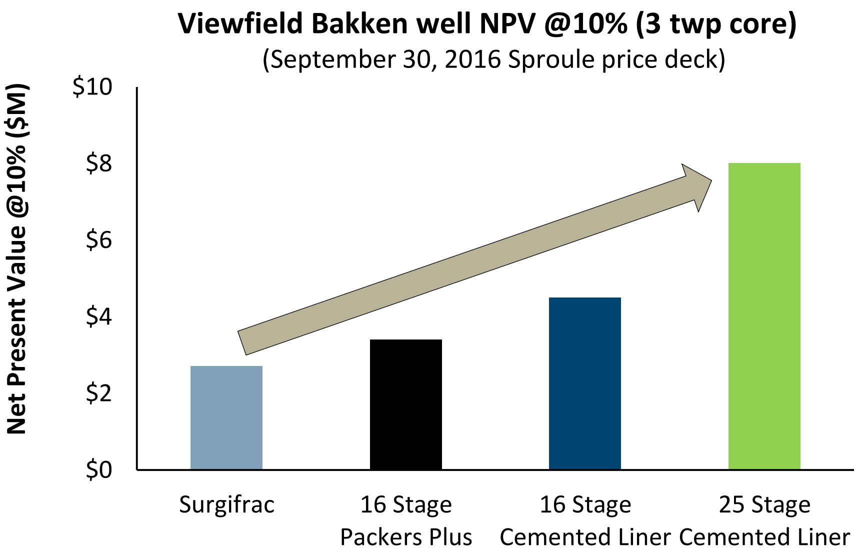
- Increased 2P reserves by >568 million boe (169%)
- Large oil-in-place pools have outperformed initially estimated recoveries over time

IMPACT OF TECHNOLOGY IMPROVEMENTS



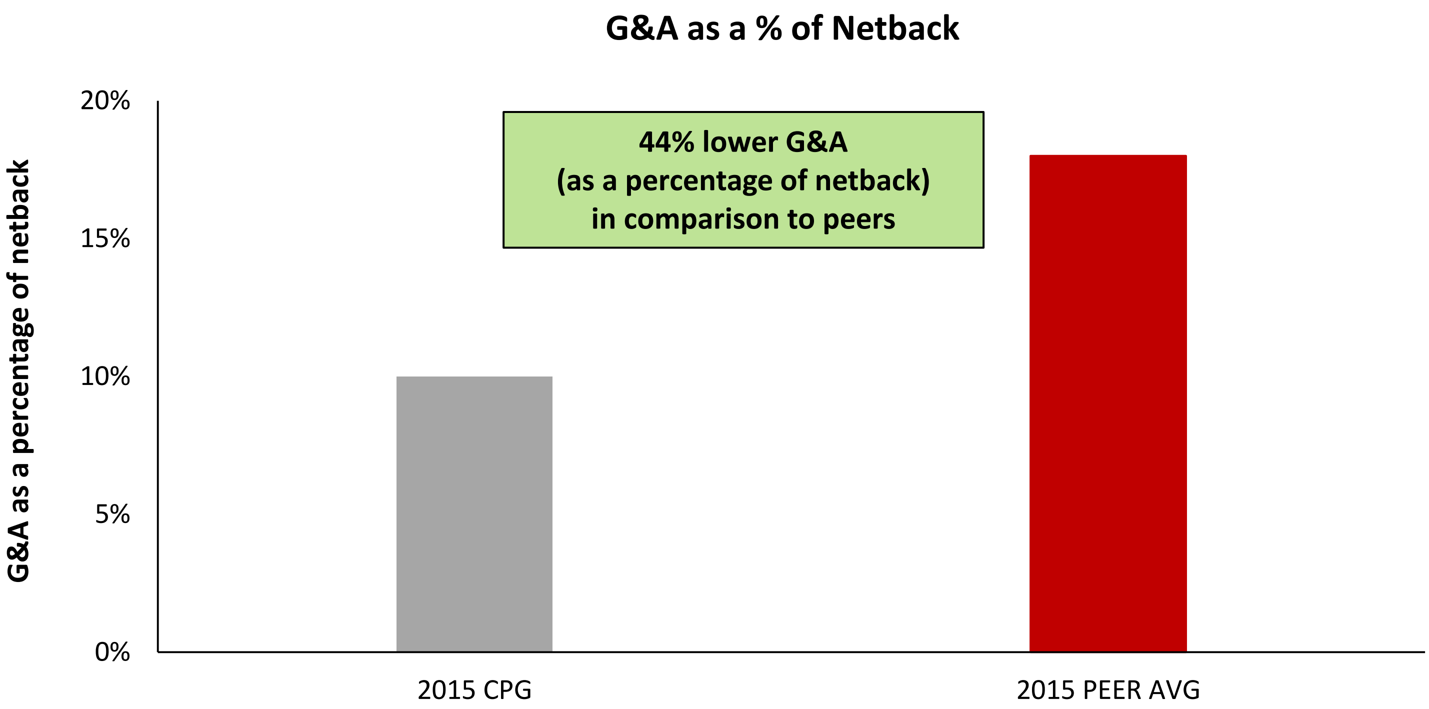






INDUSTRY-LOW G&A

Crescent Point



- Crescent Point Energy G&A/boe includes capitalized expenses for comparison purposes
  - Crescent Point Energy's reported G&A is lower than the numbers shown above due to exclusion of capitalized G&A expenses

Peer average figures are from publically disclosed financial results and include:
ARX,BTE, BNP, CVE, CNQ, ECA, ERF, HSE, LTS, MEG, POU, PGF, PWT, PEY, TOU, TET, VET

ENDNOTES

Crescent Point

1. Shares as of September 30, 2016. Based on share price of $17.19 as of market close on December 2, 2016 and 546.5 million fully diluted shares outstanding as of September 30, 2016. Directors and officers ownership represents 0.6% of issued and outstanding shares as of September 30, 2016.
2. As of December 31, 2015 as independently evaluated by GLJ Petroleum Consultants Ltd. and Sproule Associates Limited.
3. Calculated using 2017 guidance production of 172,000 boe/d and the drilling of approximately 670 net wells.
4. Approximately 8,085 internally identified net drilling locations as of December 2016. As of December 31, 2015 booked locations of 2,378 net are proved and 1,305 net are probable reserve locations as independently evaluated by GLJ Petroleum Consultants Ltd. and Sproule Associates Limited. The remaining net locations are internally identified locations that are unbooked.
5. Productive capacity of ~80,000 boe/d from the castle peak zone is based on IP-90 rates of ~680 boe/d from recent horizontal well results multiplied by the internally identified ~120 net drilling locations.
6. Uinta Basin inventory of 830 net locations as of December 2016. Booked locations of 274 net are proved and 130 net are probable reserve locations as independently evaluated by GLJ Petroleum Consultants Ltd. and Sproule Associates Limited as of December 31, 2015. Remaining locations are internally identified unbooked locations. The Company has internally identified ~120 net horizontal locations during 2016, which decreases the vertical drilling inventory to ~700 locations.
7. ~220 net locations in Flat Lake added through step-out drilling program are all internally identified. ~300 acquired net drilling locations, of which 36 are net proved and 37 are net probable as independently evaluated by GLJ Petroleum Consultants Ltd. and Sproule Associates Limited. ~120 horizontal drilling locations in the Uinta Basin are all internally identified unbooked locations. ~700 vertical drilling locations in the Uinta basin as of December 2016, of which 274 net are proved and 130 net are probable reserve locations as independently evaluated by GLJ Petroleum Consultants Ltd. and Sproule Associates Limited. Remaining locations are internally identified unbooked locations.
8. ~1,300 net drilling locations, of which 115 net are proved and 146 net are probable reserve locations as independently evaluated by GLJ Petroleum Consultants Ltd. and Sproule Associates Limited. Remaining locations are internally identified unbooked locations.
9. As of December 31, 2015, excluding the change in future development capital and based on the five year average netback (prior to realized derivatives) of $44.47 per boe.
10. ~1,200 net drilling locations, of which 536 net are proved and 157 net are probable reserve locations as independently evaluated by GLJ Petroleum Consultants Ltd. and Sproule Associates Limited. Remaining locations are internally identified unbooked locations. Calculated using ~110 net drills in 2016.
11. F&D based on OOIP of 6.1mmbbls per section in township core and estimated recovery factor of >30-40% above estimated primary recovery of 19%. Includes historical land acquisition costs of $1M per section, primary well costs of $1.8M and waterflood injector conversions of $0.4M per well. Recovery factors and F&D are approximate values. Current primary well costs are ~$1.3M. Estimated recovery factors are internally calculated based on independent (P+P) reserves, comparable analog pools, independent studies commissioned by Crescent Point Energy and company targets.
12. Waterflood reserve additions represent internally evaluated incremental reserves over the average primary type curve described above.
13. The non-waterflood infill profile is based on an internal evaluation of existing, 200 meter direct offset infill drilled wells where no waterflood influence has occurred, normalized to start of production. NPVs are before-tax and are based on September 30, 2016 Sproule price deck.
14. Positive reserve revisions include reserves obtained from “Discoveries”, “Extensions”, “Infill Drilling”, “Improved Recovery”, “Technical Revisions” and “Economic Factors” as defined in COGEH.

DEFINITIONS / NON-GAAP FINANCIAL MEASURES

Crescent Point

DEFINITIONS:

1. Original Oil-In-Place (OOIP) means Discovered Petroleum Initially-In-Place (DPIIP) as at December 31, 2015. DPIIP, as defined in the Canadian Oil and Gas Evaluations Handbook (COGEH), 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 DPIIP includes production, reserves and contingent resources; the remainder is unrecoverable.

2. OOIP/DPIIP estimates and recovery rates are as at December 31, 2015, and are based on current accepted technology and have been prepared by Crescent Point's qualified reservoir engineers.

3. There is significant uncertainty regarding the ultimate recoverable OOIP/DPIIP. For further information see Crescent Point's Annual Information Form for the year-ended December 31, 2015.

4. Cash flow equates to funds flow from operations. Cash flow from operations equals funds flow from operations per share.

5. Net present values disclosed in this presentation are calculated before tax.

6. Enhanced Ultimate Recovery (or EUR) relates to the extraction of additional crude oil, natural gas, and related substances from reservoirs through a production process other than natural depletion, which includes both secondary and tertiary recovery processes such as pressure maintenance, cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids.

7. Dividend reinvestment plans include the Dividend Reinvestment Plan (DRIP) and Share Dividend Plan (SDP).

8. Type wells are internally generated based on actual well results and data that is interpreted by internal qualified reserves evaluators.

9. Pricing assumptions used for economic analysis: 2017 – US WTI $52.00 / 0.75 CAD/USD exchange, 2018 – US WTI $57.50 / 0.76 CAD/USD exchange, 2019 – US WTI $60.00 / 0.77 CAD/USD exchange

NON-GAAP FINANCIAL MEASURES:

Throughout this presentation the Company uses the terms "total payout ratio", "drilling capital efficiencies", "funds flow from operations", "funds flow from operations netback", "net debt", "net debt to funds flow from operations", and "Q4 annualized net debt to funds flow from operations". These terms do not have any standardized meaning as prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other issuers.

Total payout ratio is calculated on a percentage basis as capital expenditures and dividends paid or declared divided by funds flow from operations. Total payout ratio is used by management to monitor the Company's capital reinvestment and dividend policy, as a percentage of the amount of funds flow from operations.

Drilling capital efficiencies is calculated as the capital expenditures required to replace a barrel equivalent (boe) of oil and gas production. Management utilizes drilling capital efficiencies as a key measure to assess the economic viability of a particular well.

Funds flow from operations is calculated based on cash flow from operating activities before changes in non-cash working capital, transaction costs and decommissioning expenditures. Funds flow from operations netback is calculated on a per boe basis as funds flow from operations divided by total production. Management utilizes funds flow from operations as a key measure to assess the ability of the Company to finance dividends, operating activities, capital expenditures and debt repayments. Funds flow from operations as presented is not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS.

DEFINITIONS / NON-GAAP FINANCIAL MEASURES

Crescent Point

Netback is calculated on a per boe basis as oil and gas sales, less royalties, operating and transportation expenses. Netback is a common metric used in the oil and gas industry and is used by management to measure operating results on a per boe basis to better analyze performance against prior periods on a comparable basis.

Market capitalization is an indication of enterprise value and is calculated by applying a recent share trading price to the number of diluted shares outstanding.

Net debt is calculated as long-term debt plus accounts payable and accrued liabilities and dividends payable, less cash, accounts receivable, prepaids and deposits and long-term investments, excluding the equity settled component of dividends payable and unrealized foreign exchange on translation of hedged US dollar long-term debt. Management utilizes net debt as a key measure to assess the liquidity of the Company.

Net debt to funds flow from operations is calculated as the net debt divided by funds flow from operations. The ratio of net debt to funds flow from operations is used by management to measure the Company's overall debt position and to measure the strength of the Company's balance sheet. Crescent Point monitors this ratio and uses this as a key measure in making decisions regarding financing, capital spending and dividend levels.

Management believes the presentation of the Non-GAAP measures above provide useful information to investors and shareholders as the measures provide increased transparency and the ability to better analyze performance against prior periods on a comparable basis. This information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. For definitions of the non-GAAP measures listed above along with reconciliations from the non-GAAP measure to the most directly comparable GAAP measure, each of which is incorporated by reference please see the Company's most recent annual Management's Discussion & Analysis ("MD&A") available on SEDAR at sedar.com, or EDGAR as www.sec.gov and on our website as www.crescentpointenergy.com.

OIL AND GAS METRICS:

This presentation includes oil and gas metrics including "drilling inventory", "finding and development costs", "netback", "mobility ratio" and "recycle ratio". Such metrics do not have a standardized meaning and as such may not be reliable, and should not be used to make comparisons.

Drilling inventory and current inventory are calculated in years as net well count guidance divided by remainder of inventory. Drilling inventory and current inventory are used by management to assess the amount of available drilling opportunities.

Finding and development costs (or "F&D") are calculated in dollars by dividing the capital required by the number of barrels being produced. Finding and developments costs are the amounts spent to locate, and establish commodity reserves.

Netback is calculated on a per boe basis as oil and gas sales, less royalties, operating and transportation expenses. Netback is used by management to measure operating results on a per boe basis to better analyze performance against prior periods on a comparable basis.

Mobility ratio is defined as the oil's ability to move within the rock and is calculated by dividing the permeability of the reservoir's rock by the viscosity of the fluid within the reservoir. It is used to determine the ease of which OOIP may be extracted.

Recycle Ratio is calculated as the profit per barrel divided by the total cost of discovering and extracting the barrel. For the purposes of this presentation the recycle ratio is calculated as netback divided by finding and development costs per barrel. It is used in determining the profitability of the Company.

Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf : 1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the 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 oil, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

COMPANY INFORMATION

Crescent Point

BANKER	Bank of Nova Scotia
AUDITOR	PricewaterhouseCoopers LLP
LEGAL COUNSEL	Norton Rose Fulbright Canada LLP
EVALUATION ENGINEERS	GLJ Petroleum Consultants Ltd Sproule Associates Ltd
REGISTRAR & TRANSFER AGENT	Computershare Trust Company
INVESTOR CONTACTS	403.767.6930 1.855.767.6923 (Toll Free) investor@crescentpointenergy.com

www.crescentpointenergy.com

Suite 2000, 585 – 8th Ave SW, Calgary, AB T2P 1G1

T: 403.693.0020 | F: 403.693.0070 | TF: (Canada & USA) 1.888.693.0020