

FirstEnergy Capital East Coast Energy Conference



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Forward-looking information

This presentation contains certain forward-looking statements and other information (collectively "forward-looking information") about our current expectations, estimates and projections, made in light of our experience and perception of historical trends. Forward-looking information in this presentation is identified by words such as "anticipate", "believe", "expect", "plan", "forecast" or "F", "target", "project", "could", "focus", "vision", "goal", "milestone", "proposed", "scheduled", "outlook", "potential", "may" or similar expressions and includes suggestions of future outcomes, including statements about our growth strategy and related schedules, projected future value or net asset value, forecast operating and financial results, planned capital expenditures, expected future production, including the timing, stability or growth thereof, anticipated finding and development costs, expected reserves and contingent, prospective or in-place resources estimates, potential dividends and dividend growth strategy, anticipated timelines for future regulatory, partner or internal approvals, forecasted commodity prices, future use and development of technology and projected increasing shareholder value. Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied.

2012 guidance is based on an average diluted number of shares outstanding of approximately 759 million. It assumes WTI of US\$90.00/bbl; Western Canada Select of US\$75.00/bbl; NYMEX of US\$3.50/MMBtu; AECO of \$3.10/GJ; Chicago 3-2-1 Crack Spread of US\$14.50; and exchange rate of \$0.975 US\$/C\$. For the period 2013 to 2021 assumptions include WTI of US\$85.00-US\$105.00/bbl; Western Canada Select of US\$71.00-US\$85.00/bbl; NYMEX of US\$4.00-US\$6.00/MMBtu; AECO of \$3.30-\$5.25/GJ; Chicago 3-2-1 crack spread of US\$9.00; exchange rate of \$0.98-\$1.07 US\$/C\$; and average number of shares outstanding of approximately 752 million.

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:** assumptions inherent in our current guidance, available at www.cenovus.com; our projected capital investment levels, the flexibility of capital spending plans and the associated source of funding; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects; our ability to generate sufficient cash flow from operations to meet our current and future obligations; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities. **The risk factors and uncertainties that could cause our actual results to differ materially, include:** volatility of and assumptions regarding oil and gas prices; the effectiveness of our risk management program, including the impact of derivative financial instruments and our access to various sources of capital; accuracy of cost estimates; fluctuations in commodity prices, currency and interest rates; fluctuations in product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; maintaining a desirable ratio of debt to adjusted EBITDA and debt to capitalization; our ability to access external sources of debt and equity capital; success of hedging strategies; accuracy of our reserves, resources and future production estimates; our ability to replace and expand oil and gas reserves; the ability of us and ConocoPhillips to maintain our relationship and to successfully manage and operate our integrated heavy oil business; reliability of our assets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; refining and marketing margins; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in manufacturing, transporting or refining of crude oil into petroleum and chemical products at two refineries; risks associated with technology and its application to our business; the timing and the costs of well and pipeline construction; our ability to secure adequate product transportation; changes in the regulatory framework in any of the locations in which we operate, 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 our business, our financial results and our consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits, indemnification obligations and regulatory actions against us.

The forward-looking information contained in this presentation, including the underlying assumptions, risks and uncertainties, are made as of the date hereof. For a full discussion of our material risk factors, see "Risk Factors" in our 2011 Annual Information Form and "Risk Management" in our most recent Management's Discussion and Analysis, available at www.sedar.com and www.cenovus.com.

Oil & gas information & non-GAAP measures

Oil & gas information The contingent resources estimates, effective December 31, 2011, and the discovered bitumen initially-in-place estimates, effective December 31, 2009, were prepared by McDaniel & Associates Consultants Ltd., an independent qualified reserves evaluator, and are based on definitions contained in the Canadian Oil and Gas Evaluation Handbook. For further discussion regarding our (i) contingent resources, see our 2011 Annual Information Form (AIF) and (ii) our total bitumen initially-in-place and all subcategories thereof, see our June 16, 2010 news release, available on SEDAR at www.sedar.com and at www.cenovus.com. Actual resources may be greater than or less than the estimates provided.

- Discovered Bitumen Initially-In-Place (56 Bbbls) is that quantity of bitumen that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered bitumen initially-in-place includes production, reserves, and contingent resources; the remainder is categorized as unrecoverable. BIIP estimates include unrecoverable volumes and are not an estimate of the volume of the substances that will ultimately be recovered. There is no certainty that it will be commercially viable to produce any portion of the estimate.
- Contingent Resources are those quantities of bitumen estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include such factors as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. The estimate of contingent resources has not been adjusted for risk based on the chance of development.
- Economic contingent resources (8.2 Bbbls) are those contingent resources that are currently economically recoverable based on specific forecasts of commodity prices and costs. In Cenovus's case, contingent resources were evaluated using the same commodity price assumptions that were used for the 2011 reserves evaluation, which comply with NI 51-101 requirements. Best estimate is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources that fall within the best estimate have a 50% confidence level that the actual quantities recovered will equal or exceed the estimate.

Contingent resources are estimated using volumetric calculations of the in-place quantities, combined with performance from analog reservoirs. Contingencies which must be overcome to enable the reclassification of contingent resources as reserves can be categorized as economic, non-technical and technical. The Canadian Oil and Gas Evaluation Handbook identifies non-technical contingencies as legal, environmental, political and regulatory matters or a lack of markets. The contingencies applicable to our contingent resources are not categorized as economic and for the most part are due to regulatory approval of development projects at our properties, partner sanction and adequate capital funding within five years.

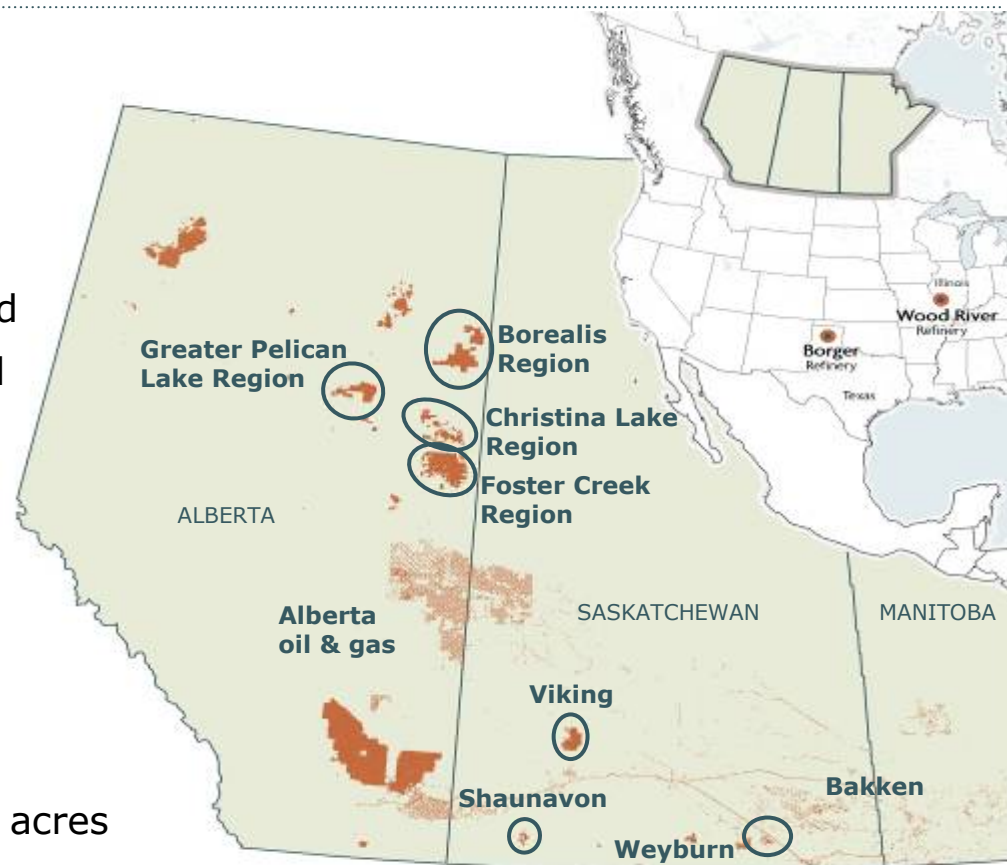
Additional information relating to our oil and gas reserves and resources is presented in our AIF, available at www.sedar.com and on our website at www.cenovus.com. Certain natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of one barrel (bbl) to six thousand cubic feet (Mcf). 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 well head.

Non-GAAP measures This presentation may contain references to non-GAAP measures as identified herein. These measures have been described and presented 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. Readers are encouraged to review our Third Quarter Report to Shareholders, available at www.cenovus.com for a full discussion of the use of each measure.

TM is a trademark of Cenovus Energy Inc.

Cenovus: Building from a strong base

Tickers – TSX, NYSE	CVE
Enterprise value	\$32 billion
Shares outstanding	754 MM
2012F production	
Oil & NGLs	163 Mbbls/d
Natural gas	588 MMcf/d
2011 proved & probable reserves	2.7 BBOE
Bitumen	
Economic contingent resources*	8.2 Bbbls
Discovered bitumen initially-in-place*	56 Bbbls
Lease rights**	1.5 MM net acres
P&NG rights	6.1 MM net acres
Refining capacity	226 Mbbls/d

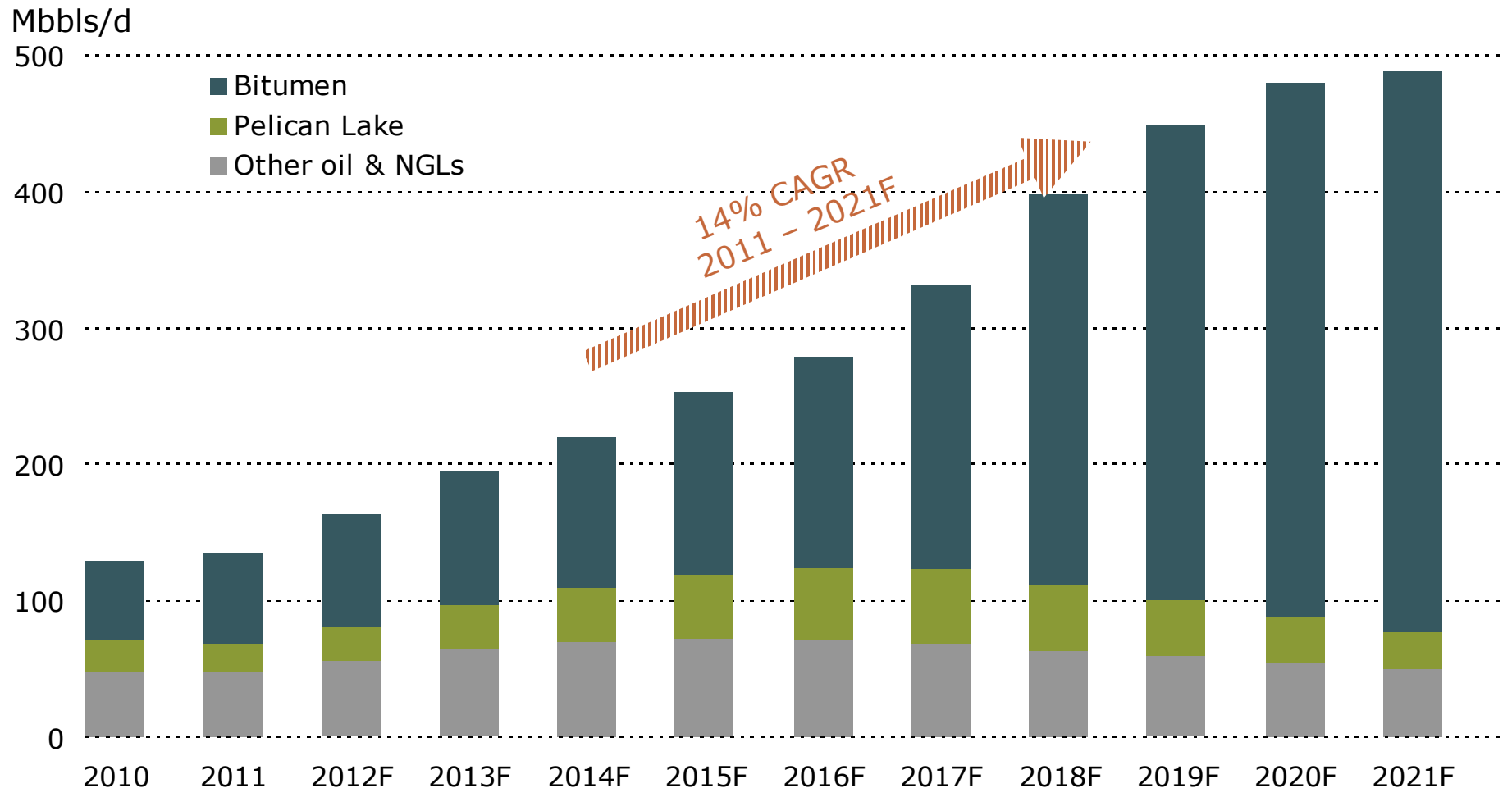


Values are approximate. Forecast production based on midpoints of 2012 guidance dated December 7, 2011. Cenovus land and bitumen estimates at December 31, 2011.

*See advisory.

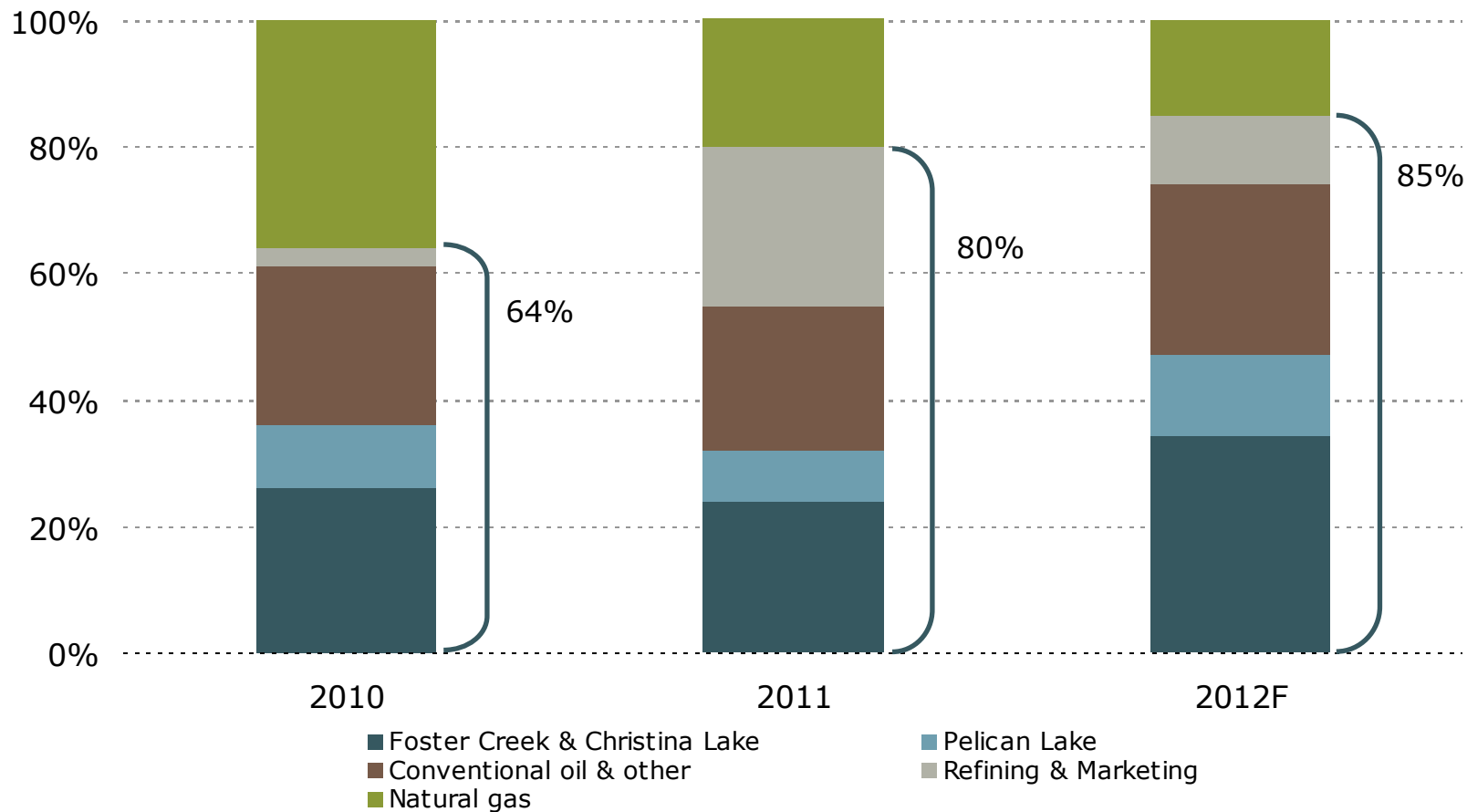
**Includes an additional 0.5 million net acres of exclusive lease rights to lease on our behalf and our assignees behalf.

Providing sustainable, predictable oil growth



Volumes are shown before royalties and net to CVE. 2012F based on midpoints of December 7, 2011 guidance document. 2013F through 2021F based on future price assumptions as noted in the advisory. Forecast volumes are estimates only and subject to regulatory and partner approvals. See advisory.

Integrated oil drives operating cash flow*



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

Why we're successful – how we do it

- Top quality reservoirs
- Manufacturing approach & project execution
- Operational excellence
- Technological innovations
- Top quality people



Advancing oil sands projects

Project phase	Regulatory application filings ¹	First production target ^{1,2}	Expected production capacity (bbls/d) gross	
Foster Creek³				
A – E ⁴			120,000	
F ⁴	Q2-2009	2014	45,000	
G ⁴	Q2-2009	2015	40,000	
H ⁴	Q2-2009	2016	40,000	
Future phases			45,000 – 65,000	
Total capacity			290,000 – 310,000	
Christina Lake³			Prior	New
A – C ⁴			58,000	
D ⁴	Q3-2007	Q4-2012	40,000	
E ⁴	Q4-2009	Q4-2013	40,000	
F ⁴	Q4-2009	2016	40,000	50,000
G ⁴	Q4-2009	2017	40,000	50,000
H	2013F	2019	40,000	
Total capacity			258,000	278,000
Narrows Lake³	Q2-2010	2016	130,000	
Grand Rapids	Q4-2011	2017	180,000	

Timelines are subject to regulatory and partner approvals.

¹ Future dates are company forecasts, see advisory-forward looking information.

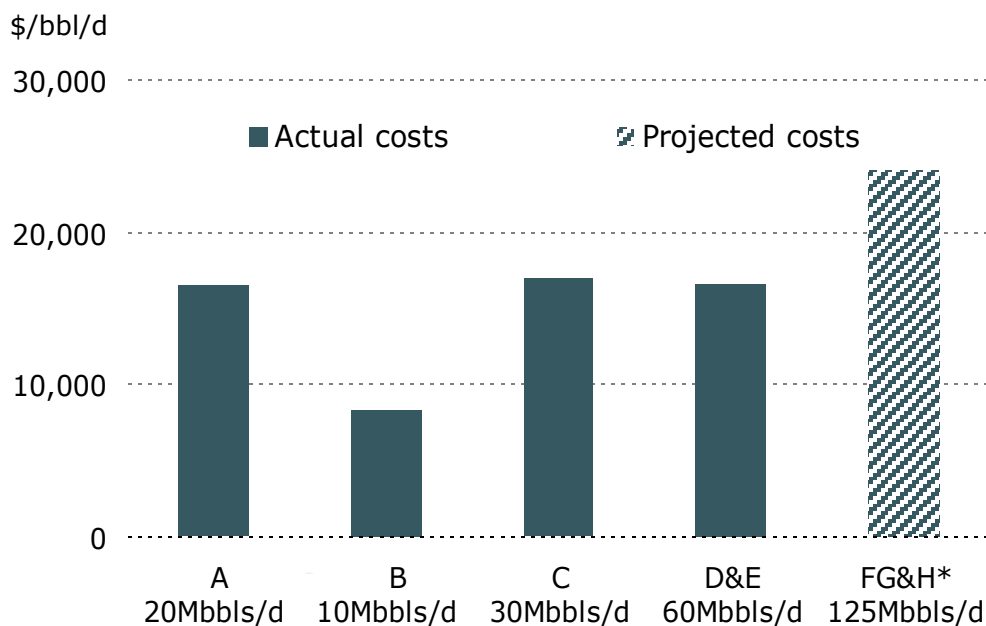
² There is an anticipated ramp up period of approximately 12 to 18 months following first production although the accelerated start-up process being tested at Christina Lake is currently showing improvements to that timing.

³ Properties 50% owned by ConocoPhillips.

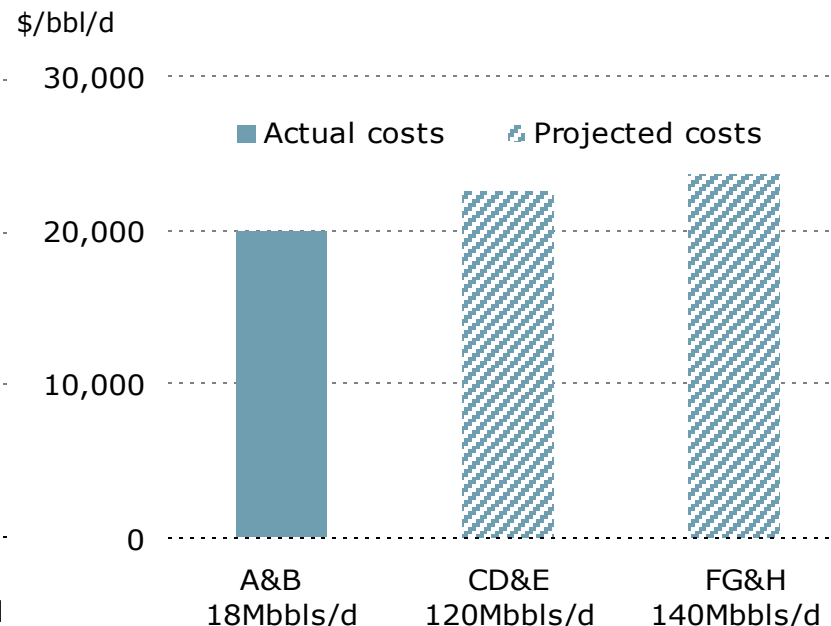
⁴ Approved by regulator.

Leading capital efficiency

Foster Creek



Christina Lake

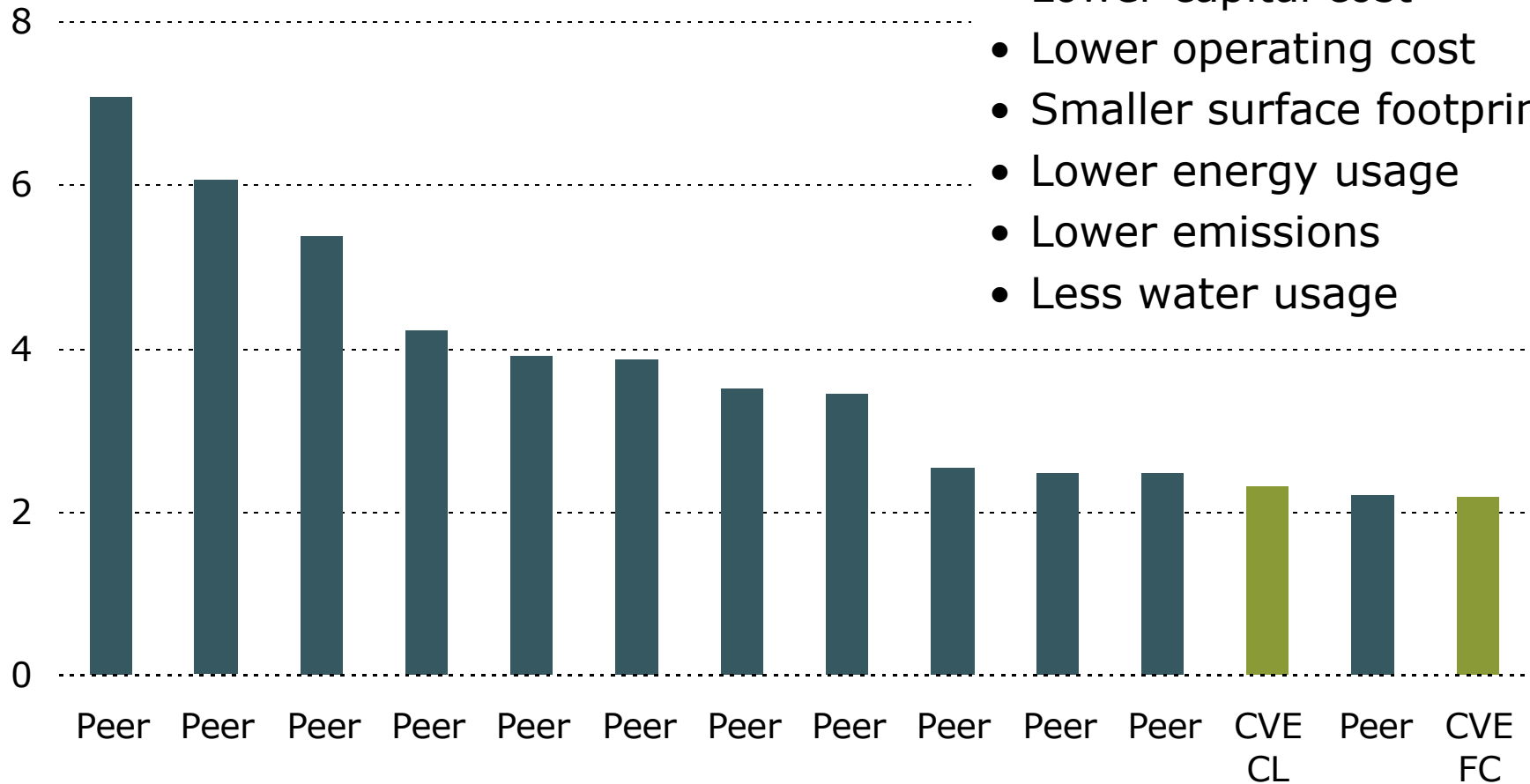


Capital efficiency is calculated based on production design capacity for each phase.

*Foster Creek F,G&H expectations reflect greenfield expansion and design enhancement initiatives.

Reservoir quality drives performance

Steam-to-oil ratio
(bbl/bbl)



Low SOR means

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

Peers include: CNQ, COP, CLL, DVN, HSE, IMO, JACOS, MEG, NXY, RDS, SU.
Source: ERCB public domain data, November 2010 – October 2011.

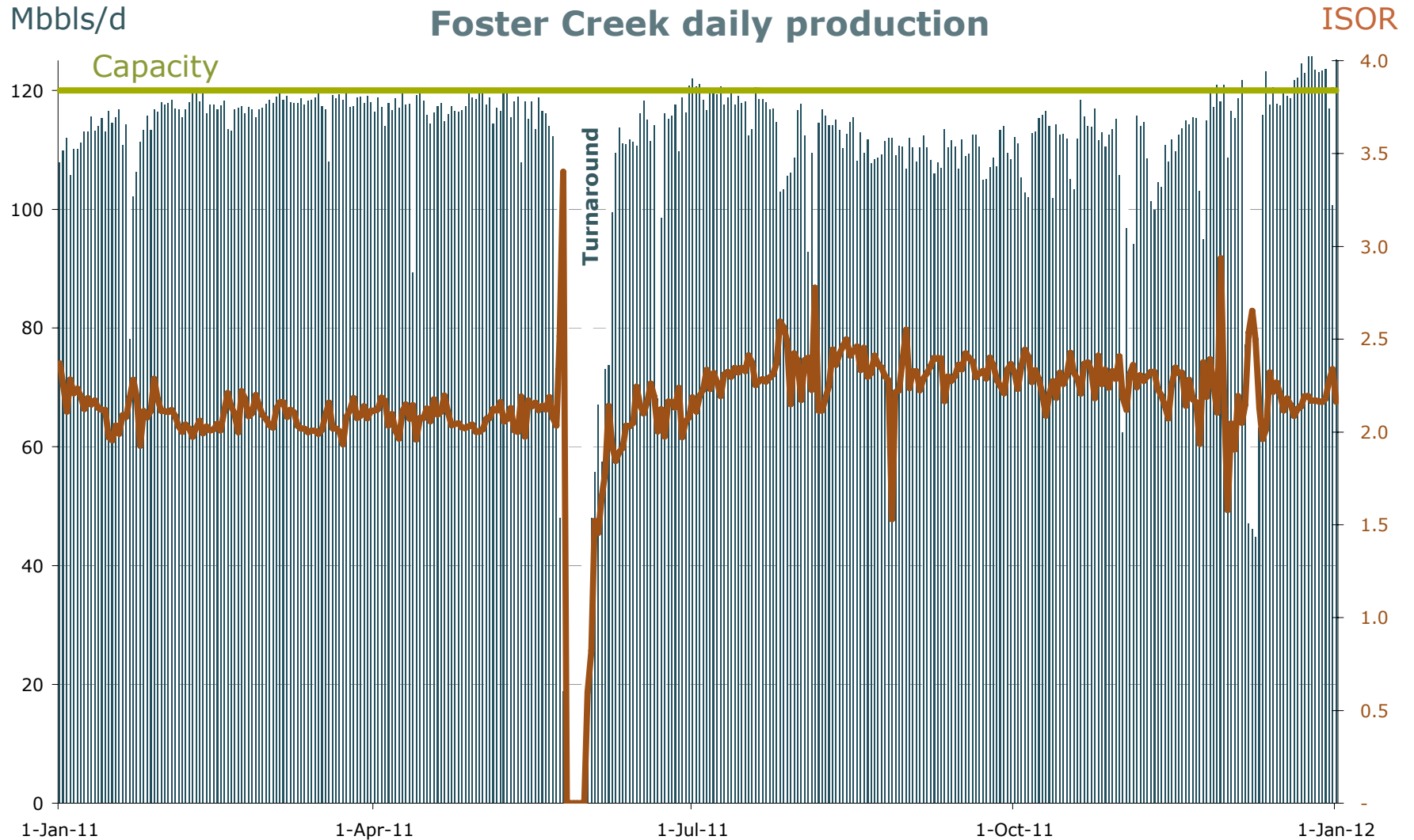
2012F – oil sands



	Foster Creek	Christina Lake
Production (Mbbbls/d)	53 – 57	26 – 29
Capital (\$ MM)	\$650 – \$700	\$475 – \$575
Operating costs (\$/bbl)	\$11.25 – \$12.45	\$13.00 – \$14.35
SOR	2.0 – 2.2	1.9 – 2.1

Forecasts shown are net to Cenovus based on December 7, 2011 guidance document.

Focusing on operational excellence



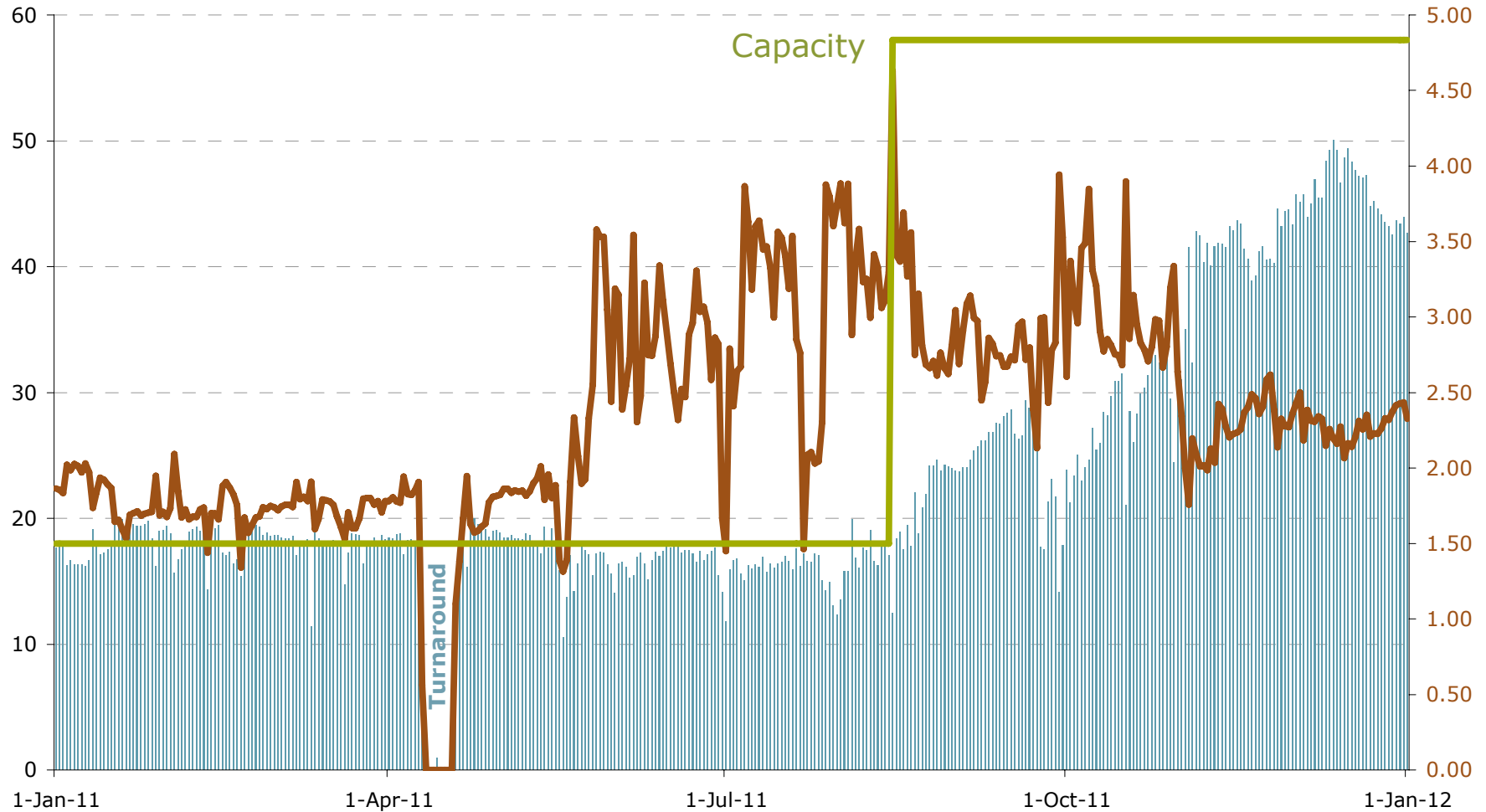
Production is shown on a gross basis.

Improving start-up performance

Mbbls/d

Christina Lake phases A, B & ramp up of C

ISOR



Production is shown on a gross basis.

2012F - Pelican Lake



Production (Mbbbls/d)

23 – 26

Capital (\$ MM)

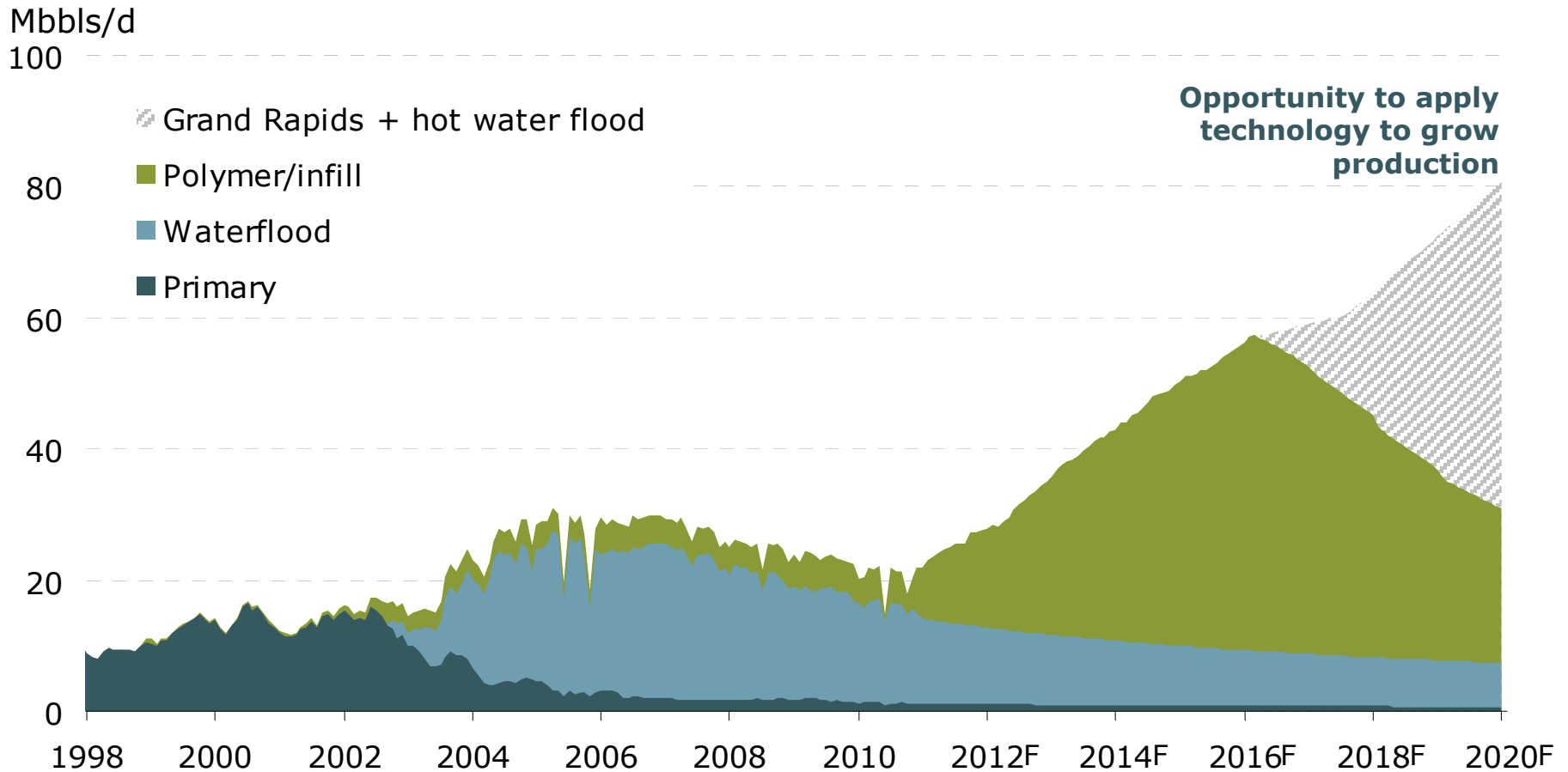
\$525 – \$575

Operating costs (\$/bbl)

\$14.55 – \$16.10

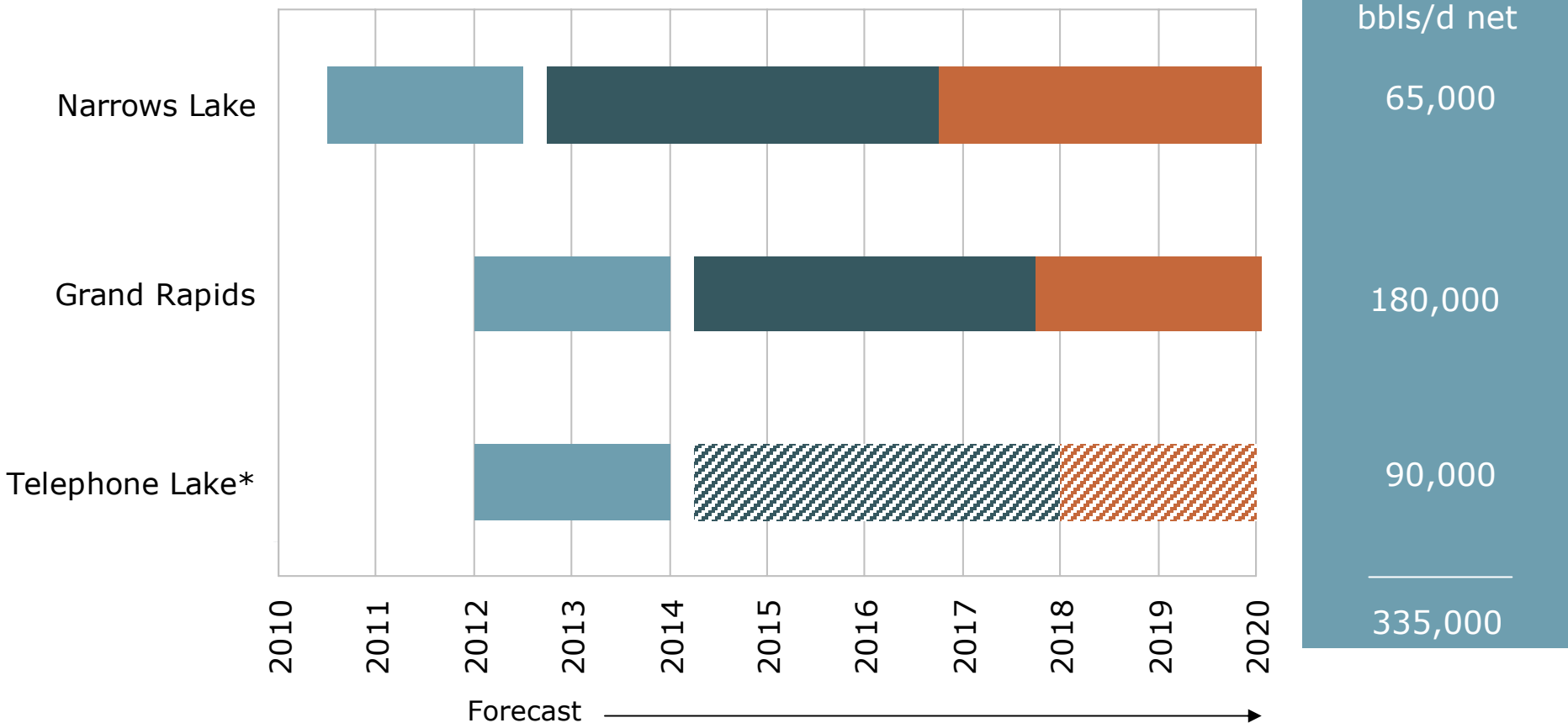
Forecasts based on December 7, 2011 guidance document.

Pelican Lake – tremendous growth opportunity



Volumes are shown before royalties. 2012F based on midpoints of December 7, 2011 guidance document. 2013F through 2020F based on future price assumptions as noted in the advisory.

Advancing our emerging projects



Steam and production includes ~6 months initial steaming with no production followed by 12 - 18 month production ramp up. Timing subject to regulatory approval and project sanction.

*Timeline subject to change; production not currently included in 10-year plan.

Managing our conventional assets

2012 objectives:

- Growing liquids production by 17%
- Expanding conventional oil
- Optimizing natural gas
 - minimal natural gas investment, strong cash flow
- Improving reliability
 - Bakken & Shaunavon centralized facilities & pipeline connected
- Increasing recoveries
 - down spacing
 - water flood
 - ASP & CO₂ floods



Cenovus land at December 31, 2011.

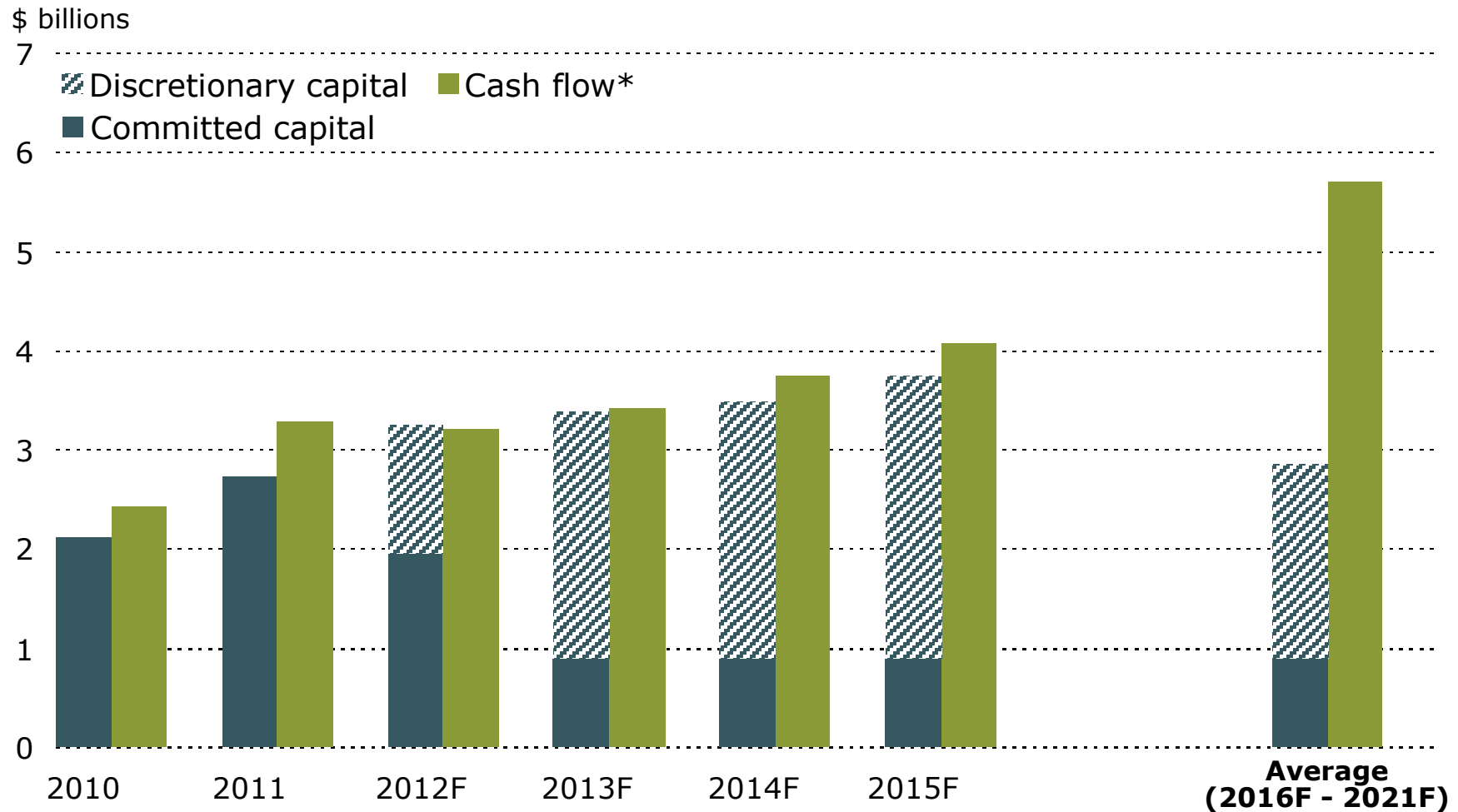
Refining assets are key to integration

- Wood River
 - 306 Mbbls/d crude capacity
 - 200 - 220 Mbbls/d heavy crude
 - 85% clean product yield
- Borger
 - 146 Mbbls/d crude capacity
 - 35 Mbbls/d heavy crude
 - 89% clean product yield
- 2012F operating cash flow* of \$300 - \$600 MM



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

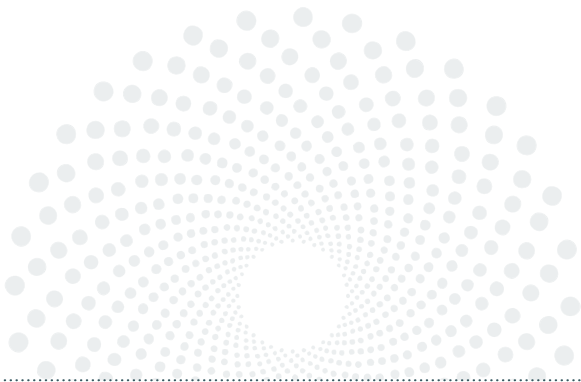
Building flexibility into capital programs



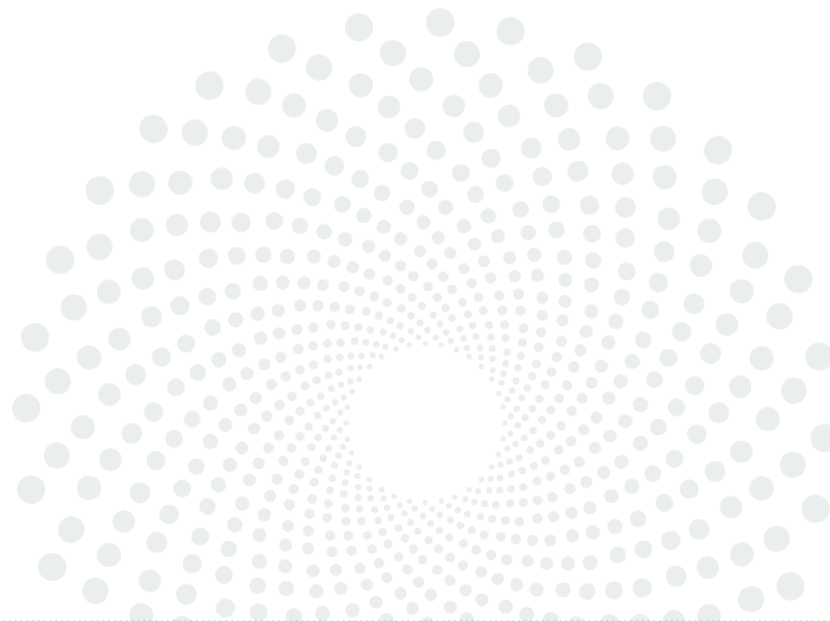
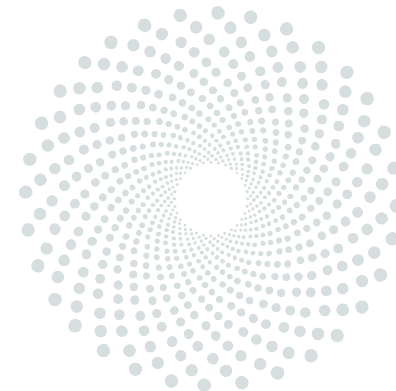
2012F based on commodity price assumptions outlined in the December 7, 2011 guidance document. 2013F through 2021F based on future price assumptions as noted in the advisory.

*Non-GAAP measure. See advisory.

Focused on increasing total shareholder return



Supplemental information



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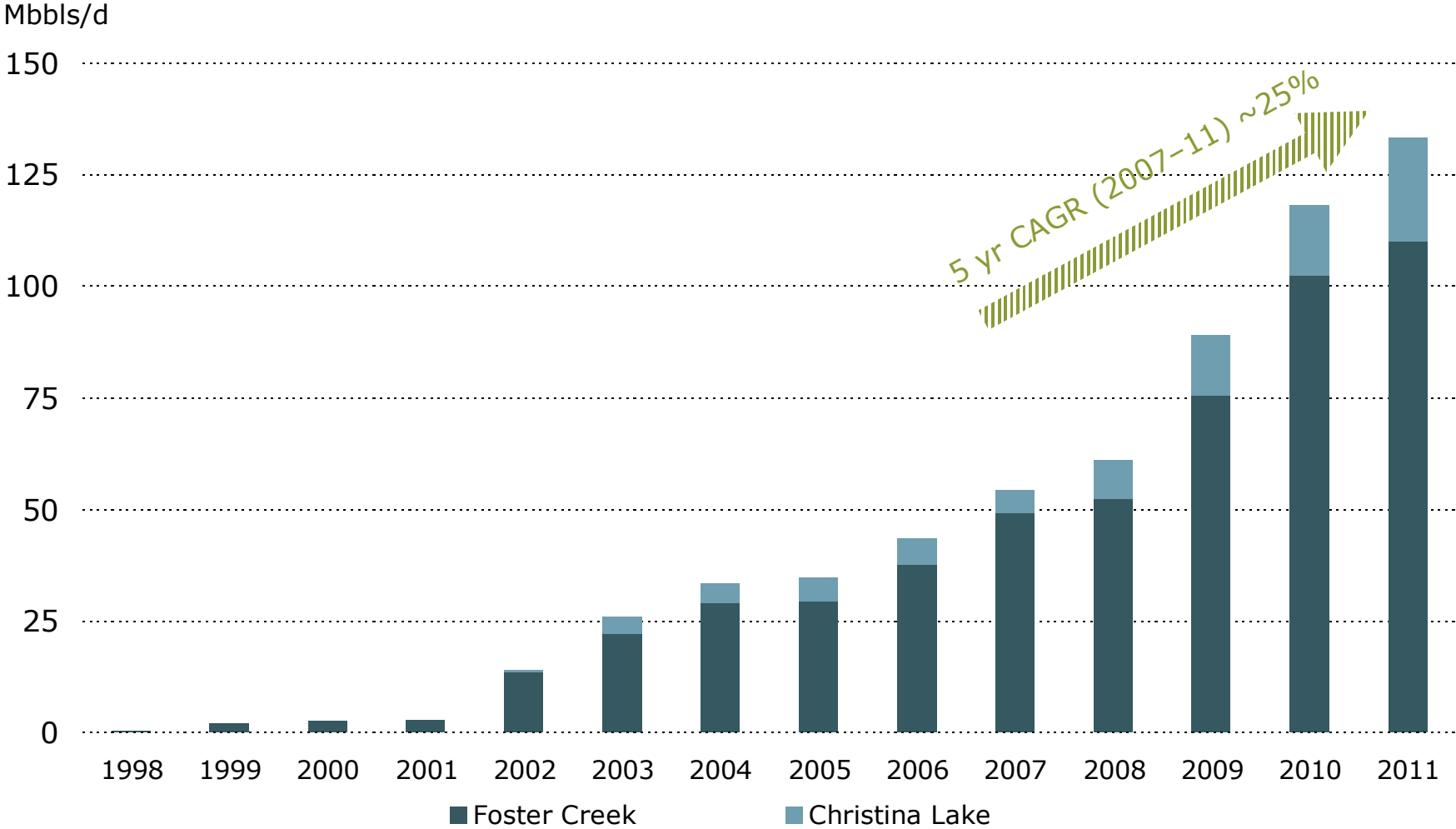
Cenovus's value pledge

- Deliver on commitments
- Achieve step change in net asset value
- Sustain decades of growth with manufacturing model



Focused on increasing total shareholder return

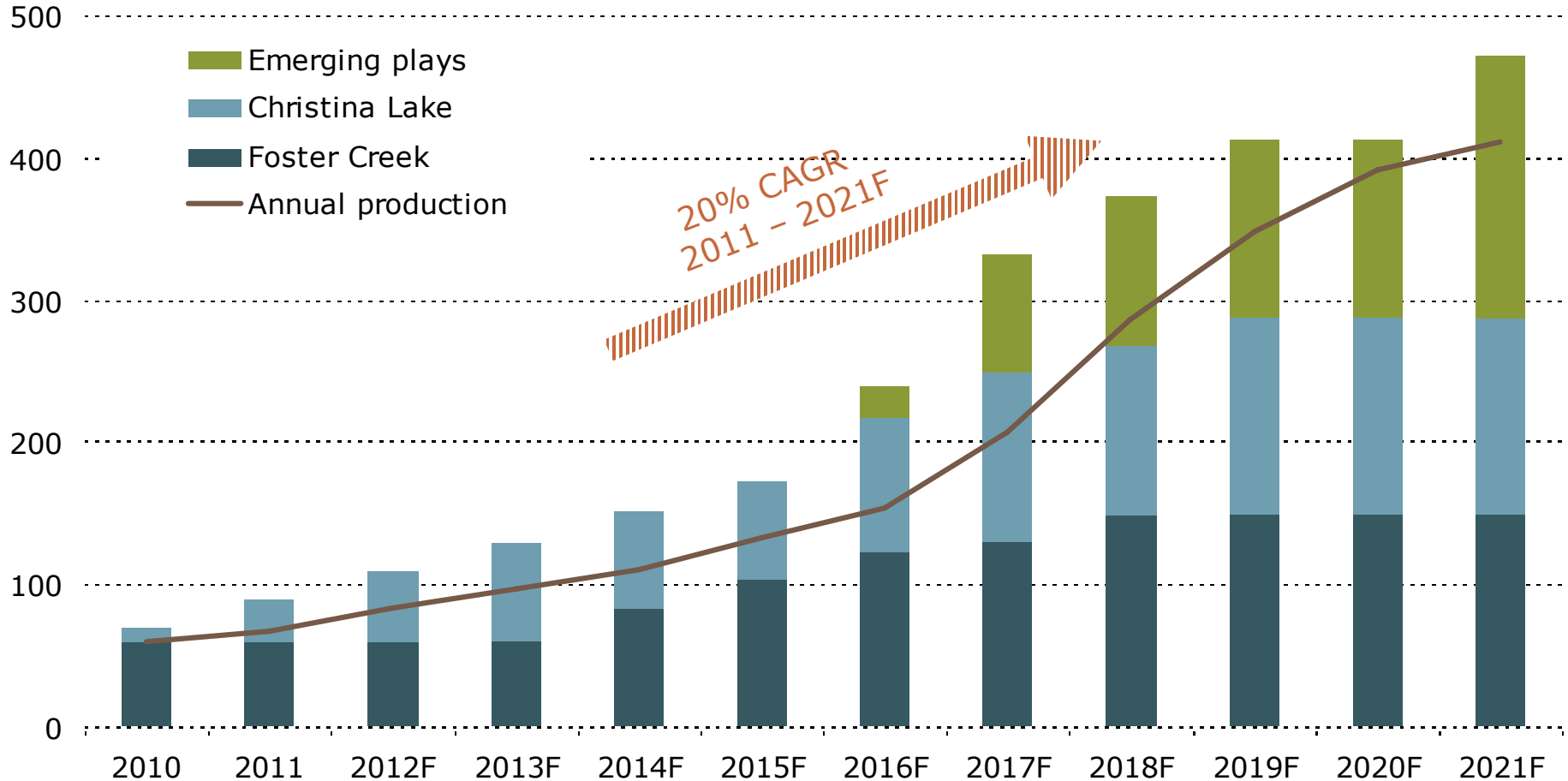
Cenovus SAGD operating experience



Production is shown before royalties and on a gross basis.

Growing bitumen

Year-end production capacity (Mbbbls/d)



Volumes are shown before royalties and net to CVE. 2012F based on midpoints of December 7, 2011 guidance document. 2013F through 2021F based on future price assumptions as noted in the advisory. Forecast volumes are estimates only and subject to regulatory and partner approvals. See advisory.

Delivering on our commitments

2011

Q1

Added significant reserves & contingent resources



Executed strat well program: 440 wells



Q2

Sanctioned Foster Creek F, G & H



Received results from 2011 strat well & seismic programs



Updated 10-year strategic plan



Received regulatory approval for Christina Lake E, F & G



Q3

Achieved first production at Christina Lake C



Sanctioned Christina Lake E



Achieved Grand Rapids SAGD pilot first oil



Q4

Completed start up of CORE project at Wood River



Submitted Grand Rapids application



Submitted revised Telephone Lake application



Advancing oil growth with strong execution

2012F

Q1

Disclose 2011 reserves & contingent resource ✓

Execute seismic & strat well program

Establish Telephone Lake dewatering pilot

Provide update on Telephone Lake & area strategic commercial initiative

Connect Shaunavon & Bakken central facilities to pipeline

Q2

Demonstrate stable & reliable CORE operation

Achieve production growth response from Pelican Lake expansion

Receive regulatory approval & initiate sanctioning for Narrows Lake A, B & C*

Q3

Pursue additional oil growth opportunities from conventional oil

Q4

Achieve first production at Christina Lake D

Start construction of Narrows Lake A

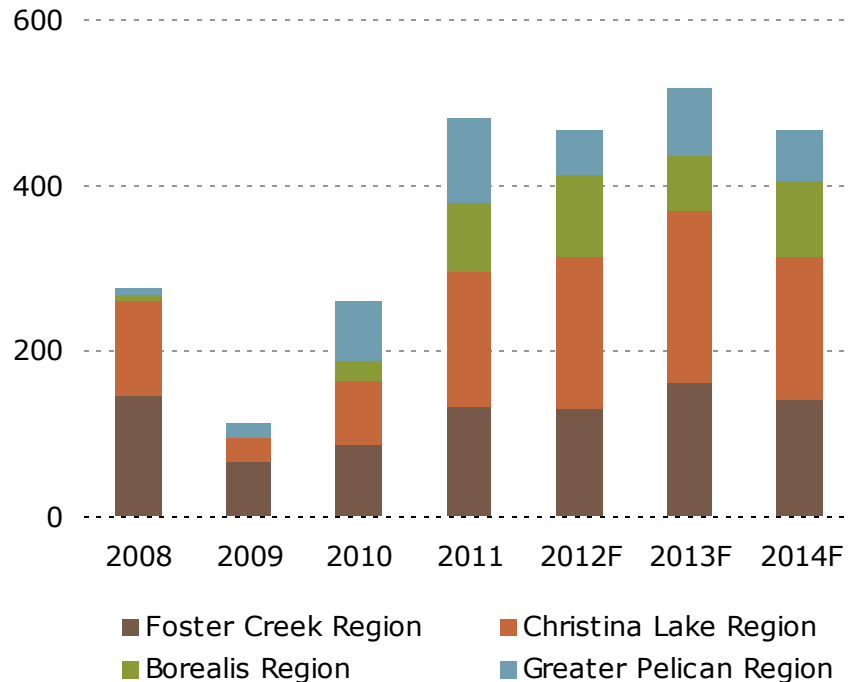
*Represents expected timelines subject to regulatory and/or partner approvals.

Generating sustainable growth for decades

- Increased resource base
- Evolved technology to build value
- Improved our execution

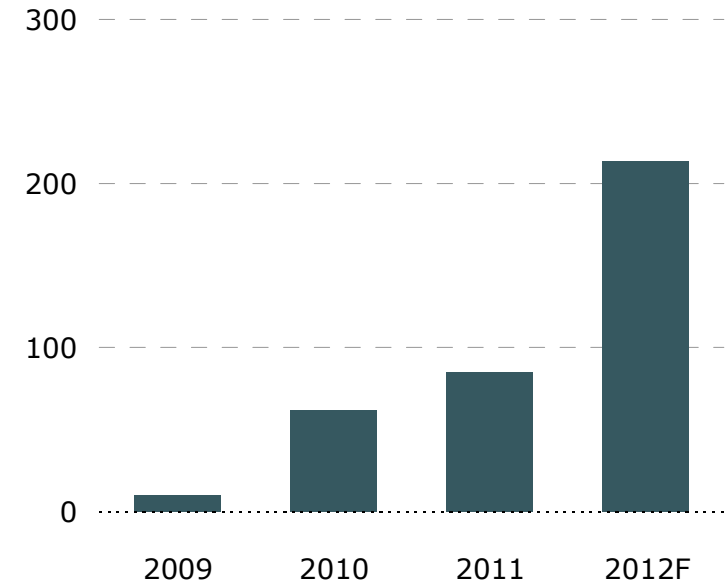
Stratigraphic well programs

strat wells

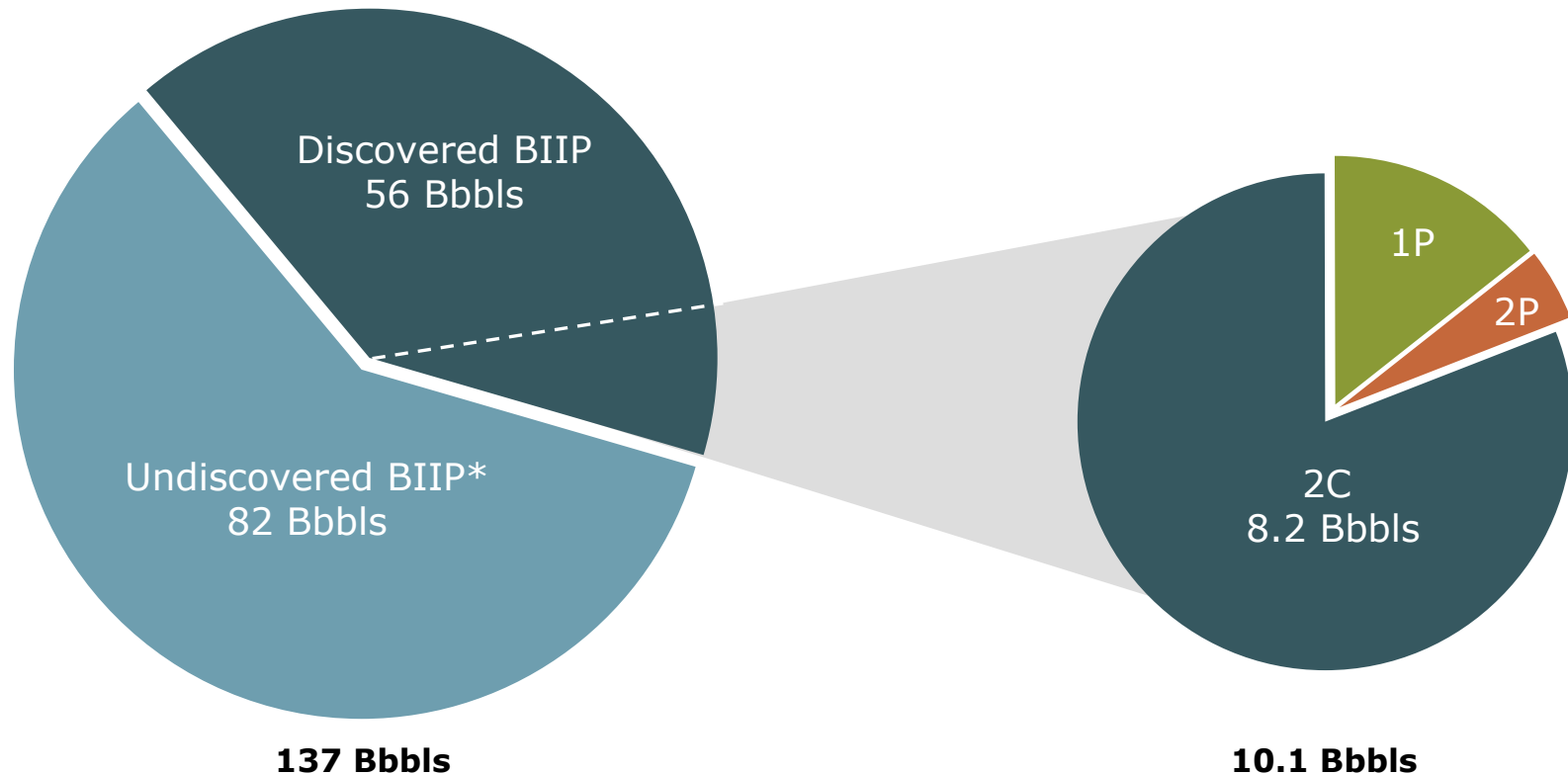


Investment in technology

\$MM



Building NAV by converting resources



*Undiscovered BIIP is unrisked. Volumes are shown before royalties and on a net basis.

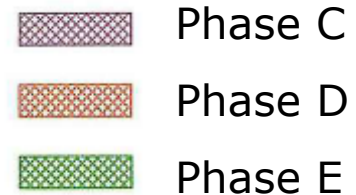
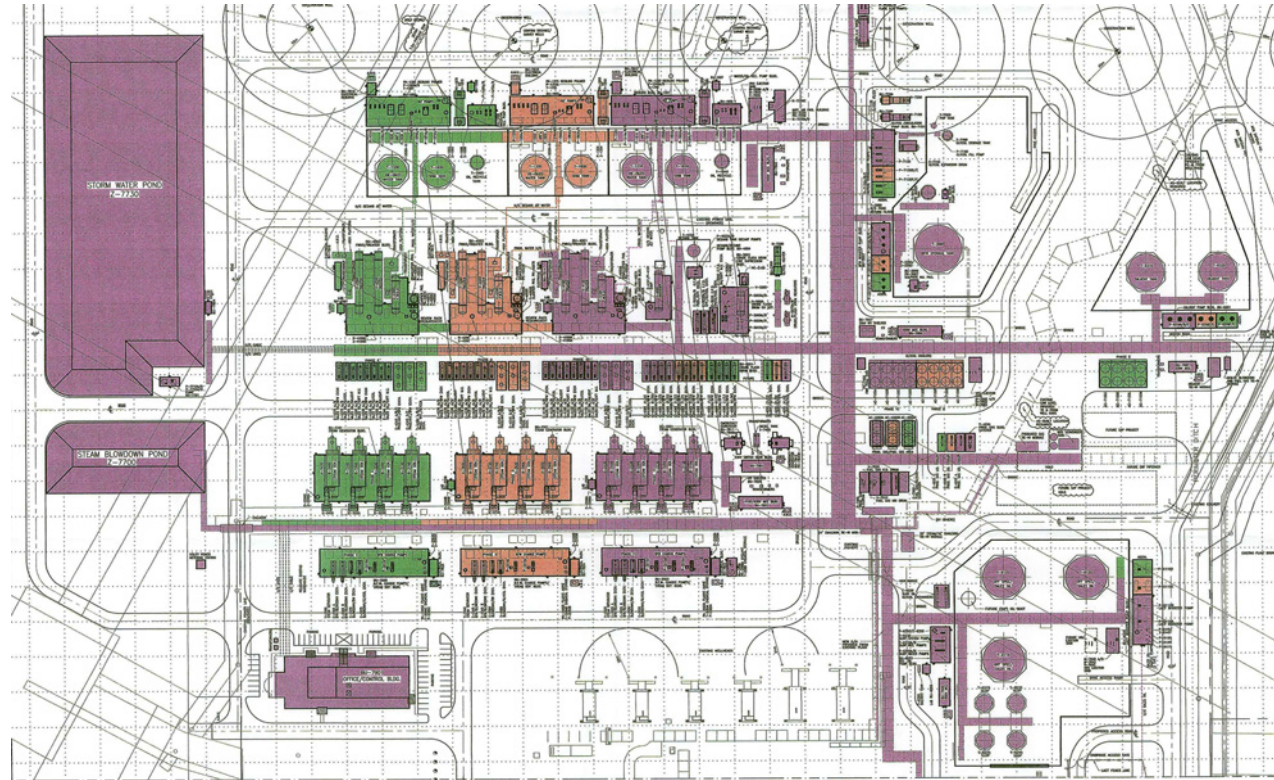
Applying manufacturing expertise

- Utilize dedicated in-house construction management teams
- Employ multiple small contractors
- Develop projects in staged, manageable phases
- Operate assembly-line drilling & completions
- Reduce execution timeline through increased development efficiency



Phased design approach

- Template design – 4 boiler packages
 - same for Foster Creek and Christina Lake
- Generally 3 phases designed together
- First project construction takes ~30 months
 - following 2 phases follow 12 months apart



Putting innovation into practice



Nisku module fabrication yard

Oil sands overview

Foster Creek

- Pilot project began in 1996
- Became the industry's first commercial SAGD project in 2001
 - largest producing SAGD operation in Alberta
- Pioneered use of Wedge Well™ technology
- Achieved royalty payout in Feb 2010
- Total planned capacity between 290,000 and 310,000 bbls/d

Christina Lake

- Pilot project began in 2000
- First production in 2002
- Total planned capacity of ~278,000 bbls/d

Volumes are shown on a 100% basis.

Oil sands project comparison

	Foster Creek	Christina Lake	Narrows Lake	Grand Rapids	Telephone Lake
Working interest	50%	50%	50%	100%	100%
Potential size (Mbbbls/d gross)	290 – 310	278	130	180	90
Design SOR	2.1	1.7	2.1 SAGD 1.6 SAP	3.0 – 3.5	2.1
Best estimate contingent resource (Bbbls)	0.9	1.1	0.4	1.6	2.1
Supply cost (US\$/bbl WTI)	35 – 45	40 – 50	45 – 55	55 – 65	55 – 65
Core area well density (wps)	8 – 26	8 – 40	11 – 26	1 – 8	0 – 16
Land position (net acres)	70,720	19,840	12,960	64,750	146,560

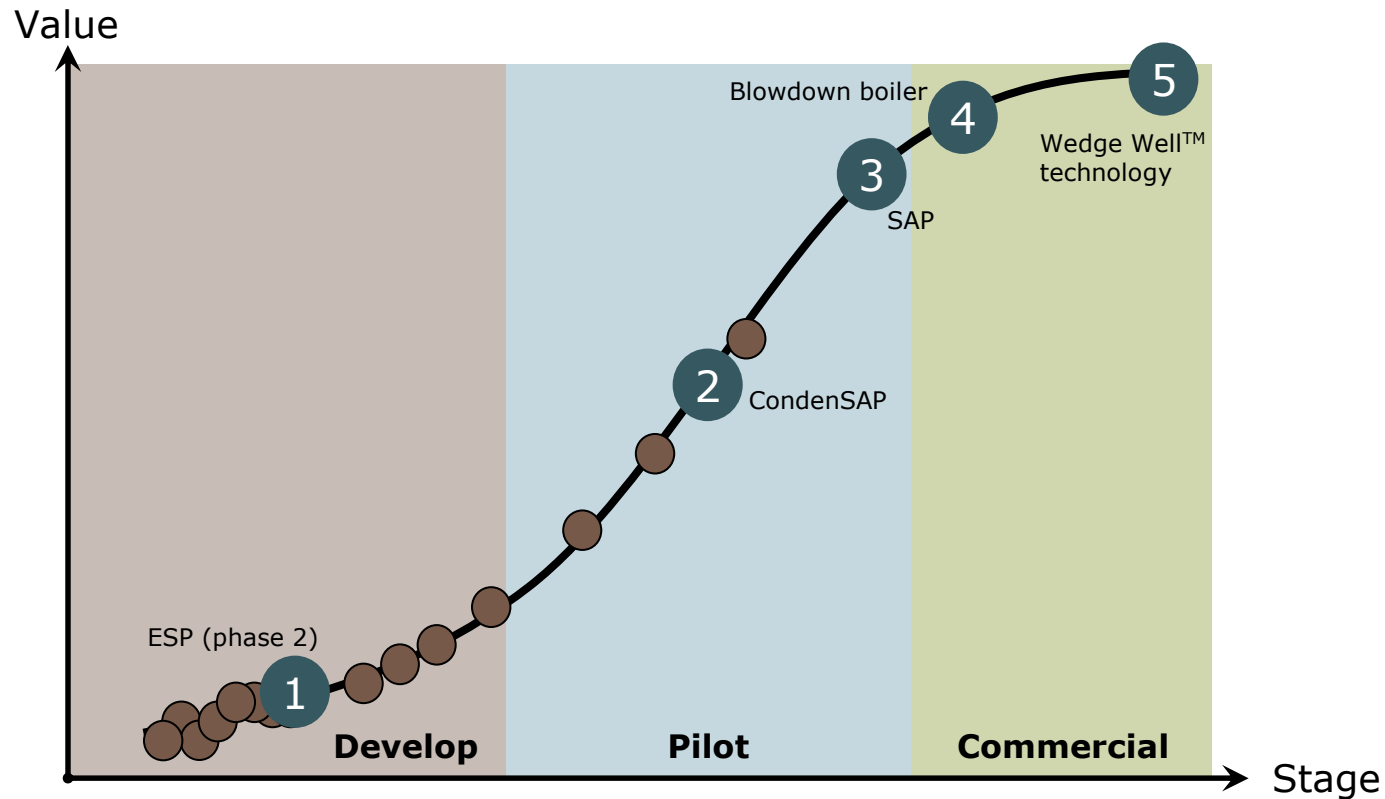
Updated bitumen contingent resources

Best estimate bitumen economic contingent resources (Billion bbls)				
		2011	2010	2009
Foster Creek	Total region	0.9	0.8	0.8
Christina Lake	Core & other areas	0.4	0.4	0.4
	Narrows Lake	0.4	0.5	0.5
	Winefred Lake	0.7	0.4	0.3
Borealis	Telephone Lake	2.1	2.0	1.8
	Steepbank & East McMurray	2.0	0.8	0.7
Pelican Lake	Grand Rapids	1.6	1.3	0.9
Total		8.2	6.1	5.4

Totals may not add due to rounding.

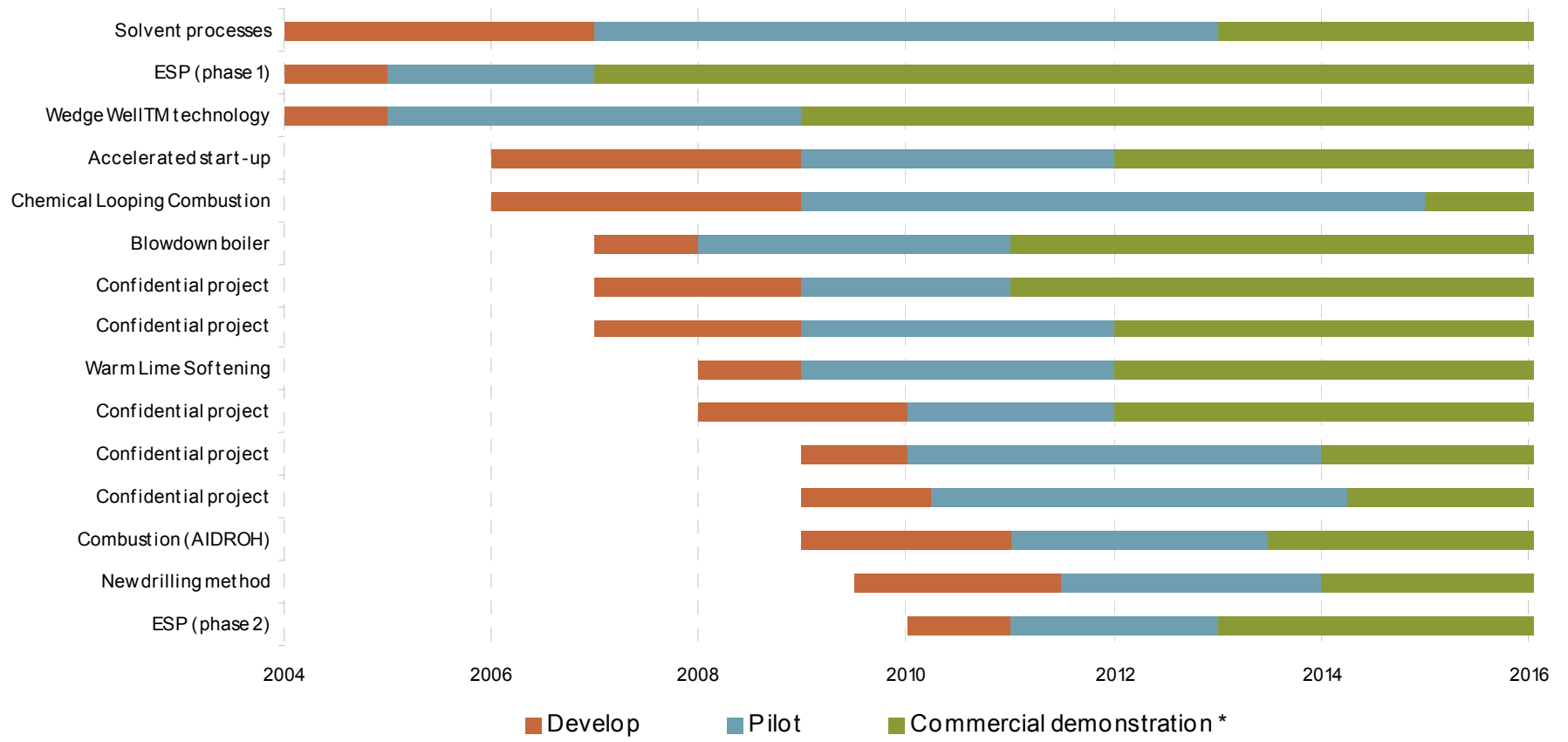
¹ For the definition of contingent resources, economic contingent resources and best estimate and a description of the contingencies associated with Cenovus's economic contingent resources, please see the Advisory. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

Developing technology to build value



1. ESP (phase 2) – early stage enhancement of pump technology
2. CondenSAP – a condensate based Solvent Aided Process
3. SAP – butane based, being piloted at Christina Lake, commercial plans for Narrows Lake
4. Blowdown boiler – part of all future template designs, makes more steam per mcf of gas used
5. Wedge Well™ technology – commercialized at Foster Creek

Commercializing one technology per year

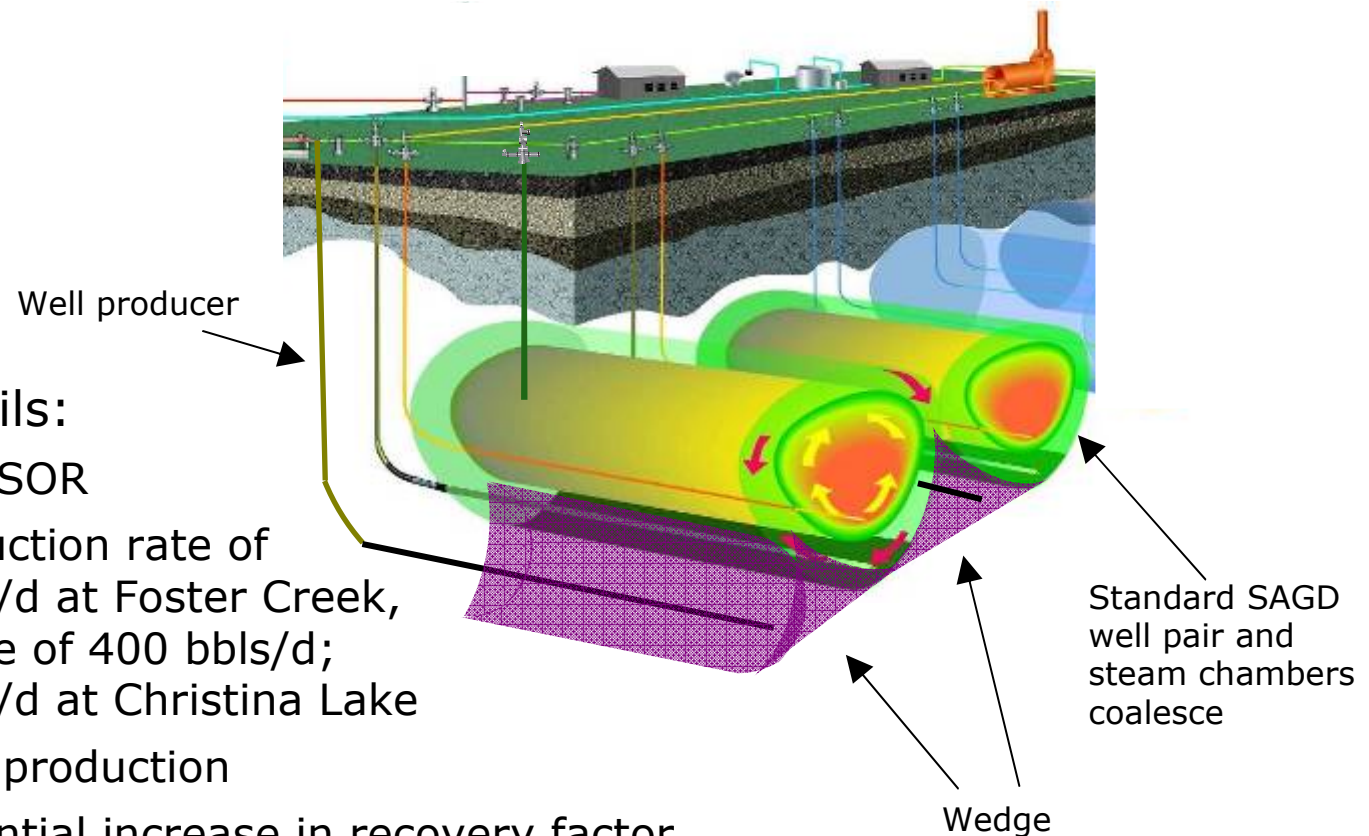


*Commercial demonstration may take up to 4 years to become part of mainstream process.

Wedge Well™ technology commercialized in 2010

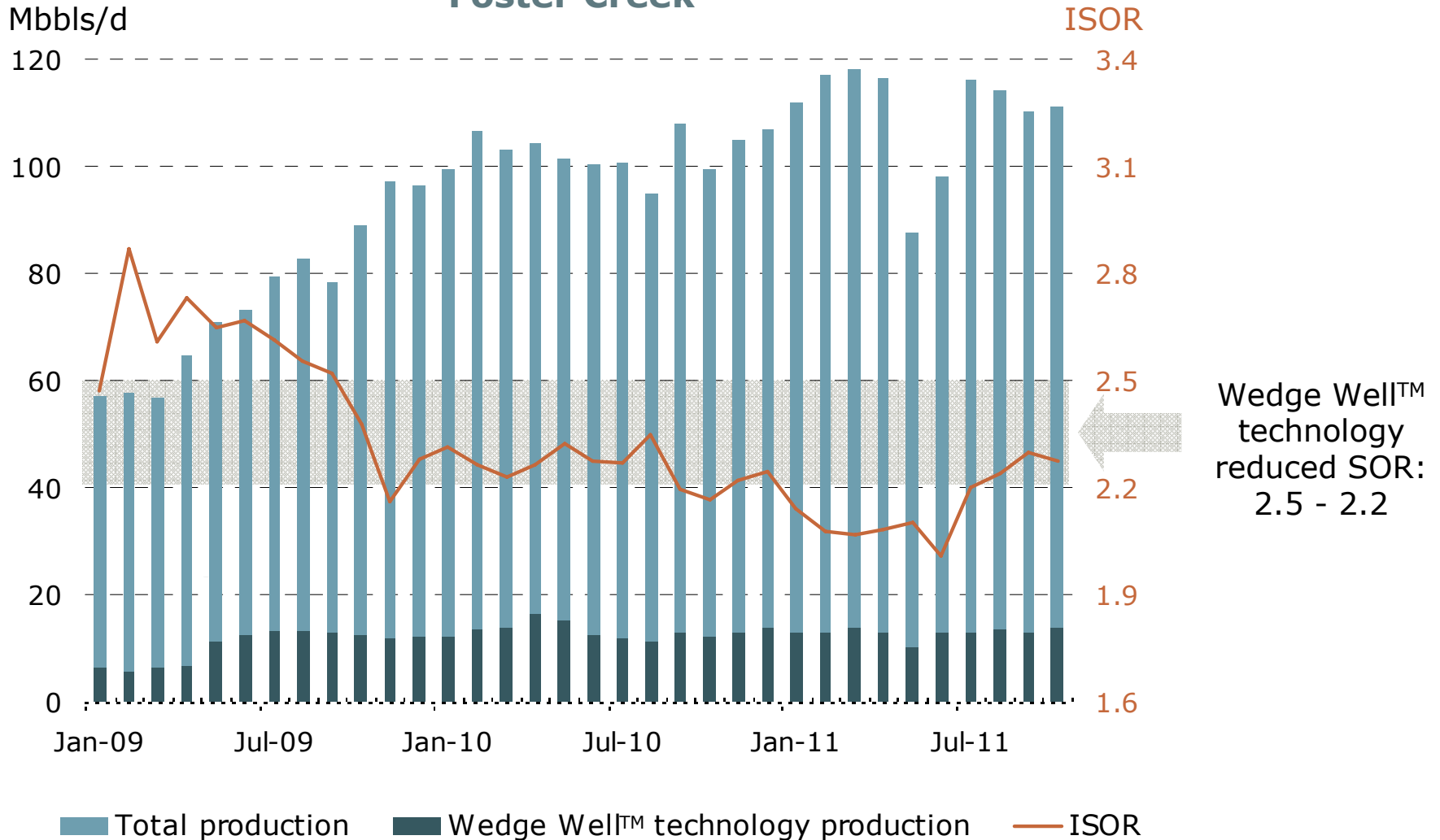
- Technology details:

- < 0.1 average SOR
- first year production rate of 600 – 800 bbls/d at Foster Creek, current average of 400 bbls/d; 300 – 400 bbls/d at Christina Lake
- acceleration of production
- 10 – 15% potential increase in recovery factor
- Foster Creek wells – 41 producing
- Christina Lake wells – 4 producing



Technology improves performance

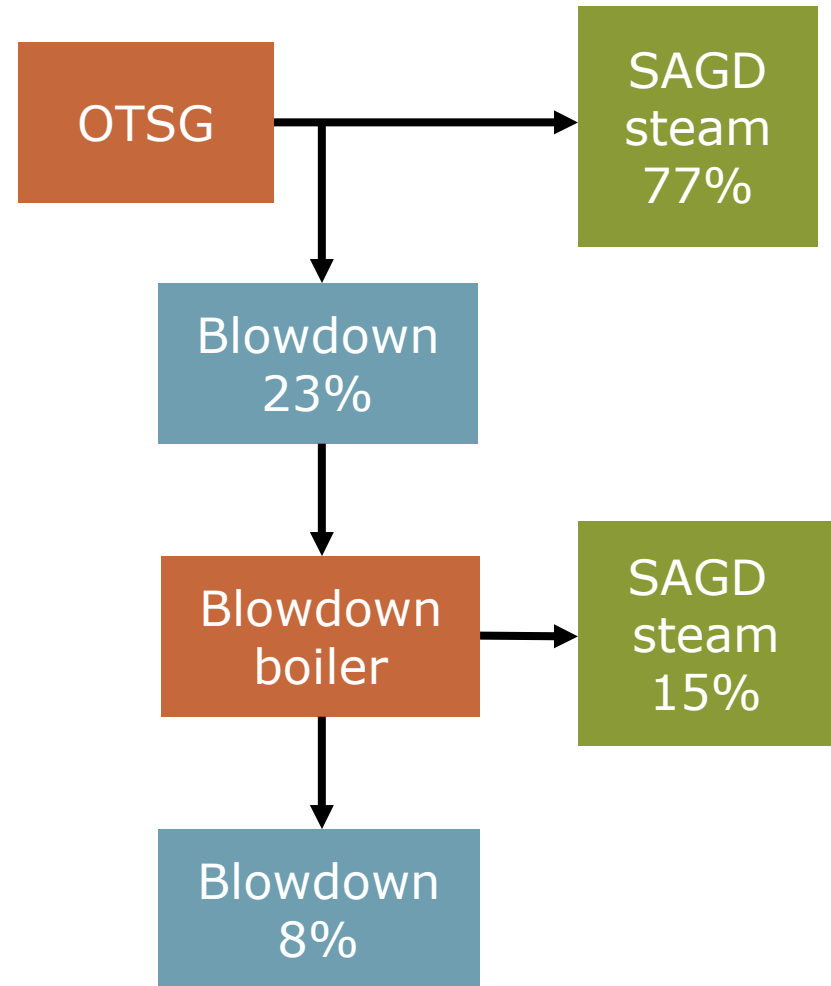
Foster Creek



Wedge Well™
technology
reduced SOR:
2.5 - 2.2

Blowdown boiler commercialized in 2011

- Utilizes boiler water (blowdown) as feed water for second boiler
- Generates more steam from the same water
- Improves heat recovery
- Lowers operating costs & emissions
- Improves steam quality from ~77% to ~92%



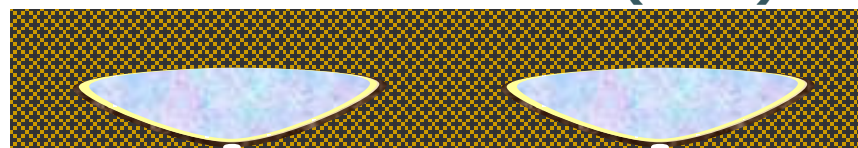
Cenovus's Solvent Aided Process (SAP)

- SAP versus SAGD metrics
 - 30% production rate improvement
 - 15% incremental total oil recovery
 - 3% reduction in annual fuel gas usage
 - 0.05 bbls solvent (butane) purchased per bbl bitumen
 - 30% increase to initial capital
 - 10% decrease in annual sustaining capital
 - 5 – 10% reduction in non-fuel operating cost
 - ~\$1.00/bbl netback uplift
- Environmental benefits
 - lower SOR & emission intensity
 - lower water usage & footprint

Steam only (SAGD)



Steam & solvent (SAP)



Milestones		
2000 – 2001	Senlac SAP pilot	✓
2004 – 2005	Christina Lake SAP pilot	✓
2009 – 2011F	Christina Lake isolated test	✓
2010	Q2 SAP & SAGD Narrows Lake	✓

2012F – conventional oil & natural gas



	Oil & liquids	Natural gas
Production	53 – 59 Mbbls/d	575 – 600 MMcf/d
Capital (\$ MM)	\$660 – \$725	\$80 – \$90
Operating costs	\$14.65 – \$16.25/bbl	\$1.15 – \$1.30/Mcf

Forecasts shown are net to Cenovus based on December 7, 2011 guidance document.

Conventional oil highlights

- Focus on drilling program
- Connect key plays to centralized facilities & pipelines
- Shaunavon – 42 wells
 - initiate down-spacing & waterflood pilots
- Bakken – 4 wells
 - initiate water-flood & CO2 pilots
- Alberta tight oil – 140 wells
 - evaluate potential
- Viking – 21 wells
 - evaluate play



Shaunavon and Bakken overview

Lower Shaunavon

- 54 net sections
- 65 producing wells in 2011
- ~3,500 bbls/d (2011 exit)
- ~5 - 10% recovery factor
- 20 - 25° API medium oil

Bakken

- 140+ undeveloped sections (fee & crown land)
- 19 producing wells in 2011
- ~2,700 bbls/d (2011 exit)
- 40 - 45° API light oil
- ~\$2.0 – 3.0 MM per well (drill, complete, tie-in)



Weyburn gross production history

Mbbls/d

40

30

20

10

0

Jan-75

Jan-85

Jan-95

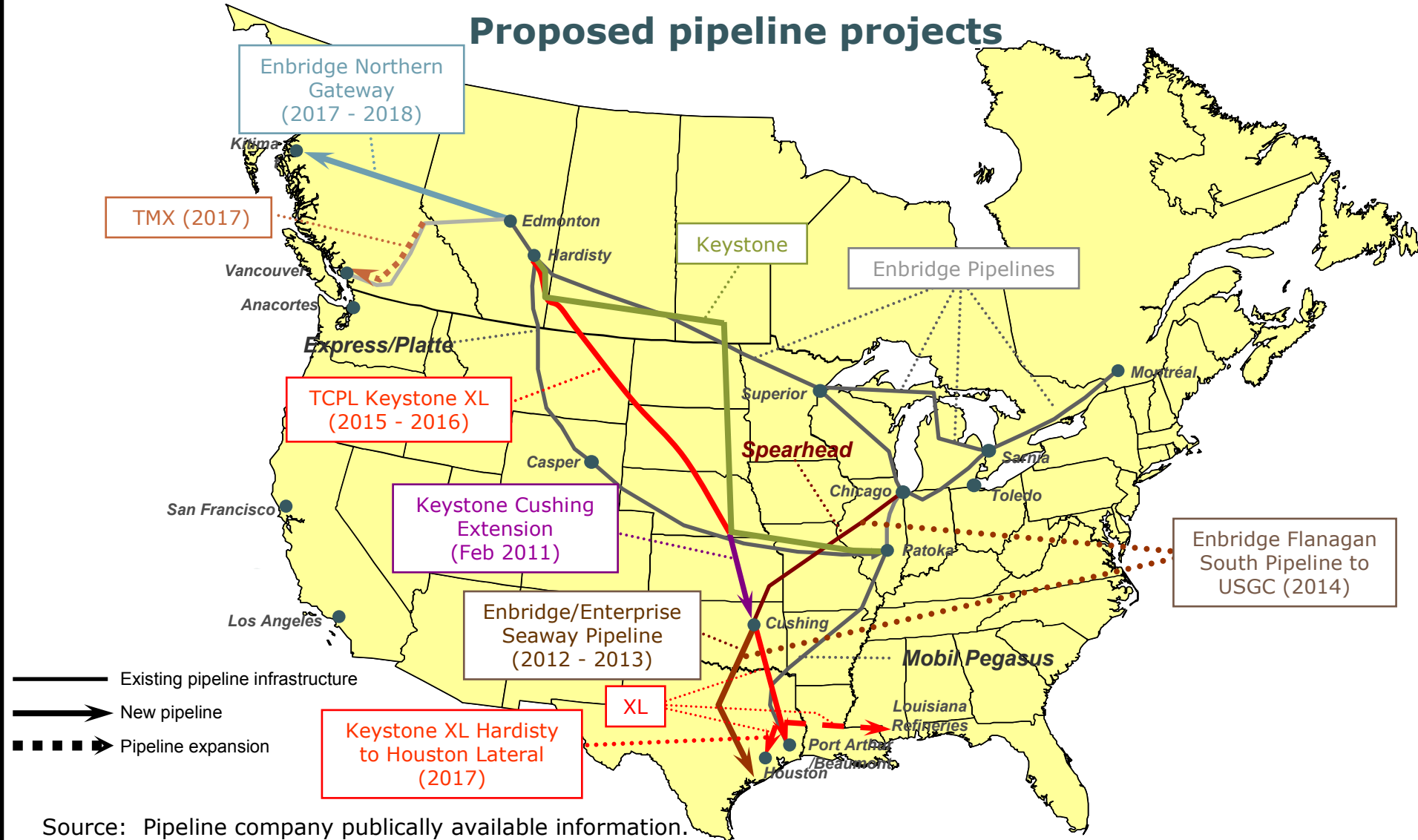
Jan-05

■ Primary & waterflood ■ Vertical infills ■ Pre CO2 Hz infills ■ Waterflood improvement ■ CO2 EOR

EOR = enhanced oil recovery.

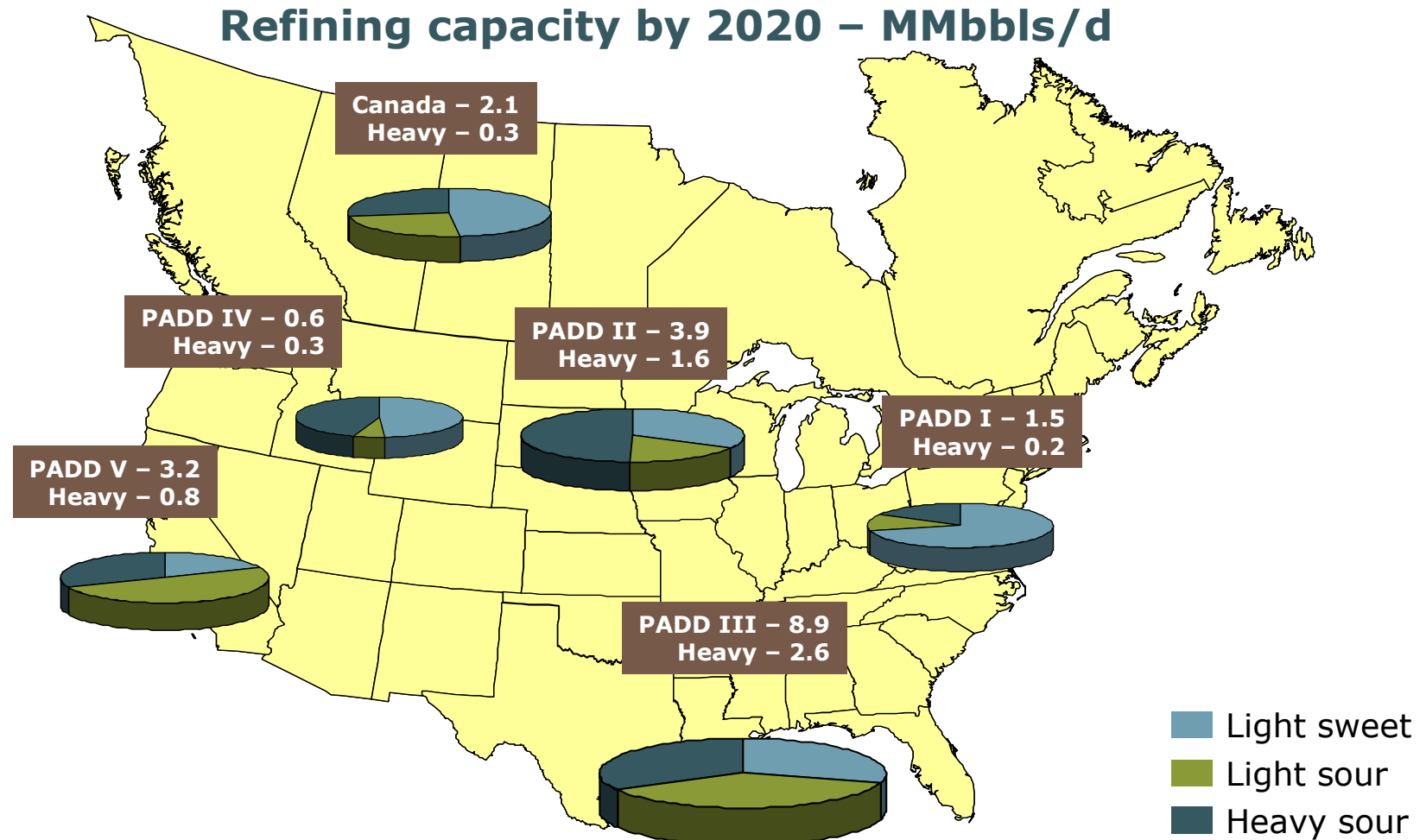
Supporting pipelines to new markets

Proposed pipeline projects



Source: Pipeline company publically available information.

Increasing demand for Canadian heavy crude

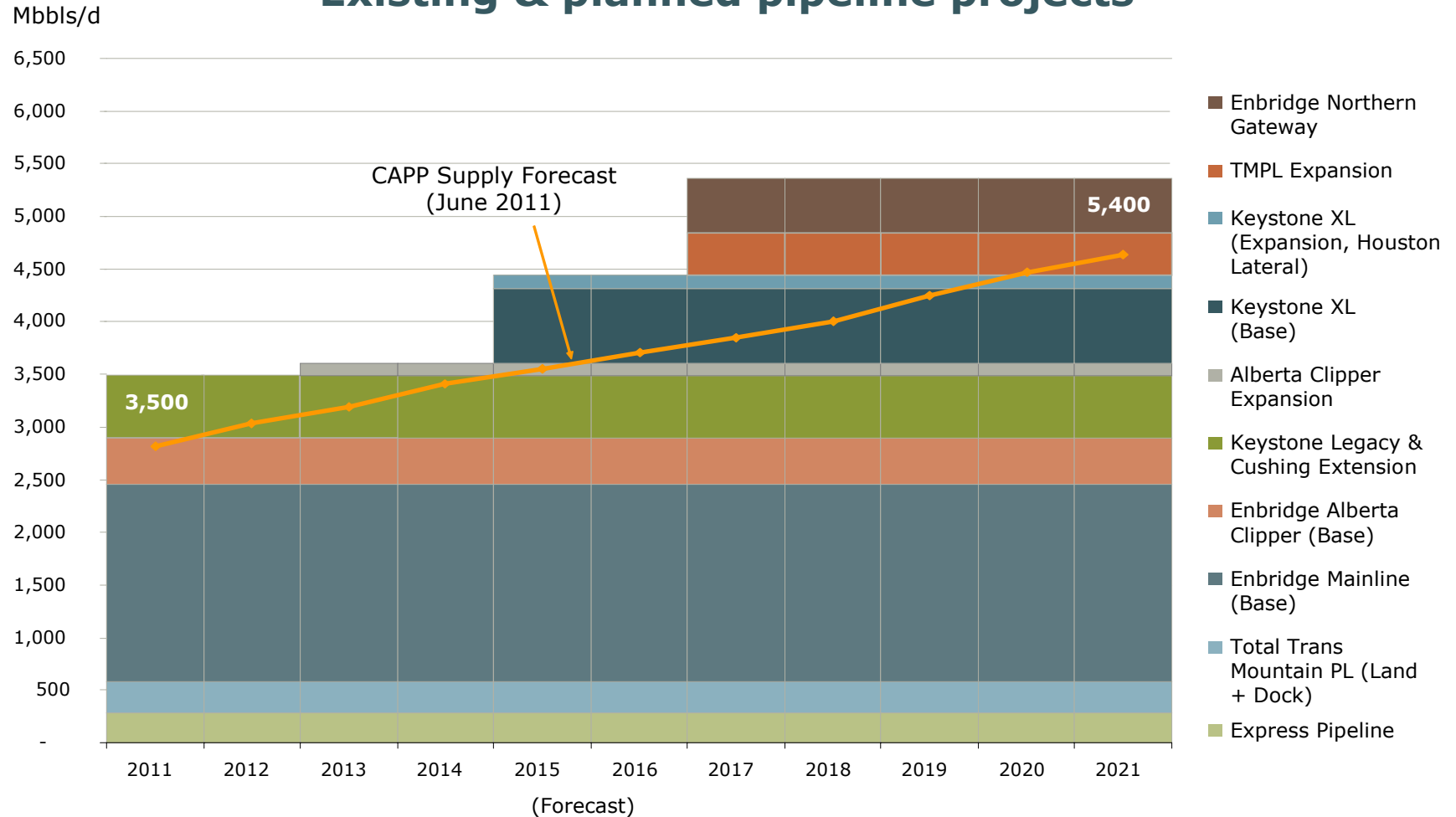


PADD III expected to be the biggest growth market

Source: P&G Crude Oil & Oilsands Outlook 2011.

Pipelines essential to Canadian oil growth

Existing & planned pipeline projects



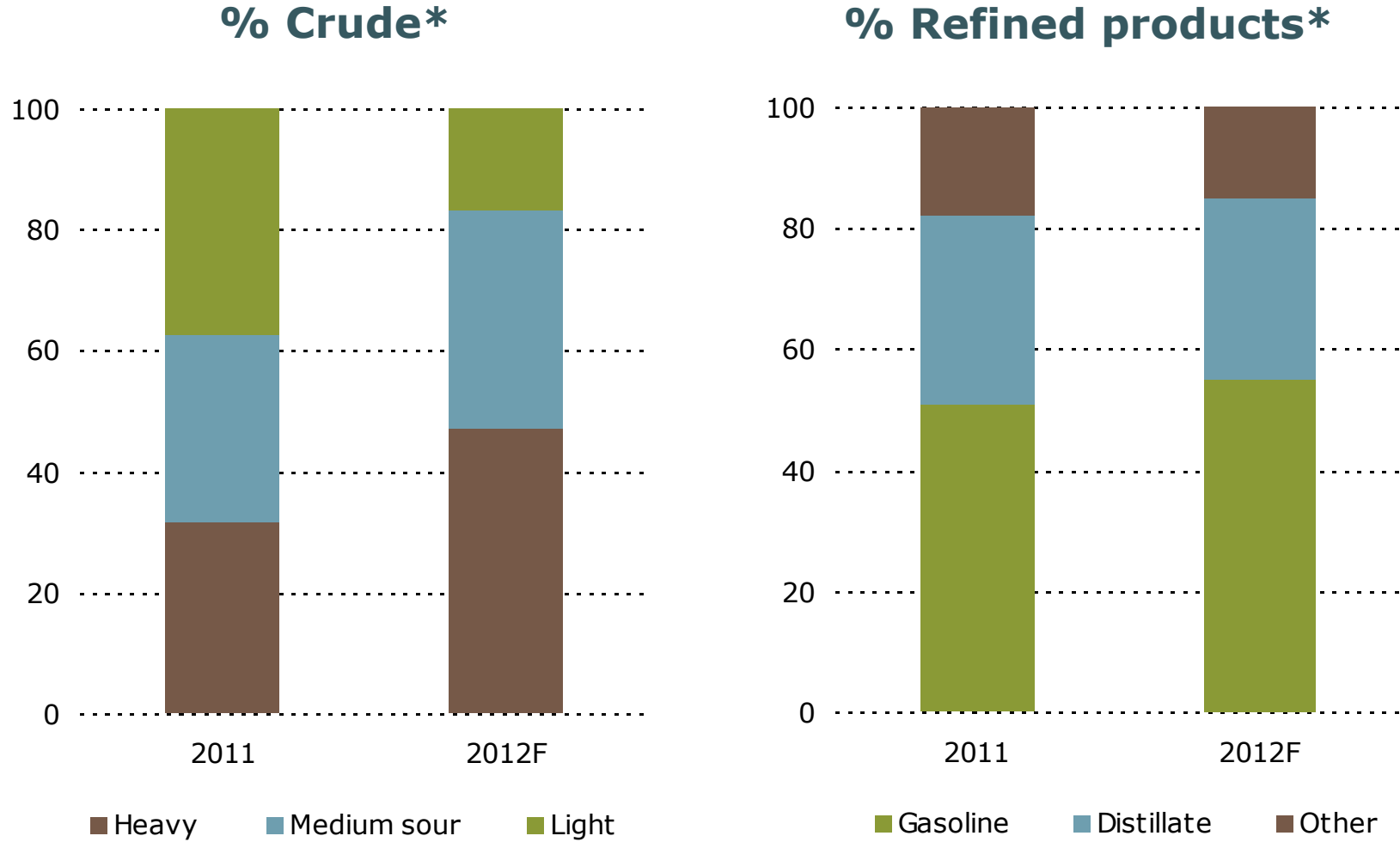
Source: Pipeline company publically available information, CAPP.

CORE completion adds significant value

- Objectives
 - leverage Wood River's strategic location
 - become a major processor of bitumen-blended heavy oil
- Value drivers
 - reduces input costs
 - increases clean product yield
 - reduces asphalt production
 - increases crude throughput
- Platform for future growth

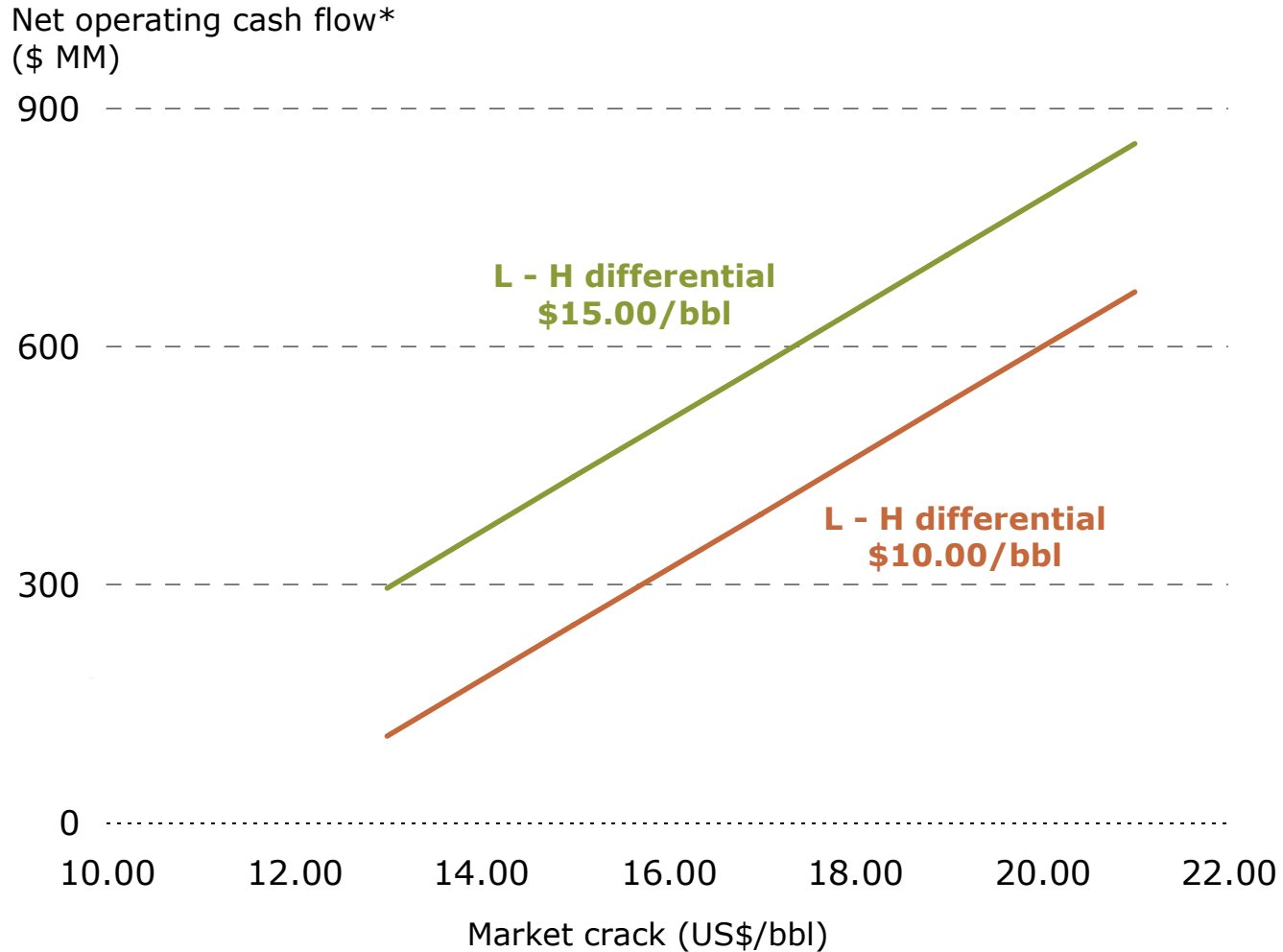


Increasing heavy oil processing & clean product yield



*Illustrative crude slates and product yields. Includes Wood River and Borger refineries.

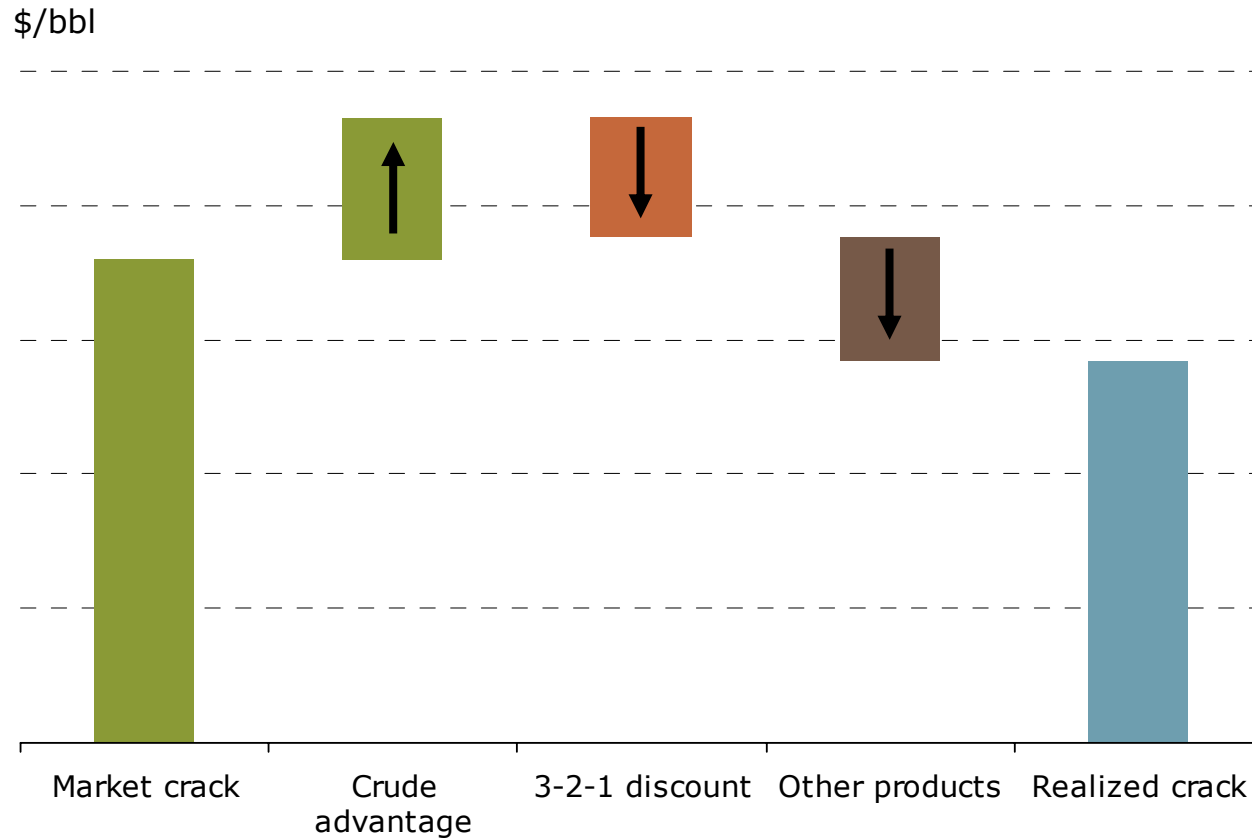
2012 refinery margin sensitivities



Based on US\$90.00/bbl WTI.

*Non-GAAP measure. See advisory.

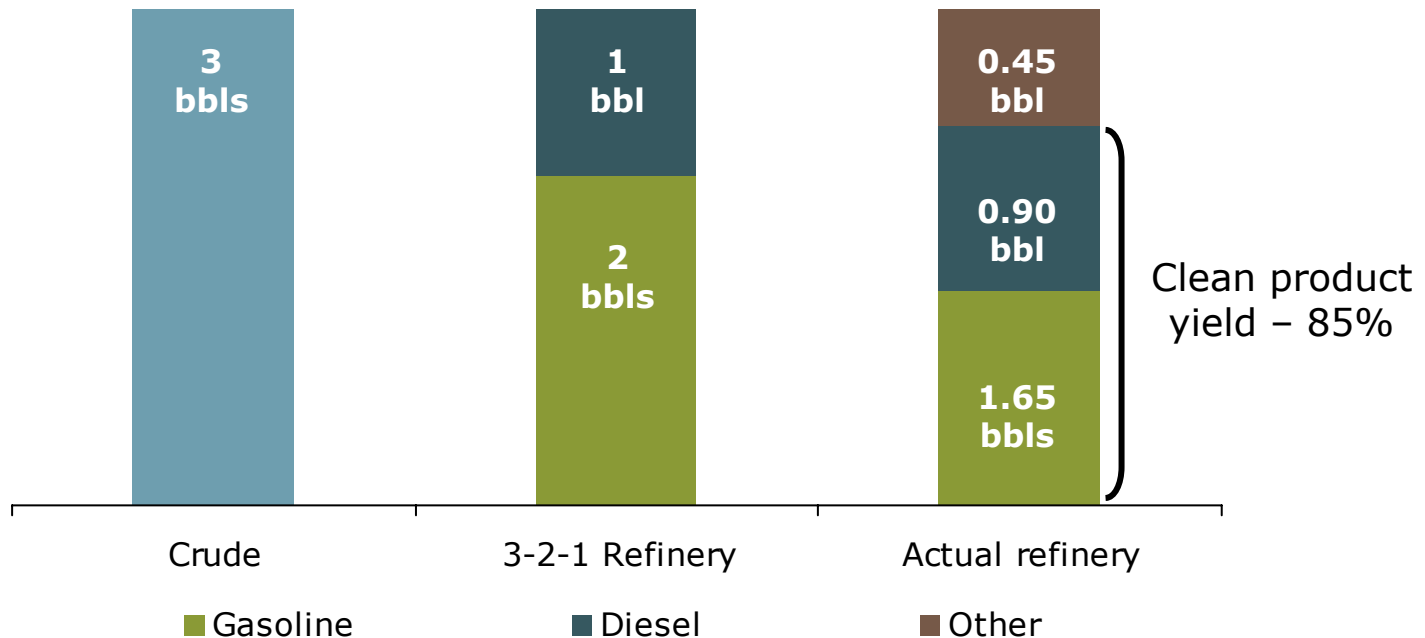
Market vs realized crack spreads



Crude advantage increases total margin available – effectively increasing realized crack spread

Understanding refinery performance

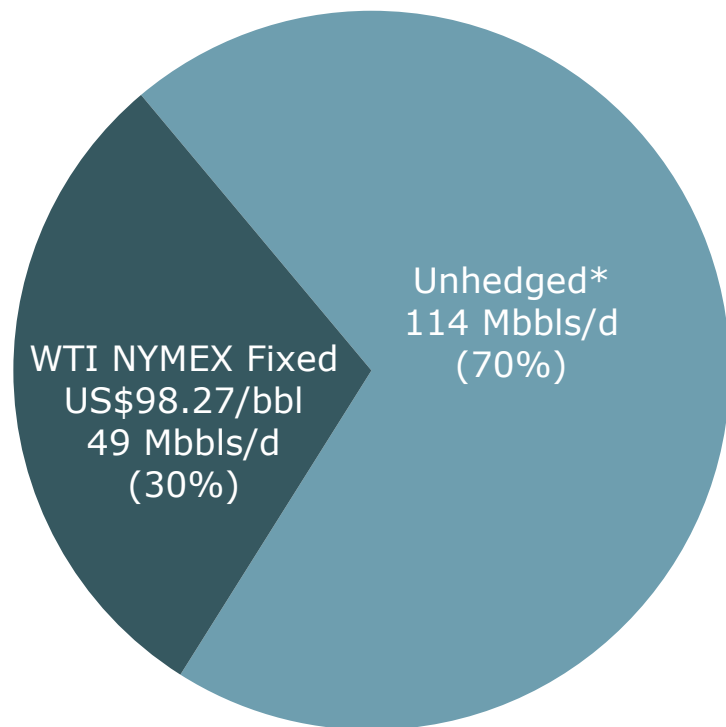
Market vs realized crack spreads



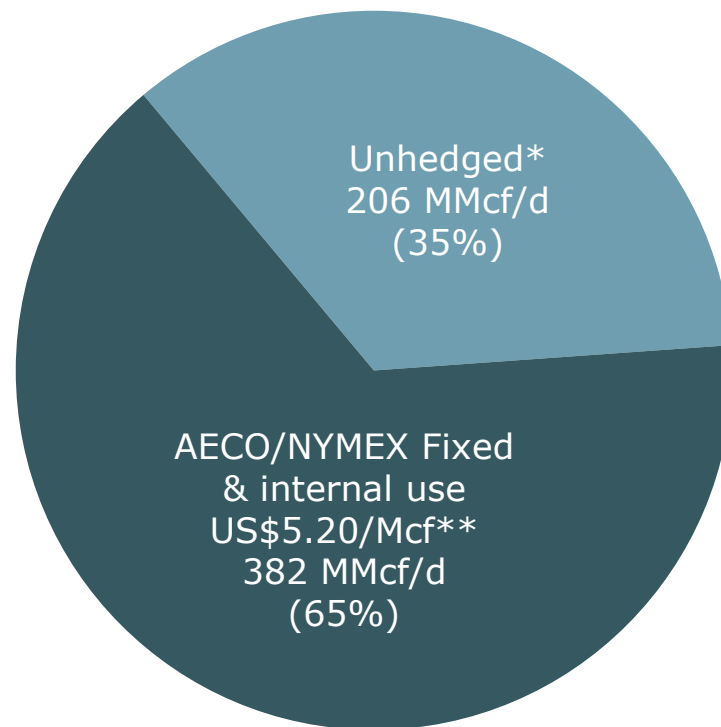
Market cracks do not account for other product pricing

Managing commodity price risk

2012 Oil hedge positions



2012 Natural gas hedge positions



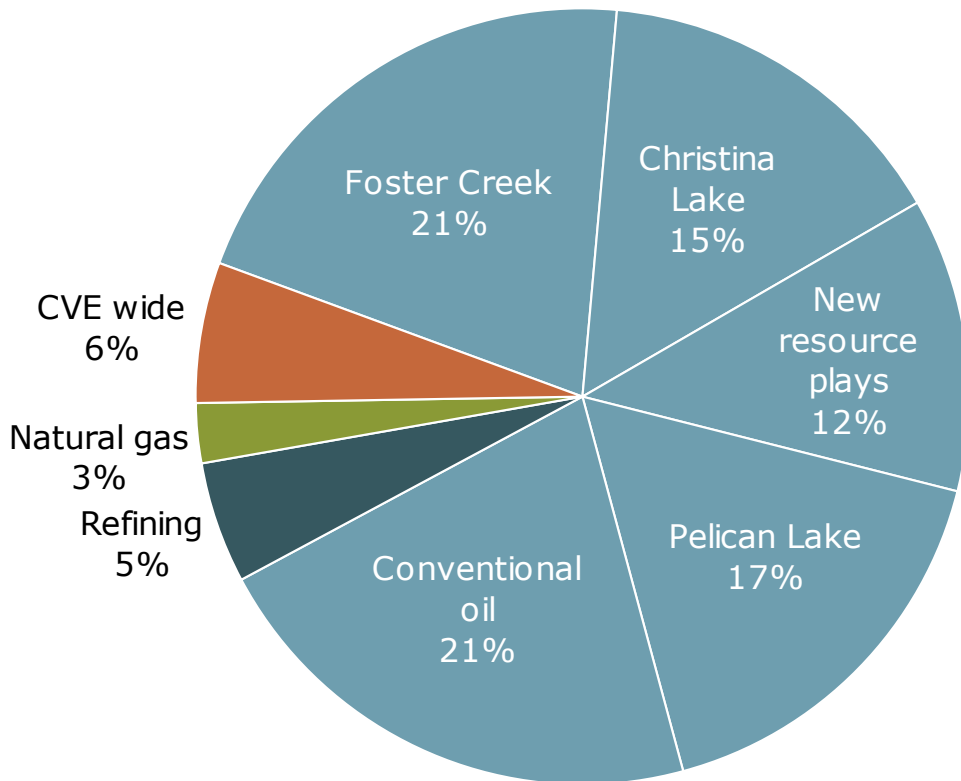
Hedge positions at December 31, 2011.

*Unhedged production volumes based on midpoints of December 7, 2011 guidance.

**Internal use volumes not included in the hedge price and hedged volumes exclude long term fixed price sales.

Capital investment focused on oil growth

2012 capital budget: \$3.1 - \$3.4 B



- 91% oil-directed*
- ~65% contributes to growth beyond 2012
- ~\$2.0 billion or 60% is committed capital

*Oil-directed spending includes upstream oil and refining capital expenditures.

Key credit metrics & ratings

Credit metrics

	Q4 2011	Q4 2010	Target Range
Debt to capitalization*	27%	29%	30 – 40%
Debt to adjusted EBITDA*	1.0x	1.3x	1.0 – 2.0x
Total debt*	\$3,527	\$3,432	

Credit ratings

	Long-term		Short-term
S&P (13-Oct-2011)	BBB+	Stable	A-1 (Low)
Moody's (10-Aug-2011)	Baa2	Stable	P-2
DBRS (27-Jul-2011)	A (low)	Stable	R-1 (Low)

*Non-GAAP measures. See advisory.

Sensitivities to price changes

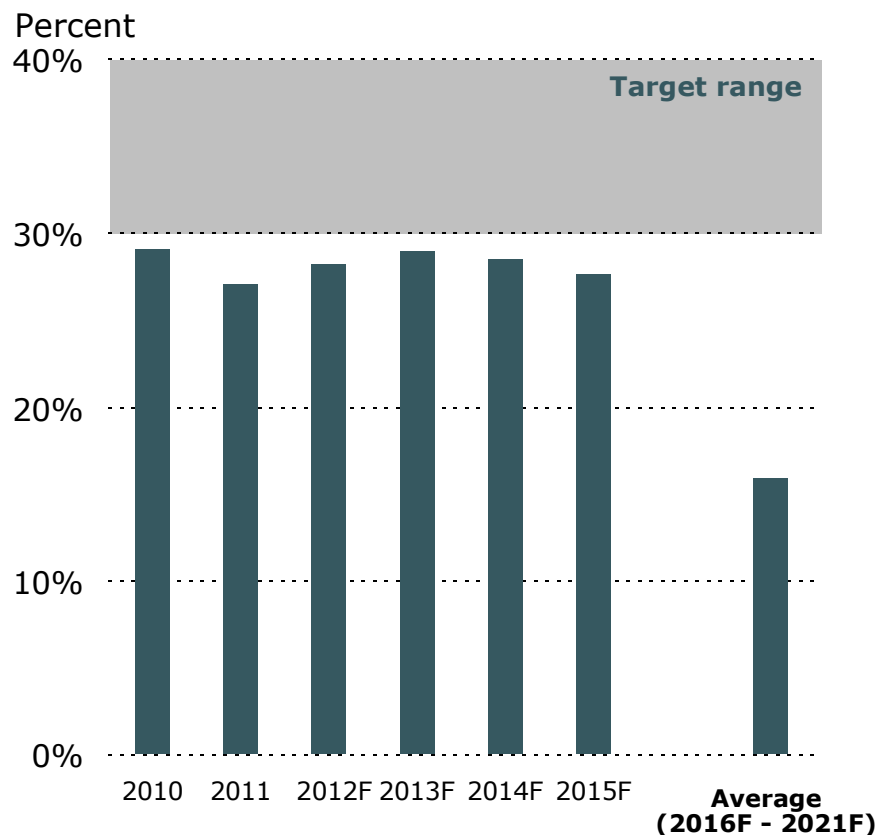
Independent sensitivities		Impact on 2012F cash flow* (\$ millions)
WTI oil	+ US\$10	185
	- US\$10	(185)
NYMEX natural gas	+ US\$1	60
	- US\$1	(60)
Light-heavy oil differential	widens: (WTI – WCS) + US\$5	(15)
	tightens: (WTI – WCS) - US\$5	30

Sensitivities based on assumptions noted in 2012 guidance: WTI US\$90.00/bbl; Light-heavy differentials US\$15.00/bbl; Chicago 3-2-1 crack spread US\$14.50/bbl; NYMEX US\$3.50/Mcf; and a foreign exchange rate of \$0.975 US\$/C\$. Sensitivities include hedge positions as at September 30, 2011.

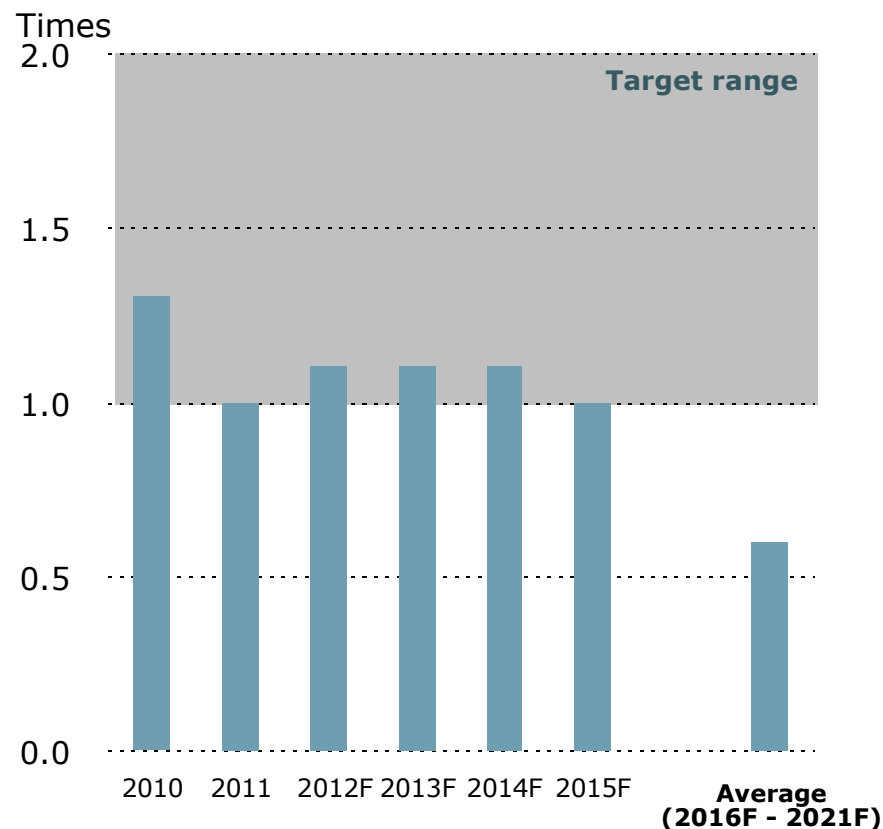
*Cash flow is a non-GAAP measure. See advisory.

Balance sheet strength provides capacity

Debt to Capitalization*



Debt to Adjusted EBITDA*



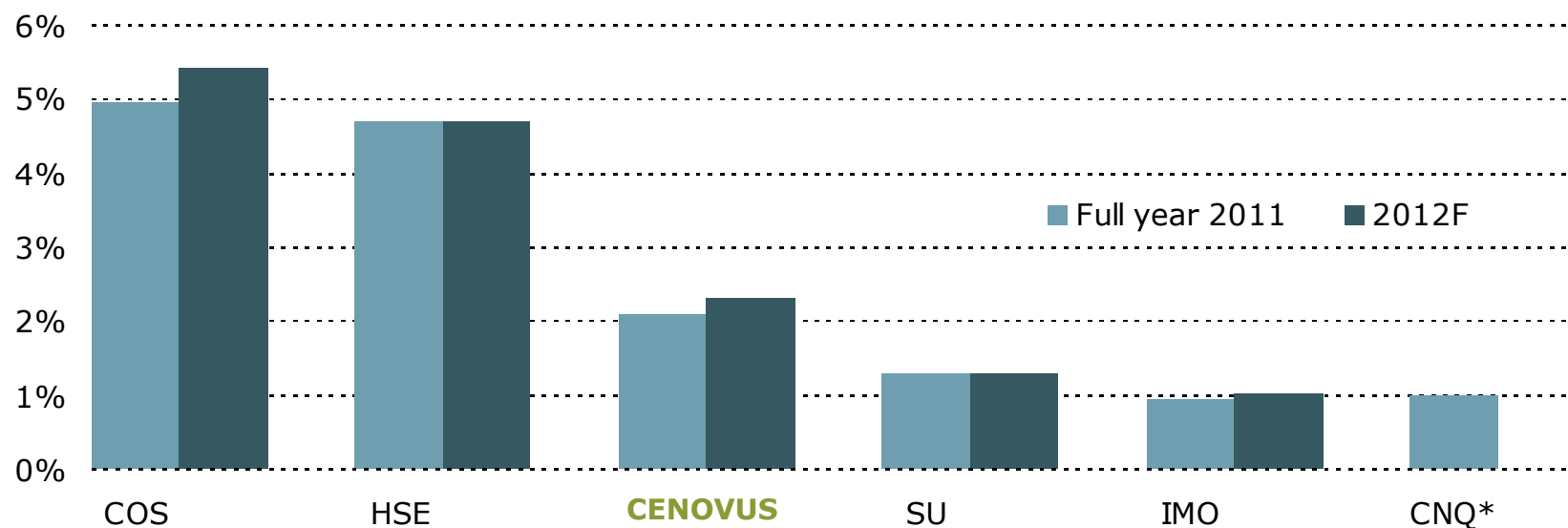
2012F based on commodity price assumptions outlined in the December 7, 2011 guidance document. 2013F through 2021F based on future price assumptions as noted in the advisory.

*Non-GAAP measure. See advisory.

Our dividend commitment

- Dividend growth requires:
 - strong financial health
 - sustainable pace of development
 - reliable, predictable cash flow to support payments

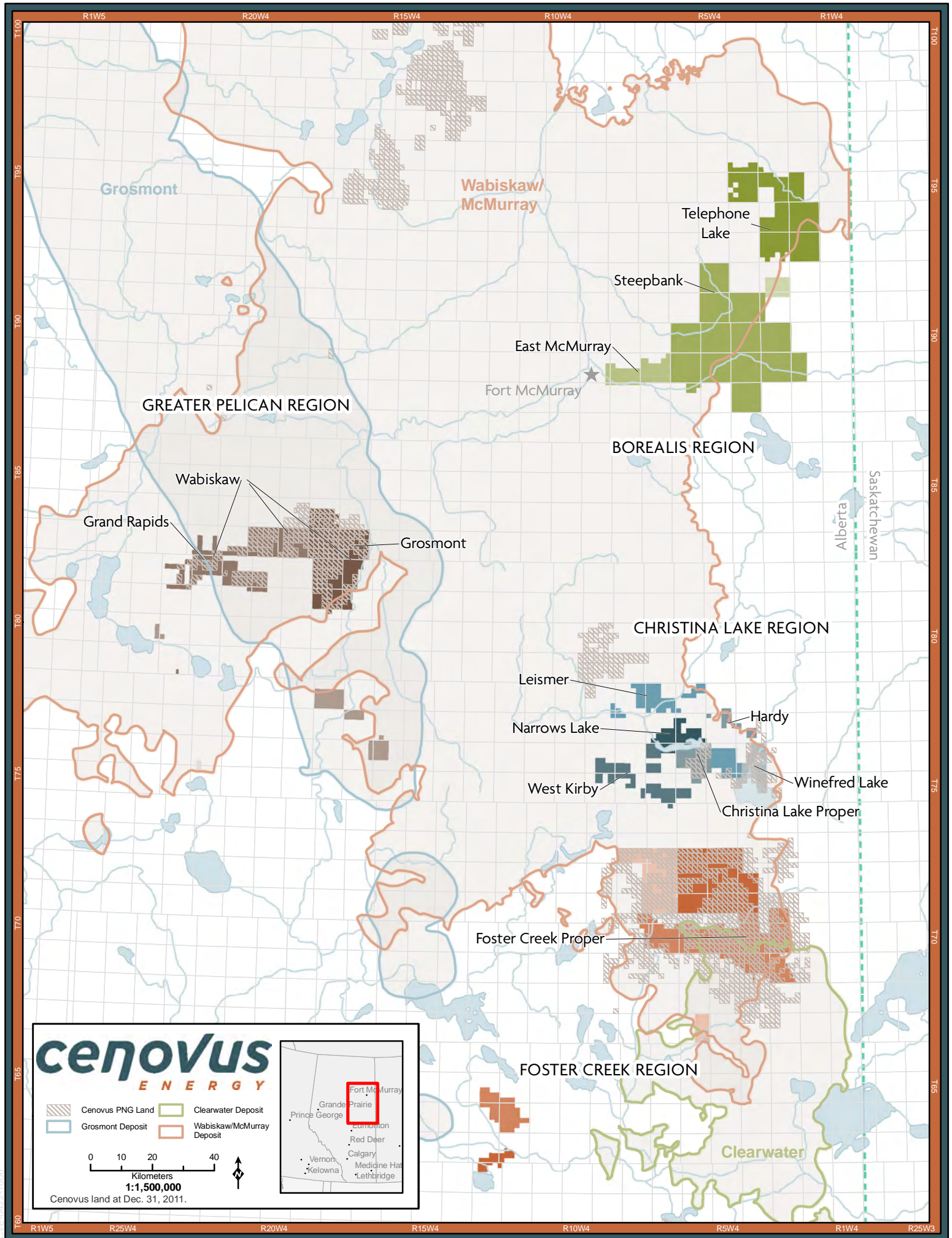
Dividend yield comparison



2012 forecasts reflect annualized Q1 2012 dividends. At Cenovus, dividends are considered by our Board of Directors on a quarterly basis.

Source: Bloomberg and TSX using February 15, 2012 closing price.

*Q1 2012 dividend has not been reported.



cenovus ENERGY

Cenovus PNG Land	Clearwater Deposit
Grosmont Deposit	Wabiskaw/McMurray Deposit

0 10 20 40
Kilometers
1:1,500,000
Cenovus land at Dec. 31, 2011.

CNE-0422-1008



2012 Corporate Guidance - C\$, before royalties

December 7, 2011

OIL SANDS

	Foster Creek	Christina Lake	Total
Production (Mbbbls/d)	53 - 57	26 - 29	79 - 86
Operating cash flow (\$ millions) ⁽¹⁾	910 - 1,010	370 - 410	1,280 - 1,420
Capital expenditures (\$ millions)	650 - 700	475 - 525	1,125 - 1,225
Operating costs (\$/bbl)			
Fuel	2.05 - 2.30	2.50 - 2.75	2.20 - 2.45
Non-fuel	9.20 - 10.15	10.50 - 11.60	9.65 - 10.60
Effective royalty rates (%)	9 - 11	5 - 6	
Steam to oil ratio	2.0 - 2.2	1.9 - 2.1	
Stratigraphic wells - gross	130	31	161
New resource plays ⁽²⁾			
Capital expenditures (\$ millions)			375 - 415
Stratigraphic wells - gross			295

PELICAN LAKE

Production (Mbbbls/d)	23 - 26
Operating cash flow (\$ millions) ⁽¹⁾	475 - 525
Capital expenditures (\$ millions)	525 - 575
Operating costs (\$/bbl)	14.55 - 16.10
Effective royalty rates (%)	5 - 6
Stratigraphic wells - gross	8

CONVENTIONAL OIL & NATURAL GAS⁽³⁾

	Oil & liquids	Natural gas	Total
Production			
Oil & liquids (Mbbbls/d)	53 - 59		53 - 59
Natural gas (MMcf/d)		575 - 600	575 - 600
Operating cash flow (\$ millions) ⁽¹⁾	1,000 - 1,115	550 - 600	1,550 - 1,715
Capital expenditures (\$ millions)	660 - 725	80 - 90	740 - 815
Operating costs (\$/bbl)	14.65 - 16.25		
(\$/Mcf)		1.15 - 1.30	
Effective royalty rates (%)	13 - 14	2	

REFINING

Operating cash flow (\$ millions) ⁽¹⁾⁽⁴⁾	300 - 600
Capital expenditures (\$ millions)	150 - 175



2012 Corporate Guidance - C\$, before royalties

December 7, 2011

CONSOLIDATED

Total cash flow (\$ billions) ⁽¹⁾	2.9 - 3.5
- per common share, diluted (\$/share)	3.80 - 4.60
Operating cash flow (\$ billions) ⁽¹⁾	3.6 - 4.2
Total capital expenditures (\$ billions) ⁽⁵⁾	3.1 - 3.4
Administrative expenses (\$ millions)	345 - 375
DD&A (\$ billions) ⁽⁶⁾	1.2 - 1.4
Effective tax rate (%) ⁽⁷⁾	25

CASH FLOW SENSITIVITIES⁽⁸⁾

Independent base case sensitivities (\$ millions)	Increase	Decrease
Crude oil (WTI) - US\$10.00 change	185	(185)
Light-heavy differential (WTI-WCS) - US\$5.00 change	(15)	30
Natural gas (NYMEX) - US\$1.00 change	60	(60)

(1) This is a non-GAAP measure as described in the Advisory below.

(2) New Resource Plays includes Narrows Lake, Grand Rapids, Telephone Lake, and other emerging plays.

(3) Oil & liquids includes oil and NGLs from Alberta and Saskatchewan. Natural gas includes all natural gas production.

(4) Prepared under FIFO inventory accounting.

(5) Includes one-time 2012 capital expenditures of \$125 MM related to leasehold improvements of office space and Information Technology infrastructure costs, as part of Cenovus wide corporate capital.

(6) Relates to upstream DD&A only, excludes Refining & Marketing, Corporate and Eliminations.

(7) Excludes the effect of mark-to-market gains and losses.

(8) Sensitivities include hedge positions as at September 30, 2011 and are applicable to 2012. 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 realisable value.

ADVISORY

NON-GAAP MEASURES. This document contains references to non-GAAP measures as follows: Operating cash flow is defined as revenues, less purchased product, transportation and blending, operating expenses, production and mineral taxes and realized gains or minus realized losses on risk management, and is used to provide a consistent measure of the cash generating performance of the company's assets and improves the comparability of Cenovus's underlying financial performance between periods. Cash flow is defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital from continuing operations, both of which are defined on the Consolidated Statement of Cash Flows in our interim financial statements, available at www.cenovus.com.

FORWARD-LOOKING INFORMATION. This document contains certain forward-looking statements and other information (collectively "forward-looking information") about our current expectations, estimates and projections, made in light of our experience and perception of historical trends. Although we believe that the expectations represented by such forward-looking information are reasonable, there can be no assurance that such expectations will prove to be correct. Forward-looking information in this document includes: estimates of production volumes; estimates of cash flow, operating cash flow and operating costs; projected capital expenditures; estimates of administrative expenses; estimates of US\$/C\$ exchange rates, depreciation, depletion and amortization (DD&A); effective tax rates, royalty rates and price assumptions; and projected sensitivities and impact on cash flow. Readers are cautioned not to place undue reliance on forward-looking information as our 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.

2012 guidance is based on an average diluted number of shares outstanding of approximately 759 million. It assumes: WTI of US\$90.00/bbl; Western Canada Select of US\$75.00/bbl; NYMEX of US\$3.50/MMBtu; AECO of \$3.10/GJ; Chicago 3-2-1 crack spread of US\$14.50/bbl; exchange rate of \$0.975 US\$/C\$. The other factors or assumptions on which the forward-looking information is based include: our projected capital investment levels, the flexibility of capital spending plans and the associated source of funding; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects; our ability to generate sufficient cash flow from operations to meet our current and future obligations; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities.

The risk factors and uncertainties that could cause our actual results to differ materially, include: volatility of and assumptions regarding oil and gas prices; the effectiveness of our risk management program, including the impact of derivative financial instruments and our access to various sources of capital; accuracy of cost estimates; fluctuations in commodity prices, currency and interest rates; fluctuations in product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; maintaining desirable ratios of debt to adjusted EBITDA as well as debt to capitalization; our ability to access external sources of debt and equity capital; success of hedging strategies; accuracy of our reserves, resources and future production estimates; our ability to replace and expand oil and gas reserves; the ability of us and ConocoPhillips to maintain our relationship and to successfully manage and operate our integrated heavy oil business; reliability of our assets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; refining and marketing margins; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in manufacturing, transporting or refining of crude oil into petroleum and chemical products at two refineries; risks associated with technology and its application to our business; the timing and the costs of well and pipeline construction; our ability to secure adequate product transportation; changes in Alberta's regulatory framework, 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 our business, our financial results and our consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; 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 us.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a full discussion of our material risk factors, see "Risk Factors" in our most recent annual information form, available at www.cenovus.com. Readers should also refer to "Risk Management" in our current Management's Discussion and Analysis and to the risk factors described in other documents we file from time to time with securities regulatory authorities, available at www.sedar.com, www.sec.gov and www.cenovus.com.

Investor Relations contacts

Susan Grey

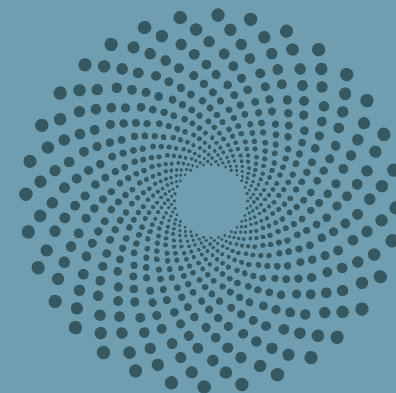
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