Canadian Natural

CORPORATE PRESENTATION

February 2017

Delivering Value and Growth

SNAPSHOT

	2016F	2017B
Cash flow[1] *(C$ million)*	$3,700 - 4,100	$6,500 - 6,900
Per share – basic[1] *(C$)*	$3.35 - 3.70	$5.90 - 6.25
Capital expenditures – net *(C$ million)*	$3,845	$3,890
Current annualized dividend *(C$/Share)*		$1.00
Production *(annual average, before royalties)*		
Oil *(Mbbl/d)*	525	550 - 590
Natural gas *(MMcf/d)*	1,698	1,700 - 1,760
BOE *(MBOE/d)*	808	833 - 883

[1] Based upon the following actual and average strip pricing as of December 2016, including the impact of hedging.

	2016F	*2017B*
Oil WTI (US$/bbl)	*$42.86*	*$55.58*
Natural gas NYMEX (US$/MMbtu)	*$2.44*	*$3.41*
Natural gas AECO (C$/GJ)	*$1.98*	*$3.06*
Heavy oil diff (%)	*32%*	*29%*
Exchange rate (C$ = XUS$)	*$0.75*	*$0.76*

Company Gross Reserves, before royalties, of crude oil and natural gas
(as at December 31, 2015)

Proved crude oil and NGLs *(MMbbl)*	4,695
Proved natural gas *(Bcf)*	6,106
Proved BOE *(MMBOE)*	5,713
Proved and probable BOE *(MMBOE)*	9,041

Canadian Natural's Strengths

- Proven, effective strategy
  - Flexible capital allocation
  - Nimble to capture opportunities
  - Balanced cash flow allocation
  - Cultural advantage
- Strong, balanced portfolio
  - Large, diverse, well balanced assets
  - Long-life, low decline, low risk assets
  - Lower maintenance capital requirements
  - Owned and controlled infrastructure
- Strong operations
  - Effective, efficient and reliable
  - Safe and environmentally responsible
  - Proven ability to execute
  - Operational, technical, financial expertise
- Financial resilience
  - Strong financial discipline
  - Investment grade ratings
  - Access to capital
  - Financial levers
  - Shareholder friendly

Our Strategy

- Flexible capital allocation to maximize value
- Strong Balance Sheet to support investment grade credit
- Defined growth/value enhancement plans by product/basin
- Diverse, balanced asset base
  - Product mix
  - Project timelines
  - Drill bit and acquisitions
- Opportunistic acquisitions
- Effective and efficient operations
  - Area knowledge
  - Extensive infrastructure ownership
  - Operatorship of core areas

Balance & Optimize the Four Pillars of Cash Flow Allocation

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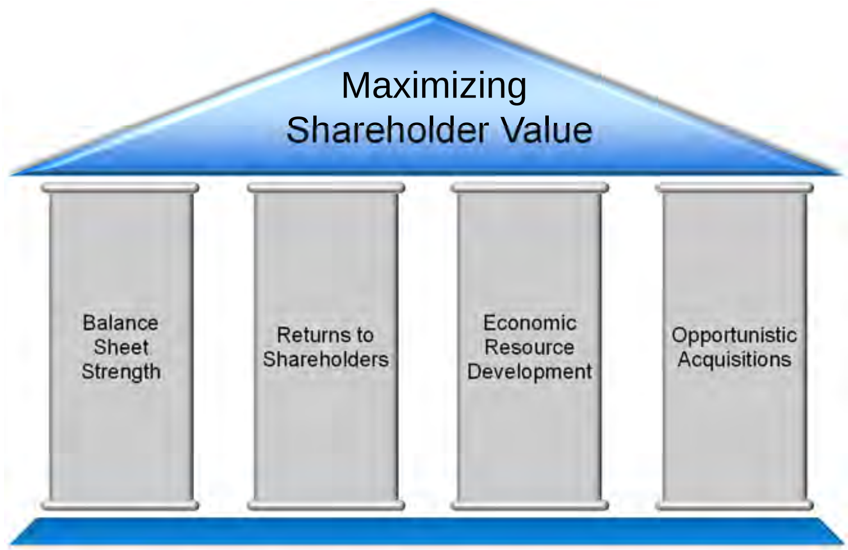

CNQ **FLEXIBLE CAPITAL ALLOCATION MAXIMIZIES SHAREHOLDER VALUE** 4

Advantages of a Balanced Portfolio

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- Significant portion of portfolio long-life, low decline
  - Provides robust, sustainable cash flow
  - Low reserve replacement risk
- Facilitates capital flexibility to maximize returns
- Deep inventory of mid-term projects
  - Pelican Lake and Thermal In Situ
  - Horizon debottlenecking
  - Longer-life, low decline
  - Strong return on capital
- Strong inventory of low capital exposure projects
  - Primary Heavy Oil, Light Oil in Canada and Offshore Africa, Natural Gas in the Deep Basin and Montney
  - Leverage infrastructure
  - Full capital flexibility

CNQ **BALANCED ASSET BASE PROVIDES COMPETITIVE ADVANTAGE** 5

Balanced, Diverse Portfolio

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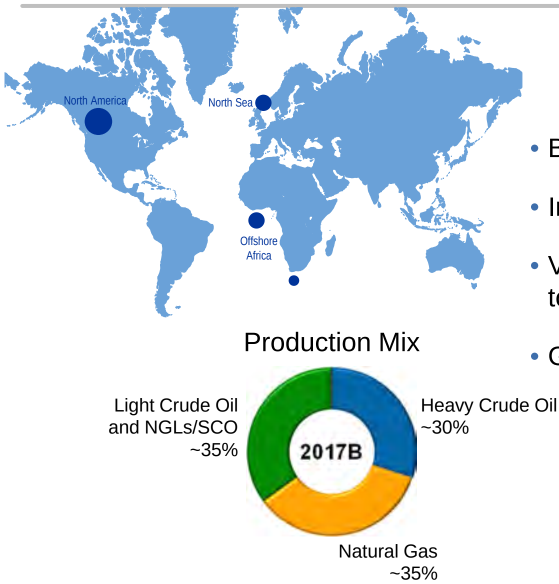

- Balanced, diverse production mix
- International exposure
- Vast, balanced resource base to develop
- Growing, sustainable cash flow

CNQ **BUILDING A WORLD CLASS COMPANY** 6

1P Reserves After Royalties

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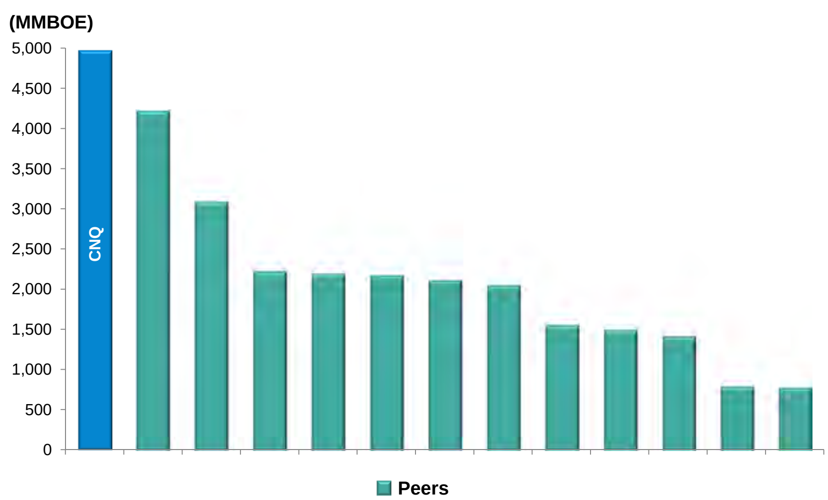

Note: Based on SEC reserve reporting, sourced from 2015 corporate reports. Peers include: APA, APC, EOG, CVE, CHK, DVN, ECA, HSE, IMO, OXY, NBL, SU.

CNQ **SIGNIFICANT VALUE TO UNLOCK** 7

Delivering the Best of All Worlds

- Long-life, low decline assets
  - Sustainable production
  - Free cash flow
  - Price volatility resilience
- Low capital exposure assets
  - Capital flexibility
  - High return on capital
  - Leverage infrastructure

Maximizes Cash Flow

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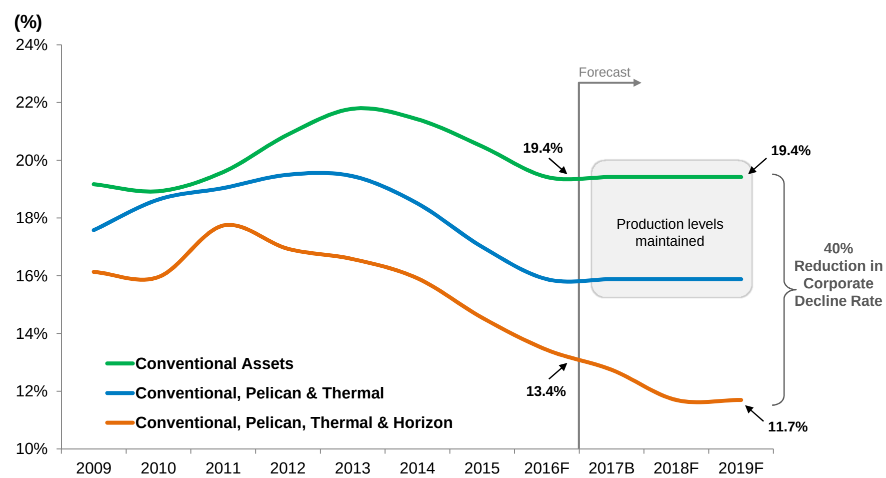
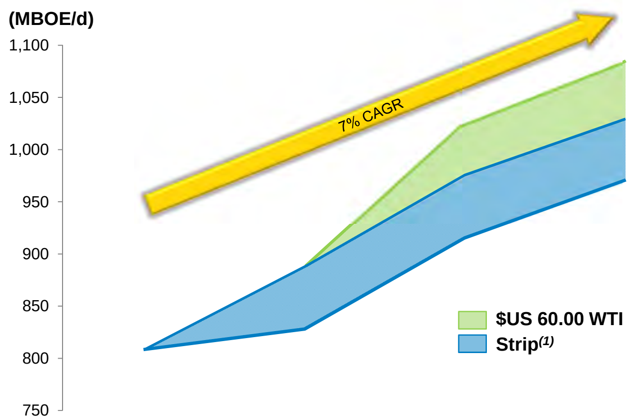
Canadian Natural's Advantage
Impact of Long-Life Assets on Decline Rates



Note: Conventional Assets include North America crude oil and NGLs, International crude oil and NGLs and natural gas. Assumes Conventional, Pelican and Thermal production held constant post 2016F.

CNQ **DECLINE RATE SIGNIFICANTLY REDUCED BY LONG-LIFE PRODUCTION** 9

Canadian Natural
4 Year Production Growth Targets



Capital ($ billion)	2016F(2)	2017B	2018F	2019F
Strip(1)	$3.9	$3.9	$4.1	$4.4

Note: 7% CAGR production growth reflects Strip case between 2016F to 2019F midpoint.
(1) Strip pricing as at December 12, 2016 for 2017B and December 1, 2016 for 2018F and 2019F. See advisory for pricing assumptions.
(2) 2016F reflects proceeds from Cold Lake Pipeline disposition.

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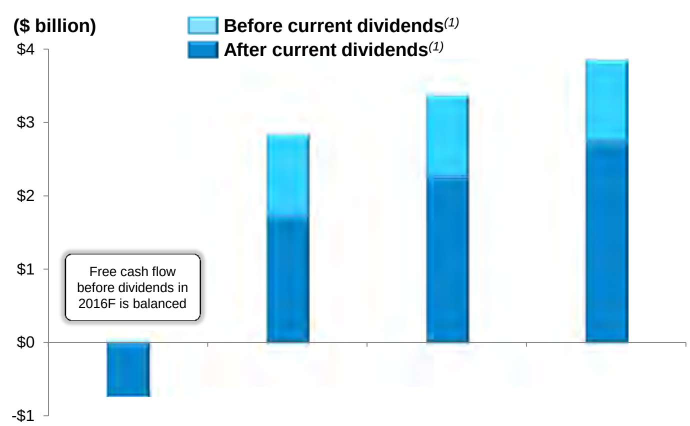
Canadian Natural
4 Year Free Cash Flow Targets



Capital ($ billion)	2016F(2)	2017B	2018F	2019F
Strip(1)	$3.9	$3.9	$4.1	$4.4

Note: Free cash flow represents cash flow from operations less capital.
(1) Strip pricing as at December 12, 2016 for 2017B and December 1, 2016 for 2018F and 2019F. See advisory for pricing assumptions.
(2) 2016F reflects proceeds from Cold Lake Pipeline disposition.

CNQ **SIGNIFICANT CASH FREE FLOW GENERATION** 11

Delivering Safety Excellence

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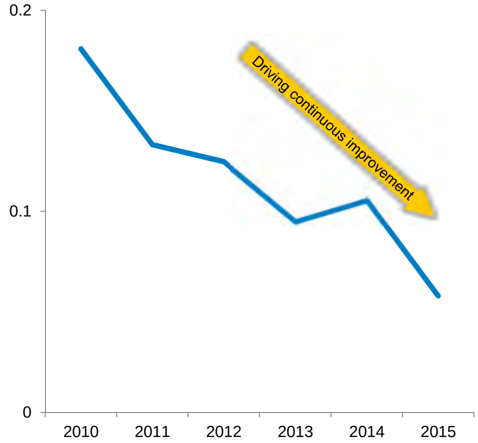
Lost time incident rate
(Incident per 200,000 hours)



- Safety is a core value
- Committed to continuous improvement
- No harm to people, no safety incidents
- Top tier recordable injury frequency in North America conventional operations

CNQ **SAFETY IS A CORE VALUE** 12

Environmental Performance

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- Proactive environmentally responsible operations
- Drive continuous improvement to reduce environmental impacts
- Meet or exceed all regulatory requirements
- Reducing Greenhouse Gas Emissions Intensity

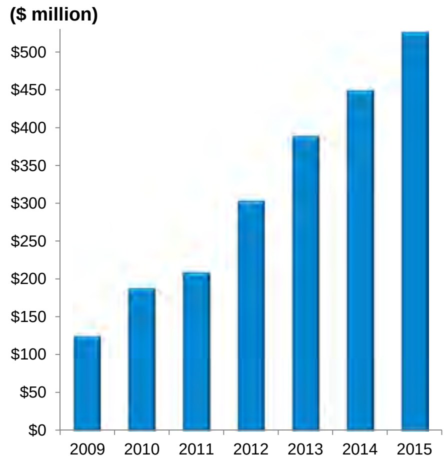
	2015 Reduction vs 2014 Levels
Conventional Operations	7%
Horizon Operations	5%
International Operations	13%

- Restoring sites to natural conditions
  - Safe abandonment of old wellbores
    - 519 wells in 2015
    - 3,825 wells or 26% of industry between 2010 and 2014

CNQ **DELIVERING ENVIRONMENTALLY RESPONSIBLE OPERATIONS** 13

Leveraging Technology to Create Value & Enhance Performance

Research & Development Investment



Note: Sourced from Company internal reports.
**Per Infosource Inc. R&D Spending Survey 2016.*

Leading R&D Investor

- Largest crude oil and natural gas R&D investor in Canada in 2015
- 5th largest R&D investor for all industries in Canada in 2015*
  - 2015 → $527 million
  - 2014 → $450 million
  - 2013 → $390 million

Creating Value

- Reduces environmental footprint
- Lowers operating costs
- Enhances productivity
- Unlocks reserves

2017 Plan

- Enhance Balance Sheet strength
- Horizon Phase 3 targeted start-up in Q4/17
  - Incremental 80,000 bbl/d of SCO production
- Horizon debottleneck decision in Q2/17
- Target 6% production growth
- Capital ~$3.9 billion
- Cash flow $6.5 - $6.9 billion(1)
- Free cash flow $1.5 - $1.9 billion, after current dividends(2)
- Deliver returns to shareholders

(1) See advisory for pricing assumptions.
(2) Free cash flow is defined as cash flow from operations less capital expenditure and dividends.

Canadian Natural
2017 Capital Budget

($ million)	2016F	2017B
North America natural gas & NGLs	$295	$460
North America crude oil	550	910
International crude oil	480	420
Total Exploration and Production	$1,325	$1,790
Thermal In Situ Oil Sands	$170	$365
Horizon		
Capital projects	$1,920	$1,055
Sustaining capital	370	415
Turnarounds, reclamation & other	440	225
Technology and Phase 4	5	15
Total Horizon	$2,735	$1,710
Net acquisitions (dispositions), midstream & other	(385)	25
Total	$3,845	$3,890

CNQ **SIGNIFICANT CAPITAL FLEXIBILITY** 16

Canadian Natural
2017 Production Forecast

Targeted Production	2016F	2017B	% Change(1)
Natural Gas (MMcf/d)	1,698	1,700 - 1,760	2%
Crude Oil & NGLs (Mbbl/d)			
North America	241	232 - 242	(2%)
North America – Thermal In Situ	111	105 - 115	(1%)
North America – Oil Sands Mining(2)	123	170 - 184	44%
International	50	43 - 49	(8%)
Total crude oil & NGLs	525	550 - 590	9%
Total MBOE/d	808	833 - 883	6%

(1) Percent change of 2017B midpoint over 2016F.
(2) Oil Sand Mining 2017B annual production guidance reflects 24 day production downtime for planned turnaround and Phase 3 tie-ins.
Note: Rounded to the nearest 1,000 bbl/d. Numbers may not add due to rounding.

CNQ **STRATEGIC, DEFINED GROWTH PLAN** 17

Advantages of Infrastructure Ownership/Operatorship

- Control of our destiny
  - Control costs, development timing and pace – eliminates commitments
  - Operations flexibility with high working interest
- Minimal capital exposure and return on capital maximized
- Drill-to-fill strategy
  - Leverage existing infrastructure
- Optimization of reliability
- Integration of well operations and facility operations
  - Reduced labour and increased expertise
- ~62,000 km of pipelines

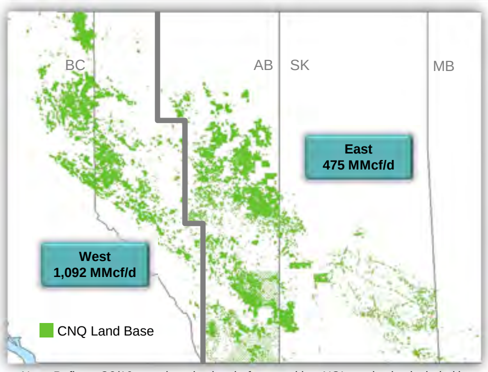
Natural Gas

37 Operated Major Natural Gas Processing Facilities
~50,000 km - natural gas pipelines

Heavy Oil

15 Crude Oil Processing Facilities
8 Sand Disposal Caverns

Natural Gas & NGLs Core Area Summary



Note: Reflects Q3/16 actual production, before royalties. NGL production included in light crude oil production volumes.

2017B

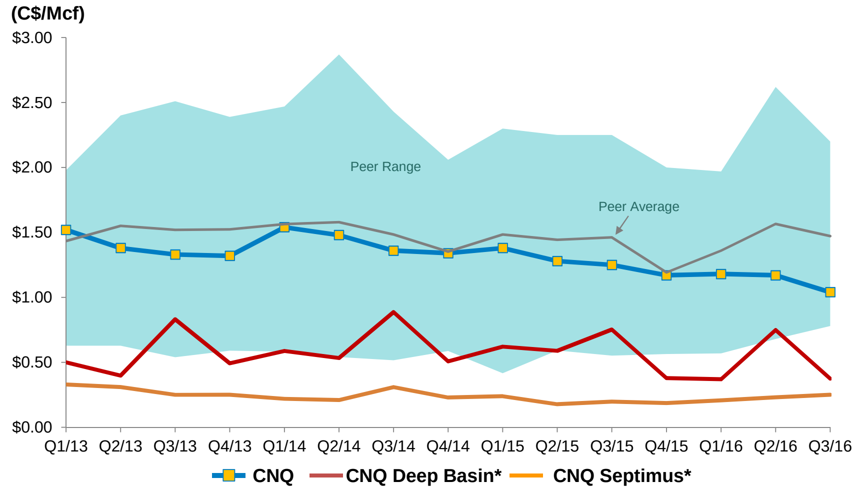
Targeted net wells*	Operating costs
21	\$1.00 - \$1.20/Mcf

Producer Wells.

- Largest natural gas producer in Canada
  - Q3/16 natural gas production
    - 1,567 MMcf/d
  - Q3/16 average NGL yield
    - ~26 bbl/MMcf
- Large resource base
  - 10.0 Tcfe reserves(1)
- Significant unconventional assets
  - Montney and Deep Basin
- High working interest, low decline assets
- Owned and operated infrastructure
- \$1 increase in AECO = ~\$360 million additional annual cash flow(2)

(1) Company Gross proved plus probable reserves at December 31, 2015; North America natural gas and NGLs.
(2) See advisory for pricing assumptions and cautionary statements.

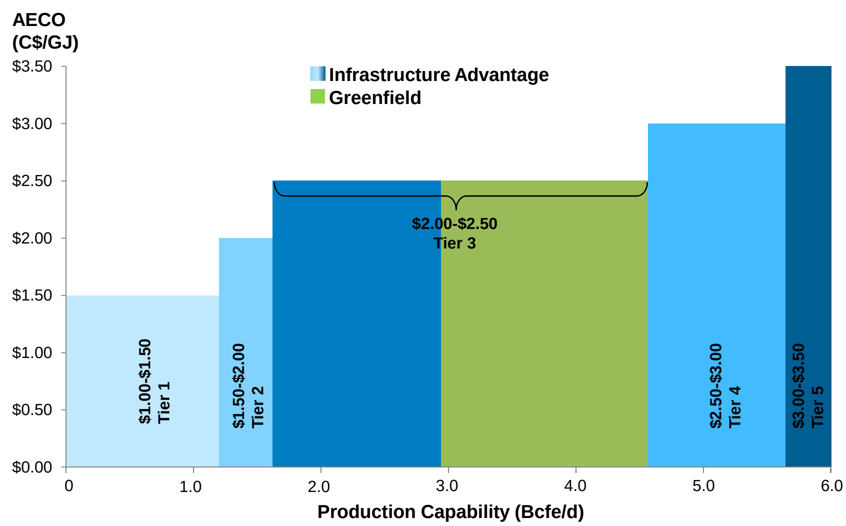
Operating Costs
Natural Gas – Canada



Source: Company reports.
Note: Peers include ARX, BNP, ECA, HSE, PGF, PWT.
**Deep Basin/Septimus operating costs disclosed on a C$/Mcfe basis.*

CNQ **STRONG NATURAL GAS OPERATING COSTS** 20

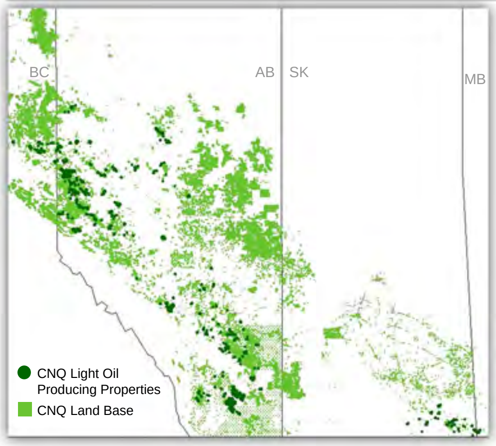
Deep Basin/Montney Natural Gas Projects
Return on Capital, 15% After Tax



Note: Assumes WTI = $50.00 US$/bbl benchmark for natural gas liquids. See Advisory for pricing assumptions and cautionary statements.

CNQ **STRONG PORTFOLIO OF LIQUIDS-RICH GAS PROJECTS** 21

North America Light Crude Oil Core Area Summary



*Company Gross proved plus probable reserves at December 31, 2015.

- Q3/16 light crude oil and NGL production
  - ~90 Mbbl/d
- 2P reserves
  - 192 million barrels(1)
- High quality light crude oil horizontal multi-frac opportunities
- ~182 active waterfloods
  - Maximize recovery
  - Shallow decline

2017B

Targeted net wells*	Operating costs
43	$11.00 - $13.00/bbl

Producer Wells

(1) Company Gross proved plus probable reserves at December 31, 2015.

CNQ SIGNIFICANT LAND BASE AND OPPORTUNITY 22

International Light Crude Oil Summary

- Q3/16 light crude oil production
  - ~50 Mbbl/d
- 2P reserves
  - 426 million barrels(1)
- North Sea
  - Operating efficiency gains and more favorable tax regime increase returns
- Offshore Africa
  - High return development opportunities
- Exploration upside

2017B

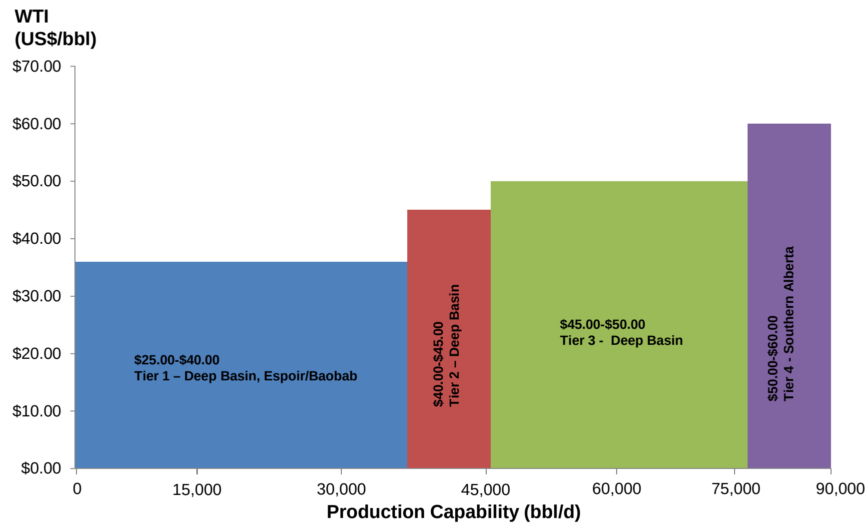
	Targeted net wells*	Operating costs
North Sea	3	$33.00 - $36.00/bbl
Offshore Africa	-	$10.50 - $12.50/bbl

*Producer Wells.

(1) Company Gross proved plus probable reserves at December 31, 2015.

CNQ OPTIMIZATION OF SIGNIFICANT RESERVE BASE 23

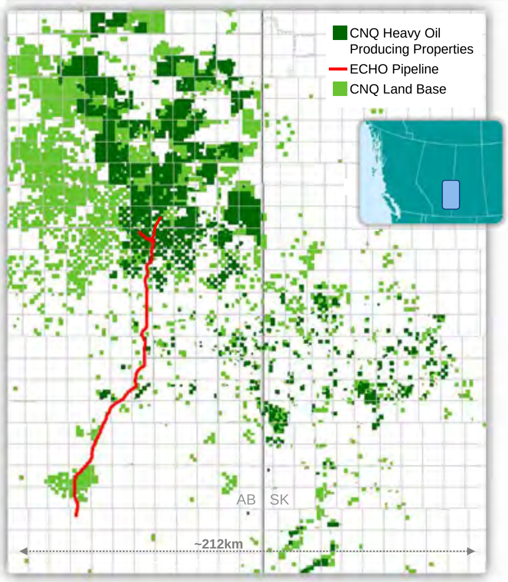
Light Crude Oil Projects Return on Capital, 15% After Tax



Note: Assumes AECO= $2.50 C$/GJ for natural gas, and an exchange rate of US$1.00 to C$1.30. See Advisory for cautionary statements.

CNQ **DIVERSE ASSET PORTFOLIO** 24

Primary Heavy Crude Oil Core Area Summary



- Largest primary heavy oil producer in Canada
  - Q3/16 production of ~102 Mbbl/d
- Large inventory of development opportunities
- Premium land base and extensive infrastructure
- 2P reserves
  - 294 million barrels[(1)]
- Low operating costs

2017B

Targeted net wells*	Operating costs
427	$12.75 - $14.75/bbl

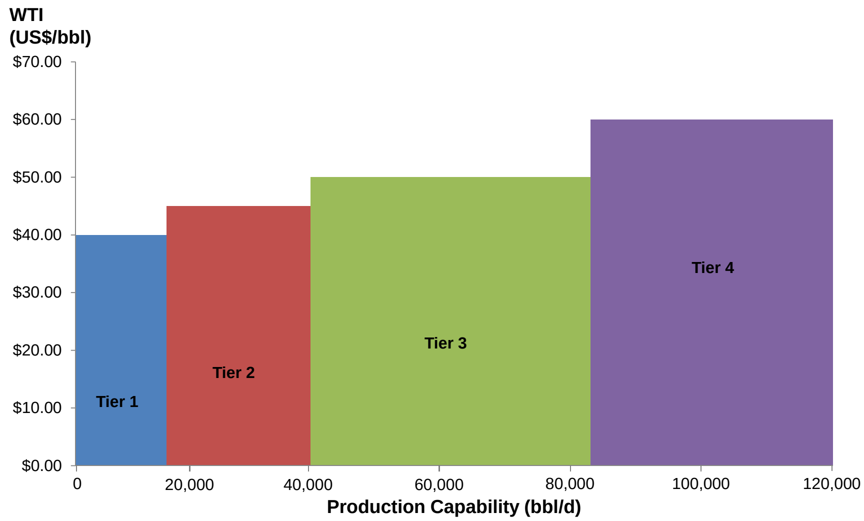
**Producer Wells.*

(1) Company Gross proved plus probable reserves as at December 31, 2015.

CNQ **VAST LAND BASE AND INFRASTRUCTURE CAPTURES VALUE** 25

Primary Heavy Crude Oil Projects Return on Capital, 15% After Tax

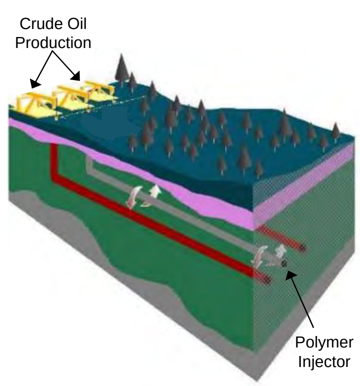
Canadian Natural



Note: Assumes an exchange rate of US$1.00 to C$1.30 and a WCS differential range of 22%-27%. See Advisory for cautionary statements.

Pelican Lake Polymerflood

Canadian Natural



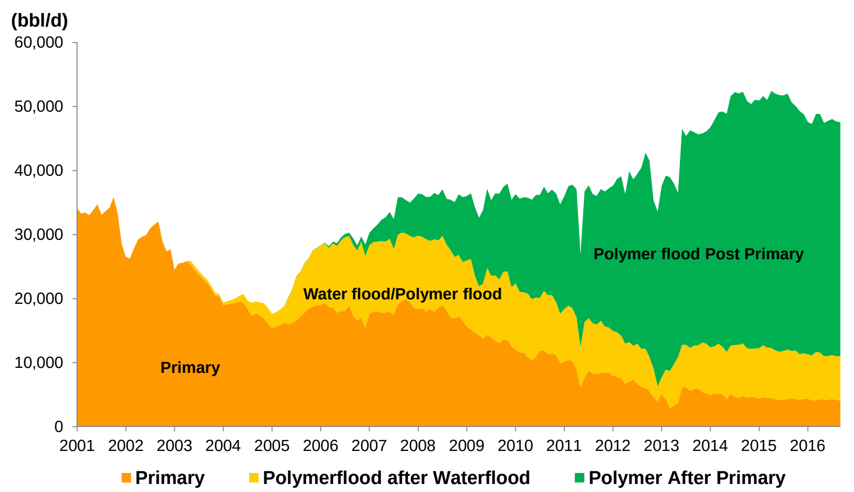
- Industry leading EOR technology
- Capital requirements are reduced and polymer driven performance is realized
  - Q3/16 production ~48 Mbbl/d
- Industry leading operating costs
  - Q3/16 operating costs $6.09/bbl
- 2P reserves
  - 388 million barrels[(1)]
- High quality infrastructure
- Significant expansion opportunities
  - 55% of developed pool under polymerflood

2017B

Targeted net wells*	Operating costs
15	$5.25 - $6.25/bbl

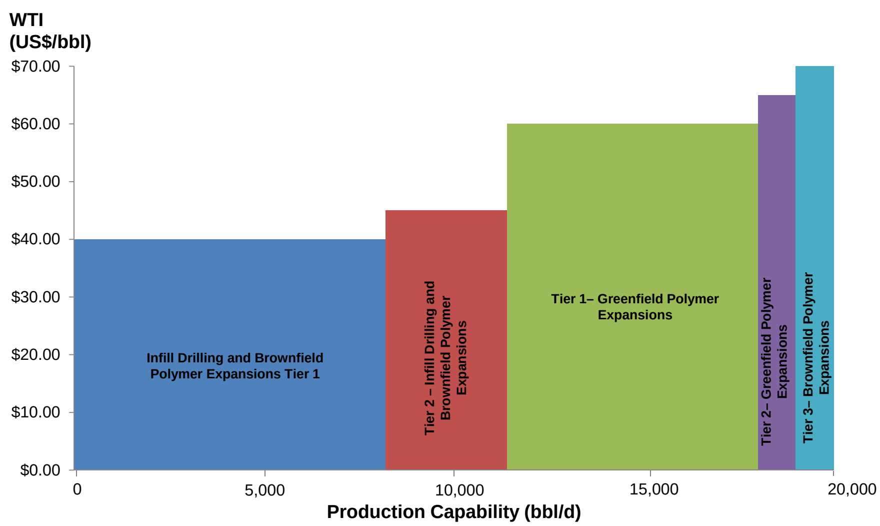
**Producer Wells.*
(1) Company Gross proved plus probable reserves as at December 31, 2015.

Pelican Lake
Production by Recovery Method



CNQ **THREE PRODUCING REGIMES – THREE DIFFERENT PROFILES** 28

Pelican Lake Projects
Return on Capital, 15% After Tax



Note: Assumes an exchange rate of US$1.00 to C$1.30 and a WCS differential range of 22%-27%. See Advisory for cautionary statements.

CNQ **GROWING PRODUCTION WITH LEADING EDGE TECHNOLOGY** 29

Thermal In Situ Oil Sands Portfolio

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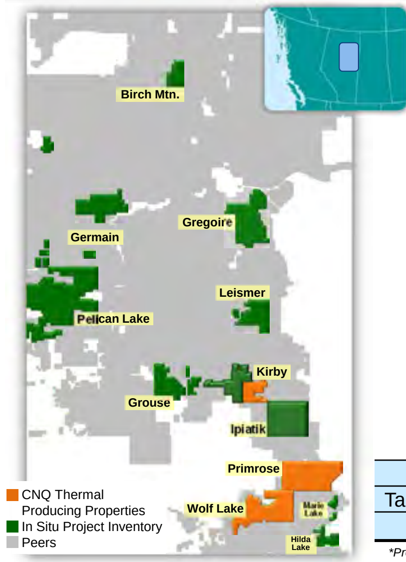


- Vast resource base with short, mid and long-term value
- 2P reserves
  - 2.41 billion barrels(1)
- Majority working interest and operatorship
- Effective and efficient thermal operator
- Leverage use of technology to enhance recovery and optimize costs
  - Expertise in Cyclic Steam Stimulation (CSS), Steam Assisted Gravity Drainage (SAGD) and Steamflood

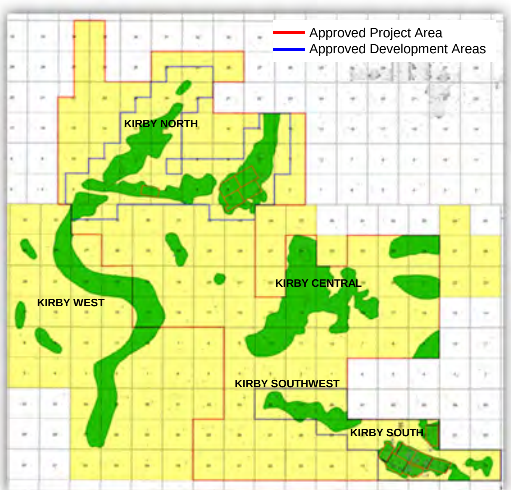
2017B

	Operating costs	
Targeted net wells*	Non-Fuel	Fuel
54	\$6.00 - \$6.50/bbl	\$8.75 - \$9.25/bbl

*Producer Wells.
(1) Company Gross proved plus probable reserves as at December 31, 2015.

Thermal In Situ Oil Sands Kirby SAGD

Canadian Natural



Kirby North

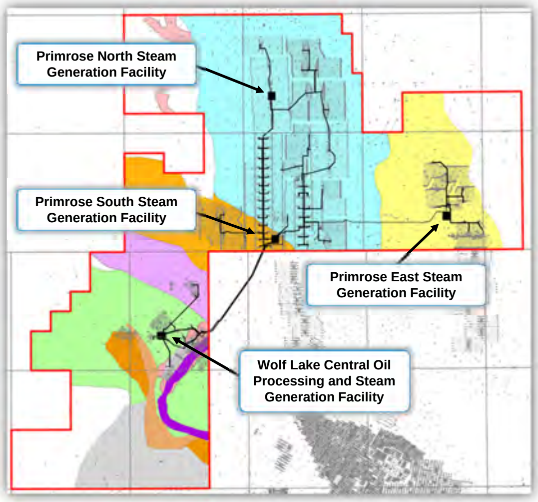
- Reinitiated for development
- Major facility equipment purchased
- Lease delineated and ready for drilling
- Targeted first oil in Q1/2020

Kirby South

- Strong performance
  - Quarterly production in Q3/16
    - ~38 Mbbl/d with an SOR of 2.6
- 2P reserves
  - 176 million barrels*

*Company Gross proved plus probable reserves as at December 31, 2015.

Thermal In Situ Oil Sands
Primrose/Wolf Lake

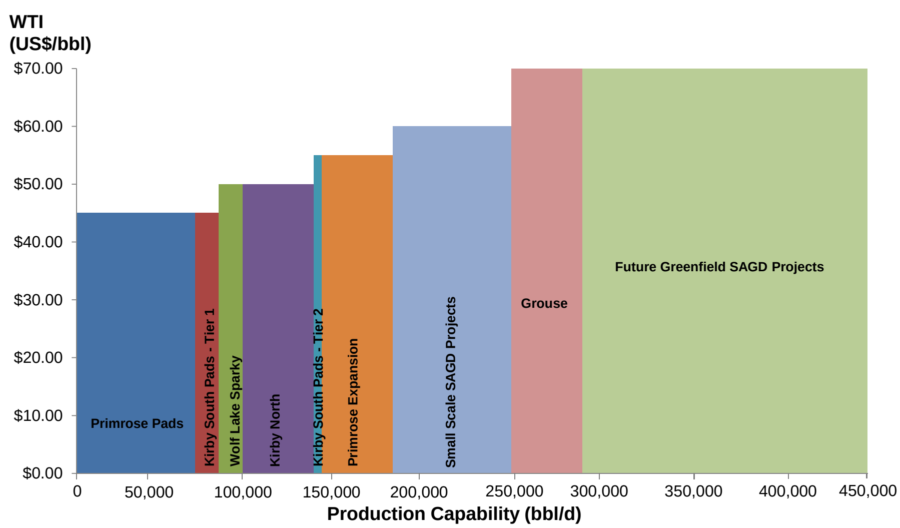


Primrose/Wolf Lake

- Strong netbacks
  - High quality crude oil
  - Produced solution gas offsets fuel requirements
  - Significant development opportunities
- Steamflooding
  - First commercial horizontal well steamflood at Primrose East, Primrose South and Wolf Lake
  - Follow-up process to CSS
  - Targeted recovery factor of ~69% OOIP at Primrose East

CNQ STRONG DEVELOPMENT OPPORTUNITIES 32

Thermal In Situ Oil Sands Projects
Return on Capital, 15% After Tax



Note: Assumes AECO= $2.50 C$/GJ for natural gas, an exchange rate of US$1.00 to C$1.30 and a WCS differential range of 22%-27%.
See Advisory for cautionary statements.

CNQ LONG-LIFE, LOW DECLINE ASSETS GROWTH POTENTIAL 33

Horizon Oil Sands – Operations Core Area Summary

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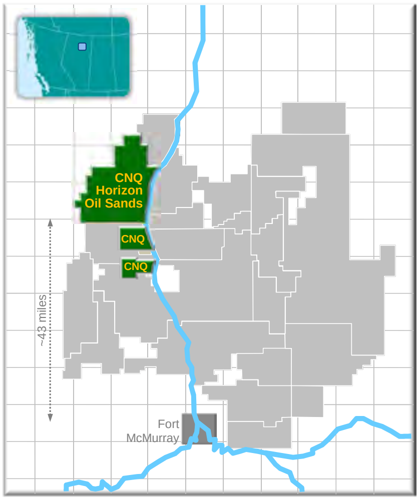


- World Class asset
- 2P SCO reserves
  - 3.63 billion barrels(1)
- Phased development (SCO)
  - Current design capacity of 182,000 bbl/d
    - Phase 2B on stream
  - Targeted start-up of Phase 3 → Q4/17
  - Potential 5,000 -15,000 bbl/d debottleneck
  - 50+ years of production with no declines
- 100% working interest

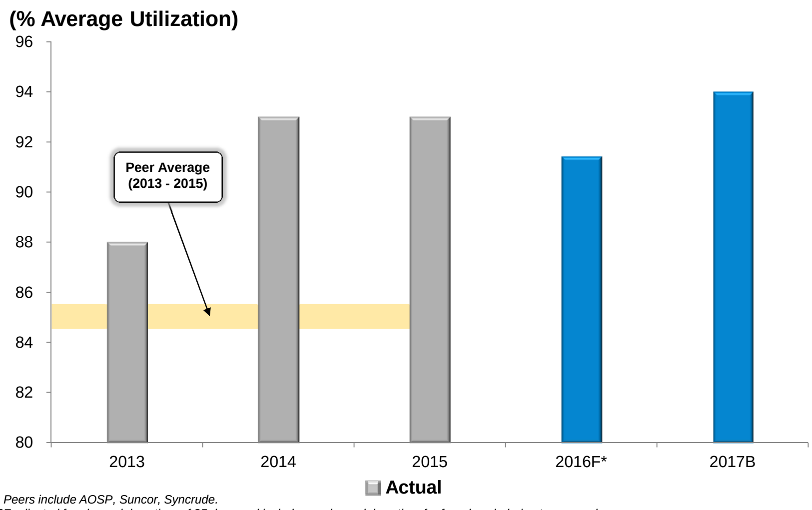
2017B
Operating costs (SCO)
\$24.00 - \$27.00/bbl*

*2017B reflects 24 day planned downtime for turnaround and Phase 3 tie-ins.
(1) Company Gross proved plus probable reserves as at December 31, 2015.

CNQ **LONG-LIFE, LOW DECLINE ASSET** 34

Horizon Oil Sands – Operations Industry Leading Utilization Rate

Canadian Natural

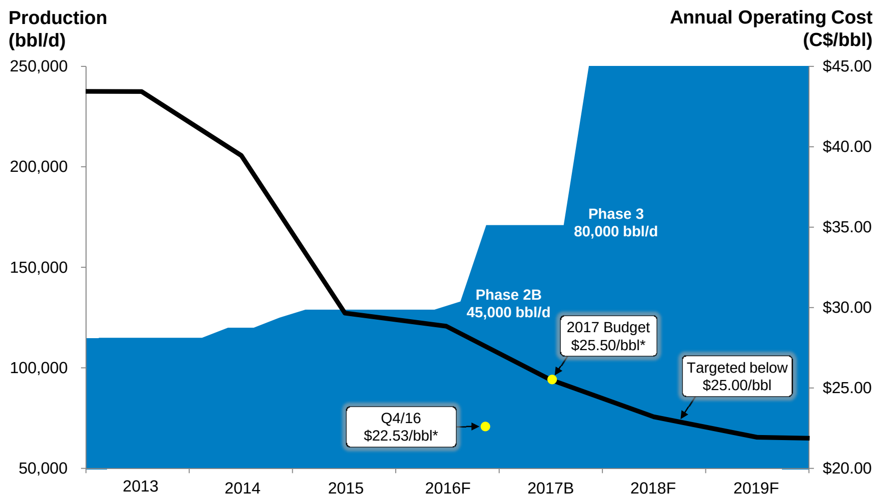


Note: Peers include AOSP, Suncor, Syncrude.
**2016F adjusted for planned downtime of 35 days and includes unplanned downtime for found work during turnaround.*
Source: Peer data per GMP FirstEnergy – Synopsis: Integrated, Oilsands, and Large Cap Oil & Gas Producers, April 2016.

CNQ **BEST IN CLASS OPERATIONAL PERFORMANCE** 35

Horizon Oil Sands
Significant Operating Cost Reductions

Canadian Natural



Note: Production capacity assumes 3 months ramp up to full rates and excludes planned turnaround time. Project progress dependent upon economic and regulatory conditions, commodity prices, global economic factors, project sanction and capital allocation. 2016F - 2019F based on internal Company forecast as at December 2016.
**2017B is at midpoint of guidance range, updated February 2, 2017 and reflects 24 day planned downtime for turnaround and Phase 3 tie-ins.*

Horizon Potential Debottleneck

Canadian Natural

- Phase 2A exceeded design rates
- Early indications show Phase 2B may exceed design rates
  - November 2016 → ~188,000 bbl/d
- 2017 budget includes a 24 day turnaround and tie-in of Phase 3
- Preserve option for 2017 capital to debottleneck fractionation tower
  - Decision targeted for Q2/17
  - Potential for 5,000 bbl/d - 15,000 bbl/d added production
  - Project capital cost ~$70 million
    - Turnaround could be extended by 21 days
    - Additional cost for accelerated turnaround work ~$90 million

Robust Financial Position

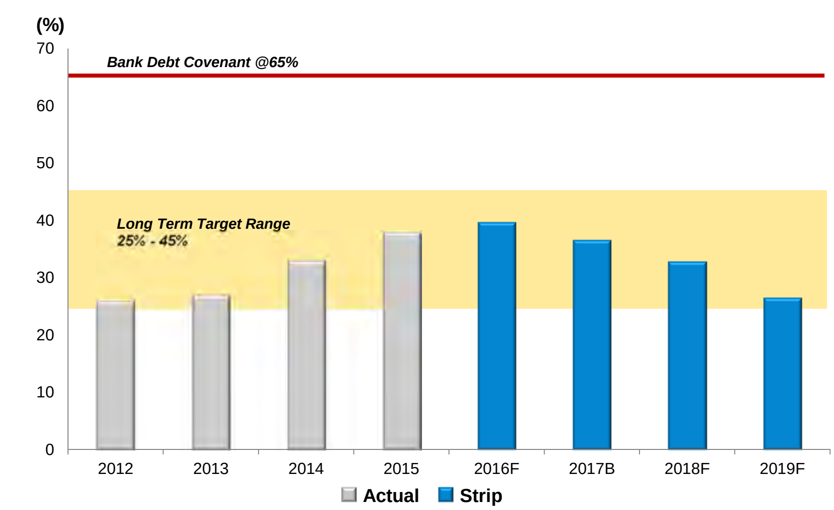
	Long-Term Ratings	Outlook	Short-Term Ratings
Standard & Poor's	BBB+	Stable	A-2
DBRS	BBB High	Stable	n/a
Moody's	Baa3	Stable	P-3

- Strong financial position as of September 30, 2016
  - Debt/book capitalization → 40%
  - Available bank lines of ~$2.7 billion (Pro Forma)(1)
- Disciplined allocation of capital delivers sustainable dividend policy
  - 16 consecutive years of dividend increases
    - $1.00 per share annualized dividend declared November 2016
    - 8.7% increase to quarterly dividend per common share
  - PrairieSky share distribution ~$542.8 million → May 2016

(1) Pro Forma – Includes cash proceeds from the Cold Lake Pipeline disposition.

CNQ **DELIVERING ON OUR FINANCIAL PLAN** 38

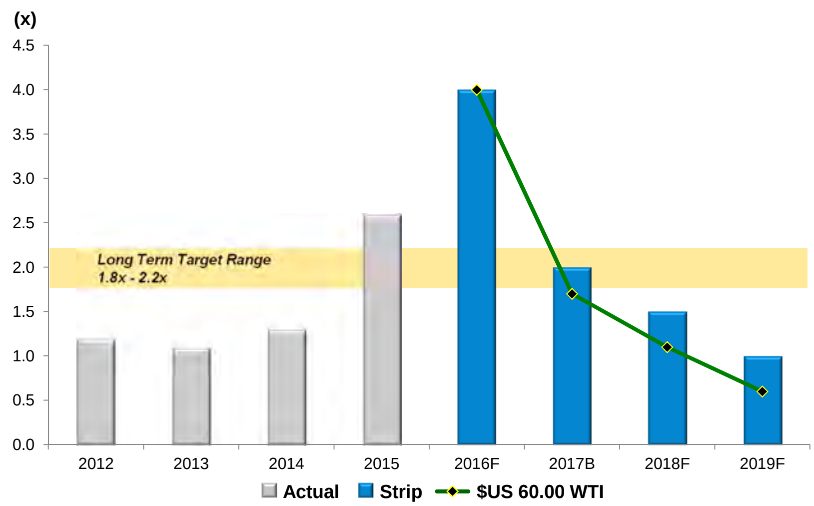
Debt / Book Capitalization



Note: See Advisory for pricing assumptions and cautionary statements. 2016F reflects cash proceeds from the Cold Lake Pipeline disposition.

CNQ **WELL WITHIN COVENANTS AND LONG-TERM RANGES** 39

Debt / Annual EBITDA



Note: See Advisory for pricing assumptions and cautionary statements. 2016F reflects cash proceeds from the Cold Lake Pipeline disposition.

CNQ **RETURN TO TARGET RANGE IN 2017B** 40

Credit Facility Summary

	(C$ million)	Maturity
Revolving bank line 1[(1)]	$2,425	June 2019
Revolving bank line 2[(1)]	$2,425	June 2020
Non-revolving syndicated term facility[(1)]	$1,500	April 2018
Non-revolving term facilities[(1)]	$ 875	February 2019
Operating demand loan	$100	Demand
North Sea operating line (£15 million)	$26	Demand
Total bank lines	$7,351	
Available September 30, 2016 (Pro Forma)[(2)]	$2,695	

(1) Financial covenant – Consolidated Debt to Book Capital ratio not to exceed 0.65 : 1.00.
(2) Pro Forma – reflects cash proceeds from the Cold Lake Pipeline disposition.

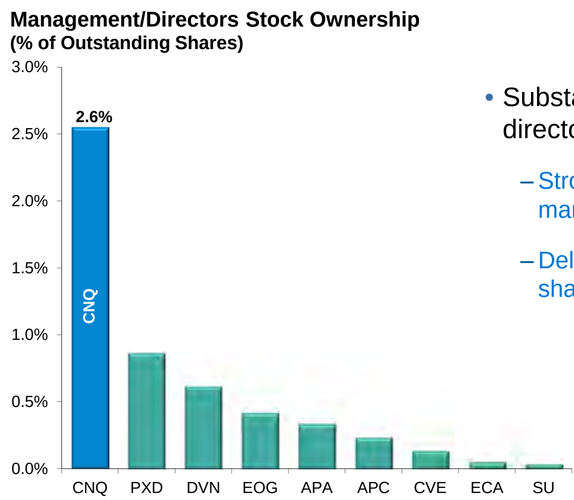
CNQ **SOLID LINES OF LIQUIDITY** 41

Return to Shareholders

Note: Based upon dividends declared.

CNQ **RETURNS TO SHAREHOLDERS A PRIORITY** 42

Committed Management



- Substantial management and director wealth at stake
  - Strong motivation for management to perform
  - Delivers clear alignment with shareholder interests

Note: Based on share ownership data excluding options and priced at November 4, 2016. Outstanding shares as at Q3/16 as per Bloomberg.
Source: SEDI and BD Corporate. Peers include APC, APA, CVE, DVN, ECA, EOG, PXD and SU.

CNQ **CONSISTENT HISTORY OF VALUE CREATION** 43

Canadian Natural's Advantage

- Strong balance sheet
- Large, diversified, well balanced asset base
- Transition to longer-life, low decline assets reduces capital requirements while maintaining production
- Delivering increasing and more sustainable cash flow to allocate to:
  - Resource development
    - Transitioning to longer-life assets
  - Returns to shareholders
  - Balance Sheet strength
  - Opportunistic acquisitions
- Driven by:
  - Effective capital allocation
  - Effective and efficient operations
  - Strong management teams

Notes

Advisory

Special Note Regarding Currency, Production and Reserves

In this document, all references to dollars refer to Canadian dollars unless otherwise stated. Reserves and production data are presented on a before royalties basis unless otherwise stated. In addition, reference is made to crude oil, natural gas and NGLs in common units called barrel of oil equivalent ("BOE") or thousand cubic feet of gas equivalent ("McfGE"). A BOE is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil or NGLs (6Mcf:1bbl). An McfGE is derived by converting one barrel of crude oil or NGLs to six thousand cubic feet of natural gas (1bbl:6Mcf). These conversions may be misleading, particularly if used in isolation, since the 6Mcf:1bbl ratio or the 1bbl:6Mcf ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil or NGL prices relative to natural gas prices, the 6Mcf:1bbl or 1bbl:6Mcf conversion ratios may be misleading as an indication of value.

This document, herein incorporated by reference, have been prepared in accordance with IFRS, as issued by the International Accounting Standards Board.

For the year ended December 31, 2015 the Company retained Independent Qualified Reserves Evaluators ("IQREs"), Sproule Associates Limited and Sproule International Limited (together as "Sproule") and GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate and review all of the Company's proved and proved plus probable reserves with an effective date of December 31, 2015 and a preparation date of February 1, 2016. Sproule evaluated the North America and International light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), natural gas and NGLs reserves. GLJ evaluated the Horizon SCO reserves. The evaluation and review was conducted in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") requirements. Reserves disclosure is presented in accordance with Canadian reporting requirements using forecast prices and escalated costs.

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States Financial Accounting Standards Board Topic 932 "Extractive Activities - Oil and Gas" in the Company's Form 40-F filed with the SEC in the "Supplementary Oil and Gas Information" section of the Company's Annual Report.

Special Note Regarding non-GAAP Financial Measures

This document includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings from operations, cash flow from operations, cash production costs and net asset value. These financial measures are not defined by International Financial Reporting Standards ("IFRS") and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings, as determined in accordance with IFRS, in the "Net Earnings and Cash Flow from Operations" section of the Company's MD&A. The derivation of adjusted cash production costs and adjusted depreciation, depletion and amortization are included in the "Operating Highlights – Oil Sands Mining and Upgrading" section of the Company's MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of the Company's MD&A.

Volumes shown are Company share before royalties unless otherwise stated.

Forward Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, operating costs, capital expenditures, income tax expenses, and other guidance provided throughout this presentation constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands operations and future expansion, Septimus, Primrose thermal projects, Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, construction of the proposed Keystone XL Pipeline from Hardisty, Alberta to the US Gulf coast, the proposed Kinder Morgan Trans Mountain pipeline expansion from Edmonton, Alberta to Vancouver, British Columbia, the proposed Energy East pipeline from Hardisty to Eastern Canada, and the construction and future operations of the North West Redwater bitumen upgrader and refinery also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks and the reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, 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 can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil and natural gas and natural gas liquids (NGLs") reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected disruptions or delays in the resumption of the mining, extracting or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and their ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies; production levels; imprecision of reserve estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital and operating costs); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses. The Company's operations have been, and in the future may be, affected by political developments and by federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available. For additional information refer to the "Risks Factors" section of the AIF. Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements.

Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or Management's estimates or opinions change.

Advisory

Cautionary Statement

Project progress and financial results are dependent upon economic and regulatory conditions, commodity prices, global economic factors, project sanction and capital allocation.

Pricing Assumptions

	2016F(1)	2017F(1)	2018F(2)	2019F(2)
Strip				
US$ WTI/bbl	$ 42.86	$ 55.58	$ 53.91	$ 54.11
C$ AECO/GJ	$ 1.98	$ 3.06	$ 2.71	$ 2.59
WCS Differential US$/bbl	$ 13.84	$ 16.09	$ 15.09	$ 14.61
FX 1.00 US$ = X C$	$ 1.33	$ 1.31	$ 1.32	$ 1.31
FX 1.00 GBP = X C$	$ 1.80	$ 1.67	$ 1.69	$ 1.70
US$60.00 Case				
US$ WTI/bbl	$ 42.86	$ 60.00	$ 60.00	$ 60.00
C$ AECO/GJ	$ 1.98	$ 3.00	$ 3.00	$ 3.00
WCS Differential US$/bbl	$ 13.84	$ 15.00	$ 14.00	$ 14.00
FX 1.00 US$ = X C$	$ 1.33	$ 1.25	$ 1.25	$ 1.25
FX 1.00 GBP = X C$	$ 1.80	$ 1.94	$ 1.94	$ 1.94

(1) Strip as at December 12, 2016.
(2) Strip as at December 1, 2016.

Reserves Notes:

(1) *Company Gross reserves are working interest share before deduction of royalties and excluding any royalty interests.*

(2) *Company Net reserves are working interest share after deduction of royalties and including any royalty interests.*

(3) *BOE values may not calculate due to rounding.*

(4) *Forecast pricing assumptions utilized by the Independent Qualified Reserves Evaluators in the reserve estimates were provided by Sproule Associates Limited:*

	2016	2017	2018	2019	2020	Average annual increase thereafter
Crude oil and NGL						
WTI at Cushing (US$/bbl)	$ 45.00	$ 60.00	$ 70.00	$ 80.00	$ 81.20	1.50%
Western Canada Select (C$/bbl)	$ 45.26	$ 57.96	$ 65.88	$ 75.11	$ 77.03	1.50%
Canadian Light Sweet (C$/bbl)	$ 55.20	$ 69.00	$ 78.43	$ 89.41	$ 91.71	1.50%
Cromer LSB (C$/bbl)	$ 54.20	$ 68.00	$ 77.43	$ 88.41	$ 90.71	1.50%
Edmonton Pentanes+ (C$/bbl)	$ 59.10	$ 73.88	$ 83.98	$ 95.73	$ 98.19	1.50%
North Sea Brent (US$/bbl)	$ 45.00	$ 60.00	$ 70.00	$ 80.00	$ 81.20	1.50%
Natural gas						
AECO (C$/MMBtu)	$ 2.25	$ 2.95	$ 3.42	$ 3.91	$ 4.20	1.50%
BC Westcoast Station 2 (C$/MMBtu)	$ 1.45	$ 2.55	$ 3.02	$ 3.51	$ 3.80	1.50%
Henry Hub Louisiana (US$/MMBtu)	$ 2.25	$ 3.00	$ 3.50	$ 4.00	$ 4.25	1.50%

A foreign exchange rate of 0.7500 US$/C$ for 2016, 0.8000 US$/C$ for 2017, 0.8300 US$/C$ for 2018 and 0.8500 US$/C$ after 2018 was used in the 2015 evaluation.

Reserves Notes

(5) *Reserve additions and revisions are comprised of all categories of Company Gross reserve changes, exclusive of production.*

(6) *Reserve replacement ratio is the Company Gross reserve additions and revisions, for the relevant reserve category, divided by the Company Gross production in the same period.*

(7) *Reserve Life Index is based on the amount for the relevant reserve category divided by the 2016 proved developed producing production forecast prepared by the Independent Qualified Reserve Evaluators.*

(8) *Finding, Development and Acquisition (FD&A) costs are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2015 by the sum of total additions and revisions for the relevant reserve category.*

(9) *FD&A costs including change in Future Development Capital (FDC) are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2015 and net change in FDC from December 31, 2014 to December 31, 2105 by the sum of total additions and revisions for the relevant reserve category. FDC excludes all abandonment and reclamation costs.*

(10) *A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value.*

Hedging

At September 30, 2016, the Company had the following derivative financial instruments outstanding to manage its commodity price risk:

Sales contracts

	Remaining term	Volume	Weighted average price	Index
Natural Gas				
AECO swaps	Nov 2016 – Oct 2017	50,000 GJ/d	$2.80	AECO

Note: The Company's outstanding commodity derivative financial instruments are expected to be settled monthly based on the applicable index pricing for the respective contract month.

Canadian Natural

Key Historic Data

Operational Information	2010	2011	2012	2013	2014	2015
Daily production, before royalties						
Crude oil and NGLs (Mbbl/d)	425	389	451	478	531	564
Natural gas (MMcf/d)	1,243	1,257	1,220	1,158	1,555	1,726
Barrels of oil equivalent (MBOE/d)	632	599	655	671	790	852
Daily production, after royalties						
Crude oil and NGLs (Mbbl/d)	369	329	389	414	451	512
Natural gas (MMcf/d)	1,193	1,209	1,190	1,104	1,432	1,667
Barrels of oil equivalent (MBOE/d)	568	531	587	598	689	790
Proved reserves, after royalties(1)						
Crude oil and NGLs (MMbbl)	1,519	1,572	1,677	1,767	1,898	1,864
Natural gas (bcf)	3,792	3,930	3,670	3,813	5,173	5,443
Mining reserves, SCO (MMbbl)	1,597	1,750	1,891	1,827	1,764	2,013
Barrels of oil equivalent (MMBOE)	2,151	2,227	4,179	4,230	4,524	4,784
Drilling activity, net wells						
Crude oil	934	1,103	1,203	1,117	1,023	115
Natural gas	92	83	35	44	75	19
Dry	33	48	33	30	19	6
Strats and service	491	657	727	384	437	166
Realized product pricing, before hedging activities & after transportation costs						
Crude oil and NGLs (C$/bbl)	65.81	77.46	70.24	70.24	71.59	38.53
Natural gas (C$/Mcf)	4.08	3.73	2.44	2.44	3.30	2.78
Results of operations (C$ million, except per share)						
Cash flow from operations	6,333	6,547	6,013	7,477	9,587	5,785
per share – Basic	*5.82*	*5.98*	*5.48*	*6.87*	*8.78*	*5.29*
Net earnings	1,673	2,643	1,892	2,270	3,929	(637)
per share – Basic	*1.54*	*2.41*	*1.72*	*2.08*	*3.60*	*(0.58)*
Capital expenditures (net, including combinations)	5,514	6,414	6,308	7,274	11,744	3,853
Balance Sheet Info (C$ million)						
Property, plant and equipment (net)	38,429	41,631	44,028	46,487	52,480	51,475
Total assets	42,954	47,278	48,980	51,754	60,200	59,275
Long-term debt	8,485	8,571	8,736	9,661	14,002	16,794
Shareholders' equity	20,368	22,898	24,283	25,772	28,891	27,381
Ratios						
Debt to cash flow, trailing 12 months	1.3x	1.3x	1.5x	1.3x	1.4x	2.6x
Debt to book capitalization	29%	27%	26%	27%	33%	38%
Return on common equity, trailing 12 months	8%	12%	8%	9%	14%	(2%)
Daily production before royalties per 10,000 common shares	5.8	5.5	6.0	6.2	7.2	7.8
Proved and probable reserves before royalties MMBOE per common share*	6.9	7.2	7.2	7.3	8.1	8.3

**2009, 2010 and 2011 Horizon SCO included in Crude Oil and NGLs reserves.*

Share information	2010	2011	2012	2013	2014	2015
Common shares outstanding	1,090,848	1,096,460	1,092,072	1,087,322	1,091,837	1,094,668
Weighted average common shares – Basic	1,088,096	1,095,582	1,097,084	1,088,682	1,091,754	1,093,862
Dividend per share (C$)	0.3	0.36	0.42	0.575	0.90	0.92
TSX trading info						
High (C$)	*45.00*	*50.50*	*41.12*	*36.04*	*49.57*	*42.46*
Low (C$)	*31.97*	*27.25*	*25.58*	*28.44*	*31.00*	*25.01*
Close (C$)	*44.35*	*38.15*	*28.64*	*35.94*	*35.92*	*30.22*

(1) Reserves prior to 2010 were calculated using constant prices and 2010 forward were calculated based on escalating prices due to change in disclosure requirements.

Note: All per share data adjusted for 2004, 2005 and 2010 Stock splits.

Canadian Natural

Corporate Guidance

February 2, 2017

	2017 Budget
Daily Production Volumes (before royalties)	
Natural gas (MMcf/d)	1,700 - 1,760
Crude oil and NGLs (Mbbl/d)	
North America	232 - 242
North America – Thermal In Situ	105 - 115
North America – Oil Sands Mining*	170 - 184
International	43 - 49
	550 - 590
Total MBOE/d	833 - 883

**Oil Sands Mining 2017 annual production guidance reflects production downtime for planned tie-ins and turnarounds.*

	2017 Budget
Capital Expenditures (C$ million)	
North America natural gas and NGLs	460
North America crude oil	910
International crude oil	420
Total Exploration and Production	1,790
Total Thermal In Situ Oil Sands	365
Net acquisitions, midstream and other	25
Horizon Oil Sands Project	
Project capital	
Directive 85	185
Phase 3	585
Owner's costs and other	285
Total capital projects	1,055
Technology and Phase 4	15
Sustaining capital	415
Turnarounds and reclamation	135
Capitalized interest and other	90
Total Horizon Project	1,710
Total Capital Expenditures	3,890

Average Annual Cost Data

	Royalty Rate	Operating Cost
Natural Gas - North America (Mcf)	6.0 - 8.0%	$1.00 - 1.20
Crude oil and NGLs (bbl)		
North America (Excluding Oil Sands Mining)	13.0 - 14.0%	$11.50 - 13.50
North America – Oil Sands Mining*	1.5 - 2.5%	$24.00 - 27.00
North Sea	-	$33.00 - 36.00
Offshore Africa	7.0 - 9.0%	$10.50 - 12.50

**Oil Sands Mining Operating cost include energy costs and reflect production downtime in 2017 as noted above.*

Other Information

Cash income and other taxes (C$ millions)	
Sask. Resources Surcharge / Capital Tax	$20 - 25
Current income taxes (recovery) – North America	$235 - 285
Current income taxes (recovery) – International and Petroleum Tax	$(5) - (55)
Effective income tax rate on adjusted earnings	27 - 29%
Midstream cash flow (C$ millions)	$55 - 65
Average corporate interest rate	3.75 - 4.25%

Note: Interest rates are subject to change depending upon short term rate changes. Cash income taxes are subject to variation with commodity prices and the level and classification of capital expenditures. Cash PRT is subject to variation due to commodity price and capital spending. 2017 Budget guidance based on an average annual WTI of US$55.58/bbl, AECO of C$3.06/GJ and an exchange rate of US$1.00 to C$1.31 and £1.00 to C$1.67.

Canadian Natural

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President

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Chief Operating Officer

Corey B. Bieber
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