Crescent Point

TSX CPG | NYSE CPG

Corporate Presentation

March 2018

Knowledge First Culture

Innovation & Technology Leaders

Value Creators

Crescent Point Advantage

Scaleable Economic Growth

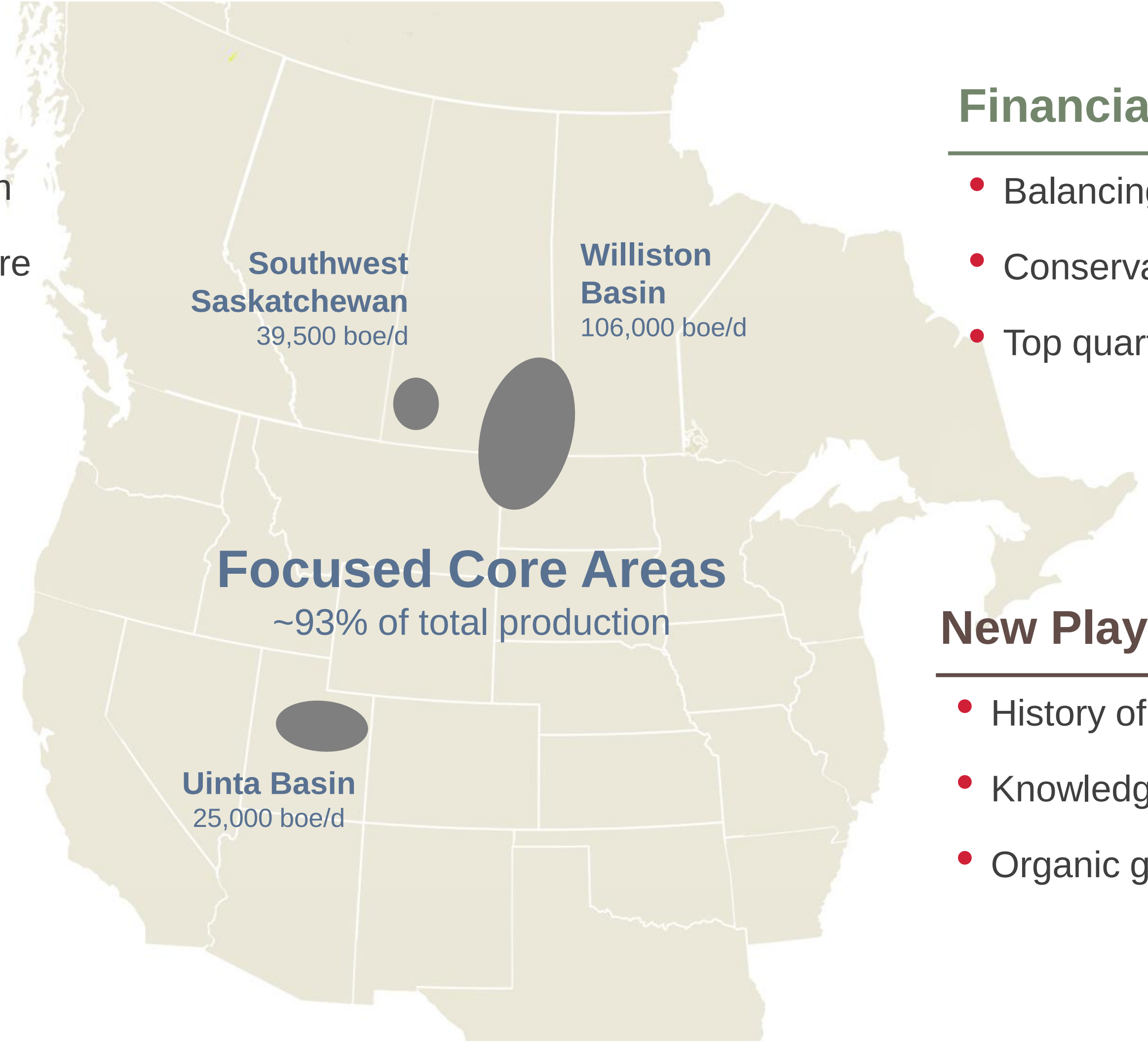
Long-Term Value Creators

Financial Discipline

Crescent Point Overview

Value Creators

- Per share focus and operational execution
- Innovation driven by knowledge-first culture
- Waterflood proprietary knowledge



Financial Discipline

- Balancing cash flows
- Conservative hedging strategy
- Top quartile netbacks and low G&A

Scaleable Growth

- ~27 billion OOIP and >4 million net acres
- ~14,000 net drilling locations (~8,100 risked)
- Significant infrastructure ownership including pipeline, rail and facilities

New Play Development

- History of success in new discoveries
- Knowledge transfer across asset base
- Organic growth of drilling inventory

Production figures shown above are approximations and represent annual averages based on 2018 guidance

Business Strategy

Develop & Enhance

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

Growth

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

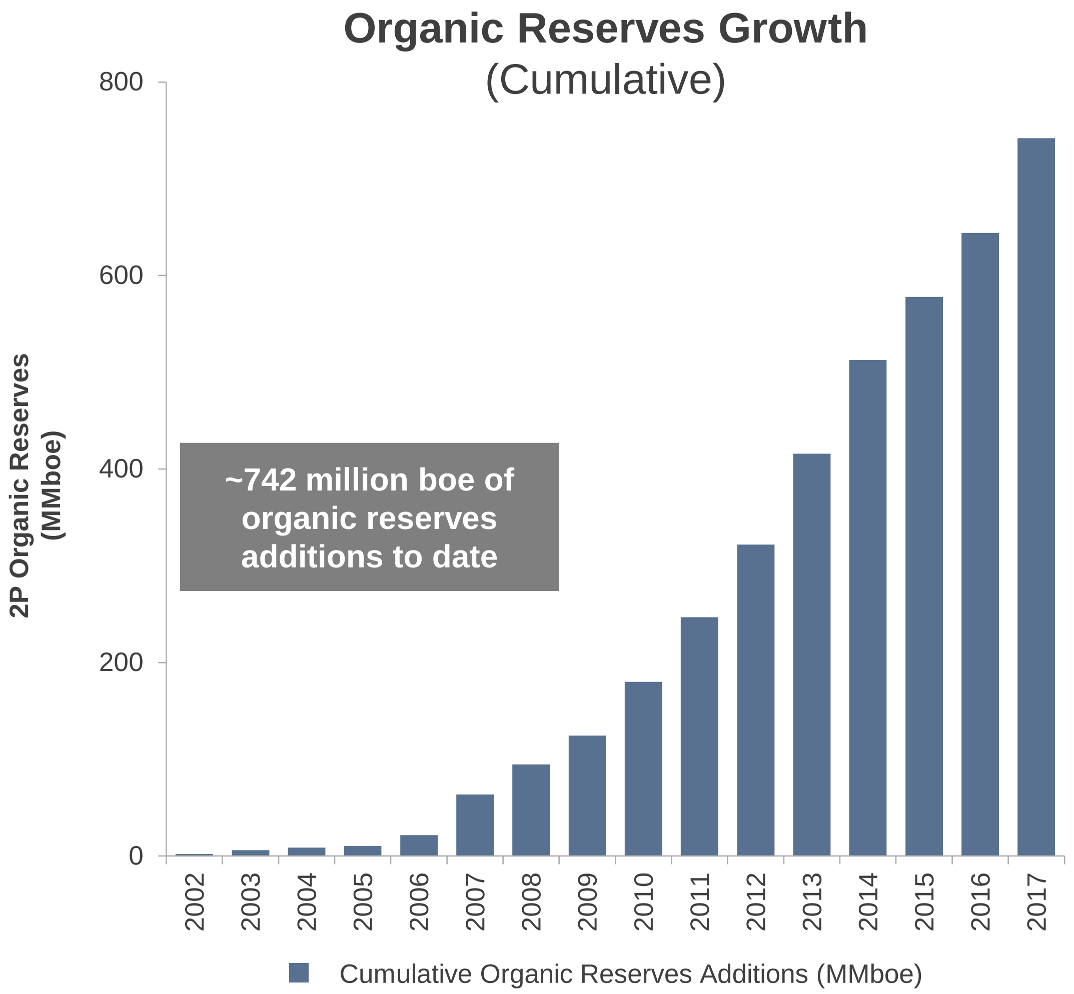
Manage Risk

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

Execution in 2017 & 2018 Outlook

2017	**Achieved** exit guidance of **183,000 boe/d** and growth target of **10%** per share	Increased productive capacity by **~70%** led by new locations and achieved record 2P reserves of **>1 billion boe**	**>$320 million of dispositions** in non-core areas
2018	**Return-focused** with **>75%** of net drills to payout in **<2 years**	**7% growth** with exit guidance of **195,000 boe/d**	**Balancing cash flows** including ongoing non-core dispositions

Organic Reserves Growth in 2017 Leading to Over 1 Billion boe

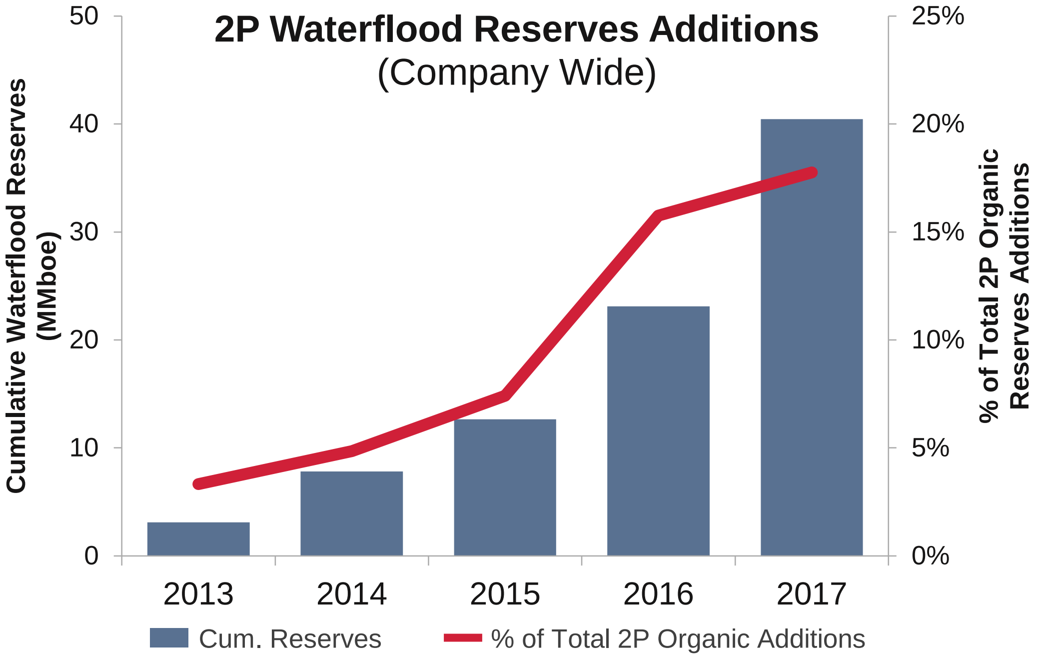


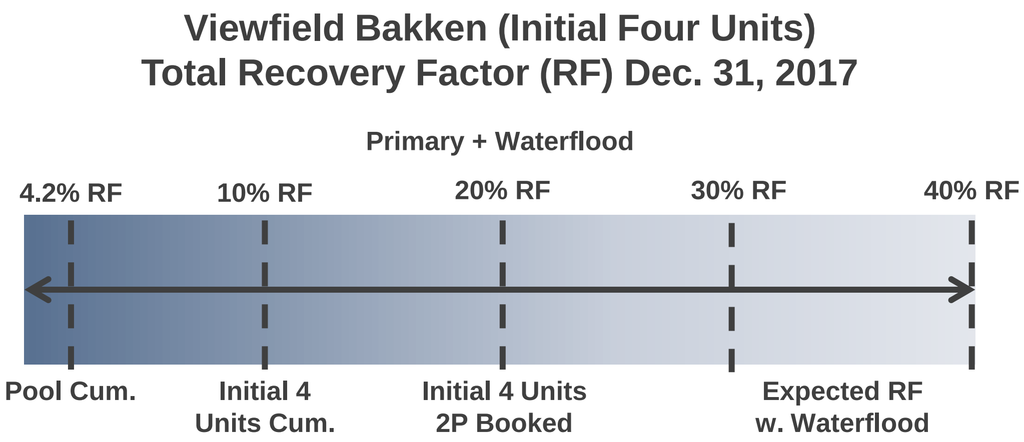
- Added ~98 MMboe of 2P organic reserves to reach over 1 billion boe
  - Organically replaced 152% of 2017 production (on a 2P basis)
  - Reserves growth in all core areas including ~40% in the Uinta Basin
  - Reserve life index of ~15 years
  - F&D costs of $18.56 per boe generated a recycle ratio of 1.6x
- Generated before-tax 2P Net Asset Value (@10%) per share of:
  - $24.44 based on independent engineering escalated pricing as of Dec. 31, 2017
  - $14.39 based on flat WTI pricing of US$55/bbl
- Large OOIP resource base allows for continued future growth
  - ~60% of risked and ~75% of unrisked inventory remains unbooked

F&D excludes acquisitions and changes in FDC
2017 recycle ratio is based on a netback prior to realized derivatives of $29.42 per boe
NAV per share based on flat US$55 WTI assumes $0.77 USD/CAD exchange

Fifth Consecutive Year of Waterflood Reserves Additions

- Waterflood additions in 2017 represent ~18% of 2P organic reserves growth across the company
  - Low 2P F&D cost of $10.24/boe in the Viewfield Bakken resource play driven by waterflood
- >40 MMboe of cumulative 2P reserves additions from waterflood projects
- Significant future waterflood growth remains with >1,000 potential waterflood injector conversions in inventory between Shaunavon and Viewfield Bakken, with additional pilots implemented in Flat Lake





18% Primary + 2% Waterflood = 20% 2P Booked to Date

Market Access

Light-Oil Exposure

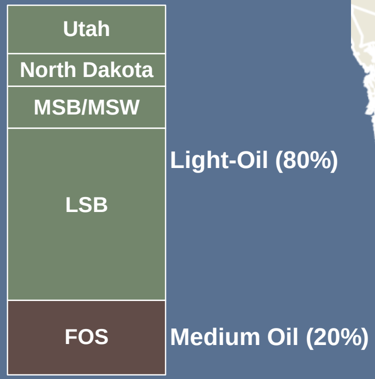
Multiple Takeaway Options

Significant Infrastructure Ownership

Market Access and Pricing Advantage

Significant light-oil production

Minimal (~20%) exposure to WCS / medium gravity oil



Majority of oil production (~80%) is light-oil

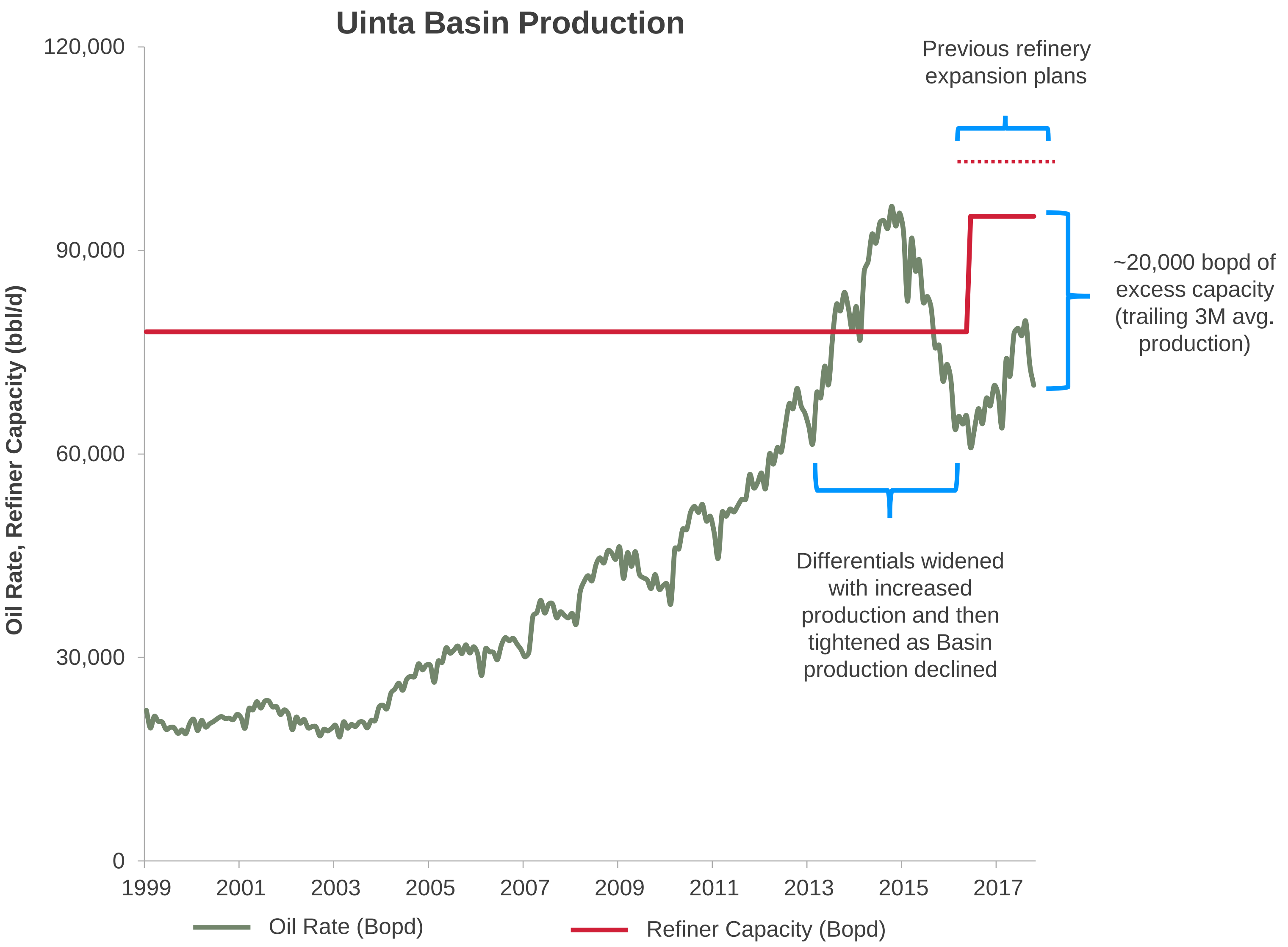
Diversified transportation methods including pipeline, rail and trucking

Majority of Saskatchewan assets downstream of current apportionment (bottleneck) points - barrels not as impacted

Significant infrastructure ownership in core areas:

- ~12,000 km of pipeline infrastructure
- Access to >80,000 bopd of additional rail capacity
- ~135 mmcf/d of gas processing
- >300,000 bbl of oil storage capacity

Uinta Basin: Marketing



- Rail infrastructure provides additional ~70,000 bopd of takeaway capacity including CPG facilities (expandable to ~90,000 bopd)
- Refining capacity has the ability to increase (scheduled expansions previously planned)
- High-quality crude
  - Yellow wax (38 to 50 API)
  - Black wax (28 to 38 API)

Salt Lake City Refiners & Rail Facilities

Uinta Basin production based on most recent public data as of February 2018

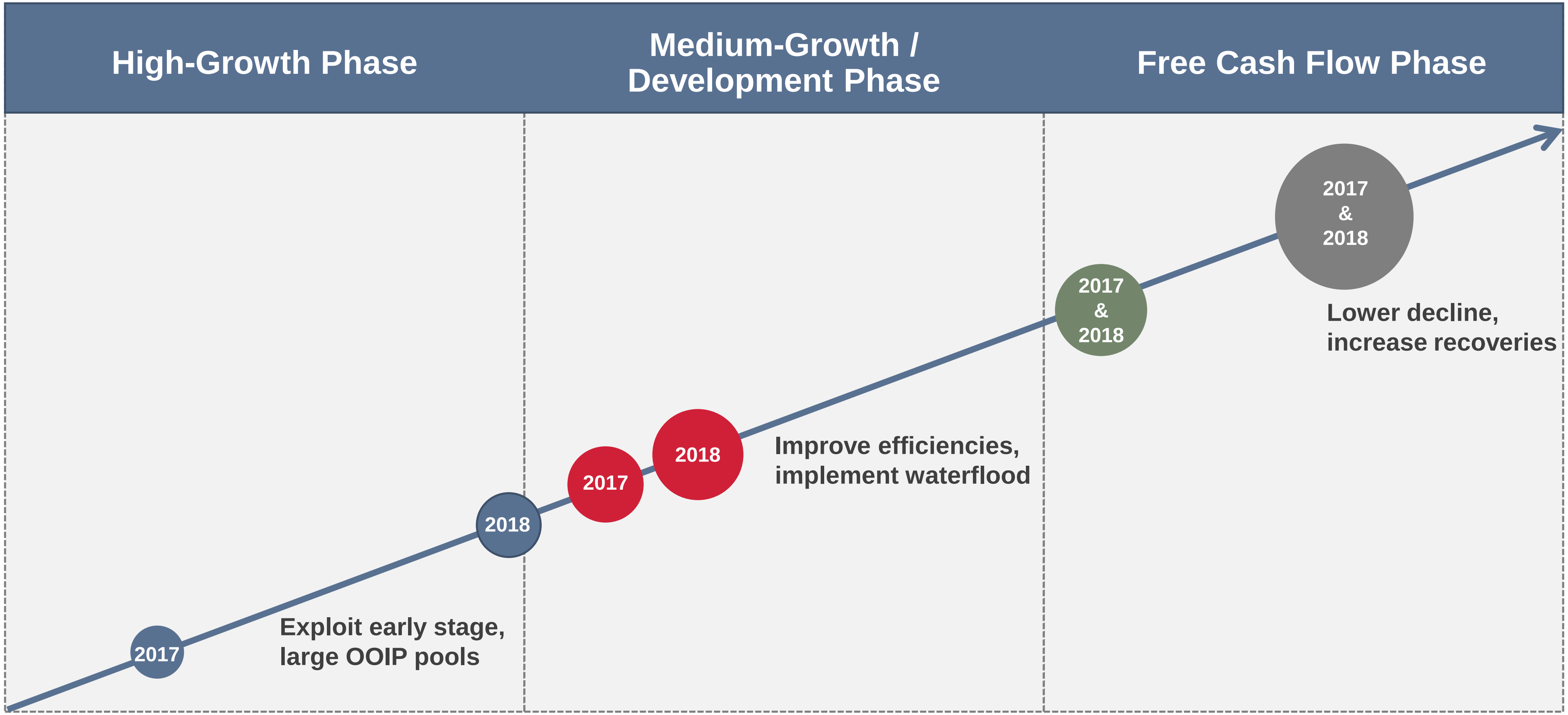
Financial Strategy

Risk Management

Financial Discipline

Strong Capital Allocation

Life Cycle of Core Resource Plays



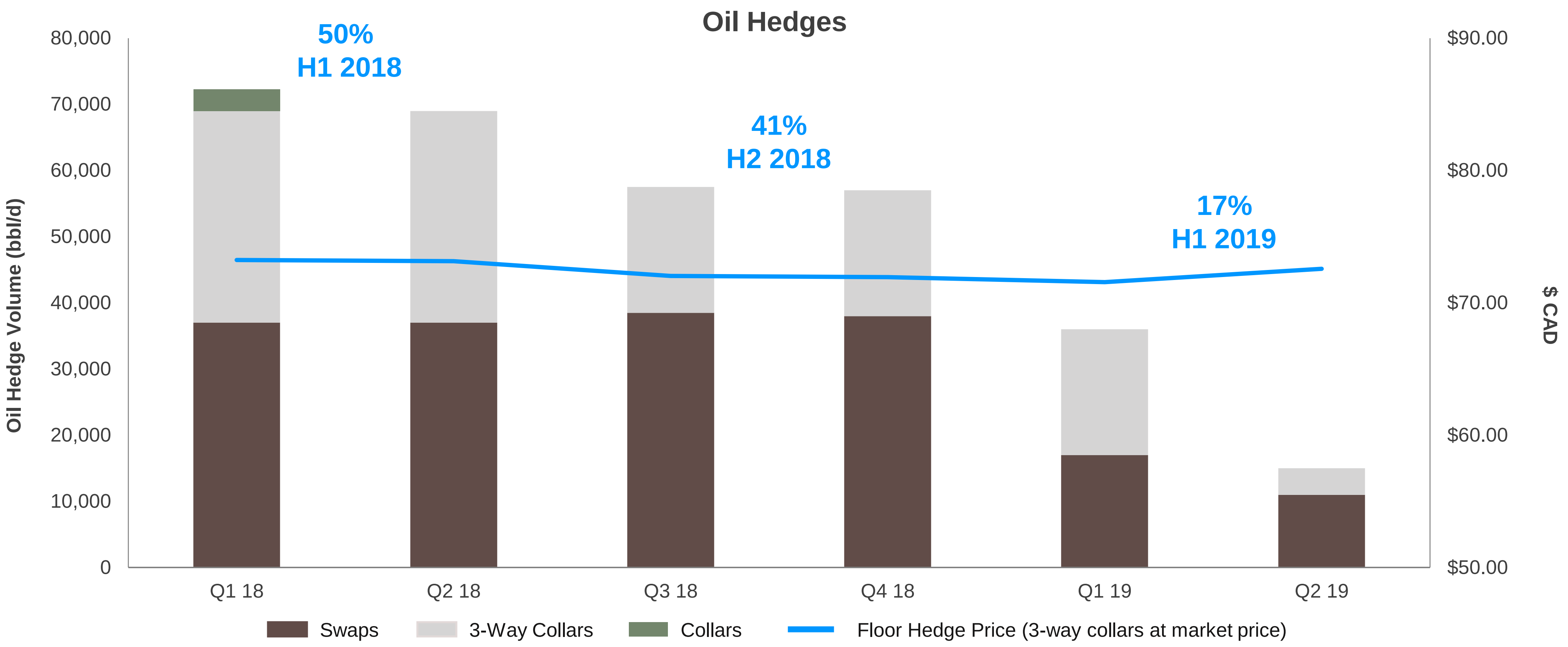
Uinta Basin

Williston Basin (Flat Lake + North Dakota)

SW Sask. (Shaunavon)

Williston Basin (Viewfield + Conventional)

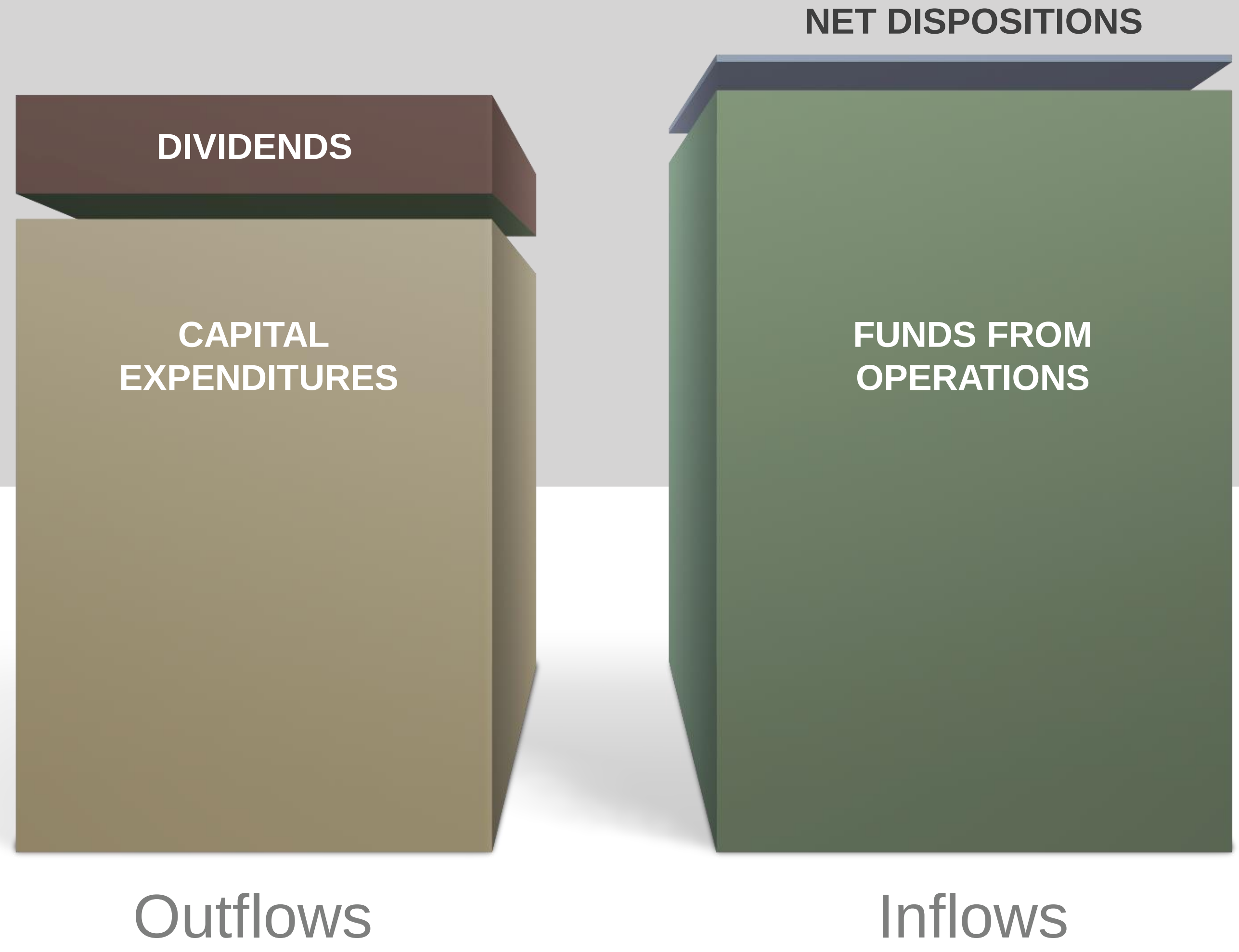
Commodity Hedging Strategy



- Active hedging program reduces funds flow from operations volatility and provides greater stability to dividends and capital spending

As of February 23, 2018. 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 oil and f/x prices
2018 percentage hedged figures based on annual average liquids production guidance net of royalties
2019 percentage hedged figures based on 2018 exit liquids production net of royalties based on 2018 guidance

Balancing Cash Outflows with Inflows



2018

Total Payout

99%

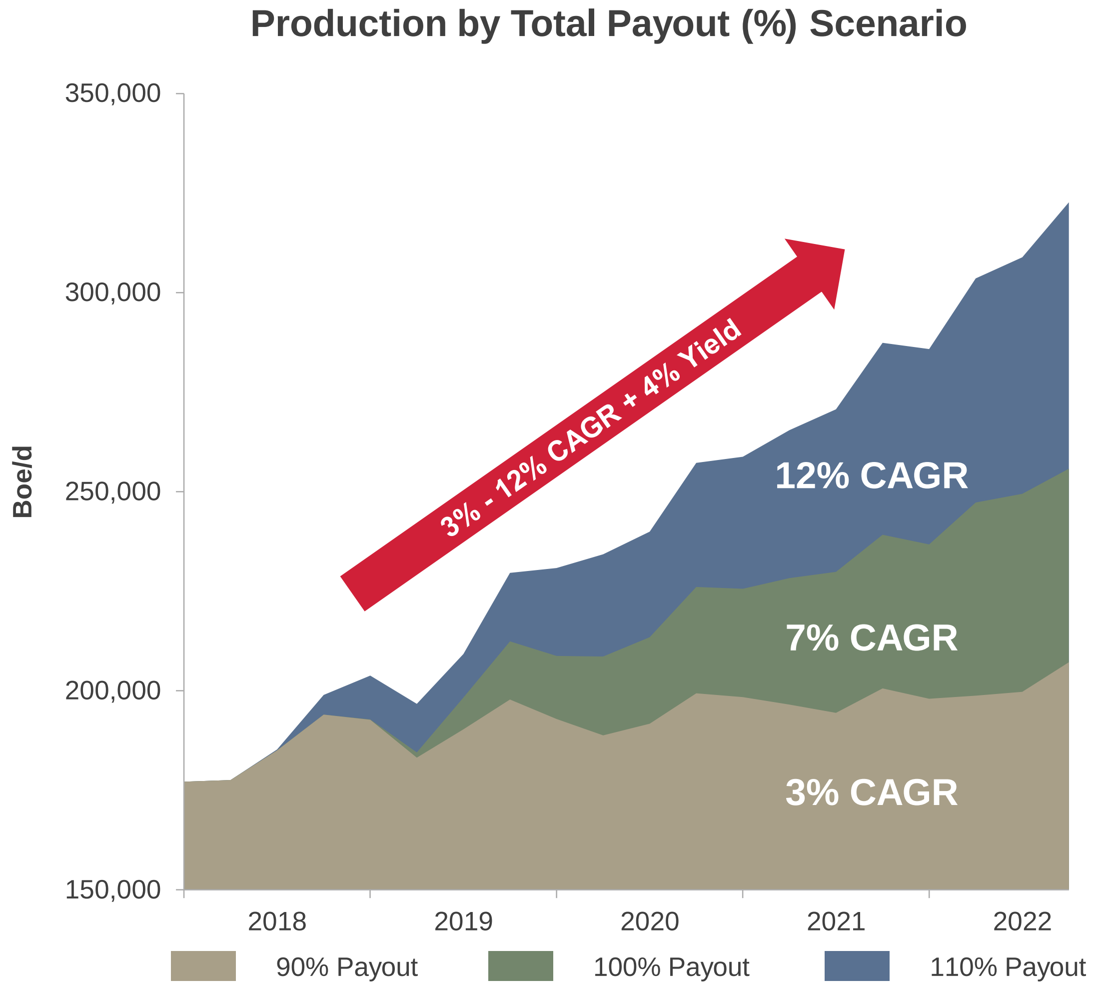
(Excludes impact of potential dispositions during 2018)

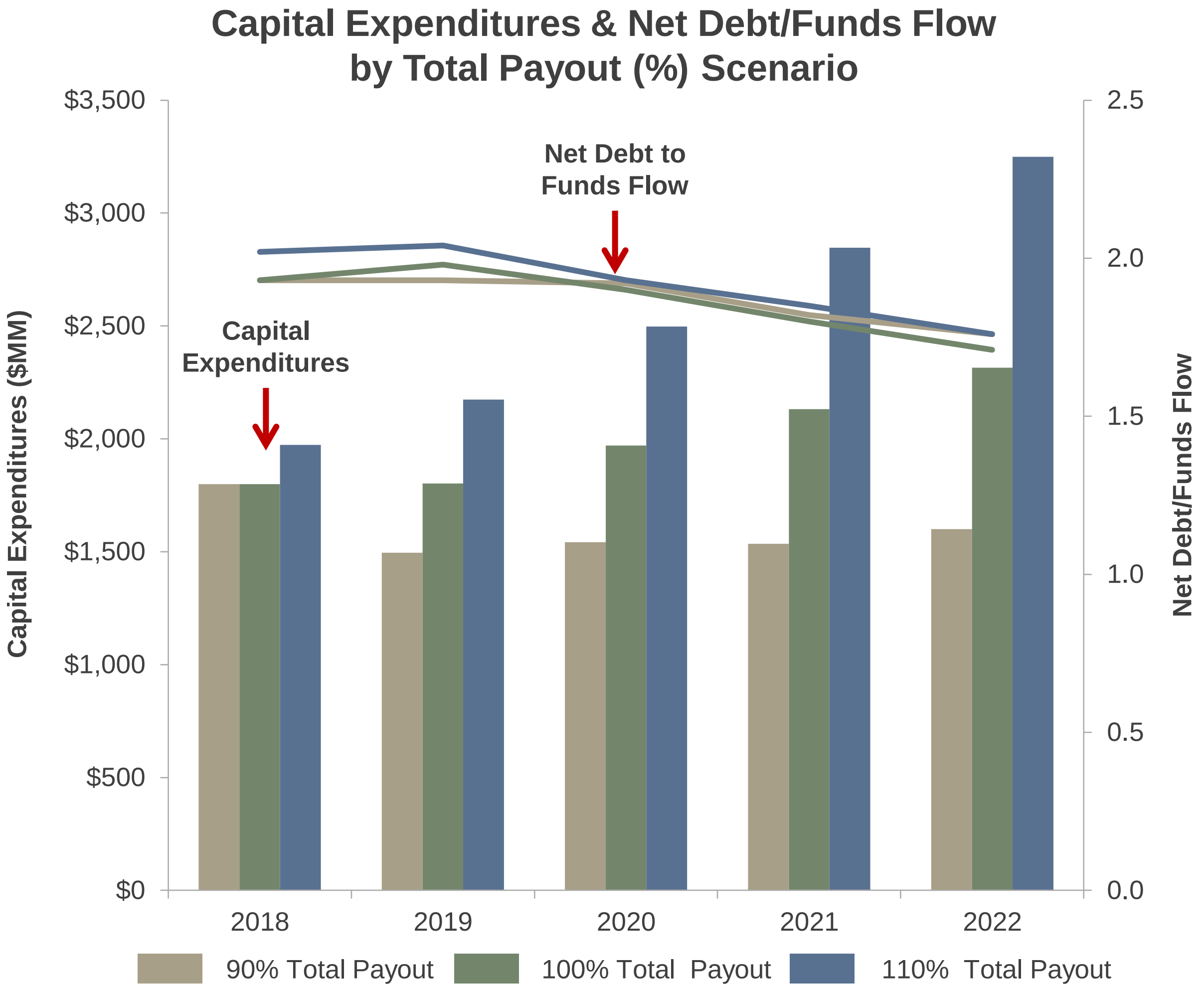
2016 – 2018 Average = 106%

Currently marketing non-core assets with potential proceeds providing increased balance sheet strength

Total payout = outflows (capital expenditures + land + acquisitions + dividends) divided by inflows (funds flow from operations and dispositions)
2018 figures based on 2018 guidance

5-Year Organic Growth Plan





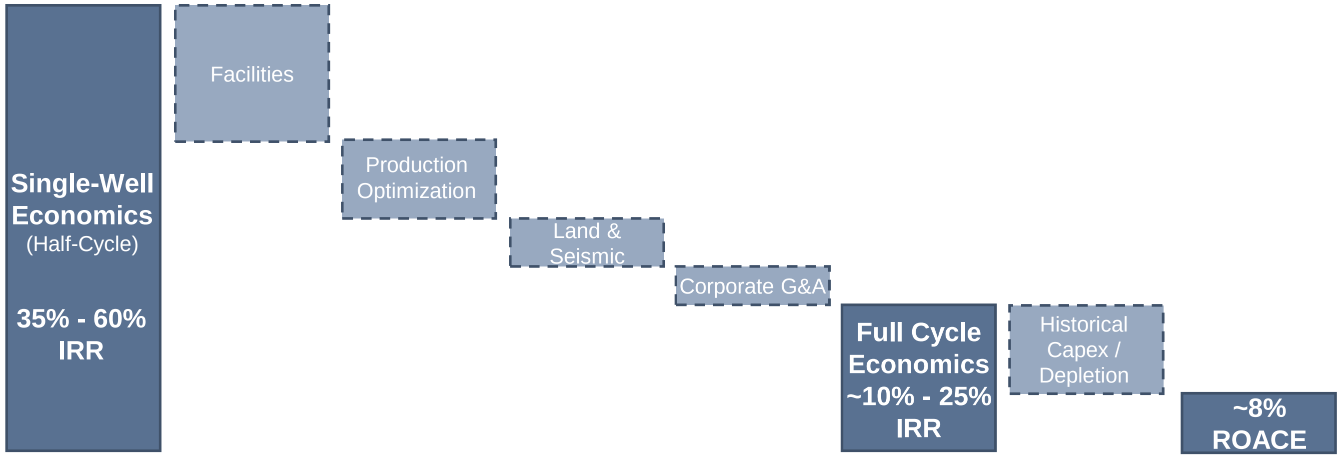
2018 net debt / funds flow based on strip prices of ~US$60/bbl WTI. 2019-2022 based on US$55 WTI
2018 capital expenditures in the 90% and 100% payout scenarios equate to the Company's 2018 guidance
Total payout = (capital expenditures + dividends) / (funds flow from operations)
2018 dividend yield based on share price as of market close on December 29, 2017

Corporate Returns

2018E ROACE at Various Capital Base Assumptions (US$55 WTI)

	Current Capital Base (Based on Sproule Deck)	Adjusted Capital Base (US$55 WTI Flat)
EBIT (Billions)	$0.4	$0.7
Capital Base (Billions)	$15.0	$9.1
ROACE	2.4%	7.8%

Go-Forward Returns (US$50 – US$60 WTI)



- Adjusted capital base aligns current cash flows to a cost base reflective of the current commodity price environment
- ROACE comparison for other companies may vary significantly due to differences in accounting methods, reserves booking and choice of depletion and depreciation methods

Capital base = total assets minus current liabilities
ROACE is defined as return on average capital employed and is calculated as earnings before interest and taxes (EBIT) divided by average capital employed
Historical capex/depletion refers to the impact of existing production and future DD&A of an adjusted capital base
Single-well economics IRR reflects the average well return in the Company’s five year capital drilling program
Sproule’s deck as at December 31, 2017: 5-year average ~US$67.50/bbl WTI and $0.83 USD/CAD exchange

Investment Thesis

Scaleable Economic Growth

- **Scaleable organic growth:** ~27 billion barrels OOIP, ~14,000 unrisked net locations and >4 million net acres of land
- **Execution history:** **~742 million boe** of organic reserve additions and consistent long-term reserves growth per share as of December 31, 2017
- **Significant infrastructure ownership** including pipeline, rail and facilities

Value Creators

- **Knowledge-first culture** and data driven company resulting in **operational excellence**
- Long-term outlook in development strategy to **maximize ultimate recovery and reserves**
- **History of successful new play discoveries** and organic growth of drilling inventory

Financial Discipline

- **Non-core asset dispositions** and a continued focus on **debt reduction**
- **~$1.5 billion of liquidity** with no material near-term maturities as of December 31, 2017
- Up to **3-½ year hedging program**

Crescent Point

Area Summaries

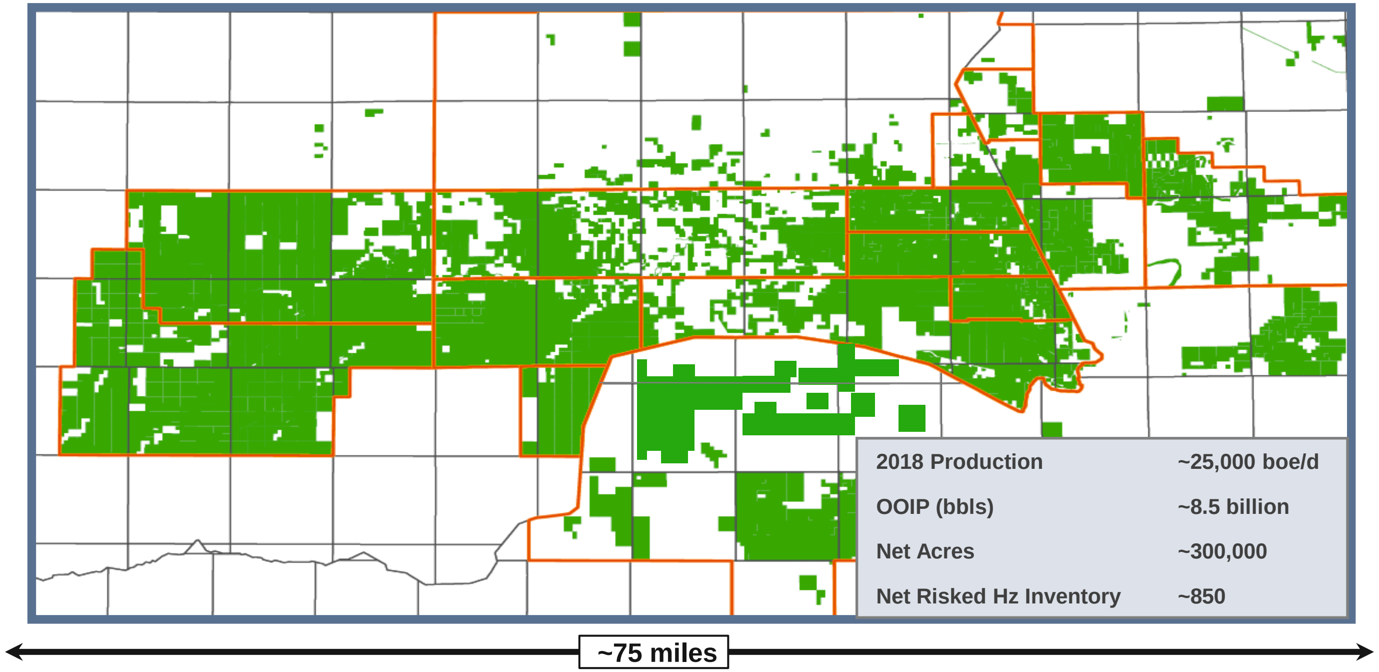
Uinta Basin – High-Growth Resource Play

Large OOIP Basin with Multi-Zone Potential

High-Quality Light Crude

Strong Well Economics With Significant Productivity

Uinta Basin: Positioned For Growth



2018 Production	~25,000 boe/d
OOIP (bbls)	~8.5 billion
Net Acres	~300,000
Net Risked Hz Inventory	~850

2017 Success

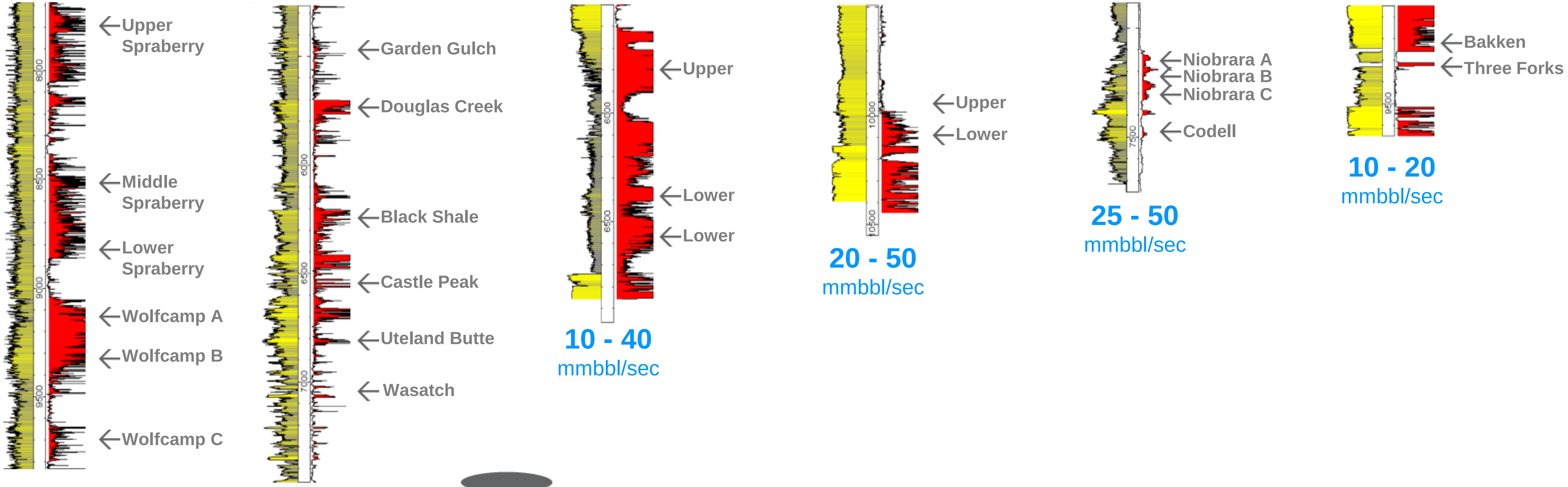
- Consolidated ~80,000 net acres, providing operatorship on western portion of the basin
- Increased net OOIP by 60% to ~8.5 billion barrels
- Advanced Castle Peak horizontal development to 2-miles and increased tonnage per stage of completion
- Successfully advanced Wasatch and Uteland Butte zones
- Increased net horizontal inventory to ~850 risked locations up from ~120 (Unrisked potential total of >1,700 horizontal locations)

2018 Priorities

- Advance 2-mile development
- Further delineate western portion of the basin
- Initiate multi-well pad drilling and completion optimization
- Continue new play development of additional zones
- Continue to develop strategy for long-term takeaway capacity

Uinta Stacked Pay Comparison vs. Major North American Shale Plays

Midland	Uinta	Montney	Eagle Ford	Niobrara	Bakken



Midland	Uinta	Montney	Eagle Ford	Niobrara	Bakken
50 - 150 mmbbl/sec	20 - 60 mmbbl/sec	10 - 40 mmbbl/sec	20 - 50 mmbbl/sec	25 - 50 mmbbl/sec	10 - 20 mmbbl/sec

Entire Uinta Basin pool equates to 55 billion barrels of OOIP

Uinta Basin: CPG Progression Overview

2013 - 2018

Increased capital spending and Horizontal development

- ~20% of corporate capital allocation in 2018 (14% in 2013)
- >30 Hz wells in 2018 program (0 in 2013)
- Identified ~850 net Hz risked locations (0 in 2013)

Completions advancement and Increased productivity

- 50+ stages, 200+ tons per stage, 2,800+ lbs/ft
- Attained recent IP30s of >1,000 boe/d in Castle Peak and ~1,700 boe/d in Wasatch

Multiple zones and Increased land position

- Drilled and completed 5 unique zones
- Increased land position to ~300,000 net acres

5-Year Development Priorities

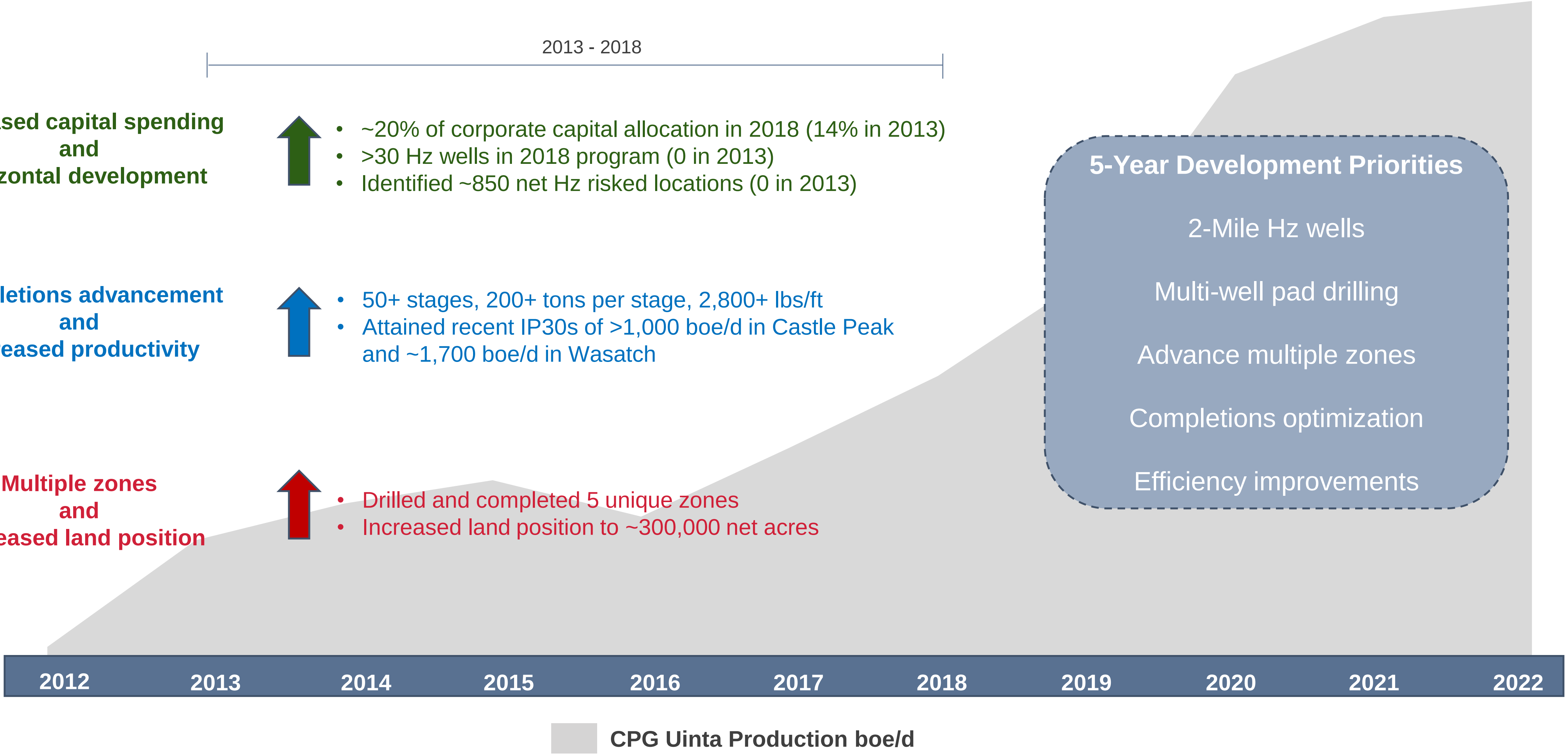
2-Mile Hz wells

Multi-well pad drilling

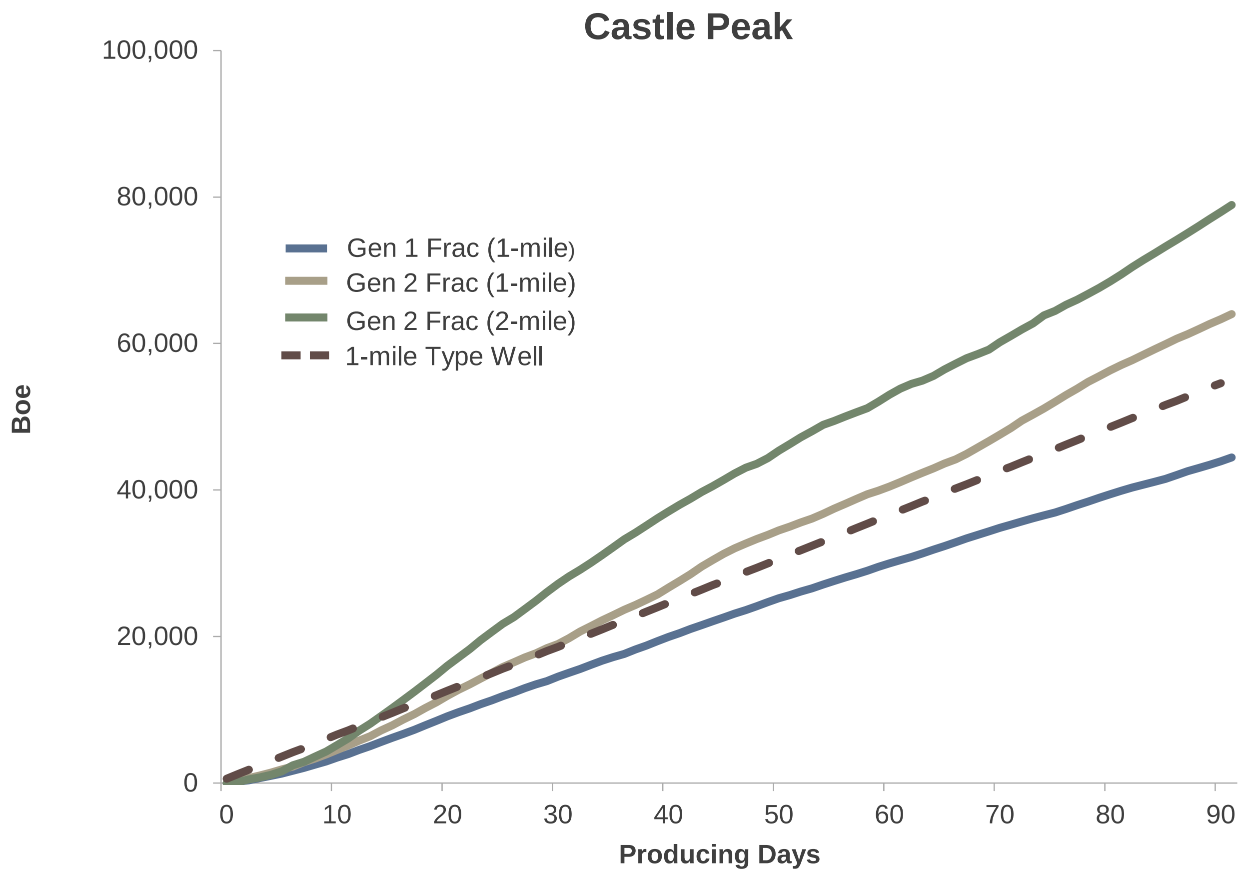
Advance multiple zones

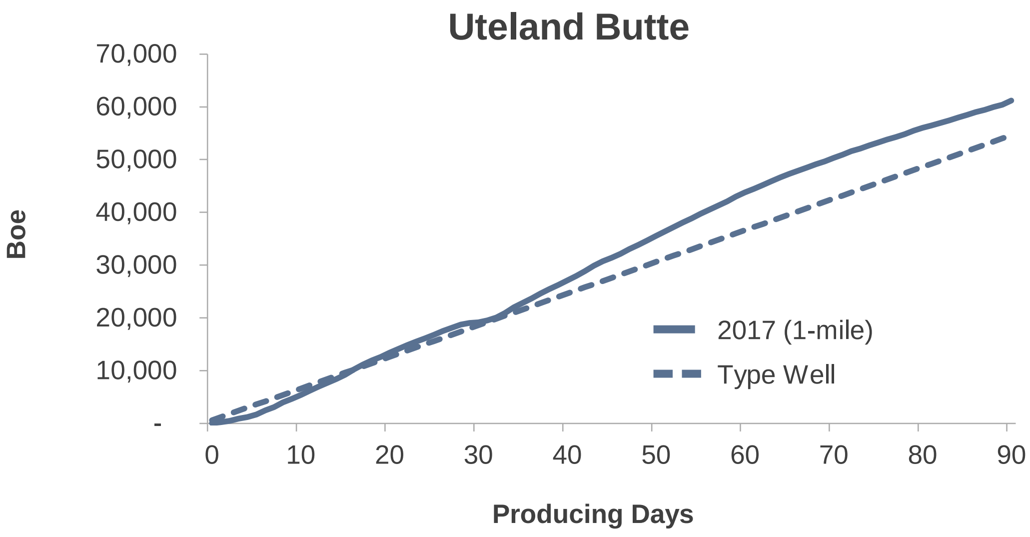
Completions optimization

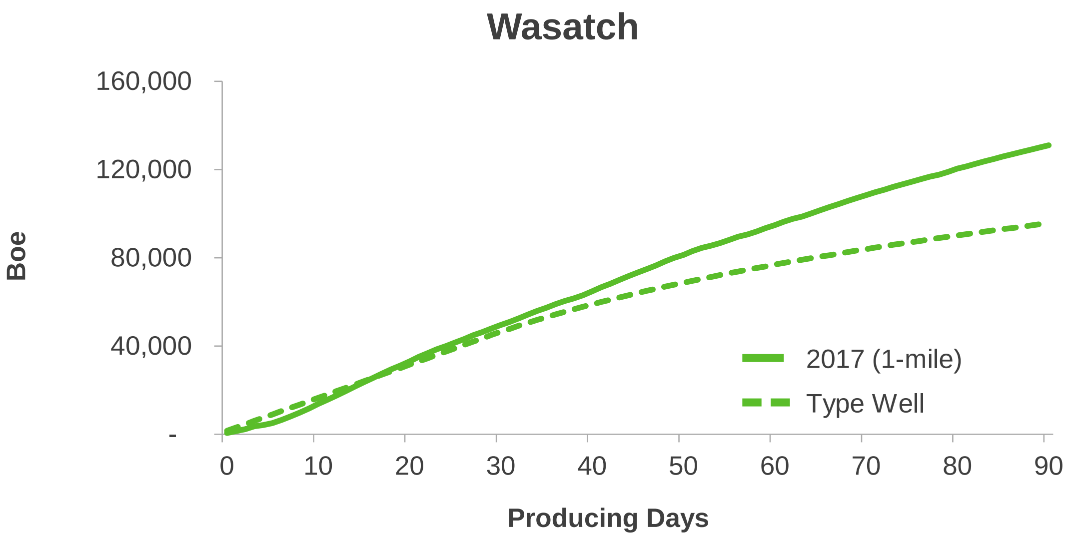
Efficiency improvements



Uinta Basin: Horizontal Well Progression by Zone







Strong current economics with quick well payouts

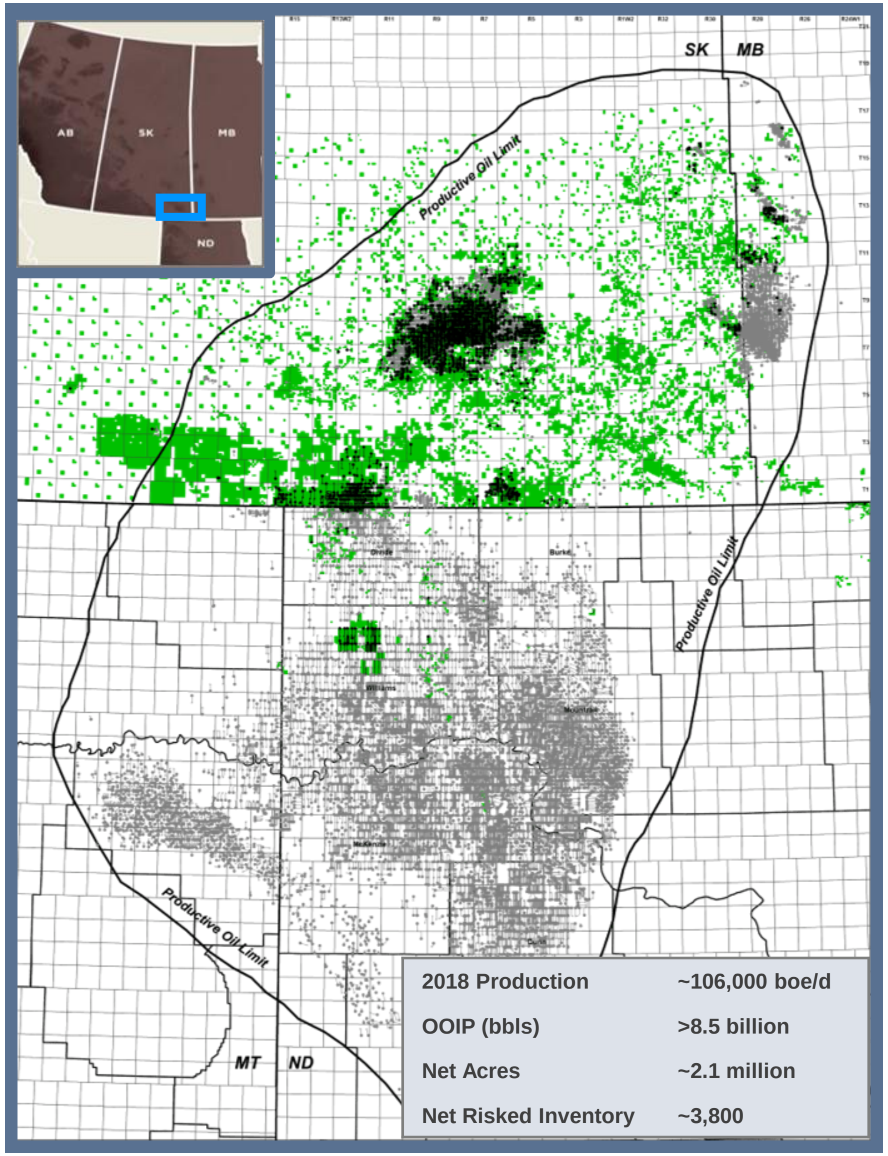
Efficiencies expected to be realized during development phase

Data used above includes all horizontal wells drilled to date with at least 90 days of production for each respective zone
Wasatch and Uteland Butte data exclude wells drilled in 2014-2015 (prior to refined geological mapping)
Gen 2 Fracs utilize increased tonnage in comparison to Gen 1 Fracs
Type wells represent wells expected to be drilled in 2018 program

Williston Basin & SW Saskatchewan – Low-Risk Production

Free Cash Flow	Largest Unconventional Waterflood Programs	Multi-Zone Growth Potential

Williston Basin



2018 Production	~106,000 boe/d
OOIP (bbls)	>8.5 billion
Net Acres	~2.1 million
Net Risked Inventory	~3,800

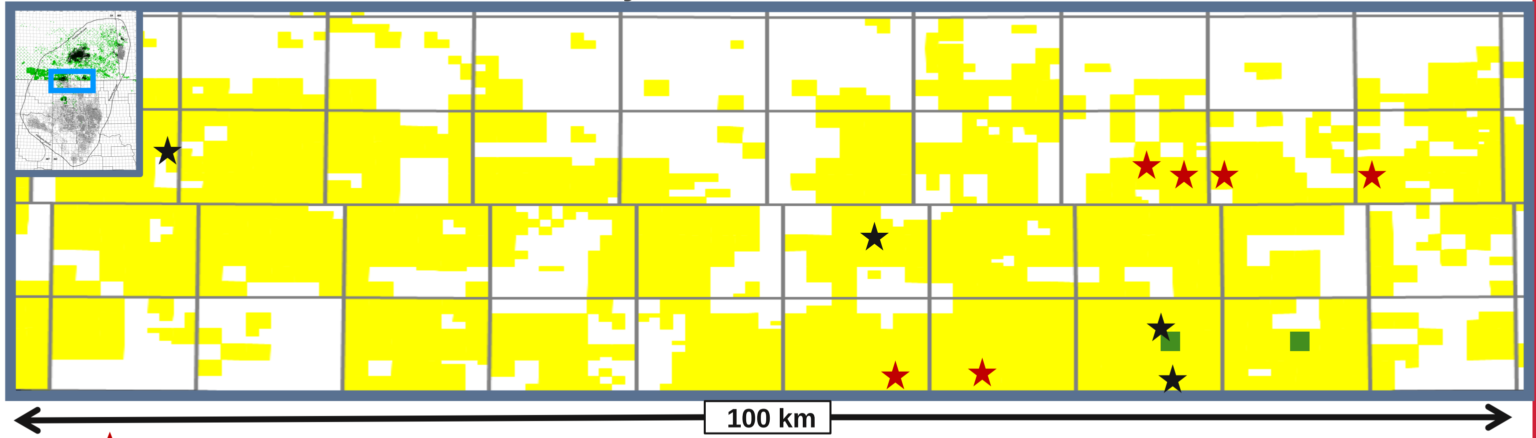
2017 Success

- Added new locations across multiple zones (step-out, down-spacing, etc.)
- Added >500 net sections in Flat Lake and North Dakota targeting multiple zones
- Proved oil productivity in the new Lodgepole zone (early stage of development)
- Increased waterflood efficiency through ICDs and proved water injectivity in Flat Lake

2018 Priorities

- Commission infrastructure projects to accommodate future growth
- Advanced pad drilling in North Dakota and Flat Lake area to improve efficiencies
- Expand Bakken and Flat Lake waterflood programs
- Continue step-out programs and evaluation of Lodgepole zone

2017 Activity in Multi-Zone Flat Lake Area



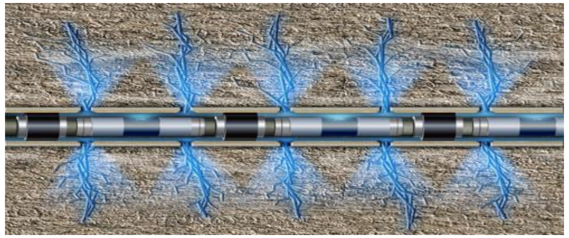
★ 2017 Torquay Step Out Well ★ 2017 Lodgepole Well ■ 2017 Ratcliffe Down-Spacing Pilot

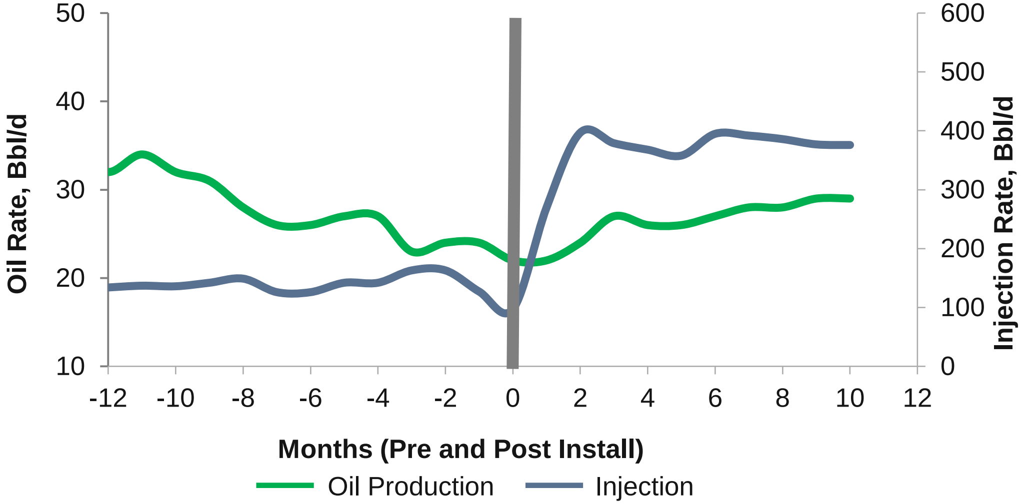
Williston Basin includes: Viewfield, Flat Lake, North Dakota and SE SK Conventional

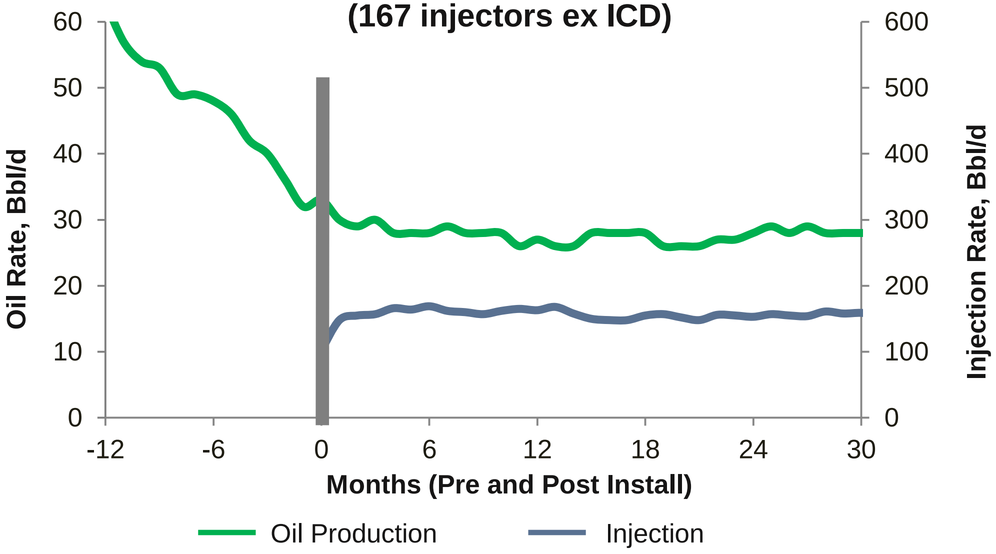
Waterflood Leaders: Realizing Gains from Waterflood Expertise

- ICD improves recovery factor by controlling flow and creating even water distribution through sleeves (50 ICDs installed as at YE 2017)
- ICD pilots in the Viewfield Bakken have seen a rapid response, offsetting oil production has increased ~30% since installation
- Testing new methods to further increase recovery including nanosurfactants and conformance gels

INJECTION CONTROL DEVICE (ICD)



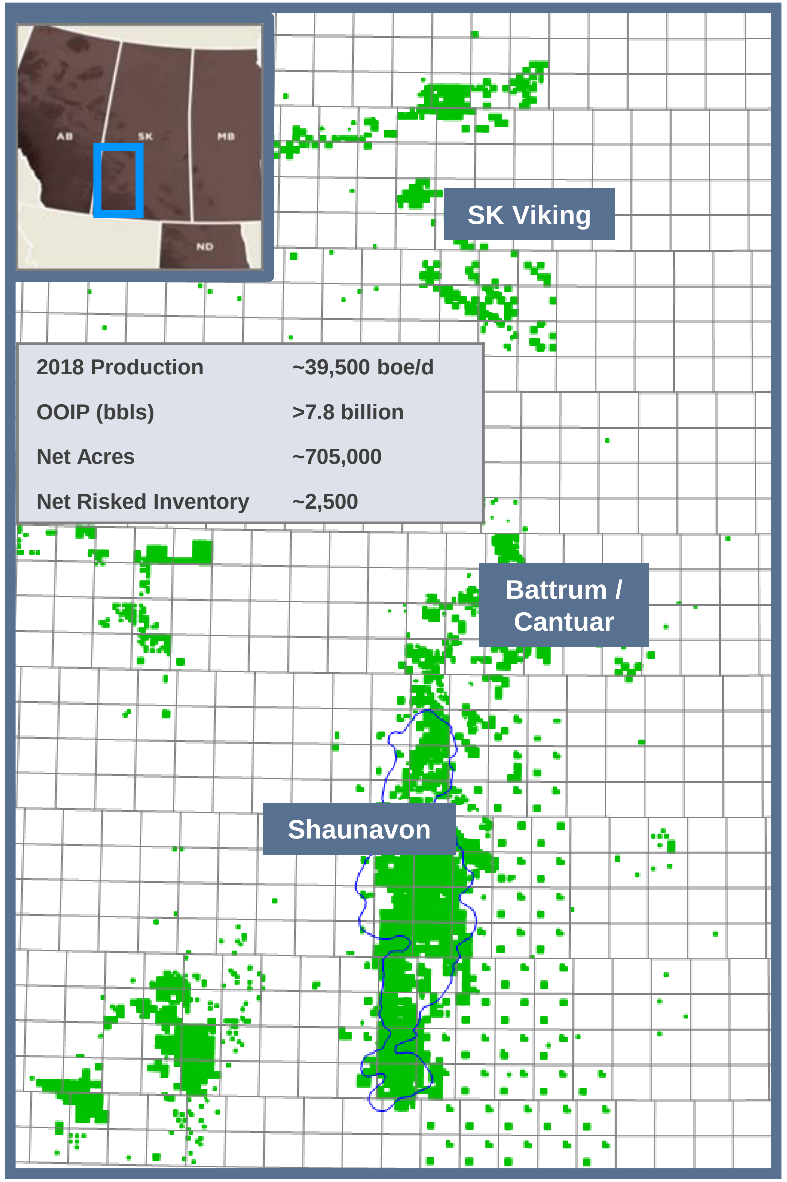




Improving Recovery Factors and Increasing Sustainability

Waterflood data normalized to first injection

SW Saskatchewan



2018 Production	~39,500 boe/d
OOIP (bbls)	>7.8 billion
Net Acres	~705,000
Net Risked Inventory	~2,500

SW Saskatchewan includes: Shaunavon, Battrum/Cantuar and Viking

2017 Success

- Added locations in the Shaunavon play due to a successful step-out program and advancement in new technology (i.e. cemented liners)
- Added new infrastructure in Shaunavon play to accommodate future growth
- Improved economic development in the Viking play through ERH wells
- Advanced waterflood program including a pilot in the Viking play

2018 Priorities

- Continue to generate free cash flow
- Advance waterflood program in Shaunavon and optimize pilots in the Viking
- Continue step-out program to extend economic boundaries
- Optimize completion processes

Forward Looking Information

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: the Corporation's estimated drilling locations and OOIP; the Corporation's three-tiered business strategy; estimated average production for 2018; the Corporation's reserve life index; the Corporation's 2P net asset value; the unbooked reserve potential of the Corporation's assets; the Corporation's 2018 outlook, including plans to be return focused, achieve 7% growth with exit production of 195,000 boe/d and balance cash flows; the expected use of proceeds from potential future non-core asset sales; the Corporation's 2018 and five year development priorities for the Uinta Basin; expected efficiencies to be realized in the Uinta Basin during the development phase; the expected ability to increase refining capacity in the Uinta Basin; the Corporation's 2018 priorities for the Williston Basin and for SW Saskatchewan; the expected position of the Corporation's core areas in their respective life cycles in 2018; the expected impact of the Corporation's hedging program on funds flow volatility and the stability of dividends and capital spending; the Corporation's expectation that it will achieve a 106% total payout over the 2016-2018 period (excluding potential additional dispositions in 2018); the expected production by total payout and capital expenditures and net debt/funds flow by total payout under the Corporation's five year organic growth plan; expected 2018 ROACE under different capital base assumptions; expected go-forward full-cycle drilling IRRs over next five years; the scalability of the Corporation's organic growth; the expected impact of the Corporation's development strategy on long term outlook; 2018 guidance for capital expenditures, average annual and exit production, funds flow from operations netback, total payout, net debt to funds flow from operations and net wells to be drilled; estimated production growth; expected balanced production growth across core areas; planned 2018 capital allocation by core area; the expected impact on inventory growth in the Uinta Basin on the number of wells needed to be drilled to maintain production; the Corporation's plans to continue to test additional methods to further increase recovery; the expected F&D, project IRR payback and long-term decline rates for an example Crescent Point resource play , a SAGD oil sands project profile and a mining oil sands project profile over an extended period; expected future climate change initiatives and their anticipated impact on $C0_2$ emissions; the expected total production from the U.S. as a percentage of the Corporation's entire production by 2022; and the Corporation's future plans for its Board renewal process.

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. 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. Information relating to "reserves" is deemed to be forward-looking information, as it involves the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and that the reserves described can be profitably produced in the future. All required reserve information for the Corporation is contained in its Annual Information Form for the year ended December 31, 2017, which is accessible at www.sedar.com. 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 and there is significant uncertainty regarding the ultimate recoverability of such resources.

All forward-looking statements are based on Crescent Point's beliefs and assumptions based on information available at the time the assumption was made. 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 report 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 Corporation's Annual Information Form for the year ended December 31, 2017 under "Risk Factors," in our Management's Discussion and Analysis for the year ended December 31, 2017, under the headings "Risk Factors" and "Forward-Looking Information" and for the year ended December 31, 2017 under "Derivatives", "Liquidity and Capital Resources", "Changes in Accounting Policies" and "Outlook". The material assumptions are disclosed in the Management's Discussion and Analysis for the year ended December 31, 2017, under the headings "Capital Expenditures", "Liquidity and Capital Resources", "Critical Accounting Estimates", "Risk Factors", "Changes in Accounting Policies" and "Outlook".

In addition, with respect to forward-looking information contained in this presentation, assumptions have been made regarding, among other things: future crude oil and natural gas prices; future interests rates and currency exchange rates; future cost escalation under different pricing scenarios; the Corporation's future production levels; the applicability of technologies for recovery and production of the Corporation's reserves and improvements therein; the recoverability of the Corporation's reserves; Crescent Point's ability to market its production at acceptable prices; future capital expenditures; future cash flows from production meeting the expectations stated in this presentation; future sources of funding for the Corporation's capital program; the Corporation's future debt levels; geological and engineering estimates in respect of the Corporation's reserves; the geography of the areas in which the Corporation is conducting exploration and development activities; the impact of competition on the Corporation; the Corporation's ability to obtain financing on acceptable terms.

These assumptions, 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 assumption, risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent. Except as required by law, Crescent Point assumes no obligation to update forward-looking statements should circumstances or management's estimates or opinions change. Certain information contained herein has been prepared by third-party sources.

Included in this presentation are Crescent Point's 2018 guidance in respect of capital expenditures, average annual production, exit production, funds flow from operations netback, total payout, net debt to funds flow from operations and number of wells to be drilled; and expectations under its 5-Year Plan, including with respect to CAGR + Yield, production by total payout and capital expenditures and net debt/funds flow by total payout, which are based on various assumptions as to production levels, commodity prices and other assumptions and are provided for illustration only and are based on budgets and forecasts that have not been finalized and are subject to a variety of contingencies including prior years' results. To the extent such estimates constitute a "financial outlook" or "future oriented financial information" in this presentation, as defined by applicable securities legislation, such information has been approved by management of Crescent Point in February 2018. Such financial outlook or future oriented financial information 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.

Crescent Point

Appendix

Capital Markets Summary

CPG (TSX and NYSE)	
Trading Price (Feb 23, 2018)	C$9.54 (TSX), US$7.52 (NYSE)
Shares Outstanding	549.4 million
Average Daily Trading Volume	~7.5 million
Dividend (Yield)	C$0.03 per month (3.8%)
Market Capitalization	C$5.2 billion
Net Debt	C$4.0 billion
Enterprise Value	C$9.2 billion
Cash & Unutilized Credit Capacity	C$1.5 billion

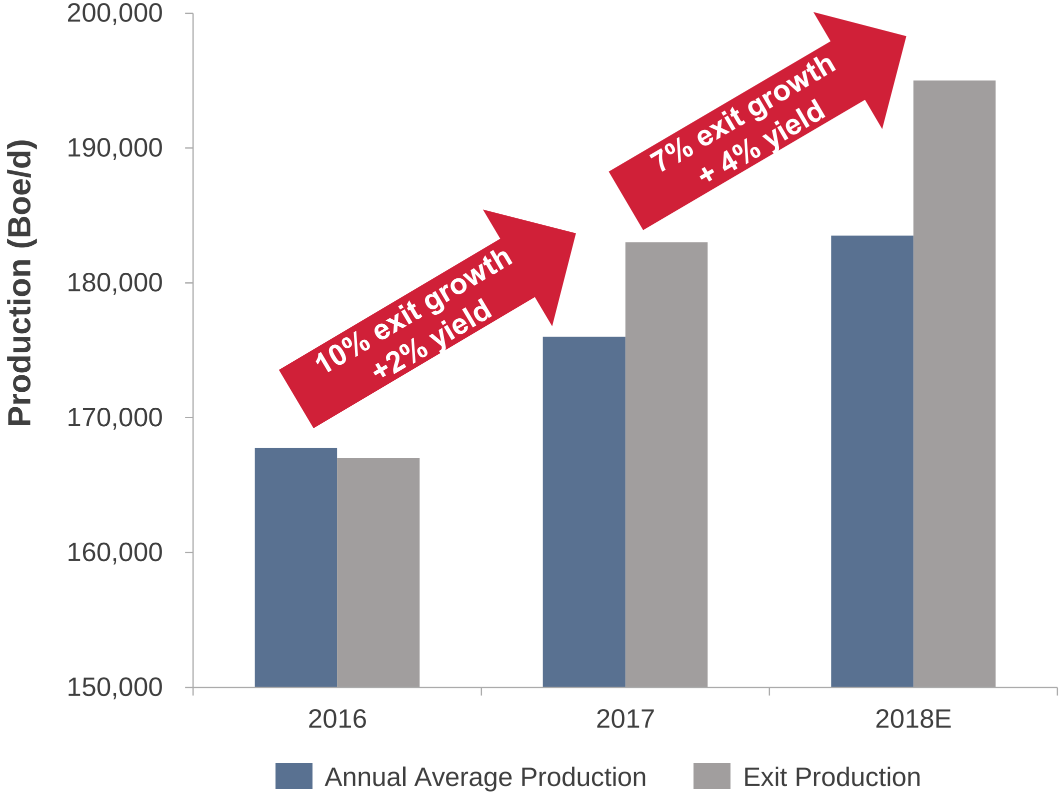
Net debt and cash and unutilized credit capacity as of December 31, 2017
Market capitalization and dividend yield based on share price as of market close on Feb 23, 2018 and 549.4 million fully diluted shares outstanding as of Dec 31, 2017
Average daily trading volume based on Canadian and US volumes from trailing 3-months as of February 23, 2018

2018 Capital Budget and Production Growth

2018 Guidance

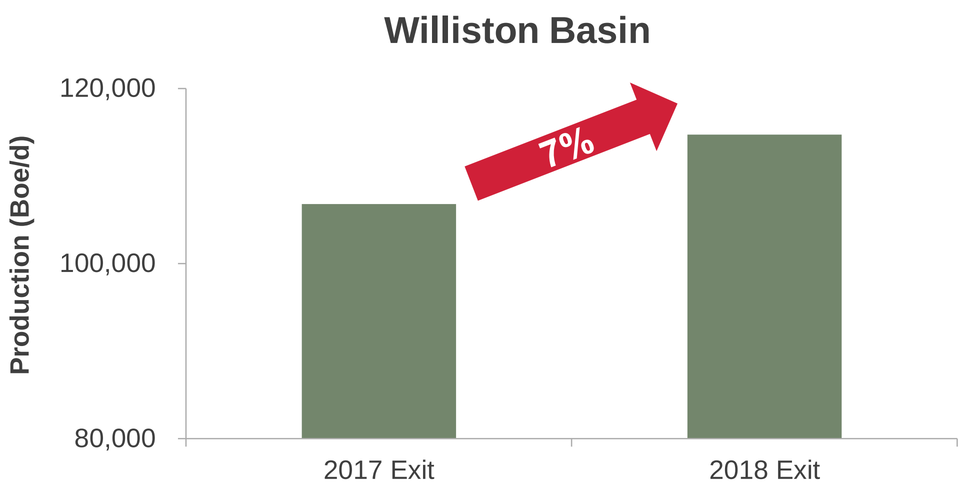
Capital Expenditures ($ millions)	$1,800
Drilling and Development (%)	89%
Facilities and Seismic (%)	11%
Average Annual Production (boe/d)	183,500
Exit Production (boe/d)	195,000
Funds Flow from Operations Netback ($/boe)	~$30.00
Total Payout (%)	99%
Net Debt to Funds Flow from Operations	1.9x
Number of Net Wells Drilled	~630
2018 Funds flow from operations sensitivity for every US$ $1.00/bbl WTI (millions)	~$40

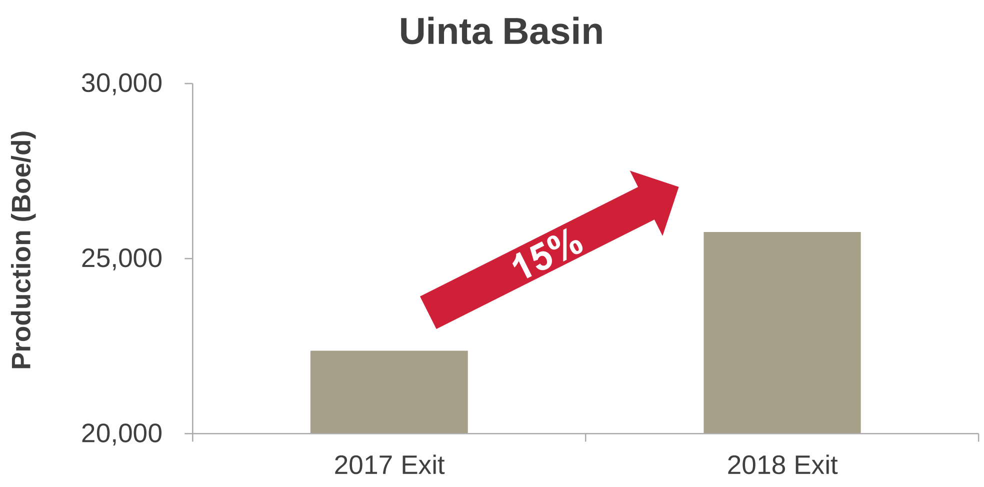
Production Growth

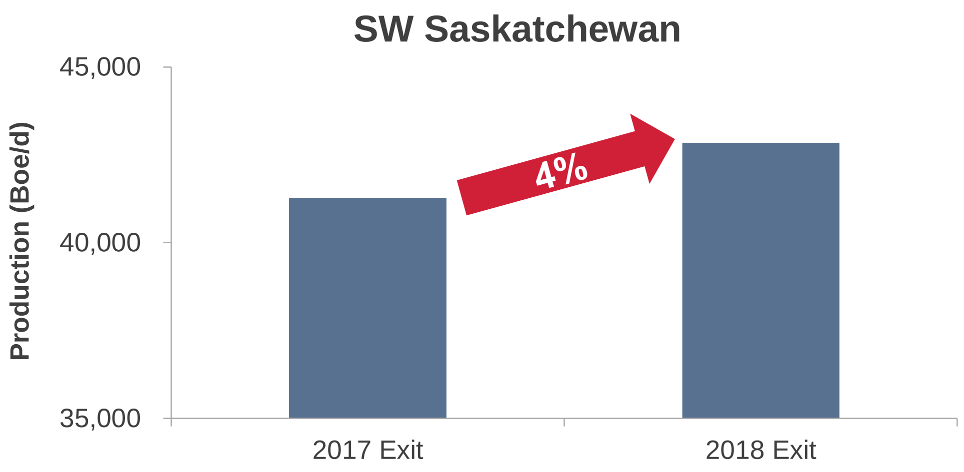


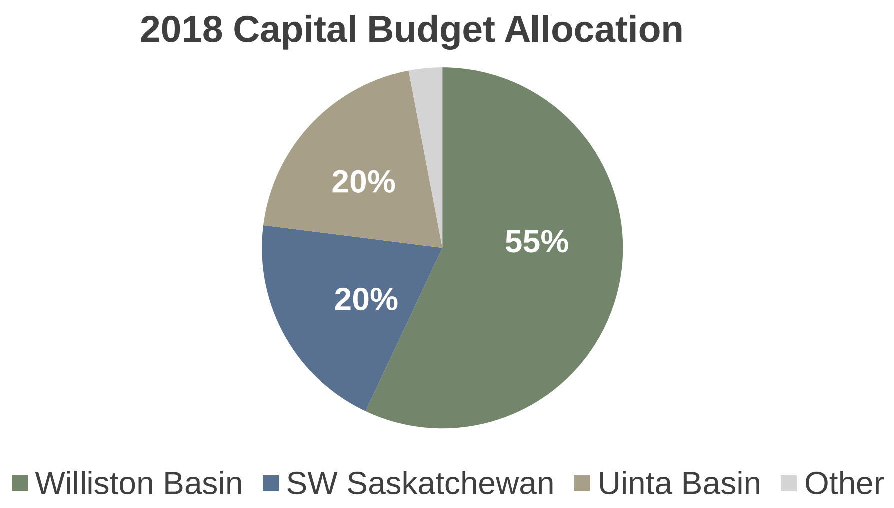
Capital expenditures excludes net land and property acquisitions
Netback, total payout and net debt to funds flow based on strip prices of ~US$60/bbl WTI and $0.80 USD/CAD exchange
Total payout is calculated on a percentage basis as capital expenditures and dividends declared divided by funds flow from operations
2017 dividend yield based on share price as of market close on December 30, 2016
2018 dividend yield based on share price as of market close on December 29, 2017

2018 Budget: Balanced Growth Across Core Areas



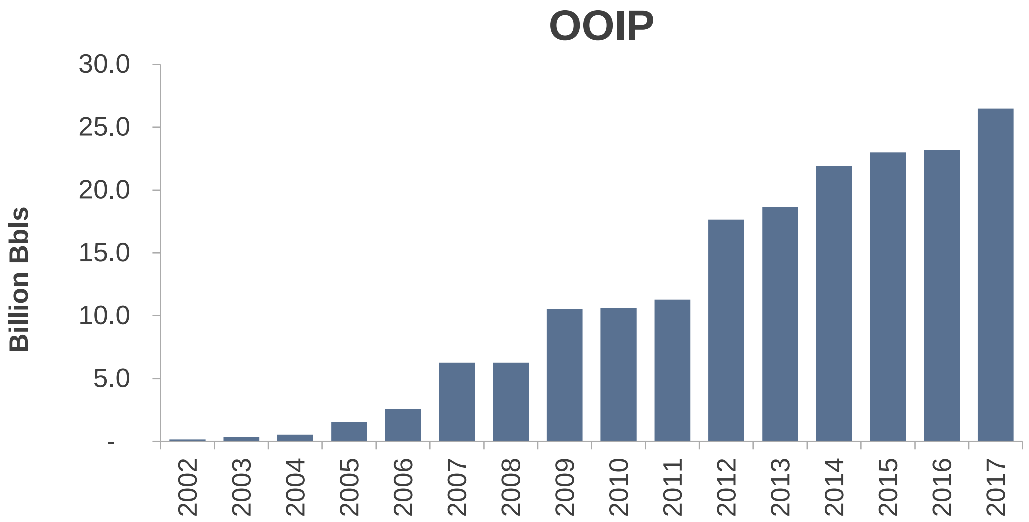


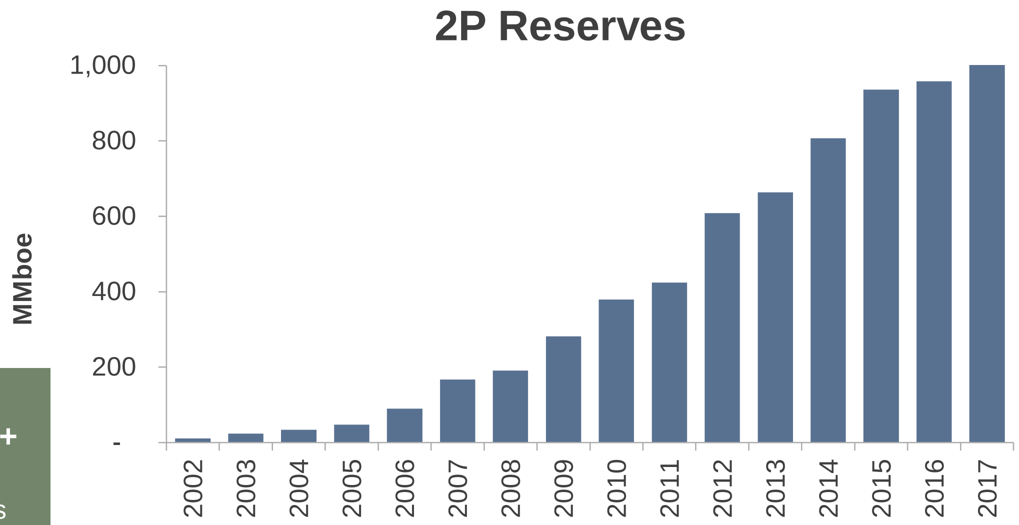




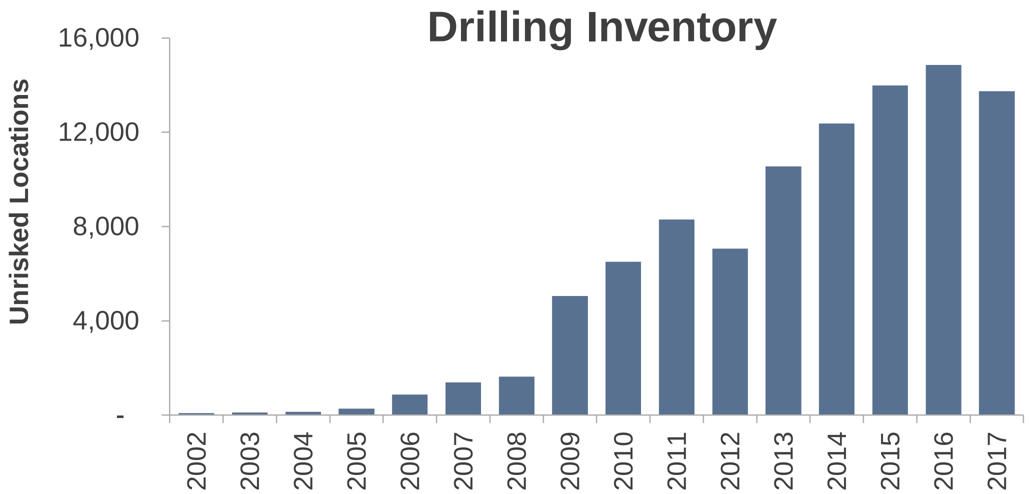
All numbers shown above are approximations

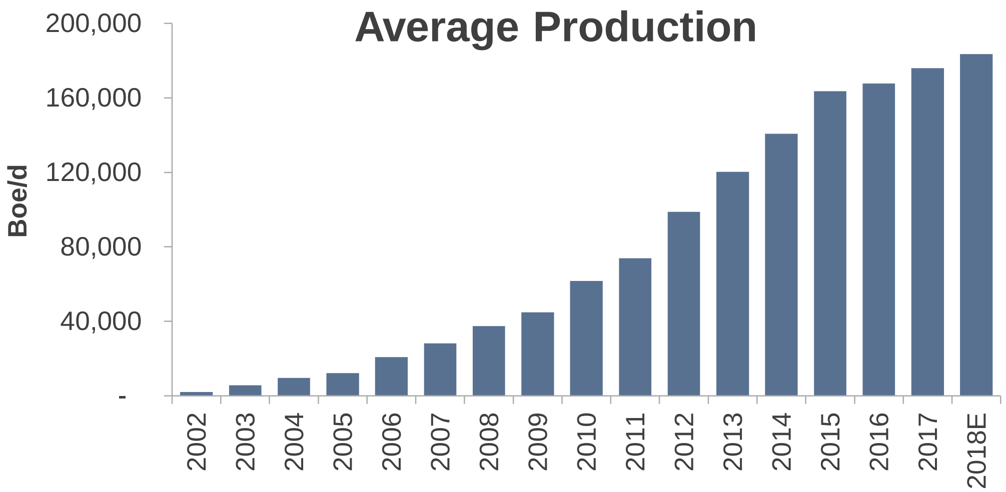
Proven Track Record





Historical per-share growth + 8% avg. yield
>$7 billion in dividends paid to date

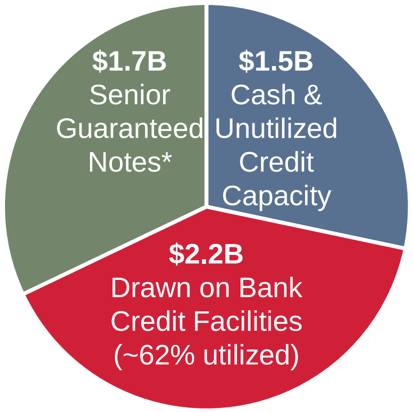




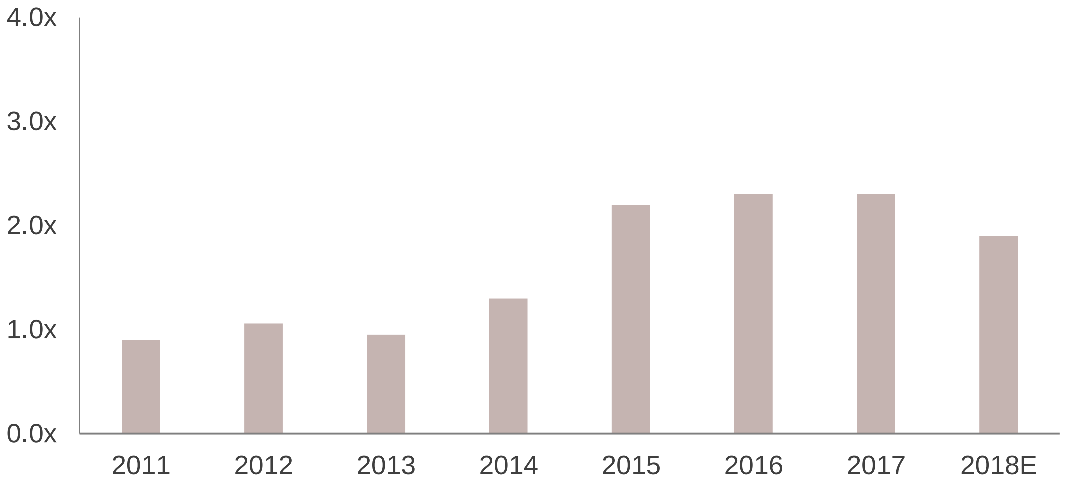
Creating value and long-term sustainability through the development of large OOIP resource plays

Balance Sheet Strength

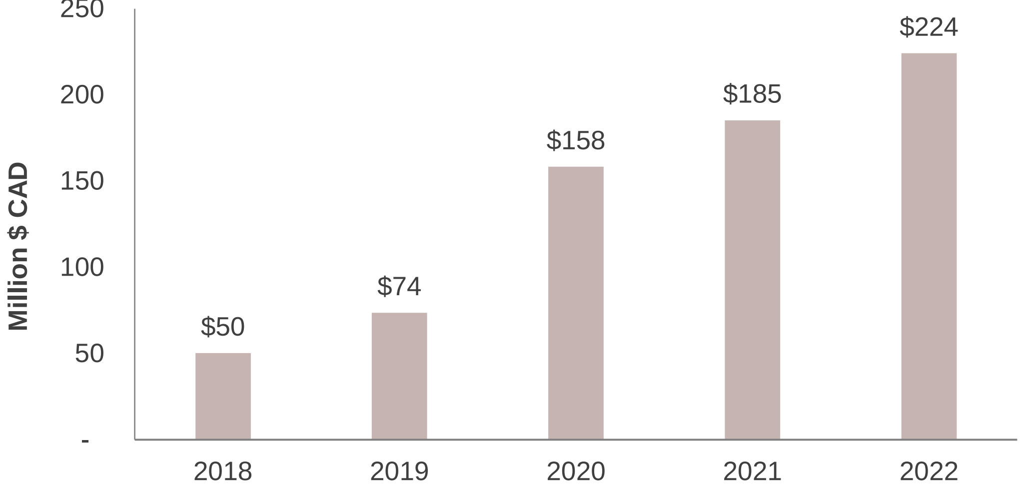
Debt Composition ($CAD) as of Dec 31, 2017



Net Debt to Funds Flow From Operations



Senior Guaranteed Notes Maturity Schedule

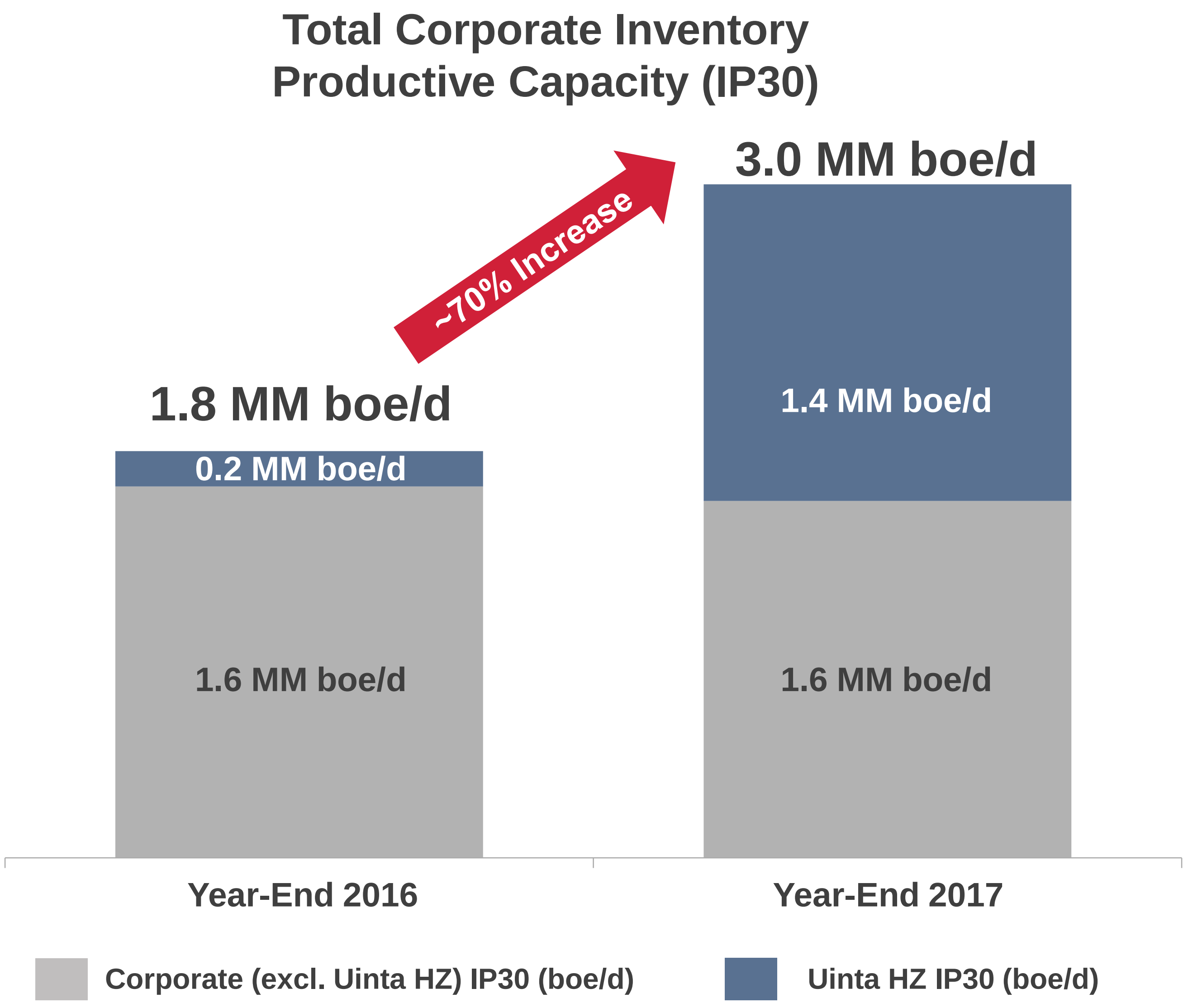


- No material near-term debt maturities, cash and unutilized credit capacity of ~$1.5 billion
- Bank credit facilities and senior guaranteed notes rank equal and are unsecured and covenant-based. Bank credit facilities have a June 2020 renewal date
- US$ denominated senior guaranteed notes fully hedged with cross currency swaps

Significant amount of liquidity and financial flexibility

*Includes underlying currency swaps

Uinta Inventory Growth Significantly Increases Productive Capacity



- Doubled average IP30 rate per well of corporate inventory vs. prior year

- Requires fewer future wells to be drilled to maintain production

Productive capacity is defined as the total IP30 rate assuming all wells in inventory are brought on production at the same time
Inventory includes unrisked wells. All numbers shown above are approximations

Economics by Play

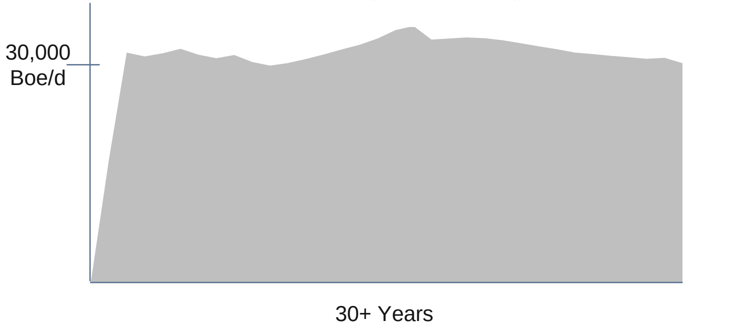
Williston Basin	Type Well (EUR) (mbbl)	Cost per well ($MM)	$55 WTI Economics NPV @ 10% ($MM)	IRR (%)	Payout (months)
Viewfield Bakken	50 – 125	1.4	0.4 – 3.4	33 – 239	24 – 9
Flat Lake – Torquay	100 – 175	2.4	1.6 – 3.8	57 - 126	17 – 12
Flat Lake – Conventional Ratcliffe	75	1.2	1.4	90	14
North Dakota ($US)	600	5.4	3.6	42	23
SE Saskatchewan Conventional	40 – 60	1.0	0.5 – 1.0	34 – 64	30 – 19
SW Saskatchewan Resource Play	**Type Well (EUR) (mbbl)**	**Cost per well ($MM)**	**NPV @ 10% ($MM)**	**IRR (%)**	**Payout (months)**
Shaunavon	80 – 130	1.5	0.7 – 1.7	42 – 113	21 – 11
Viking	41 – 54	0.9	0.4 – 0.7	32 – 50	29 – 21
Uinta Basin	**Type Well (EUR) (mbbl)**	**Cost per well ($MM)**	**NPV @ 10% ($MM)**	**IRR (%)**	**Payout (months)**
Castle Peak (1-mile & 2-mile Hz) ($US)	350 – 620	5.5 - 8.5	1.6 – 4.9	27 – 64	30 – 14
Wasatch (1-mile Hz) ($US)	490 – 540	6.0 - 7.0	2.4 – 4.1	34 – 76	24 – 12

All figures are approximates and in CAD unless otherwise noted
Capital costs per well include drilling, completion, equipment and tie-in expenditures
Economics by play represent type wells expected to be drilled in 2018 program

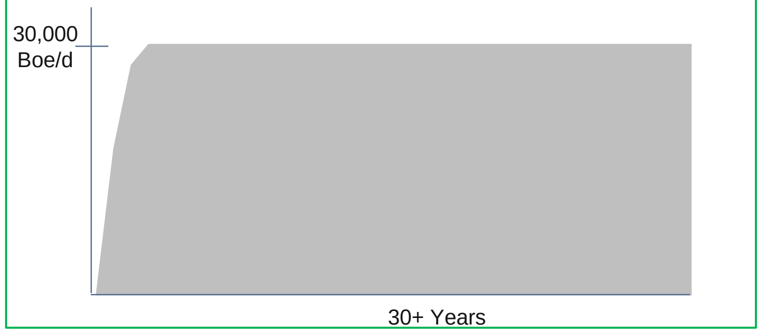
Example of CPG Resource Play vs. Oil Sands Projects

	F&D Cost ($/Boe)	Project IRR (%)	Payback (Years, Undisc.)	Long-Term Decline Rate
CPG RESOURCE PLAY (Incl. Waterflood)	✓ **Low**	✓ **Highest Returns**	✓ **Quickest Payback**	✓ **Low-Medium**
SAGD OIL SANDS PROJECT	✓ **Low**			✓ **Low**
MINING OIL SANDS PROJECT				✓ **Low**

CPG Resource Play Including Waterflood



SAGD Oil Sands Project Profile



Mining Oil Sands Project Profile

Oil Sands Projects data and economics from BMO Capital Markets Research
CPG resource play example based on a theoretical development of Viewfield and Shaunavon resource plays
Production held flat after reaching peak production of 30,000 boe/d for SAGD and 120,000 boe/d for mining project
Average pricing of US$61.49/bbl WTI and $0.78 USD/CAD exchange
Capital spent to reach peak production: $0.5B for CPG Resource Play. $1.1B for SAGD and $7.4B for Mining

Significant Reserves Growth

Property	Initial 2P Reserves (Mboe)	Estimated Production to Date (Mboe)	Current 2P Reserves (Mboe)	Total 2P Recovery (Mboe)	Increase In 2P Reserves (Mboe)	Increase In Reserves (%)
Williston Basin	196,291	207,993	470,513	679,789	483,498	246%
SW Saskatchewan	150,822	90,768	208,077	306,051	155,229	103%
Uinta Basin	81,401	25,886	131,911	157,797	76,397	94%
Other	27,928	12,914	40,047	52,961	25,033	90%
Corporate Total	**456,442**	**337,561**	**850,549**	**1,196,598**	**740,156**	**162%**

As of December 31, 2017 as evaluated by GLJ Petroleum Consultants Ltd. and Sproule Associates Limited
Total 2P reserves = estimated production plus current 2P reserves

- Increased 2P reserves by >740 million boe (162%)
- Large oil-in-place pools have outperformed initially estimated recoveries over time

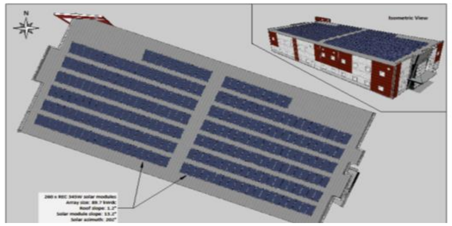
Williston Basin acquisition history includes: Viewfield Bakken, Flat Lake Resource, North Dakota, Manor and Tatagwa Unit
SW Saskatchewan acquisition history includes: Shaunavon, Battrum/Cantuar, Saskatchewan Viking and Sounding Lake
Other acquisitions includes Alberta
Amounts may not add due to rounding
Total 2P recovery and increase in 2P reserves includes disposed 2P reserves

Climate Change Initiatives

Green Energy Projects
(Completed/In Progress)

Solar Facilities

Solar Field Offices



Flare & Vent Power

Expected to reduce CO_2 emissions

Fuel Switching

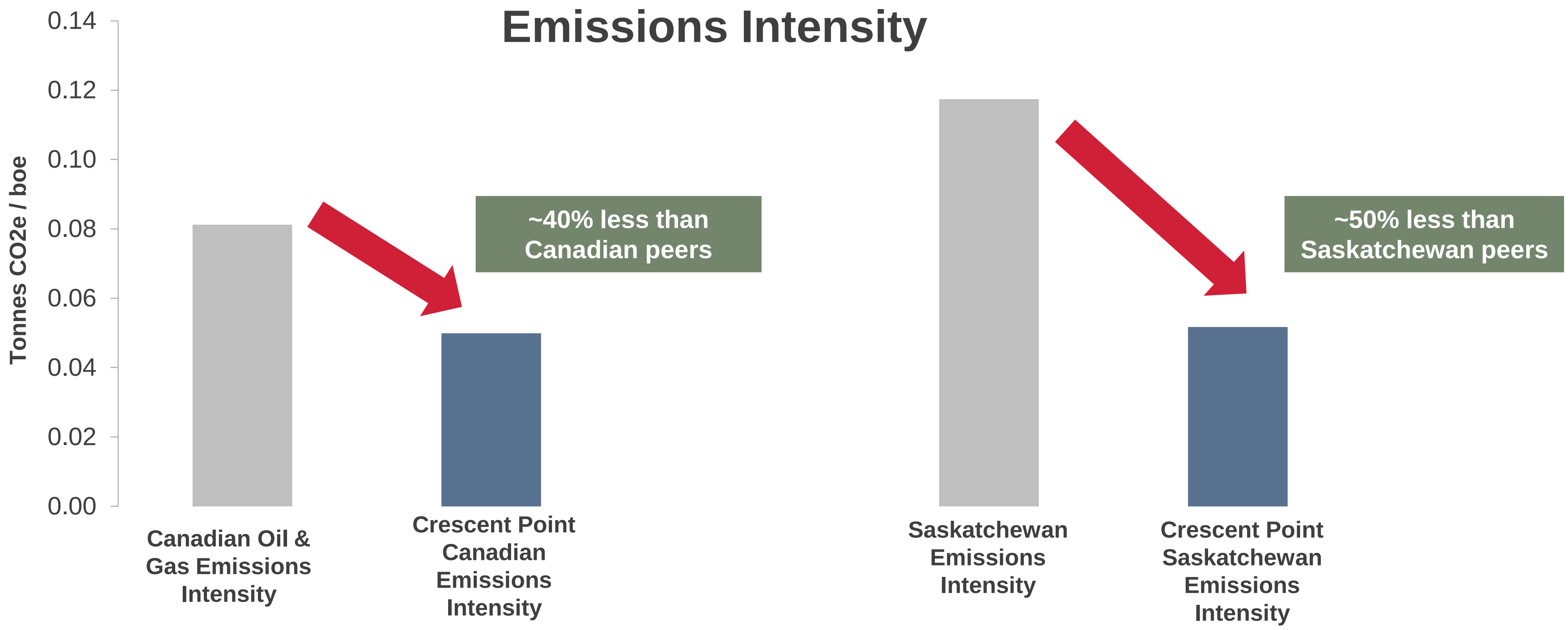
Propane Fleet Vehicles

Regenerative Power

- **Reduce Emissions**
- **Generate Clean Power**
- **Decrease Fuel Use**

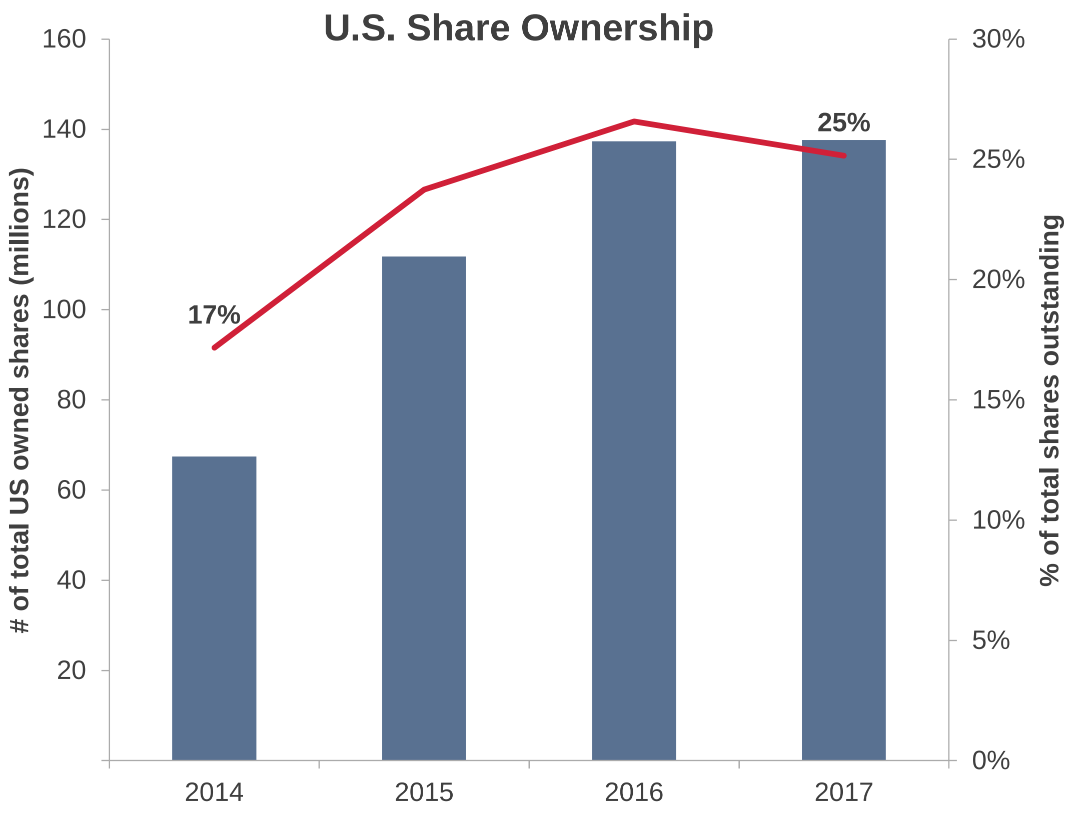
Climate Change Initiatives: Emissions Reduction

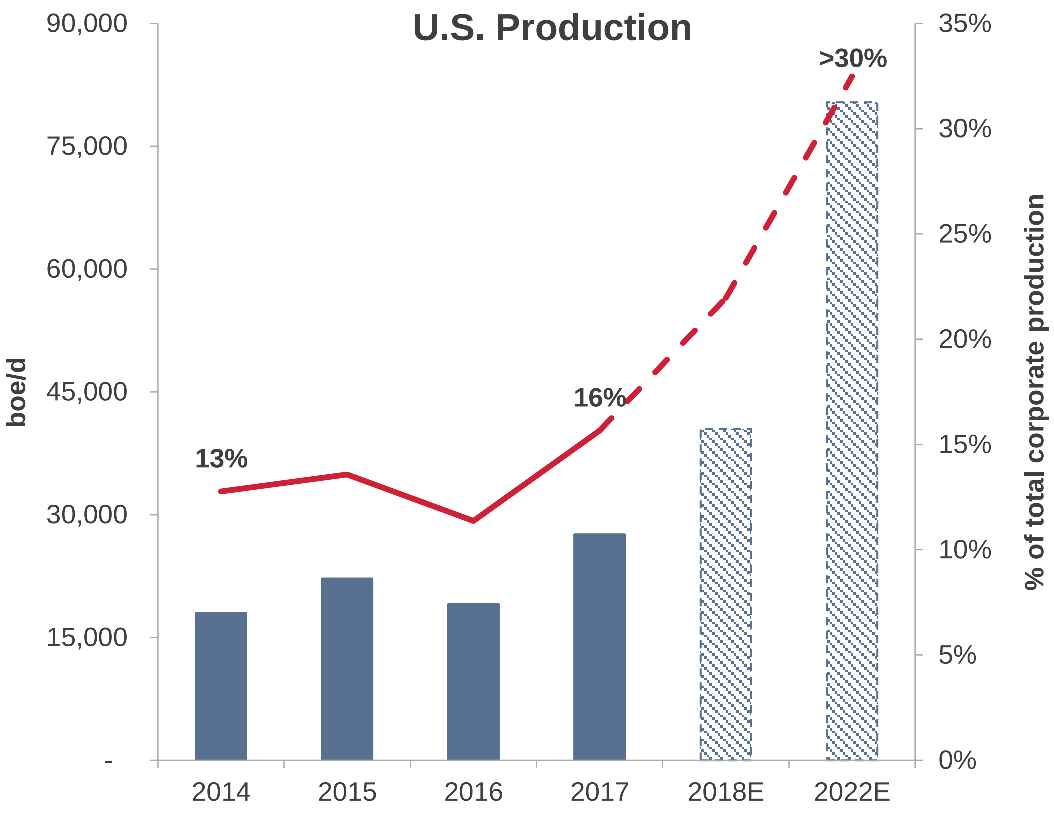
- Crescent Point continually invests in facilities, pipelines and new technologies to conserve gas and reduce emissions cost effectively and efficiently



Source: Emissions and production data is from the latest available National Energy Board data
Emissions intensity is defined as the emission rate relative to the production of oil and gas (tonnes CO_2e/annual boe production)

Expanding U.S. Presence





- Listed on the NYSE in Jan 2014 to increase exposure to U.S. and international investor base
- U.S. ownership (institutional and retail) in 2017 represented ~25% of total shares outstanding
- U.S. production continues to increase and is expected to represent >30% of total production by 2022E (up from 13% in 2014)

Source: Computershare (share information)
2018 Production estimates based on 2018 guidance
2022 Production estimates based on 100% payout scenario in 5-year plan

High Employee Engagement Contributes to Strong Corporate Governance

- 11th annual employee survey delivered to all field and office staff (81% or 941 responded in 2017) measures perception of management integrity, ethics and values; trends are consistently high

- 2017 survey responses demonstrate a **highly engaged workforce with an entrepreneurial focus**:
  - Leads to enhanced organizational productivity and efficiency
  - Lower rates of staff turnover builds team commitment and a foundation for innovation

96%
"Employees are inclined to do the right thing"

81%
"I have confidence in the executive team"

93%
"I am proud to tell people I work for Crescent Point"

92%
"I am inspired to give my very best"

87%
"Executives demonstrate integrity and ethical behaviour"

90%
"I would recommend Crescent Point as a great place to work"

97%
"I strive to improve my departments results"

We respond to survey results and make positive changes

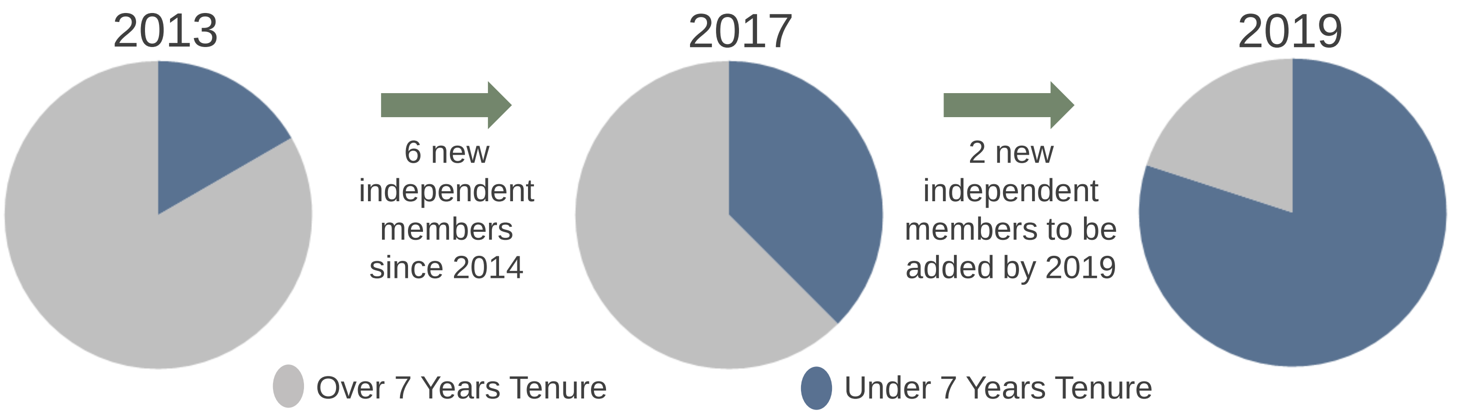
Innovation Driven by Knowledge First Culture

- Crescent Point actively participates in preparation and presentation of industry papers which highlights our team's technical expertise

Publications to Date

- Evolution of Completion Techniques in the Lower Shaunavon Tight Oil Play in Southwestern Saskatchewan
  (173368-MS SPE Conference Paper – 2015)
- Understanding Water Flood Response in Tight Oil Formations: A Case Study of the Lower Shaunavon
  (171671-MS SPE Conference Paper – 2014)
- Using Completion Diagnostics in Uinta Basin Vertical Wells to Reduce Completion Costs and Identify Horizontal Well Targets
  (181721-MS SPE Conference Paper – 2016)
- Evolving Completion Technologies Mitigate Proppant Flowback
  (187245-MS SPE Conference Paper – 2017)
- Evaluation of Downhole Multi-Cycle Sleeve Technology for Re-Frac Completions in Southwest Manitoba
  (185042-MS SPE Conference Paper – 2017)
- Improved Oil Recovery in Tight Oil Formations: Results of Water Injection Operations and Gas Injection Sensitivities in the Bakken Formation of Southeast Saskatchewan
  (185042-MS SPE Conference Paper – 2017)

Board Renewal Process Supported by Robust Orientation



Other key diversity enhancements:
- ✓ International experience
- ✓ Industry
- ✓ Gender
- ✓ Capital markets

Ongoing and Deliberate Board Renewal Process

- Board renewal process initiated in 2014
- Added 6 new members since process began
- New directors will continue to replace and build on skillsets of retiring members in the coming year

Strong Director Orientation and Training

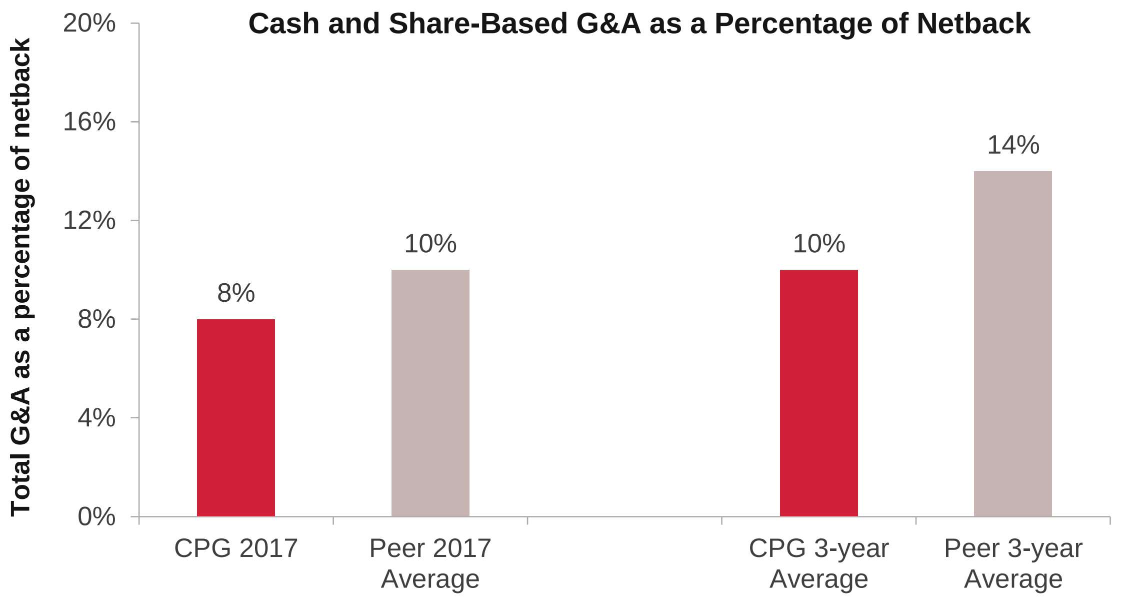
- Director orientation includes comprehensive handbook of responsibilities and corporate information as well as one-on-one meetings with key executives on our business, financial model, operations, compensation and culture
- All directors provided with membership to the Institute of Corporate Directors
- Learning opportunities provided regularly through quarterly management presentations, field tours, mentoring (on request), various in-house courses provided by technical experts and access to weekly executive meetings to maintain ongoing insight into daily operations

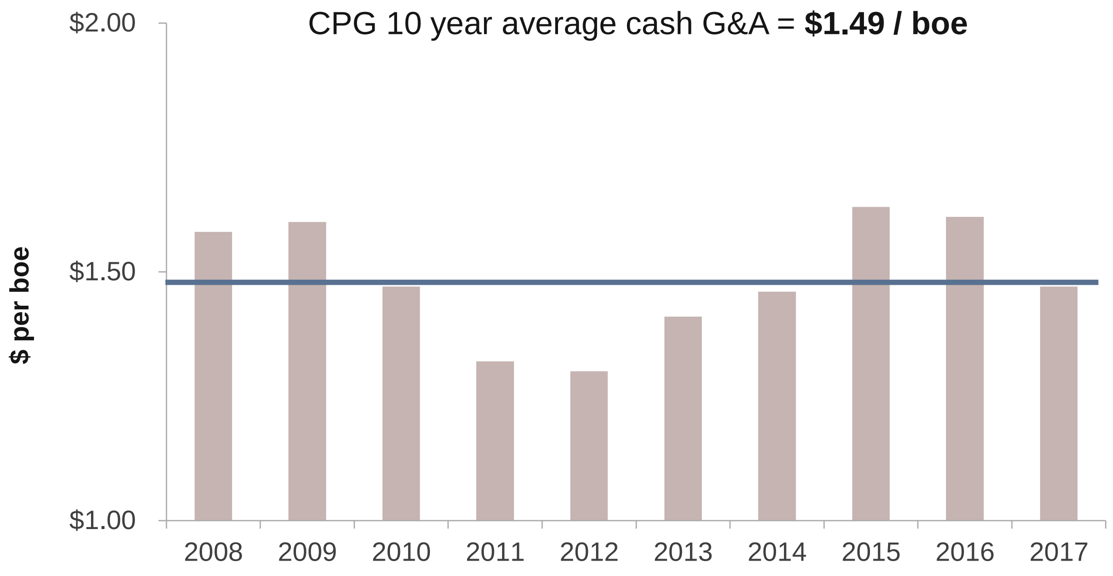
Impact of board renewal process on tenure

Entrepreneurial Culture Drives Low G&A

- We manage our compensation costs to a competitive level vs our peers

  Our philosophy is to pay-for-performance under a plan that is:
  - Aligned
  - Accountable
  - Balanced





Peer average includes members of the S&P Capped Energy Index
Netback is prior to realized derivatives

Disclosure Committee

NOTE TO READER REGARDING DISCLOSURE

In addition to obtaining all necessary Board approvals, the Company's long-established Disclosure Committee's mandate is to review and confirm the accuracy of the data and information contained in the documents, including this presentation, Crescent Point uses to communicate to the public. This review and confirmation process is formally completed prior to any such disclosure being released. This Committee is comprised of senior representatives (including officers) from each of the following departments: accounting and finance; engineering and operations (including drilling and completions, environment, health and safety and regulatory); exploration and geosciences; investor relations; land; legal; marketing and reserves.

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. Please see the “Forward-Looking Statements” and “Endnotes” sections of this presentation for additional details regarding such statements.

Definitions / Non-GAAP Financial Measures

Drilling Locations

This presentation discloses drilling locations in three categories: (i) booked locations; (ii) unbooked locations; and (iii) an aggregate total of (i) and (ii), hereafter referred to as "total location inventory". In addition, unbooked locations are subdivided into (a) risked locations; (b) unrisked locations; and an aggregate total of (a) and (b), hereafter referred to as "total unbooked location inventory". The booked locations are derived from the Corporation's most recent independent reserves evaluation as prepared by GLJ Petroleum Consultants Ltd. and Sproule Associates Limited, both as at December 31, 2017, and were aggregated by GLJ and account for drilling locations that have associated proved and/or probable reserves, as applicable, unless otherwise stated.

Of the ~8,100 risked total net corporate undrilled locations and the ~14,000 net total unrisked locations inventory disclosed in this presentation, ~3,460 are booked as of December 31, 2017. The remaining net locations are internally identified and are unbooked.

Of the approximately ~3,800 risked net Williston Basin locations disclosed and the ~6,800 net total unrisked locations in this presentation, ~1,750 are booked as of December 31, 2017. The remaining net locations are internally identified and are unbooked.

Of the approximately ~2,500 risked net Southwest Saskatchewan locations disclosed and the ~4,200 net total unrisked locations in this presentation, ~1,075 are booked as of December 31, 2017. The remaining net locations are internally identified and are unbooked.

Of the approximately ~850 risked net Uinta horizontal locations disclosed and the ~1,700 net total unrisked locations in this presentation, ~60 are booked as of December 31, 2017. The remaining net locations are internally identified and are unbooked.

Unbooked locations are internal estimates based on the Corporation's prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources (including contingent and prospective). Unbooked locations have been identified by management as an estimation of the Corporation's multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Corporation will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Corporation will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors.

The total unbooked location inventory contains risked future drilling locations that have a greater certainty of success due to these risked locations relative close proximity to current existing wells. The remainder of the unbooked drilling locations considered unrisked as they 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 oil and gas reserves, resources or production.

Well Economics

This presentation discloses well economic scenarios based on US $55 WTI constant pricing. Net present value (“NPV”) calculations are before tax.

Productive Capacity

Productive capacity is defined as the total IP30 rate assuming all wells in inventory are brought on production at the same time.

Type Wells

All type well information, including single-well economics presented herein has been prepared by qualified reserves evaluators in accordance with the COGE handbook. The type curves reflect a proved plus probable (2P) reserve level.

Definitions / Non-GAAP Financial Measures

Oil and Gas Metrics

This presentation includes oil and gas metrics including “drilling inventory” and “netback”, 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. Internally identified unbooked drilling locations may include infill, lease-edge and undrilled tracts, based on current land holdings, geologic, geophysical and engineering analysis that result in mapped type-well groupings and optimized scheduling.

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.

Oil and Gas Definitions

1. 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.

2. Original Oil-In-Place (OOIP) means Discovered Petroleum Initially-In-Place (DPIIP) as at December 31, 2016, but excluding gas. 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. OOIP/DPIIP estimates and recovery rates are as at December 31, 2017, and are based on current accepted technology and have been prepared by Crescent Point’s qualified reservoir engineers. 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, 2017.

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, 2017.

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

5. 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.

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

Definitions / Non-GAAP Financial Measures

Non-GAAP Measures

Throughout this presentation the Company uses the terms “funds flow from operations”, “funds flow from operations netback”, “total payout”, “market capitalization”, “net debt”, “enterprise value” and “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.

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. Transaction costs are excluded as they vary based on the Company’s acquisition activity and to ensure that this metric is more comparable between periods. Decommissioning expenditures are excluded as the Company has a voluntary reclamation fund to fund decommissioning costs. 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.

Total payout is calculated on a percentage basis as capital expenditures, capital acquisitions and dividends declared divided by funds flow from operations and proceeds from dispositions. Total payout 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, taking into account capital acquisition and disposition activity.

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. Market capitalization is an indication of enterprise value.

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

Enterprise value is calculated as market capitalization plus net debt. Management uses enterprise value to assess the valuation of the Company.

Net debt to funds flow from operations is calculated as the net debt divided by funds flow from operations for the trailing four quarters. 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.

Company Information

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

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