Delivering value in a volatile market

cenovus ENERGY

About Cenovus

TSX, NYSE | CVE

Enterprise value	C$17 billion
Shares outstanding	833 million
2016F production	
Oil sands	151 Mbbls/d
Conventional	54 Mbbls/d
Total liquids	205 Mbbls/d
Natural gas	385 MMcf/d
Total production	**269 MBOE/d**
2015 proved & probable reserves	3.8 BBOE
Bitumen	
Economic contingent resources*	9.3 Bbbls
Discovered bitumen initially in place*	93 Bbbls
Lease rights**	2.0 MM net acres
P&NG rights	4.1 MM net acres
Refining capacity	230 Mbbls/d net

Values are approximate. Forecast production based on July 28, 2016 guidance.
*See advisory. **Includes an additional 0.5 million net acres of exclusive lease rights to lease on our behalf and our assignee's behalf.

Oil sands
Oil sands drilling projects in northern Alberta

Conventional assets
Established conventional oil and natural gas assets in Alberta and Saskatchewan

Refineries
50 percent ownership in two U.S. refineries

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2016 priorities

- Maintain financial strength and capital discipline
- Demonstrate sustainable cost reductions
- Operational excellence
  - improvements in base operations
  - steward further improvements in environmental performance
  - execution of Christina Lake F and Foster Creek G growth phases
- Optimize the portfolio
  - value added integration and portfolio optimization

Continued focus on safe and reliable operations

Capital allocation strategy focused on value creation

Maintain balance sheet strength
Target investment grade credit metrics

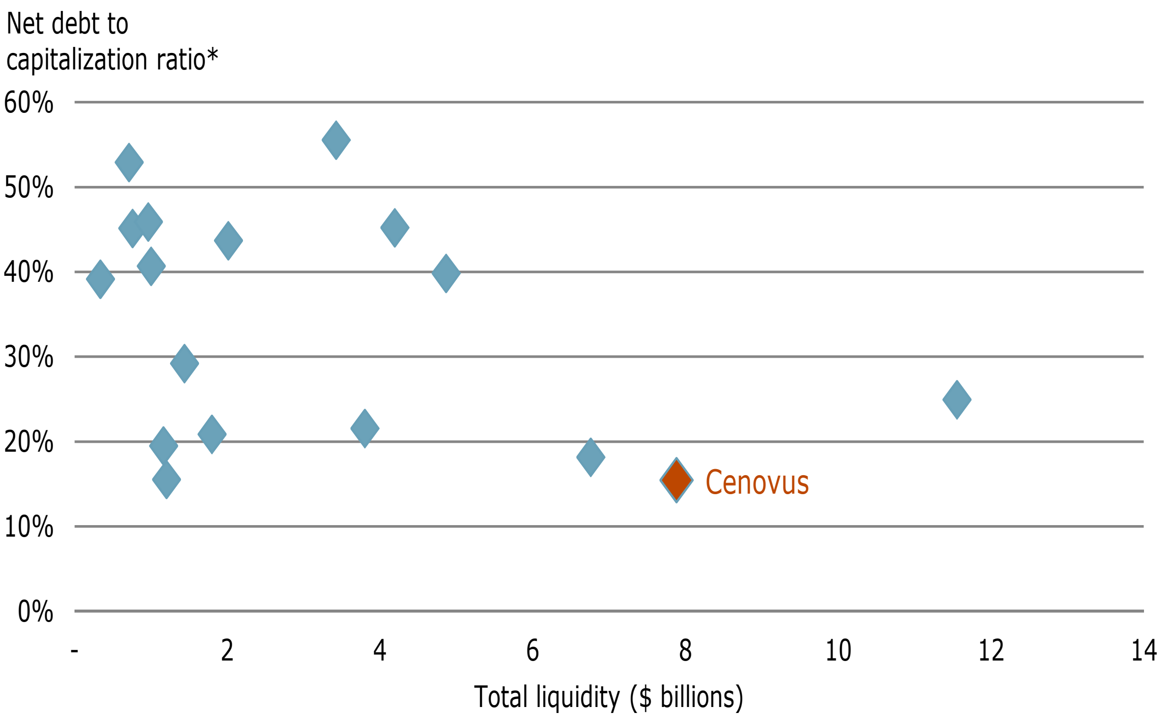
Premium asset quality	Disciplined manufacturing	Focused innovation	Value added integration	Trusted reputation

1	2	3	4
Continued improvement in base operations	**Sustainable dividend* with disciplined growth**	**Reinvest in high return organic growth opportunities**	**Value added portfolio optimization in line with strategy**
Sustaining capital at FCCL Complete FC phase G and CL phase F Safety and environmental performance	Focused on driving total shareholder return	FC, CL and NL Southern Alberta light oil Emerging oil sands	Bruderheim Energy Terminal Royalty fee lands

*Declaration of dividends is at the sole discretion of the Board and will continue to be evaluated on a quarterly basis.

Liquidity position supports financial resilience

2016F net debt to capitalization vs. total liquidity



Significant liquidity

- $3.8 billion in cash at June 30, 2016
- $4.0 billion committed credit facility, fully undrawn, maturing in 2019
- Financial covenant: debt to capitalization not to exceed 65%

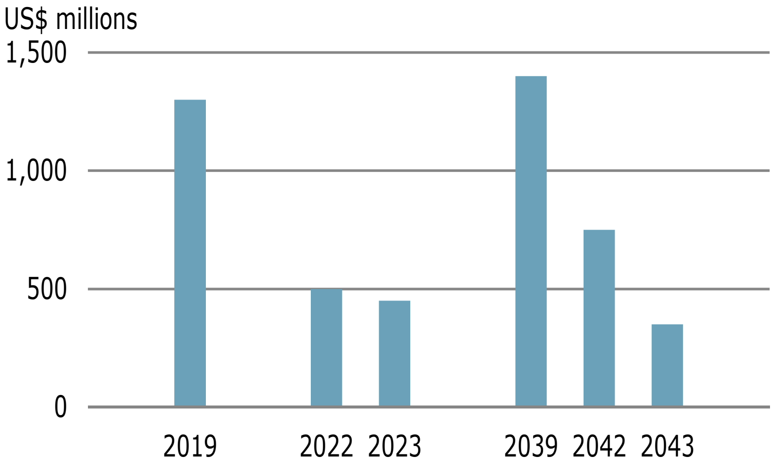
*Non-GAAP measure. See advisory.
Total liquidity reflects unused committed credit capacity and cash and cash equivalents as at March 31, 2016. Peers include: ARX, BNP, BTE, CNQ, CPG, ECA, ERF, HSE, IMO, MEG, PEY, PGF, PWT, SU, TOU, VET.
2016F net debt to capitalization and unused committed credit capacity reflect Bloomberg estimates as of July 26, 2016.

Maintaining balance sheet strength a top priority

	June 30, 2016	December 31, 2015
Net debt to capitalization*	17%	16%
Net debt to adjusted EBITDA*	1.9x	1.2x
Cash & cash equivalents	$3.8 billion	$4.1 billion

Credit ratings & outlooks	S&P	Moody's	DBRS
Senior Unsecured Long-term rating	BBB	Ba2	BBB (High)
Outlook/Trend	Stable	Stable	Negative

Debt maturity profile



Long-dated debt maturities

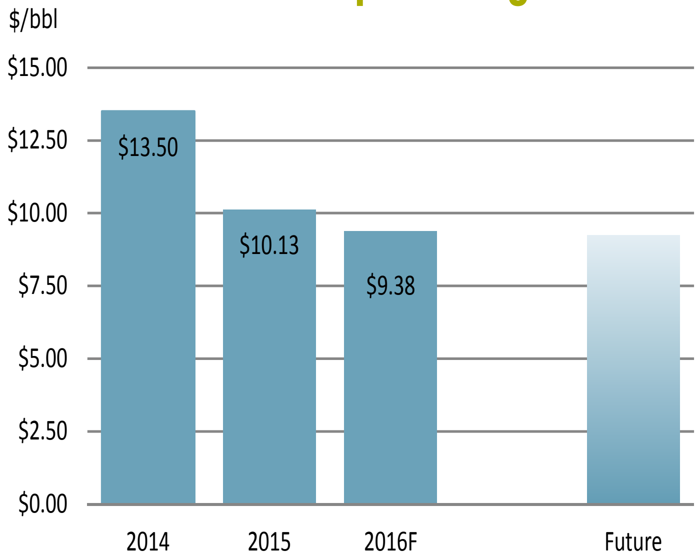
- US$4.75 billion in notes with weighted average maturity of ~16 years
- no maturities until Q4 2019

*Non-GAAP measure. See advisory. Net debt calculated as total debt less cash and cash equivalents.
Credit ratings and outlooks at July 28, 2016.

Becoming a low cost energy producer

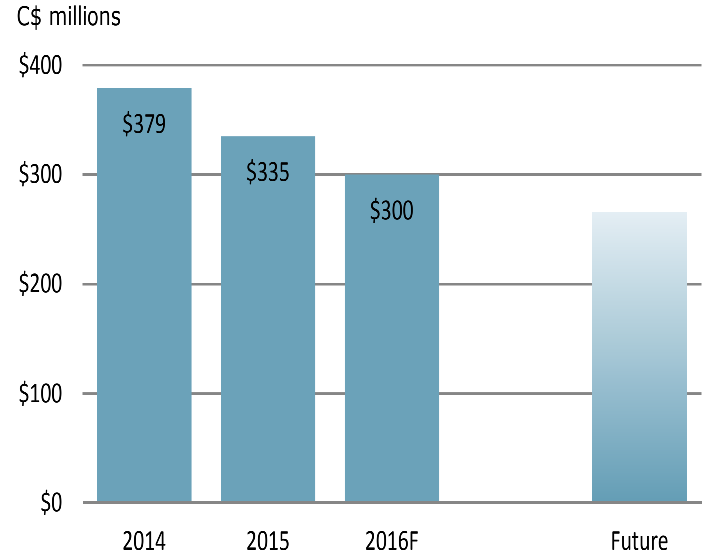
Targeting 30% reduction from 2014 levels

Oil sands operating costs



- **31% reduction to oil sands opex**
- Sustainable cost savings achieved across the value chain

G&A



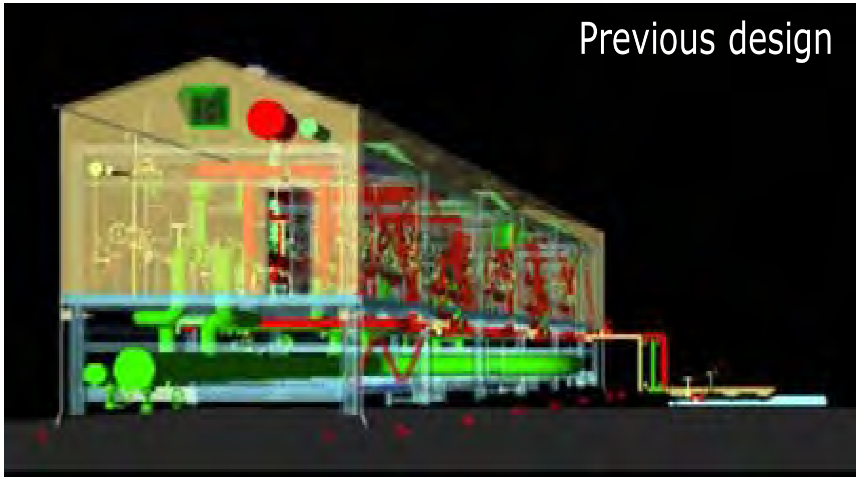
- **21% reduction to G&A**
- Improved efficiencies, workforce optimization and discretionary spending

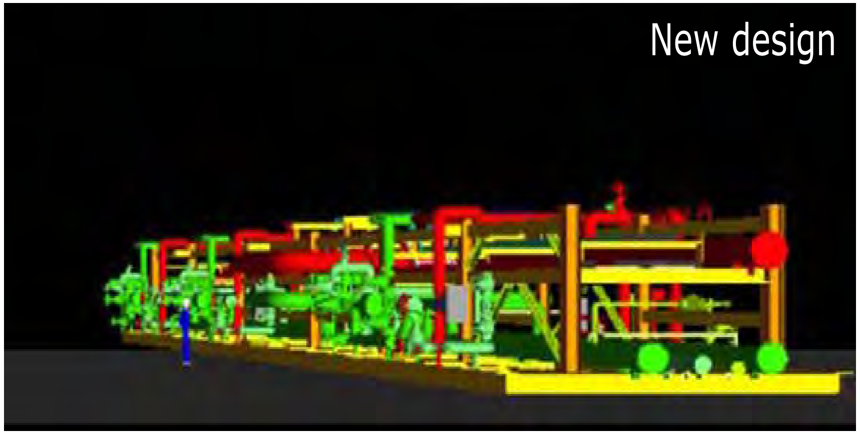
2016F represents midpoint of July 28, 2016 guidance.

Redesigned well pads expected to drive down costs

Expected impacts

- Design philosophy that uses a zero-base* approach to well pair and pad designs
- Materially reduces costs while maintaining safety, compliance and production
- 40% - 60% material reduction
- 15% - 20% well pad surface footprint reduction
- 35% - 50% cost savings
- First redesigned well pad to commence construction in Q3 2016

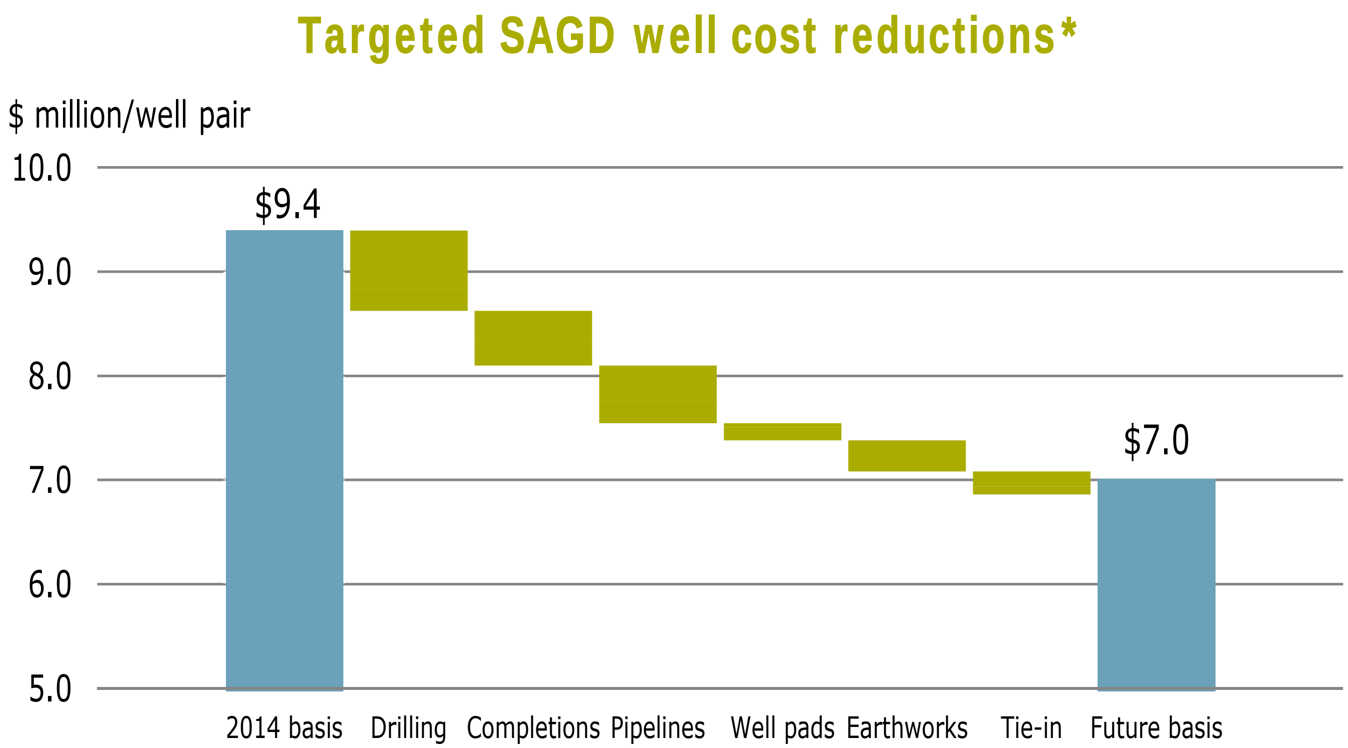




Redesigned well pad is key to reducing F&D costs

*Patent pending.

Improving SAGD well cost performance

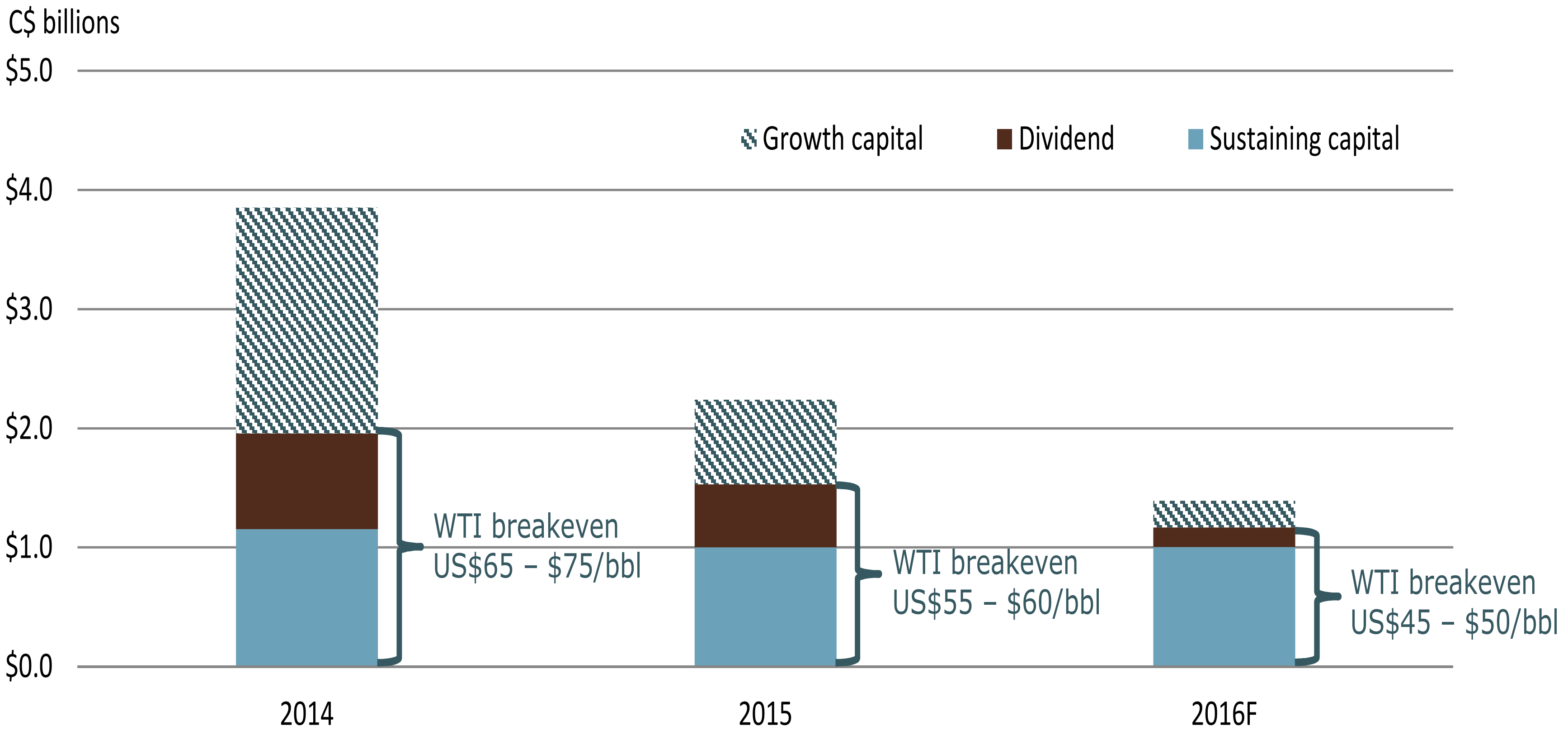


Examples

- Demonstrated a 30% reduction in the number of drilling days
- Reduced completion time by approximately 30%

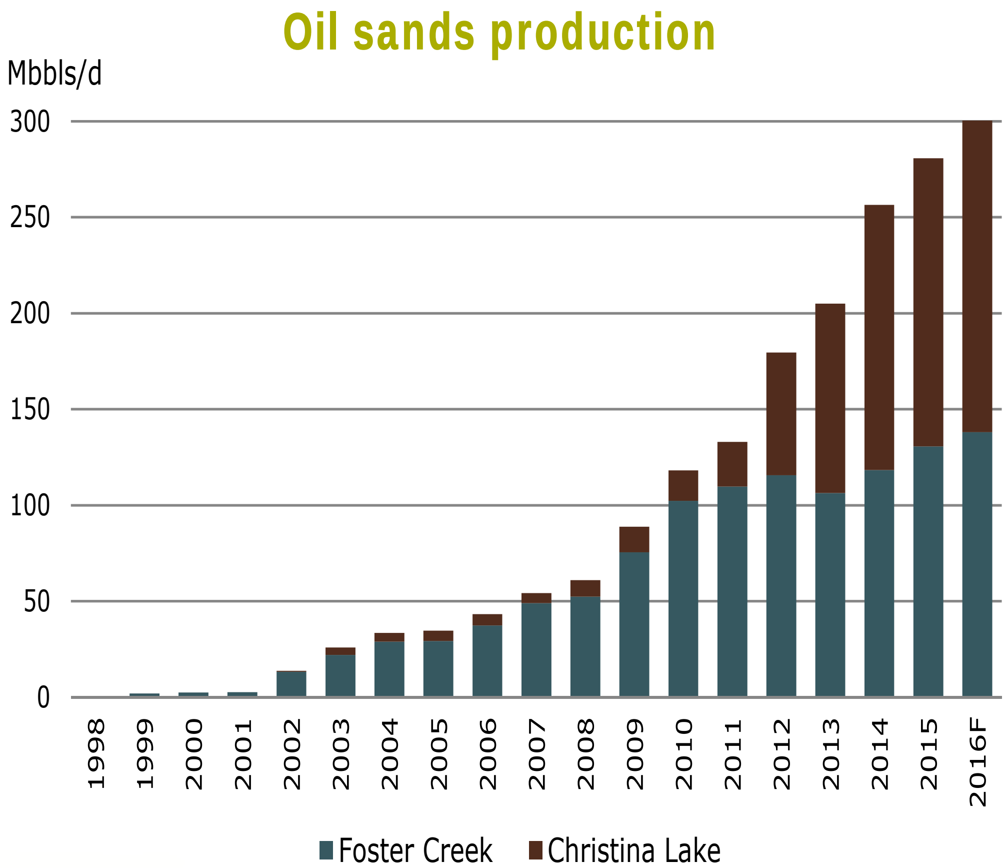
*Targeted reductions for an 800m horizontal SAGD well pair.

Improving sustainability



Breakeven is the WTI price implied to generate cash flow to cover dividend, corporate and sustaining capital.
Declaration of dividends is at the sole discretion of the Board and is evaluated on a quarterly basis.
2016F production based on July 28, 2016 production guidance.
Sustaining capital includes corporate capital expenditures.

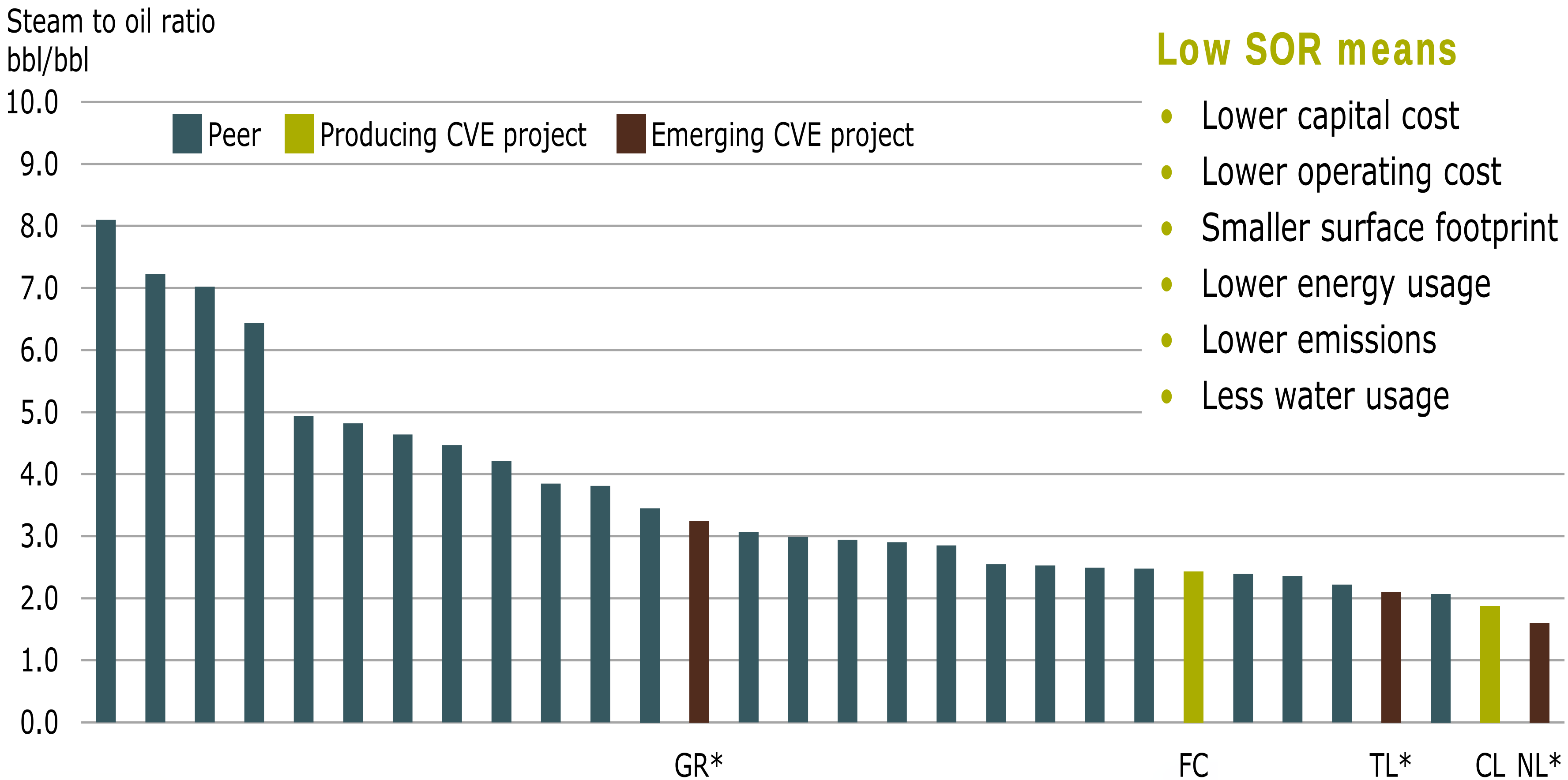
Manufacturing approach to development



- Strong execution, 13 SAGD expansions and optimizations
- Manufacturing approach to development
- 21% production compound annual growth rate since 2007

Production is shown before royalties on a gross basis. 2016F production based on the midpoint of July 28, 2016 guidance. See advisory.

SOR reflects resource quality and execution

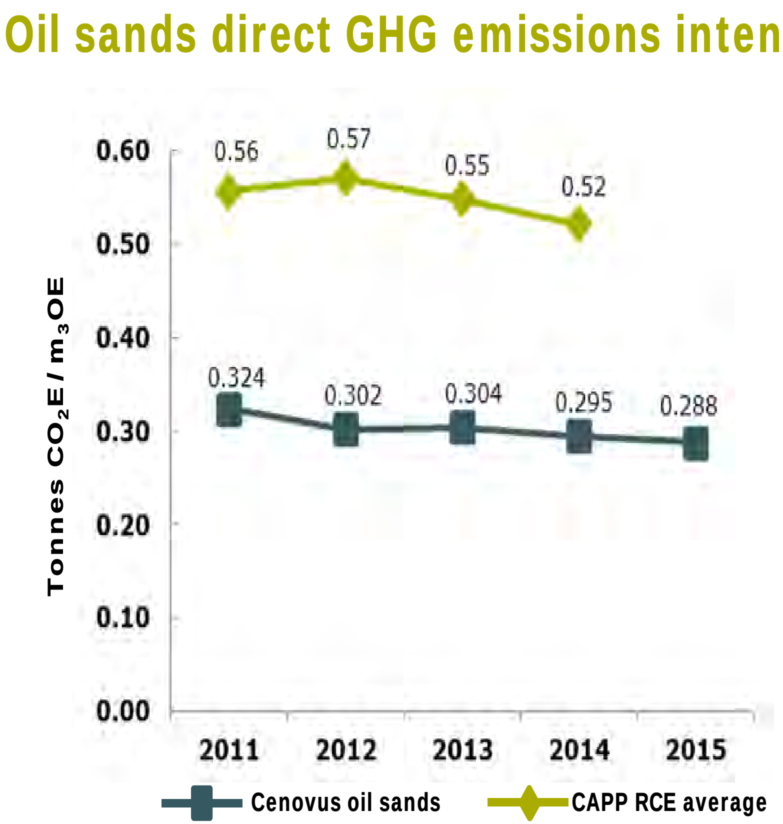


Low SOR means

- Lower capital cost
- Lower operating cost
- Smaller surface footprint
- Lower energy usage
- Lower emissions
- Less water usage

*Forecast.
Peer producing projects include: ATH, CLC, CNOOC, CNQ, COP, DVN, HSE, IMO, JACOS, MEG, OSUM, RDS, STO, SU.
Source: IHS, cumulative SOR to May 2016. Cenovus estimates of expected SOR for emerging projects.

Leading environmental performance

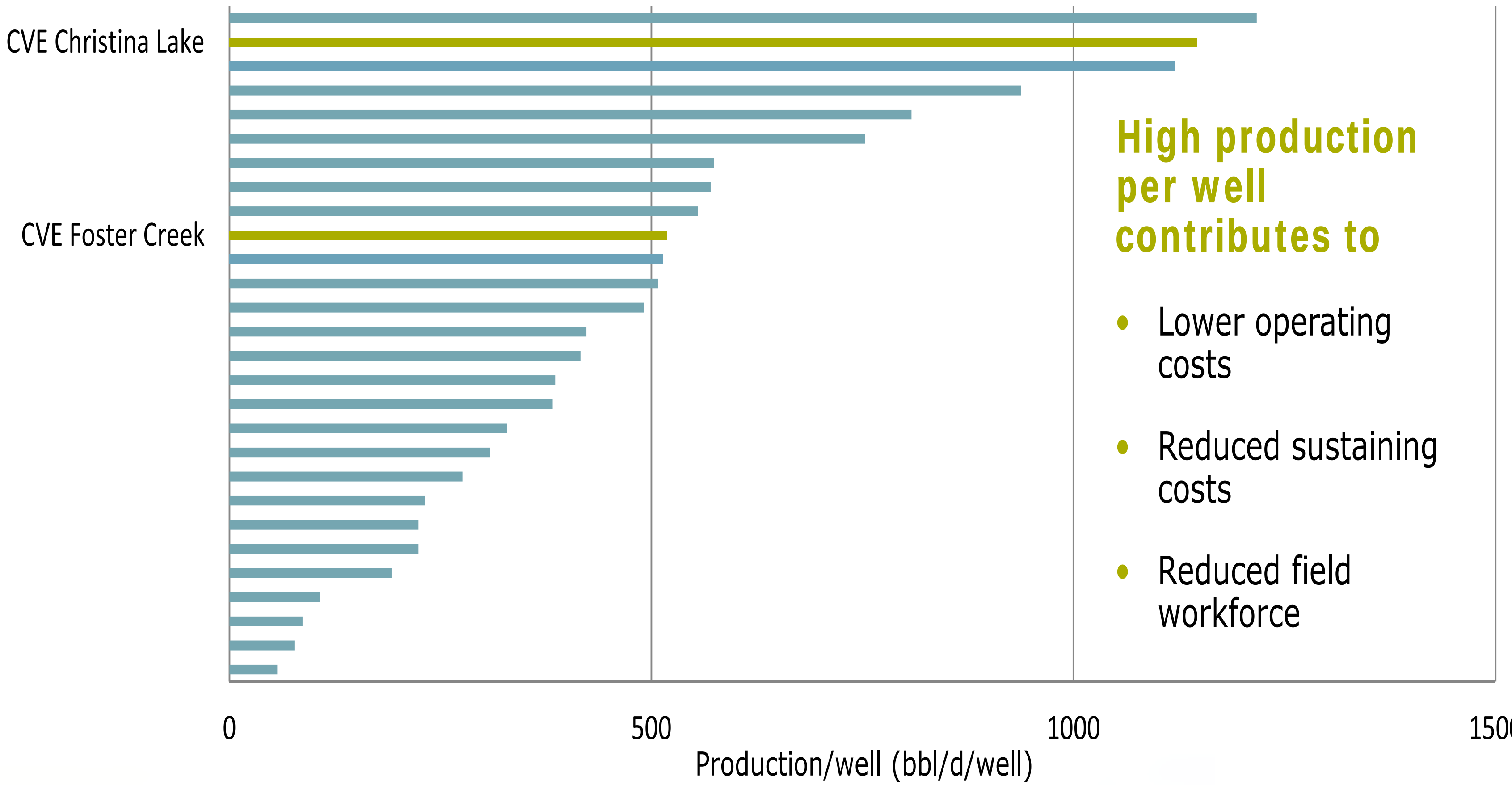


- Cenovus's direct oil sands GHG emissions intensity is:
  - 45% below industry average*
  - down 35% since 2004
- Outcome of top quartile SOR performance and technology such as:
  - Wedge Well™ technology
  - accelerated start-up
  - electric submersible pumps

Top quartile projects position us well under new Alberta Climate Leadership Plan

*2015 CAPP RCE national data table for 2014 operating year.

Top tier well performance

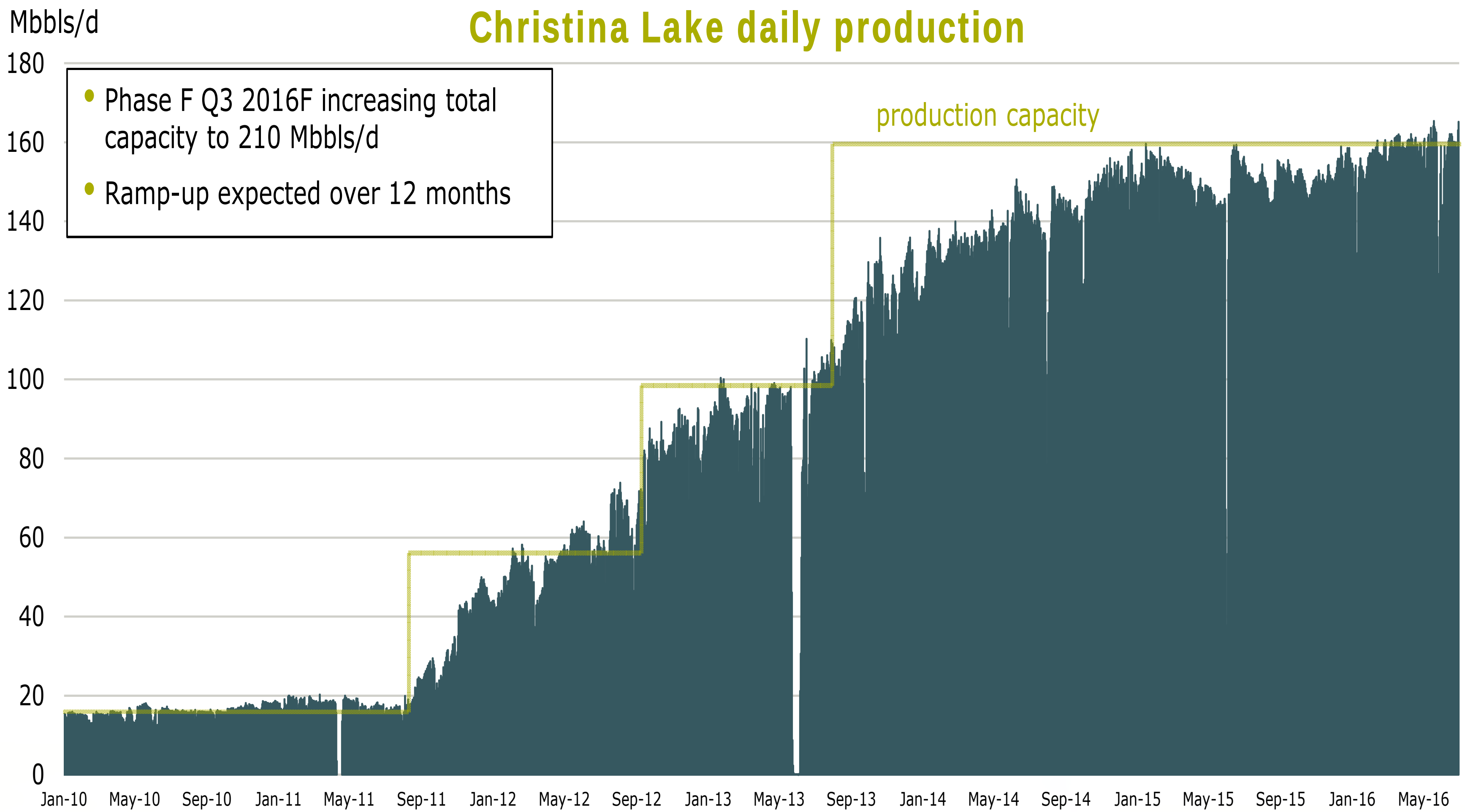


High production per well contributes to

- Lower operating costs
- Reduced sustaining costs
- Reduced field workforce

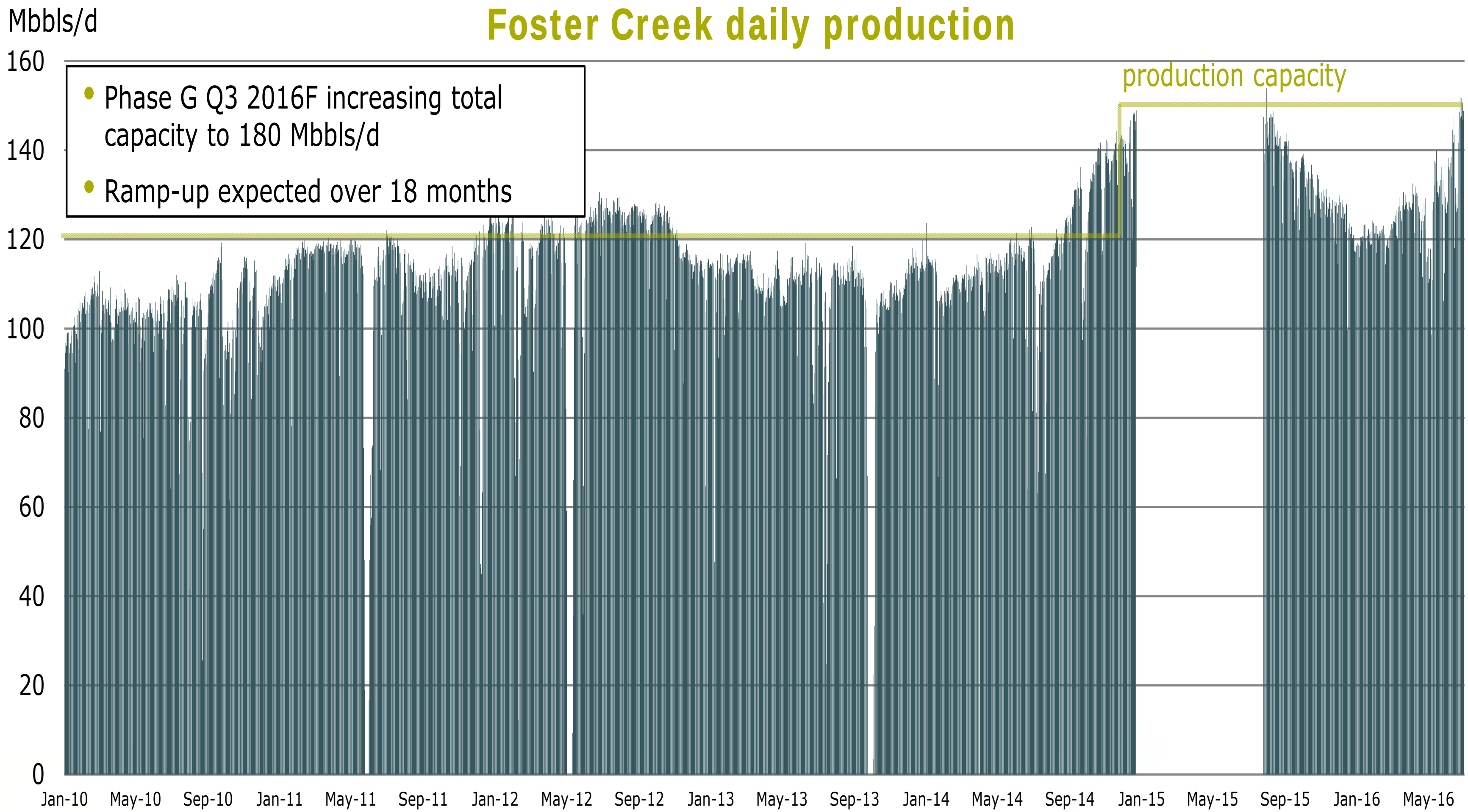
Source: IHS. Peer projects include: Algar, Christina Lake, Cold Lake, Edam East, Firebag, Hangingstone, Jackfish, Kirby South, Leismer, Long Lake, MacKay, Orion, Paradise Hill, Peace River, Pikes Peak South, Pod 1, Primrose Wolf Lake, Rush Lake, Sandall, Sunrise, Surmont, Tucker, West Ells. Based on trailing 6-month average oil rate as of May 2016. Average is calculated from all the producing wells in the project.

Demonstrating top tier reservoir performance



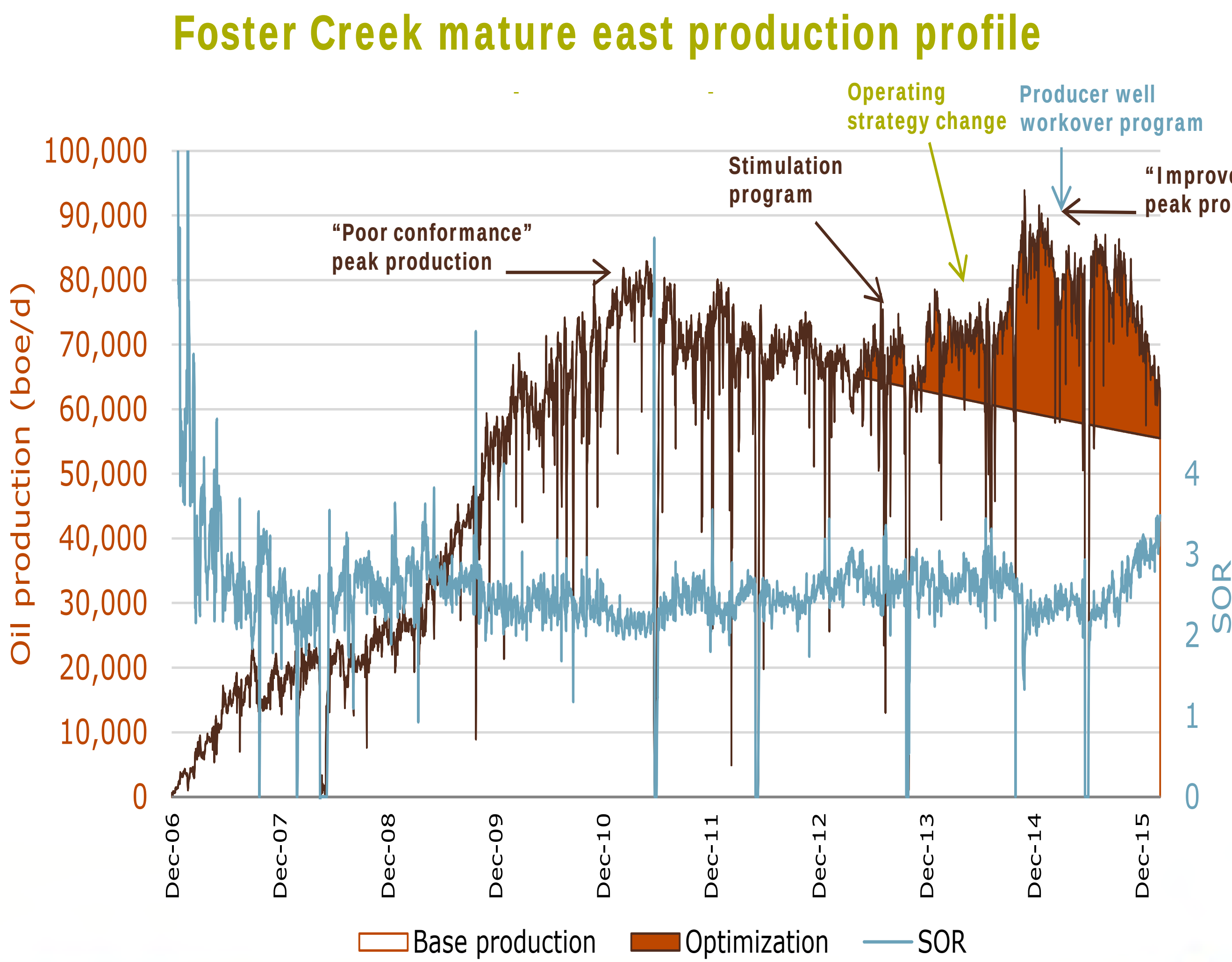
Production is shown before royalties on a gross basis.

Focusing on consistent operations



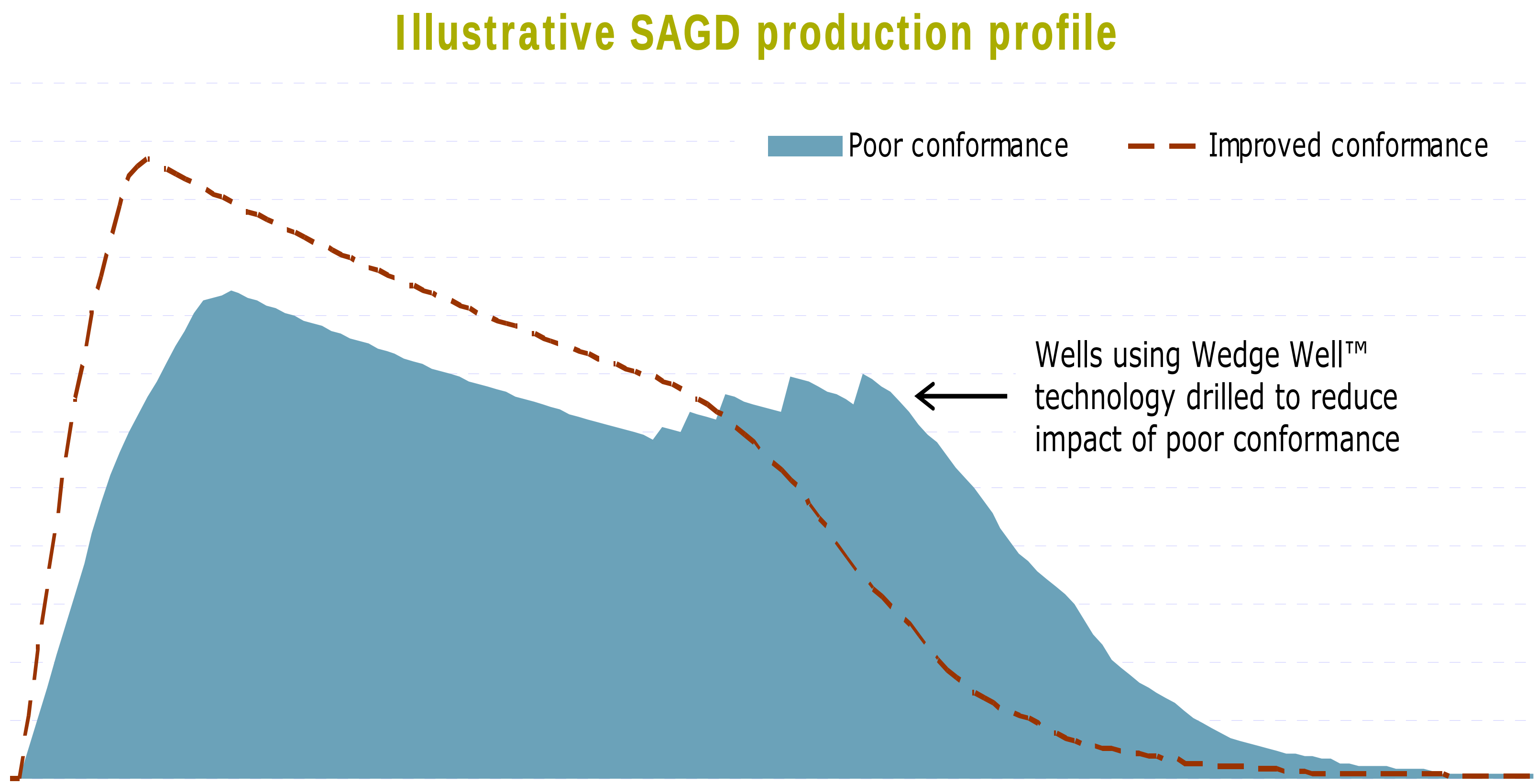
Production is shown before royalties on a gross basis.

Accelerating production from mature pads



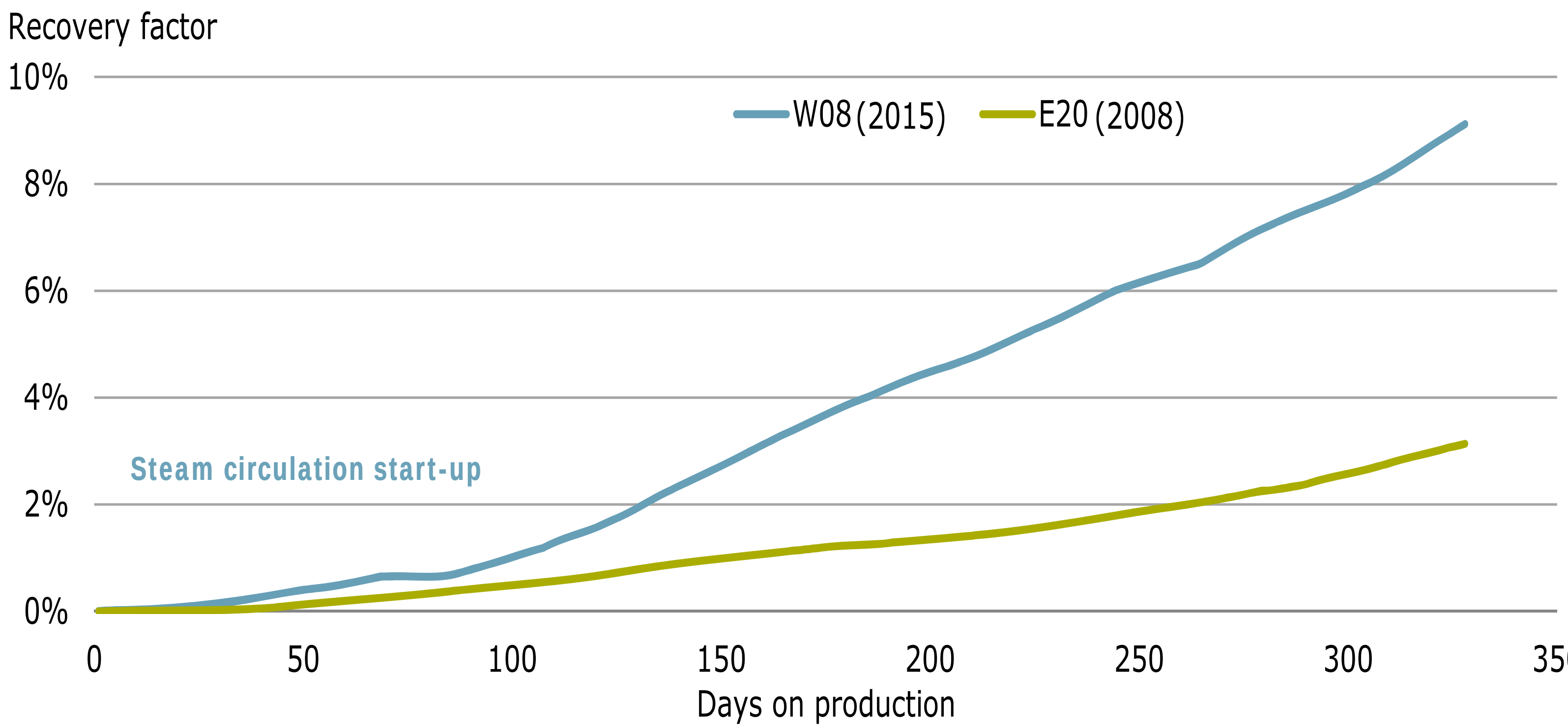
- Accelerating production from mature pads through optimization
  - stimulation
  - operating strategy
  - producing well workovers

Accelerating production with improved conformance



Improving conformance should reduce need for Wedge Well™ technology

Improved start-up procedures on new pads



- Despite the E20 (2008) pad having superior quality, improving conformance on new pads of lesser quality such as the W08 (2015) pad, has resulted in faster recovery

Conventional assets

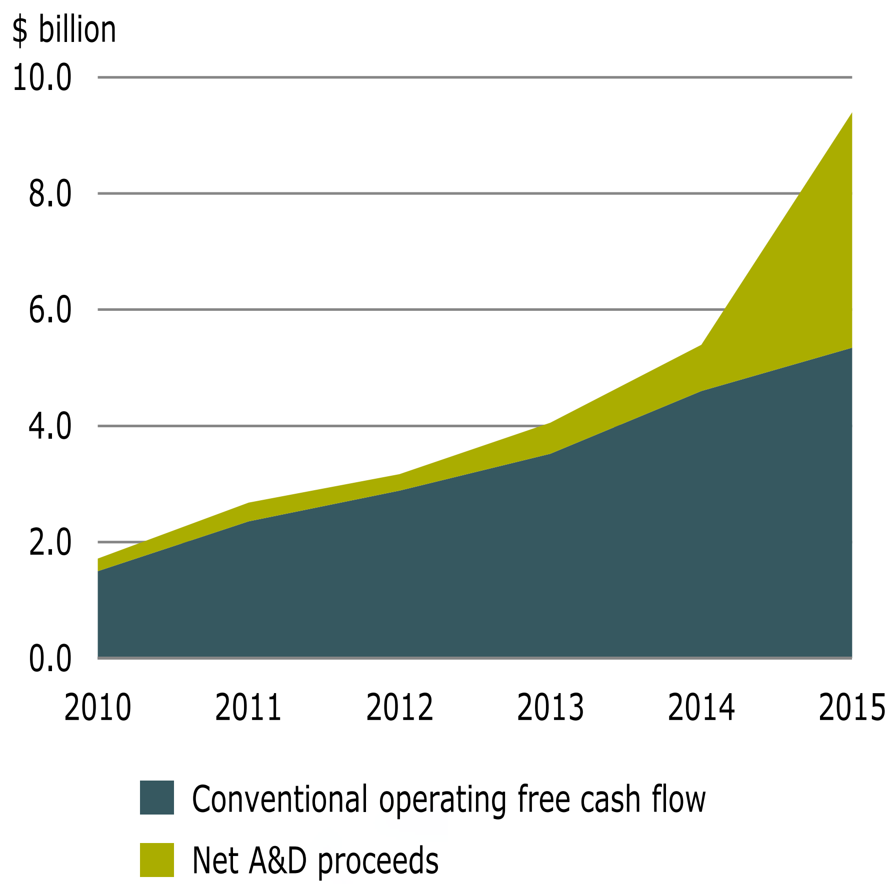
Conventional oil and natural gas

- 2016F production of 54 Mbbls/d and 385 MMcf/d
- Provided over $5.0 billion of operating free cash flow* since 2010
- Portfolio includes both free cash flow and growth assets
  - free cash flow assets include our enhanced oil recovery properties (Suffield, Pelican Lake and Weyburn)
  - growth assets include our southern Alberta tight oil assets

Portfolio optimization

- Evaluate the potential for further monetization of our non-core conventional assets
  - previous sales include Boyer, Bakken, Shaunavon, Wainwright and Heritage Royalty Limited Partnership
- Secured over $4.0 billion of A&D proceeds since 2010

Cumulative operating free cash flow*

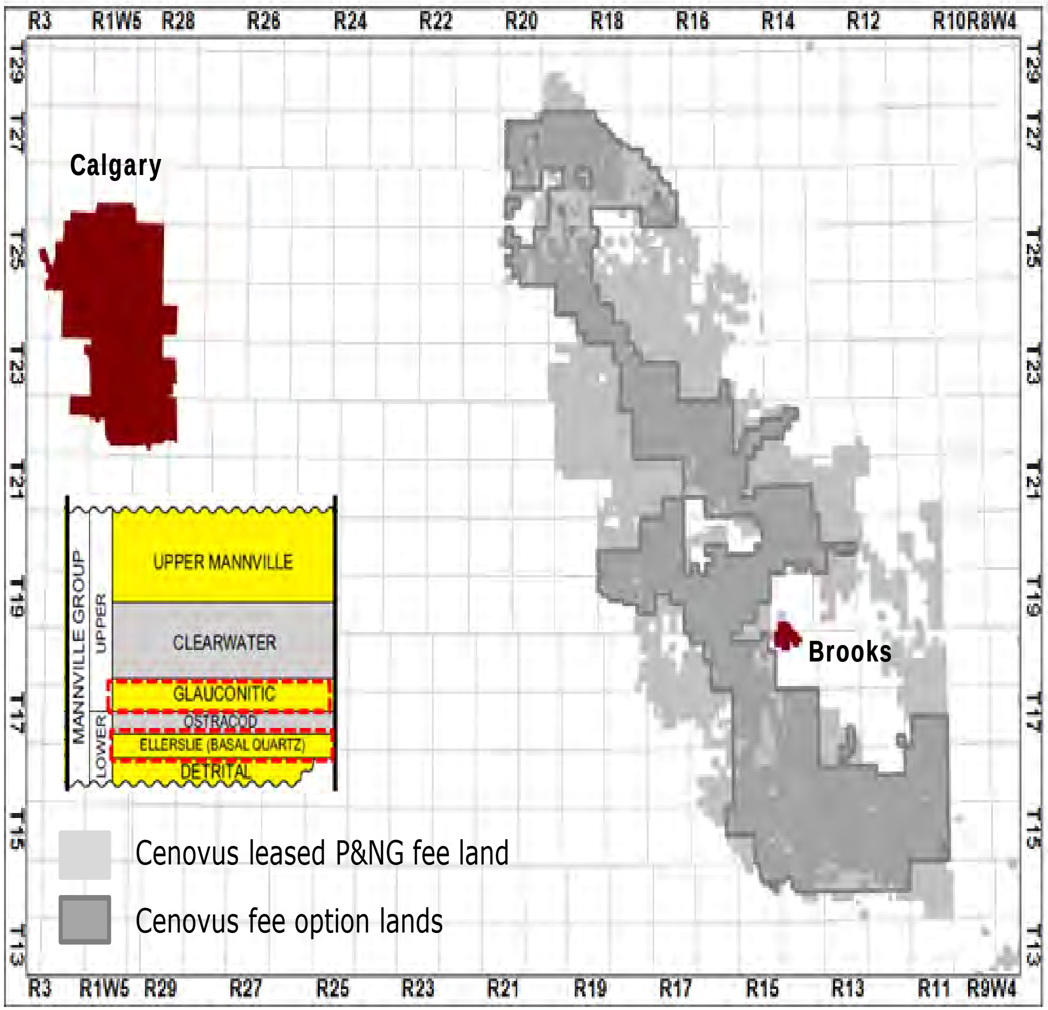


*Operating free cash flow is a non-GAAP measure. See advisory.
2016F production based on the midpoint of July 28, 2016 guidance.

Southern Alberta tight oil

Large inventory of multi zone tight oil locations on Southern Alberta lands

- Over 1,200 sections of leased and available Mannville oil lands
  - 10-year option exclusive to Cenovus
  - attractive lease terms
  - multi zone drilling targets
- Provides scalable and flexible capital opportunities
- High return, low-cost and short-cycle time growth opportunities
- Over 700 unrisked Mannville horizontal oil locations identified
- Existing area infrastructure

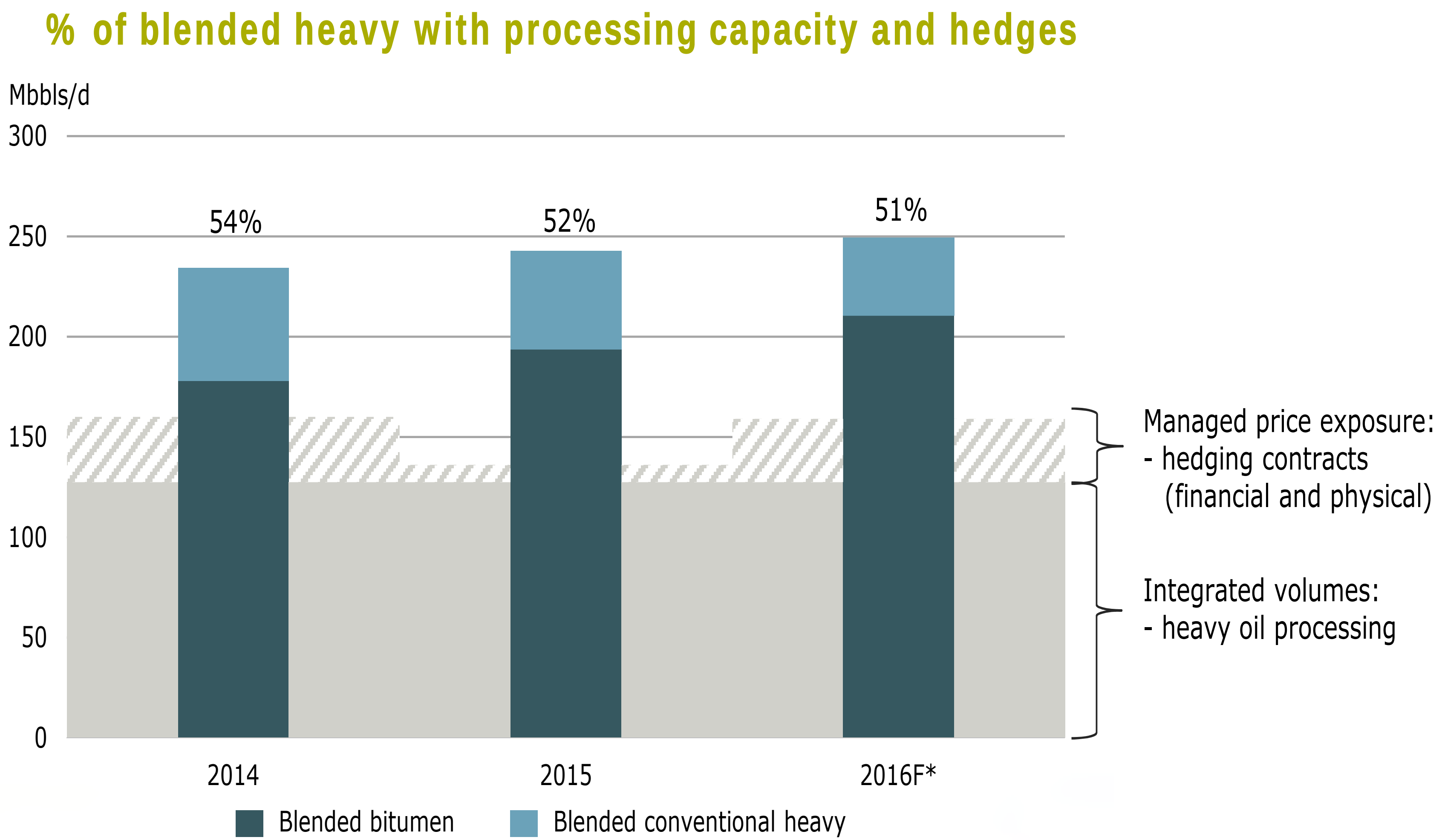


Integration continues to reduce cash flow volatility

- Refineries have access to discounted crudes
  - Wood River accesses multiple pipelines – Keystone, Express-Platte, Mustang, Ozark
  - Borger has access to Canadian heavy, West Texas Sour and growing Permian supply
- Wood River debottleneck expected to increase heavy oil processing capacity by 18,000 bbls/d gross
  - start-up expected Q3 2016
- Downstream operations generated ~$2.4 billion in operating free cash flow* since 2010

*Operating free cash flow is a non-GAAP measure. See advisory.

Mitigating heavy oil differentials



*Excludes an additional 18,000 bbls/d of heavy capacity expected as a result of the Wood River debottlenecking project (expected in the second half of 2016).

Committing to pipeline expansions for market access

Current pipeline access

- West Coast:
  Trans Mountain – 11,500 bbls/d
- US Gulf Coast:
  Enbridge USGC/Flanagan South
  75,000 bbls/d

Potential pipeline commitments

- US Gulf Coast:
  TCPL Keystone XL – 75,000 bbls/d
- East Coast:
  TCPL Energy East to Saint John, NB
  200,000 bbls/d
- West Coast:
  Trans Mountain and Northern Gateway up to
  175,000 bbls/d

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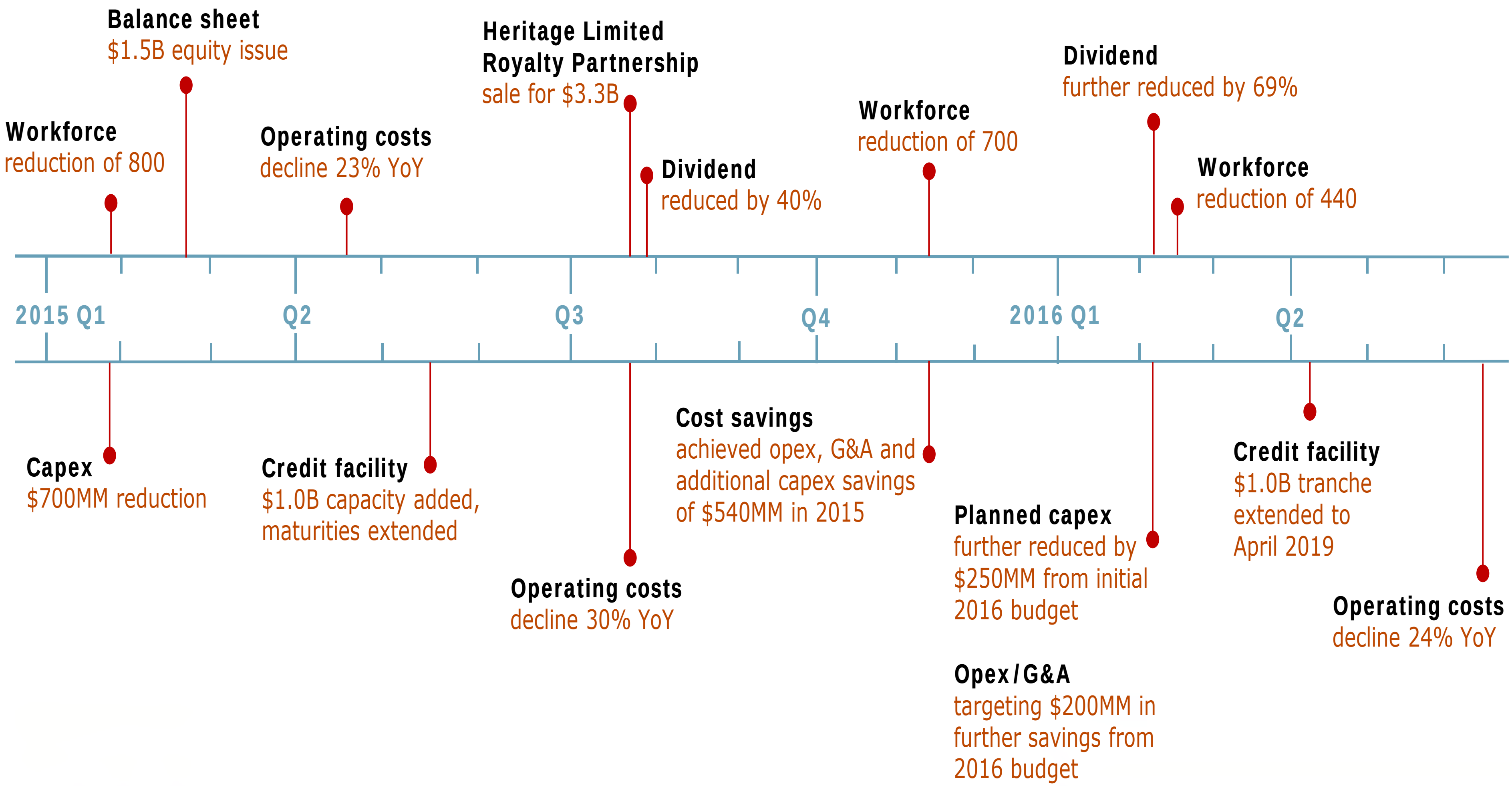
Rail capacity adds flexibility

- Long-term optionality to ship 10% – 20% of corporate volumes by rail
- Taken delivery of 825 coiled and insulated rail cars
- Secured 70,000 bbls/d of loading capacity between:
  - Bruderheim Energy terminal (Edmonton)
  - USDG/Gibsons terminal (Hardisty)

Supplemental information

Our Christina Lake SAGD project is one of our cornerstone oil sands assets.

Taking steps to preserve financial strength



Committed to maintaining low capital cost structure

Illustrative full cycle SAGD costs

$2 - $3/bbl	**Growth capital** • Phase expansion (includes all infrastructure and initial wells) • Phase debottlenecking and optimization • Numerator for capital efficiency calculation
$9 - $11/bbl	**Sustaining capital** • All wells, pads, pipelines beyond initial capacity • Operating capital • Maintenance capital • Stratigraphic wells and seismic • Environment, health and safety initiatives • Technology development

Total capital ~$11 - $14/bbl full cycle

SAGD portfolio provides development opportunity and growth potential

	2P bitumen reserves (Billions of barrels)	Bitumen best estimate economic contingent resources (Billions of barrels)					
	2015	2015	2014	2013	2012	2011	2010
Foster Creek	1.35	1.1	1.1	1.4	1.3	0.9	0.8
Christina Lake core & other areas	1.40	0.7	0.7	1.1	1.2	1.1	0.8
Narrows Lake	0.47	0.1	0.1	0.1	0.1	0.4	0.5
Telephone Lake	-	2.6	2.6	2.6	2.2	2.1	2.0
Steepbank & East McMurray	-	2.9	2.9	2.9	2.9	2.0	0.8
East Borealis	-	0.2	0.2	0.2	0.2	-	-
Grand Rapids	0.08	1.7	1.7	1.5	1.7	1.6	1.3
Total contingent resources		9.3	9.3	9.8	9.6	8.2	6.1
Total 2P bitumen reserves	3.3			2.5	2.4	1.9	1.7

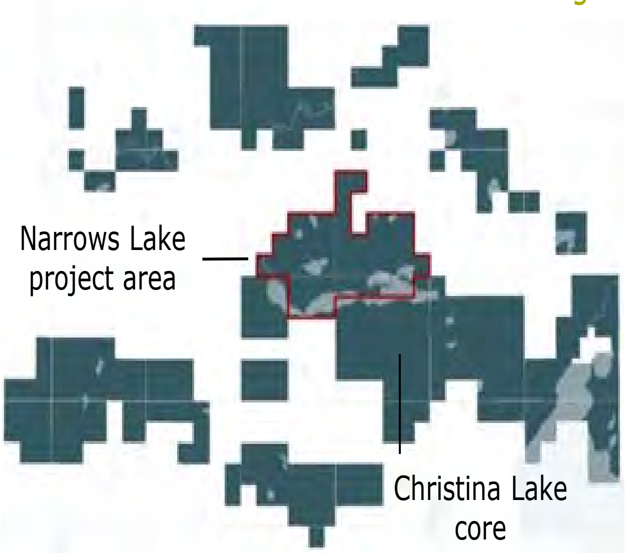
Totals may not add due to rounding. For additional information about our economic contingent resources please see the advisory. There is uncertainty that it will be commercially viable to produce any portion of the contingent resources.

SAP at Narrows Lake

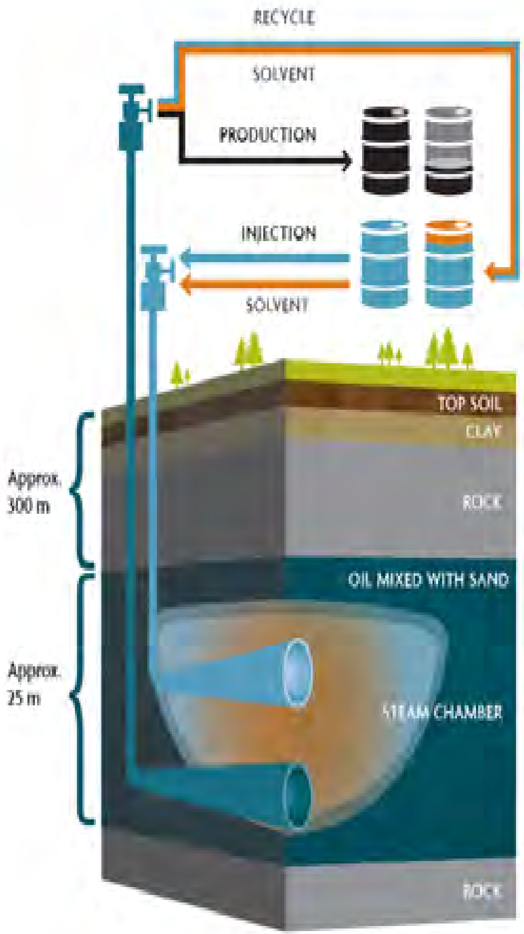
Narrows Lake commercial project

- First commercial SAGD project to incorporate solvent aided process (SAP)
- Evaluating development options to leverage existing infrastructure at nearby Christina Lake project
- Expected initial production capacity 45,000 bbls/d (phase A)
- Expected ultimate production capacity 130,000 bbls/d

Christina Lake region



SAP



Expected outcomes of SAP vs SAGD

- Decrease SOR by ~30%
- Increase full field recovery rates by ~15%
- Increase growth capital 10% - 20%
- Decrease sustaining capital by ~10%
- Reduce non-fuel operating costs by 5% - 10%
- Lower emissions, water usage and land footprint

Telephone Lake and Grand Rapids

Telephone Lake commercial project

- Regulatory approval received in 2014
- Continuing engineering work; assessing development options
- Estimated project SOR – 2.1
- Expected initial production capacity 90,000 bbls/d (phases A & B)
- Expected ultimate production capacity 300,000+ bbls/d

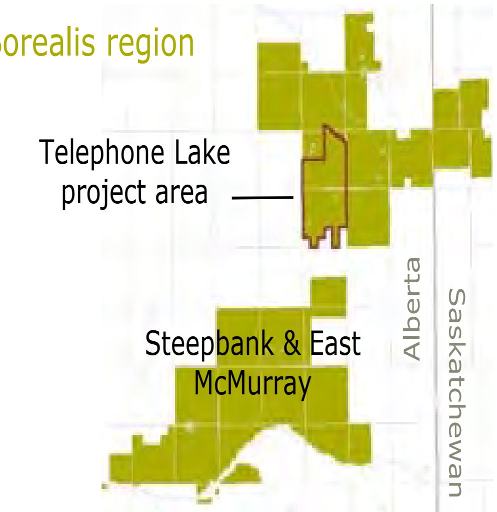
Grand Rapids SAGD pilot update

- Operating since 2010
- Two well pairs currently producing
- Third pilot well pair completed Q1 2015; steam circulation began Q2 2015
- Pilot has been deferred

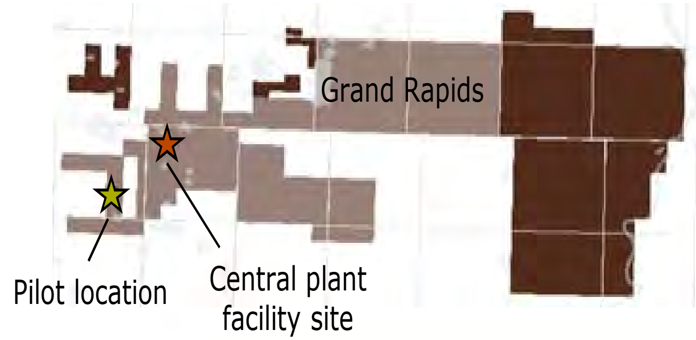
Commercial project

- Received regulatory approval Q1 2014
- Expected total production capacity of 180,000 bbls/d
- Estimated project SOR 3.0 – 3.5
- Phase A: expect 8,000 – 10,000 bbls/d
  - moved acquired facility to Cenovus yard for storage

Borealis region



Greater Pelican region



Creating value through social and governance performance

Committed to good governance

- SER Committee of the Board provides oversight of environment and sustainability performance
- Enterprise Risk Management program, practices and policy help ensure active and effective risk mitigation
- Transparent disclosure and reporting through annual Corporate Responsibility Report and CDP GHG and Water Disclosure Projects

Building long-term support in our communities

- Partnering with Aboriginal communities through employment, education, and business development
  - more than $1.8 billion spent since 2009 on goods and services supplied by Aboriginal businesses
- Participating as an Imagine Canada Company - >1% of pre-tax profits donated to non-profit and charitable organizations to create shared value and build long-term relationships in the communities where we operate
  - more than $76 million donated through our community investment program since 2010

DJSI World Index and **North American Index**

Euronext Vigeo World 120 Index for Responsible Performance

IR Magazine Best Sustainability Practice

Carbon Disclosure Leadership Index Canada

Corporate Knights Global 100 and Best 50 Corporate Citizens in Canada

Advancing our environmental performance

- Rigorous regulatory framework ensures environment considerations throughout project lifecycle
- Dedicated internal environment team focused on mitigating environmental risks
- Ongoing technology investment and collaboration through COSIA aimed at advancing Cenovus and industry environmental performance
- Low carbon intensity, carbon price modelling, and innovation drive leadership in oil sands carbon emissions performance
    - life-cycle carbon emissions on par with average crude oil consumed in North America

CVE a top performer for key indicators	
Indicator	CVE vs industry average
Direct GHG emissions intensity Oil sands	-45%
Fresh water intensity Oil sands – production water use	-76%
NO_x intensity Cenovus wide	-57%
SO_2 intensity Cenovus wide	-68%

Source: 2015 CAPP Responsible Canadian Energy National Data table December 2015.
Industry values reflect data from 2014.
Negative value reflects Cenovus performance lower than industry average.

Mitigating financial risk

	Forward hedge contracts as at July 28, 2016	Hedge position	Hedge price	Volume % hedged[2] and average price
2016	**Crude – Brent Fixed Price** July – December July - December	10,000 bbls/d 5,000 bbls/d	US$66.93/bbl C$75.46/bbl	32% of remaining year volumes hedged at ~C$63.38/bbl
	Crude – Brent Collars July – December	10,000 bbls/d	US$45.55 – $56.55/bbl	
	Crude – WTI Fixed Price July – December	10,000 bbls/d	US$39.02/bbl	
	WTI – Collars July – December	30,000 bbls/d	US$45.39 – $55.36/bbl	
	Condensate – Mont Belvieu Fixed Price July – December (purchase)	3,000 bbls/d	US$39.20/bbl	
	WCS Differential[1] July – December	31,400 bbls/d	US$(13.96)/bbl	
2017	**Crude – Brent Fixed Price** July – December	10,000 bbls/d	US$53.09/bbl	
	Crude – WTI Fixed Price January – June	70,000 bbls/d	US$46.35/bbl	
	WTI – Collars July – December	30,000 bbls/d	US$43.92 – $53.96/bbl	
2018	**Crude – Brent Fixed Price** January – June	10,000 bbls/d	US$54.06/bbl	

[1] Cenovus entered into fixed-price swaps and futures to mitigate the impact of light/heavy price differential for heavy crudes.
[2] Percent volume hedged is based on 2016F liquids of 204.5 Mbbls/d as per July 28, 2016 guidance.

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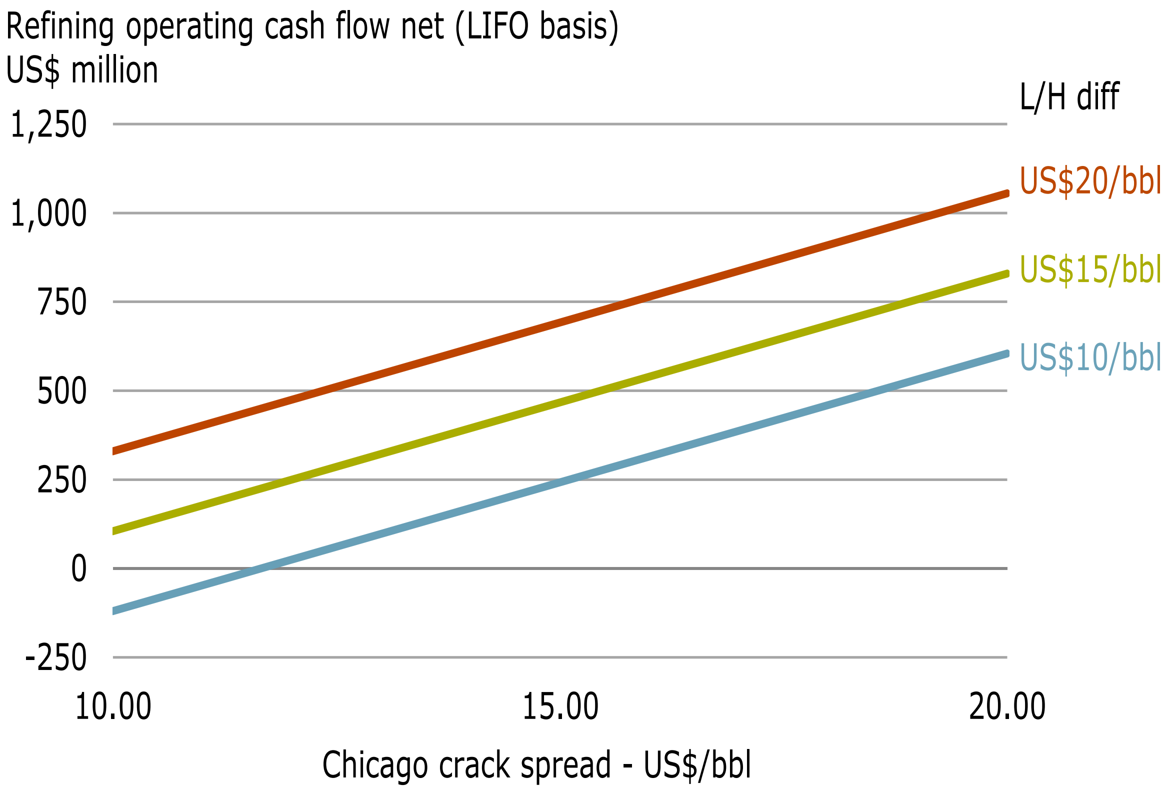
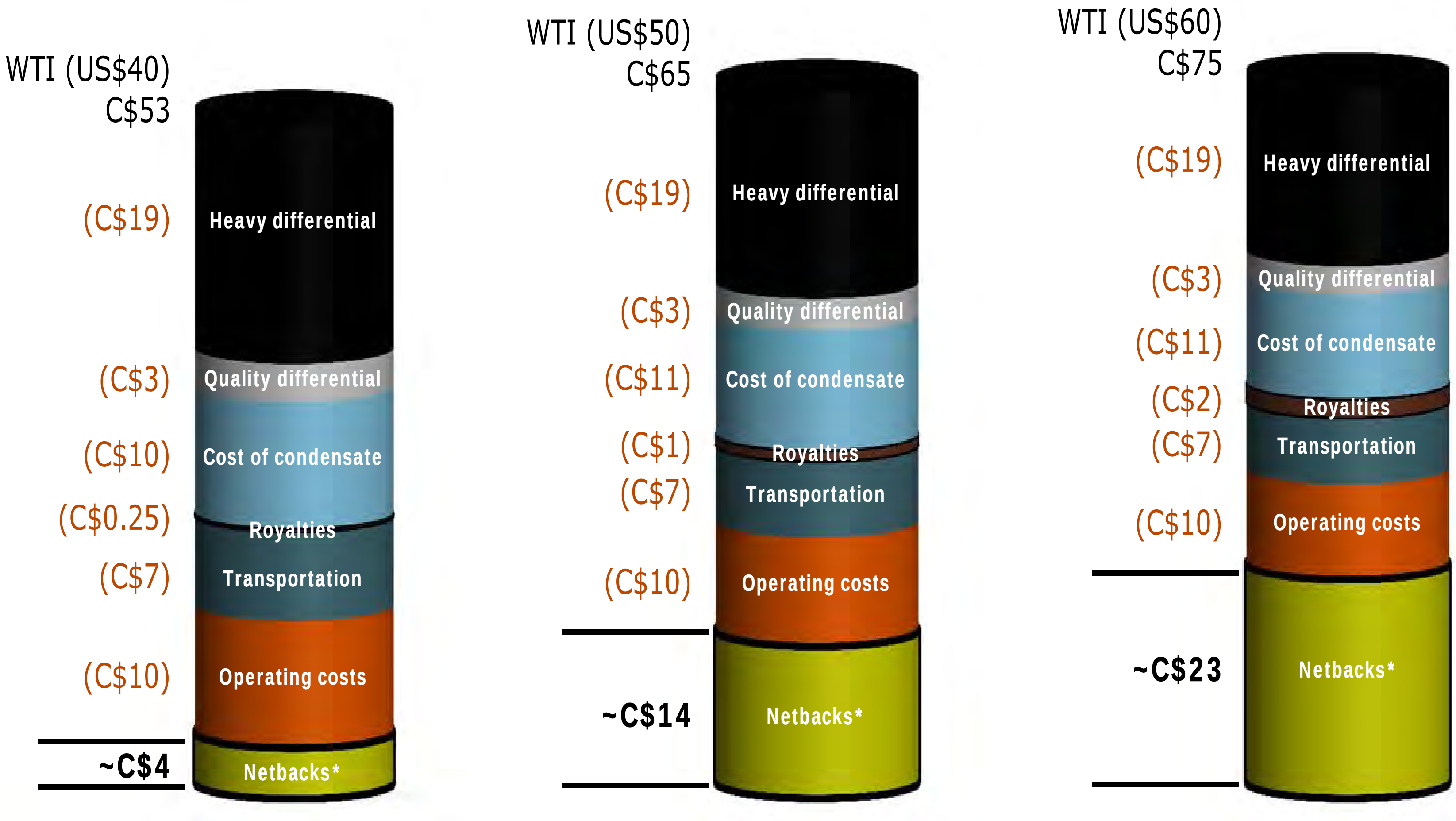
Refining operating cash flow sensitivities



U$1 change in crack spread = ~US$70 million refining operating cash flow
U$1 change in L/H differential = ~US$45 million refining operating cash flow
U$1 change in WTI = ~US$10 million refining operating cash flow

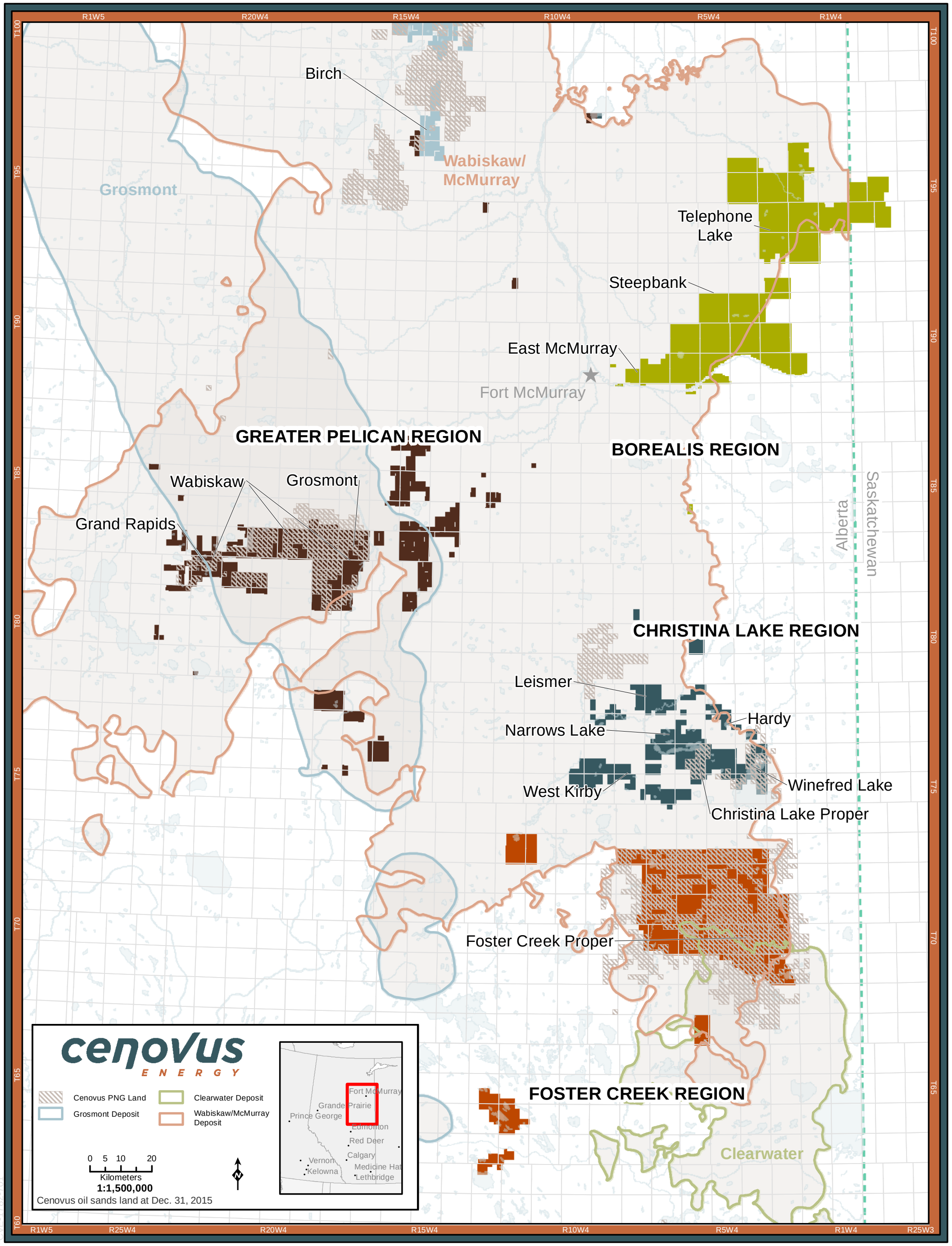
Based on an approximately US$50/bbl WTI as a basis and assumes no unplanned downtime or external disruptions.

Illustrative SAGD netbacks



*Operating netback, before hedge gains or losses.
Based on WTI prices between US$40-$60/bbl, WCS differentials between US$14-$15/bbl, AECO gas between C$2.50-$3.00/GJ and exchange rates between US$/C$0.75-$0.80.


Wood River Refinery
Roxanna, Illinois
Borger Refinery
Borger, Texas
Alberta
Borealis Region
Fort McMurray
Greater Pelican Lake Region
Christina Lake Region
Foster Creek Region
Saskatchewan
Bruderheim
Energy Terminal
Edmonton
Saskatoon
Southeast Alberta -
Palliser Block
Calgary
Suffield
Regina
Weyburn
Land as of December 31, 2015.



Birch
Wabiskaw/ McMurray
Grosmont
Telephone Lake
Steepbank
East McMurray
Fort McMurray
GREATER PELICAN REGION
BOREALIS REGION
Wabiskaw
Grosmont
Grand Rapids
Alberta
Saskatchewan
CHRISTINA LAKE REGION
Leismer
Hardy
Narrows Lake
Winefred Lake
West Kirby
Christina Lake Proper
Foster Creek Proper
FOSTER CREEK REGION
Clearwater
cenovus ENERGY
Cenovus PNG Land
Grosmont Deposit
Clearwater Deposit
Wabiskaw/McMurray Deposit
0 5 10 20
Kilometers
1:1,500,000
Cenovus oil sands land at Dec. 31, 2015
Fort McMurray
Grande Prairie
Prince George
Edmonton
Red Deer
Calgary
Vernon
Kelowna
Medicine Hat
Lethbridge

Advisory

FORWARD-LOOKING INFORMATION This presentation contains certain forward-looking statements and other information (collectively "forward-looking information") about Cenovus's current expectations, estimates and projections, made in light of the company's experience and perception of historical trends. Forward-looking information in this document is identified by words such as "aim", "anticipate", "believe", "budget", "capacity", "commit", "could", "should", "expect", "plan", "forecast" or "F", "estimate" or "E", "focus", "future", "go-forward", "guidance", "illustrative", "may", "on track", "potential", "proposed", "project", "projected", ""position", "priority", "opportunity", "outlook", schedule", "strategy", "target", or similar expressions and includes suggestions of future outcomes, including statements about: our strategy and related milestones and schedules; projected future value; projections contained in our 2016 guidance; forecast operating and financial results; planned capital expenditures, including the priorities, timing and financing thereof; expected future production, including the timing, stability or growth thereof; broadening market access and potential impacts thereof; improving cost structures, including relative to cost reduction targets and the expected timing, sustainability and potential impacts of anticipated and achieved cost savings; targeted well cost reductions; expected reserves, contingent, prospective and bitumen and petroleum initially-in-place resources estimates; bitumen recovery estimation; dividend plans and strategy; expected impacts of low SOR; forecast commodity prices; future use and development of technology; potential outcomes of our zero-base* well pads; expectations regarding future requirements with respect to Wedge Well™ technology; forecast WTI breakeven price; illustrative netbacks and full cycle SAGD costs; expected project capacities; and projected shareholder value. Readers are cautioned not to place undue reliance on forward-looking information as the company's actual results may differ materially from those expressed or implied.

Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally. The factors or assumptions on which the forward-looking information is based include: forecast oil and natural gas prices and other assumptions inherent in Cenovus's 2016 guidance (as updated on July 28, 2016), available at cenovus.com; projected capital investment levels, flexibility of capital spending plans and associated source of funding; the achievement of further cost reductions and sustainability thereof; expected condensate prices; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; future use and development of technology; ability to obtain necessary regulatory and partner approvals; successful and timely implementation of capital projects or stages thereof; the company's ability to generate sufficient cash flow to meet its current and future obligations; estimated abandonment and reclamation costs, including associated levies and regulations; and other risks and uncertainties described from time to time in the company's filings with securities regulatory authorities.

The risk factors and uncertainties that could cause Cenovus's actual results to differ materially, include: volatility of and assumptions regarding oil and natural gas prices; the effectiveness of the company's risk management program, including the impact of derivative financial instruments, the success of the company's hedging strategies and the sufficiency of its liquidity position; the accuracy of cost estimates; commodity prices, currency and interest rates; product supply and demand; market competition, including from alternative energy sources; risks inherent in the company's marketing operations, including credit risks; exposure to counterparties and partners, including ability and willingness of such parties to satisfy contractual obligations in a timely manner; risks inherent in operation of Cenovus's crude-by-rail terminal, including health, safety and environmental risks; maintaining desirable ratios of debt to adjusted EBITDA and net debt to adjusted EBITDA as well as debt to capitalization and net debt to capitalization; the Cenovus's ability to access various sources of debt and equity capital, generally, and on terms acceptable to Cenovus; ability to finance growth and sustaining capital expenditures; changes in credit ratings applicable to Cenovus or any of its securities; changes to dividend plans or strategy, including the dividend reinvestment plan; accuracy of reserves, resources and future production estimates; ability to replace and expand oil and gas reserves; the company's ability to maintain relationships with partners and to successfully manage and operate the company's integrated business; reliability of assets, including in order to meet production targets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; the occurrence of unexpected events such as fires, severe weather conditions, explosions, blow-outs, equipment failures, transportation incidents and other accidents or similar events; refining and marketing margins; inflationary pressures on operating costs, including labour, natural gas and other energy sources used in oil sands processes; potential failure of products to achieve acceptance in the market; risks associated with the fossil fuel industry reputation; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in producing, transporting or refining of crude oil into petroleum and chemical products; risks associated with technology and its application to Cenovus's business; risks associated with climate change; the timing and the costs of well and pipeline construction; ability to secure adequate product transportation, including sufficient pipeline, crude-by-rail, marine or other alternate transportation, including to address any gaps caused by constraints in the pipeline system; availability of, and Cenovus's ability to attract and retain, critical talent; changes in our labour relationships; changes in the regulatory framework in any of the locations in which Cenovus operates, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on Cenovus's business, its financial results and its consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which Cenovus operates; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against the company.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a full discussion of Cenovus's material risk factors, see “Risk Factors” in our AIF or Form 40-F for the year ended December 31, 2015, “Risk Management” in our most recent and annual Management’s Discussion and Analysis (MD&A), together with the updates under "Risk Management" in each of the company's first quarter 2016 and second quarter 2016 MD&A and risk factors described in other documents we file from time to time with securities regulatory authorities, all of which are available on SEDAR at sedar.com, on EDGAR at www.sec.gov and on Cenovus's website at cenovus.com.

*Patent pending.

OIL & GAS INFORMATION The estimates of reserves and contingent resources were prepared effective December 31, 2015 and the estimates of bitumen initially-in-place were prepared effective December 31, 2012. All estimates were prepared by independent qualified reserves evaluators, based on definitions contained in the Canadian Oil and Gas Evaluation Handbook and in accordance with National Instrument 51-101. Additional information with respect to the resources estimates including project descriptions, significant factors relevant to the resource estimates and contingencies which prevent the classification of the contingent resources as reserves, and the material risks and uncertainties associated with reserves and resources estimates, is contained in our AIF and Form 40-F for the year ended December 31, 2015 and our supplemental Statement of Contingent and Prospective Resources for the year ended December 31, 2015, available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at cenovus.com.

There is uncertainty that it will be commercially viable to produce any portion of the contingent resources. There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of those resources. Actual resources may be greater than or less than the estimates provided.

Total bitumen initially-in-place (BIIP) estimates, and all subcategories thereof, including the definitions associated with the categories and estimates, are disclosed and discussed in our July 24, 2013 news release, available on SEDAR at sedar.com, on EDGAR at www.sec.gov and on our website at cenovus.com. BIIP estimates include unrecoverable volumes and are not an estimate of the volume of the substances that will ultimately be recovered. Cumulative production, reserves and contingent resources are disclosed on a before royalties basis. All estimates are best estimate, billion barrels (Bbbls). Total BIIP (143 Bbbls); discovered BIIP (93 Bbbls); commercial discovered BIIP equals the cumulative production (0.1 Bbbls) plus reserves (2.4 Bbbls); sub-commercial discovered BIIP equals economic contingent resources (9.6 Bbbls) plus the unrecoverable portion of discovered BIIP (81 Bbbls); undiscovered BIIP (50 Bbbls); prospective resources (8.5 Bbbls); unrecoverable portion of undiscovered BIIP (42 Bbbls). Any contingent resources as at December 31, 2012 that are sub-economic or that are classified as being subject to technology under development have been grouped into the unrecoverable portion of discovered BIIP. Petroleum initially-in-place (PIIP) estimates for Pelican Lake are effective December 31, 2012 and were prepared by McDaniel. All estimates are best estimate discovered PIIP volumes as follows: Mobile Wabiskaw total PIIP (2.11 Bbbls); discovered PIIP (2.11 Bbbls); cumulative production (0.11 Bbbls); reserves (0.25 Bbbls); contingent resources (0.03 Bbbls); unrecoverable discovered PIIP (1.72 Bbbls); undiscovered PIIP (0 Bbbls). Mobile Wabiskaw development area total PIIP (1.62 Bbbls); discovered PIIP (1.62 Bbbls); cumulative production (0.11 Bbbls); reserves (0.25 Bbbls); contingent resources (0 Bbbls); unrecoverable discovered PIIP (1.26 Bbbls); undiscovered PIIP (0 Bbbls). Immobile Wabiskaw total PIIP (1.33 Bbbls); discovered PIIP (1.33 Bbbls); cumulative production (0 Bbbls); reserves (0 Bbbls); contingent resources (0 Bbbls); unrecoverable discovered PIIP (1.33 Bbbls); undiscovered PIIP (0 Bbbls).

Certain natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of six Mcf to one barrel (bbl). BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil compared to natural gas is significantly different from the energy equivalency conversion ratio of 6:1, utilizing a conversion on a 6:1 basis is not an accurate reflection of value.

NON-GAAP MEASURES Certain financial measures in this presentation do not have a standardized meaning as prescribed by International Financial Reporting Standards (IFRS) such as cash flow, operating cash flow, free cash flow, operating free cash flow, debt, net debt, capitalization, adjusted earnings before interest, taxes, depreciation and amortization (“adjusted EBITDA”) and net debt to capitalization and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this news release in order to provide shareholders and potential investors with additional information regarding Cenovus’s liquidity and its ability to generate funds to finance its operations. This information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. Operating free cash flow is defined as operating cash flow net of related capital investment. For definitions of operating cash flow and the other non-GAAP measures listed above, refer to Cenovus’s most recent and annual Management’s Discussion & Analysis (MD&A) available SEDAR at sedar.com, on EDGAR at www.sec.gov.and on our website at cenovus.com.

Corporate guidance

2016 Corporate Guidance - C$, before royalties

July 28, 2016

UPSTREAM

OIL SANDS

	Production (Mbbls/d)	Capital expenditures ($ millions)		Operating costs ($/bbl)	Effective royalty rates (%)	Steam to oil ratio
Foster Creek	66 - 72	280 - 310	*Fuel*	2.25 - 2.75	1 - 3	2.6 - 3.0
			Non-fuel	8.00 - 9.00		
			Total	10.25 - 11.75		
Christina Lake	78 - 85	280 - 310	*Fuel*	1.75 - 2.25	1 - 3	1.8 - 2.2
			Non-fuel	5.50 - 6.50		
			Total	7.25 - 8.75		
Narrows Lake	- -	10 - 20		- -	- -	- -
New resource plays [1]	- -	35 - 45		- -	- -	- -
Oil Sands total	144 - 157	605 - 685				

CONVENTIONAL

	Production	Capital expenditures ($ millions)	Operating costs	Effective royalty rates (%)
	(Mbbls/d)		($/bbl)	
Oil & liquids [2]	52 - 56	125 - 150	16.50 - 17.50	12 - 16
	(MMcf/d)		($/Mcf)	
Natural gas [3]	370 - 400	10 - 20	1.20 - 1.30	4 - 6

TOTAL

	Production (Mbbls/d, MBOE/d)	Capital expenditures ($ millions)
Total liquids	196 - 213	730 - 835
Total upstream	258 - 280	740 - 855

REFINING & MARKETING

	Capital expenditures ($ millions)	Operating costs ($/bbl)
Refining [4]	220 - 260	7.50 - 8.50
Marketing & transportation	10 - 20	

CORPORATE

Corporate & other expenditures ($ millions)	40 - 50	Upstream DD&A ($ billions)	1.4 - 1.5
Total capital expenditures ($ billions)	1.1 - 1.2	Other DD&A ($ millions) [6]	250 - 350
General & administrative expenses ($ millions) [5]	290 - 310	Cash tax (recovery) ($ millions)	(150) - (50)
		Effective tax rate (%) [7]	27 - 32

PRICE ASSUMPTIONS & CASH FLOW SENSITIVITIES [8]

Brent (US$/bbl)	46.00
WTI (US$/bbl)	44.75
Western Canada Select (US$/bbl)	31.00
NYMEX (US$/MMBtu)	2.50
AECO ($/GJ)	2.20
Chicago 3-2-1 Crack Spread (US$/bbl)	12.00
Exchange Rate (US$/C$)	0.76

Independent base case sensitivities *(for the remaining 6 months of 2016)*	Increase ($ millions)	Decrease ($ millions)
Crude oil (WTI) - US$10.00 change	260	(300)
Light-heavy differential (WTI-WCS) - US$5.00 change	(80)	70
Chicago 3-2-1 crack spread - US$1.00 change	50	(50)
Natural gas (NYMEX) - US$1.00 change	20	(20)
Exchange rate (US$/C$) - $0.05 change	(60)	70

(1) New resource plays includes Grand Rapids, Telephone Lake, and other emerging plays.
(2) Oil & liquids includes Pelican Lake as well as oil and NGLs from Alberta and Saskatchewan.
(3) Natural gas includes all natural gas production.
(4) Refining capital and operating costs are reported in C$, but incurred in US$ and as such will be impacted by FX.
(5) Consistent with our financial reporting, approximately $30 million of costs related to long-term incentives are now recorded as G&A. Previous guidance included long-term incentive costs in both G&A and operating costs. Includes $19 million in severance costs, and $31 million in lease costs.
(6) Includes DD&A related to Refining and Corporate and Eliminations.
(7) Statutory rates of 27% in Canada and 38% in the US are applied separately to pre-tax operating earnings streams for each country. Excludes the effect of mark-to-market gains and losses.
(8) Sensitivities include hedge positions as at June 30, 2016 and are applicable to the remaining six months of 2016. Refining results embedded in the sensitivities are based on unlagged margin changes and do not include the effect of changes in inventory valuation for first-in, first-out/lower of cost or net realizable value.

Advisory

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Investor relations contacts

Kam Sandhar
Vice-President, Investor Relations & Corporate Development
kam.sandhar@cenovus.com
403.766.5883

Graham Ingram
Manager, Investor Relations
graham.ingram@cenovus.com
403.766.2849

Steven Murray
Senior Analyst, Investor Relations
steven.murray@cenovus.com
403.766.3382

Michelle Cheyne
Analyst, Investor Relations
michelle.cheyne@cenovus.com
403.766.2584

Cenovus Energy Inc.
500 Centre Street SE
PO Box 766
Calgary, Alberta T2P 0M5
Telephone: 403.766.2000
Toll free in Canada: 1.877.766.2066
Fax: 403.766.7600

cenovus.com