



2012 Analyst Day

April 4, 2012

Agenda

8:00 - 8:05 a.m.	Welcome & Introduction	Vince White Senior Vice President, Communications & Investor Relations
8:05 - 8:25 a.m.	Strategy & Outlook	John Richels President & CEO
8:25 - 8:45 a.m.	E&P Overview	Dave Hager Executive Vice President, E&P
8:45 - 9:35 a.m.	New Ventures	Dave Hager Executive Vice President, E&P
-----		Q&A / Break
10:10 - 10:35 a.m.	Permian Basin	Andy Coolidge Business Unit Vice President, Permian Basin
10:35 - 11:00 a.m.	Canadian Thermal Oil	Chris Seasons President, Devon Canada
-----		Q&A / Break
11:30 - 11:50 a.m.	Barnett Shale	Brad Foster Senior Vice President, Mid-Continent
11:50 - 12:10 p.m.	Cana Woodford Shale	Kris Goforth Business Unit Vice President, Anadarko Basin
12:10 - 12:15 p.m.	Summary	John Richels President & CEO
-----		Q&A
12:30 p.m.	Adjourn / Box Lunch	

Long-Term Outlook

Economic Assumptions

- Devon's 2012-2016 forecast assumes:
 - Strip pricing as of March 20, 2012 (rounded):

	WTI Price	Henry Hub Price
2012	\$105	\$2.75
2013	\$105	\$3.50
2014	\$100	\$4.00
2015	\$95	\$4.25
2016 +	\$95	\$4.50

- NGL benchmark price: 47% of WTI
- Current cost environment held constant
- Sinopec JV transaction (\$900 million cash and \$1.6 billion drilling carry)
- Additional JV transaction during 2013 (\$450 million cash and \$0.9 billion drilling carry)
- Common dividend continues at current rate
- Utilize cash balances of \$1.5 billion through 2016

Long-Term Outlook

Economic Assumptions

- Devon's E&P capital expenditure forecast through 2016:

	E&P Capital (\$ Billions)
2012	\$6.3
2013	\$6.6
2014	\$7.4
2015	\$7.3
2016 +	\$7.8

Investor Notices

Safe Harbor

Information provided in this presentation includes “forward-looking statements” as defined by the Securities and Exchange Commission. Forward-looking statements are identified as “forecasts, projections, estimates, plans, expectations, targets, etc.” and are subject to a variety of risk factors. For representative risk factors that could cause Devon’s actual results to differ materially from the forward-looking statements contained herein, see Form 8-K filed February 15, 2012.

Cautionary Note to Investors

The United States Securities and Exchange Commission permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserves that meet the SEC's definitions for such terms, and price and cost sensitivities for such reserves, and prohibits disclosure of resources that do not constitute such reserves. This presentation may contain certain terms, such as resource potential and exploration target size. These estimates are by their nature more speculative than estimates of proved, probable and possible reserves and accordingly are subject to substantially greater risk of being actually realized. The SEC guidelines strictly prohibit us from including these estimates in filings with the SEC. Investors are urged to consider closely the disclosure in our Form 10-K for the fiscal year ended December 31, 2011, available from us at Devon Energy Corporation, Attn. Investor Relations, 20 North Broadway, Oklahoma City, OK 73102. You can also obtain this form from the SEC by calling 1-800-SEC-0330 or from the SEC’s website at www.sec.gov.

Strategy & Outlook

John Richels

President & CEO

Devon Today

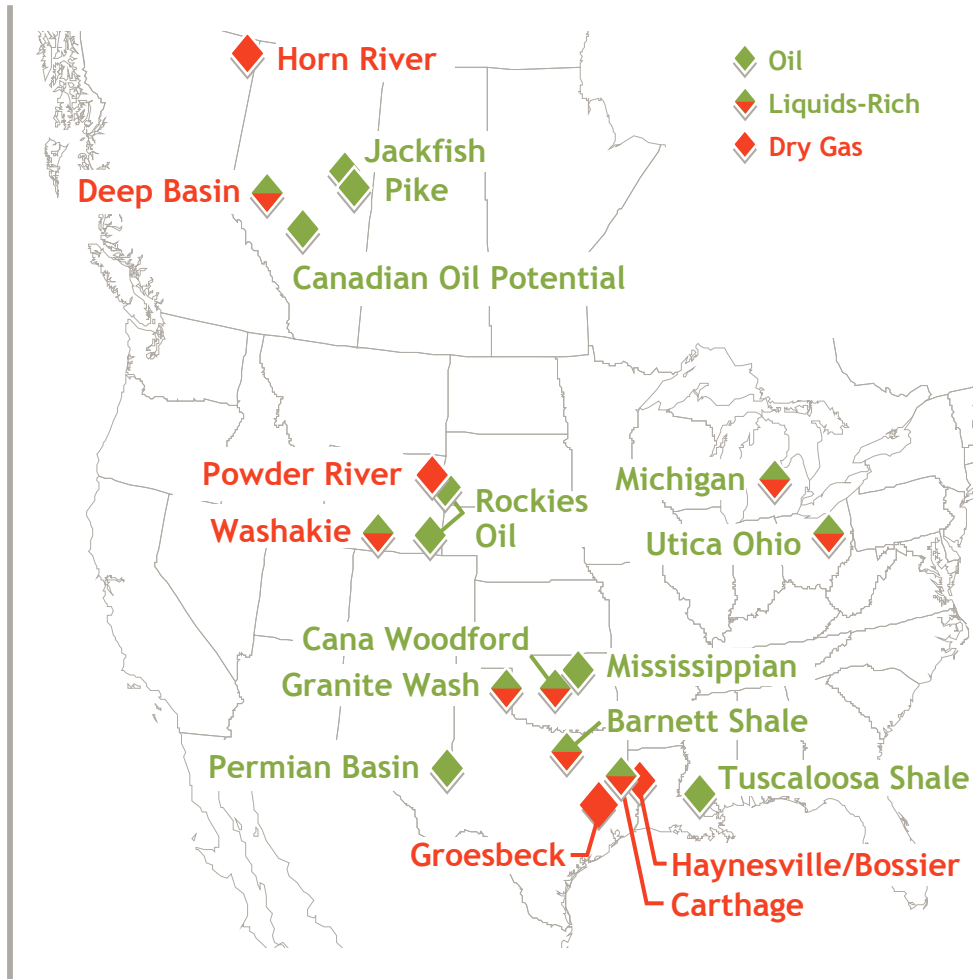
Proved reserves: ≈ 3.0 billion BOE
(42% liquids)

Q4 2011 production: ≈ 680 MBOED
(35% liquids)

Sales revenue mix: 45% oil
36% NGLs
19% natural gas
(Q4 2011)

Significant midstream business
2011 operating profit: \$542 million

Enterprise value: \approx \$30 billion

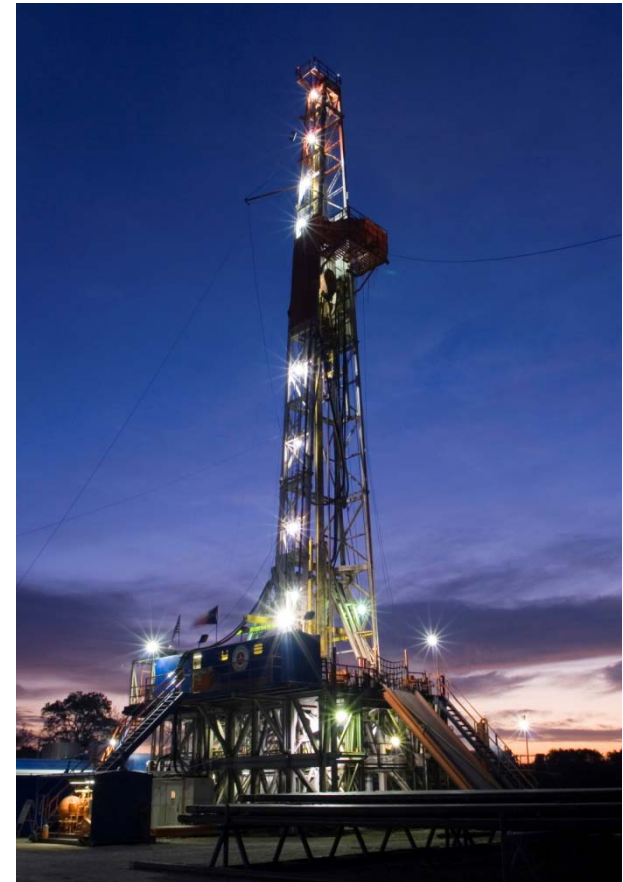


Key Messages

- Committed to delivering:
 - Top quartile per share results
 - Strong full-cycle returns
- Deep inventory of repeatable opportunities in current environment
- Strong, highly-visible oil and liquids growth
- Significant upside from exploration prospects
- Superior financial strength and flexibility

Strategic Objective

Devon strives to maximize long-term value for our shareholders by growing cash flow per share, adjusted for debt.



We Pursue Our Strategic Objective By:

- Exercising capital discipline
- Maintaining a low-cost structure to maximize operating margins
- Focusing on high-return projects
- Improving performance through our midstream operations
- Preserving financial strength and flexibility

Exercising Capital Discipline

Capital Allocation Criteria

E&P capital projects

- Balancing resource capture and development
(Exploration & leasehold capital: ~20% of E&P capital since 2009)

Debt reduction

- Reduced net debt by \$4 billion since 2003

Share repurchases

- Reduced net share count by ~20% since 2004

Dividends

- Dividend has increased 800% since 2004



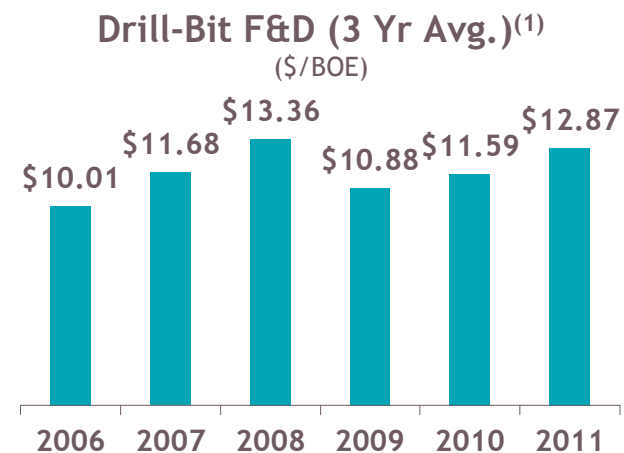
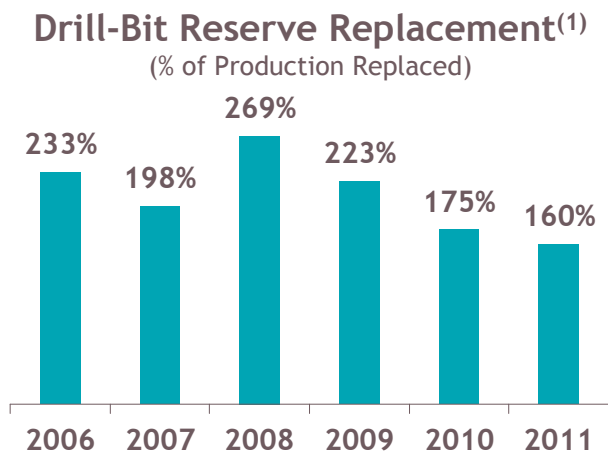
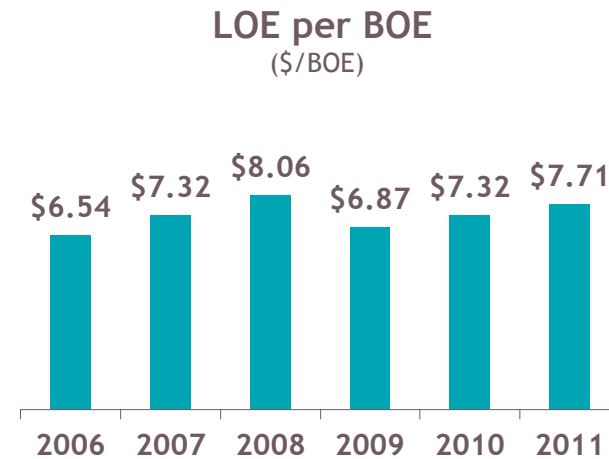
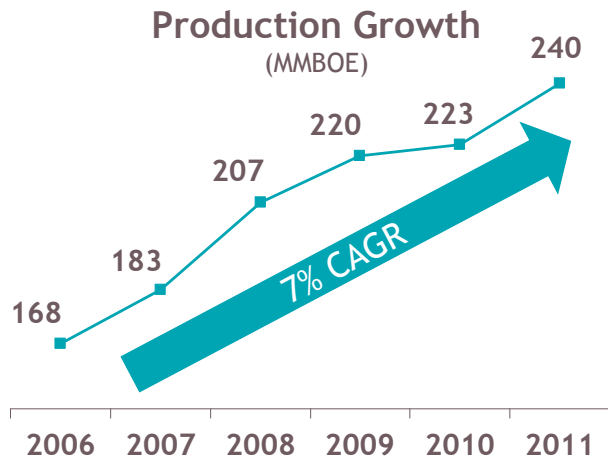
Advantaged Resource Base

- Low entry costs (acreage and royalties)
- Large, concentrated positions
- High-graded portfolio (capturing and divesting)
- Strategic midstream presence in key plays



Focused on High-Return Growth

North American Onshore Historical Performance

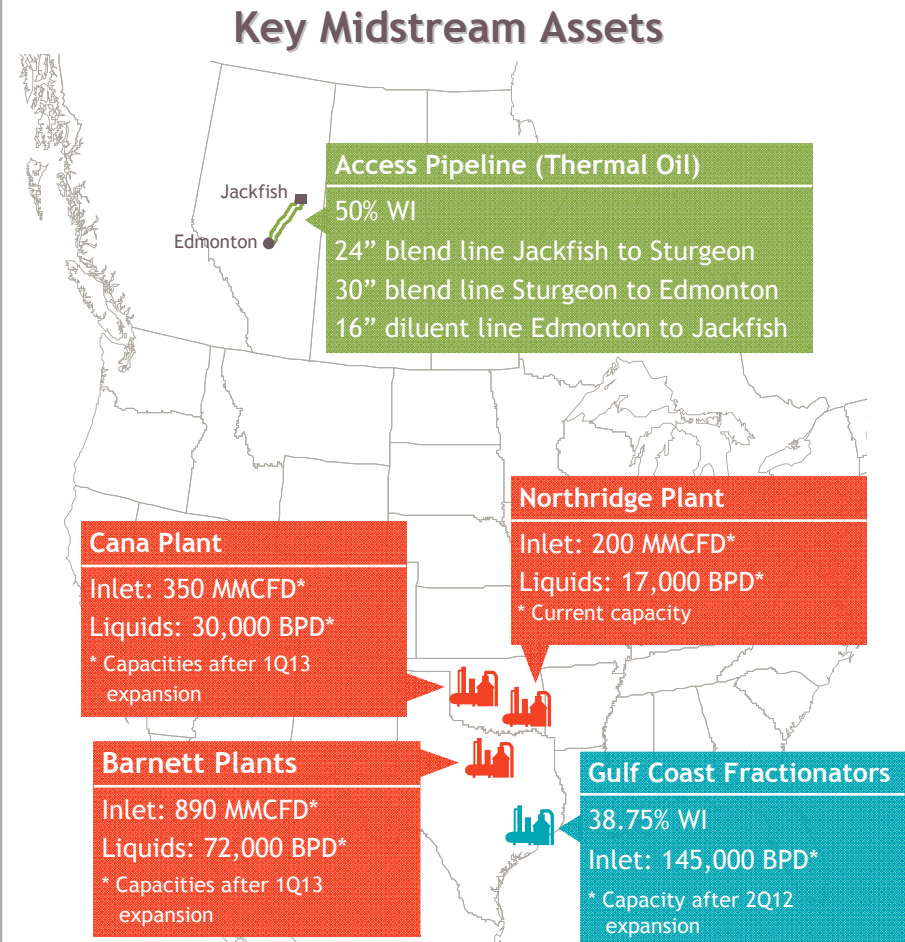


(1) Excludes price revisions

Note: Includes a non-GAAP measure, see appendix for required disclosures.

Enhanced By Midstream Operations

- Ownership in ≈15,000 miles of pipeline
 - United States: ≈6,500 miles
 - Canada: ≈9,500 miles
- Ownership in 64 plants
 - United States: 8 plants
 - Canada: 56 plants
- 2011 operating profit: \$542 million
- Enhances margins by >\$2 per BOE



Profitable midstream enhances operational effectiveness

Maintaining Financial Strength & Flexibility

As of December 31, 2011

- Cash and short-term investments: \$7.1 billion
- Net debt-to-cap ratio: 11%
- Strong investment grade ratings
 - Fitch: BBB+
 - Moody's: Baa1
 - S&P: BBB+
- Disciplined hedging program
- Providing flexibility to invest in high-return projects in all market cycles



Note: Includes a non-GAAP measure, see appendix for required disclosures.

Slide 15

Devon's Recycle Ratio

North America Onshore

Full-Year 2011 Results

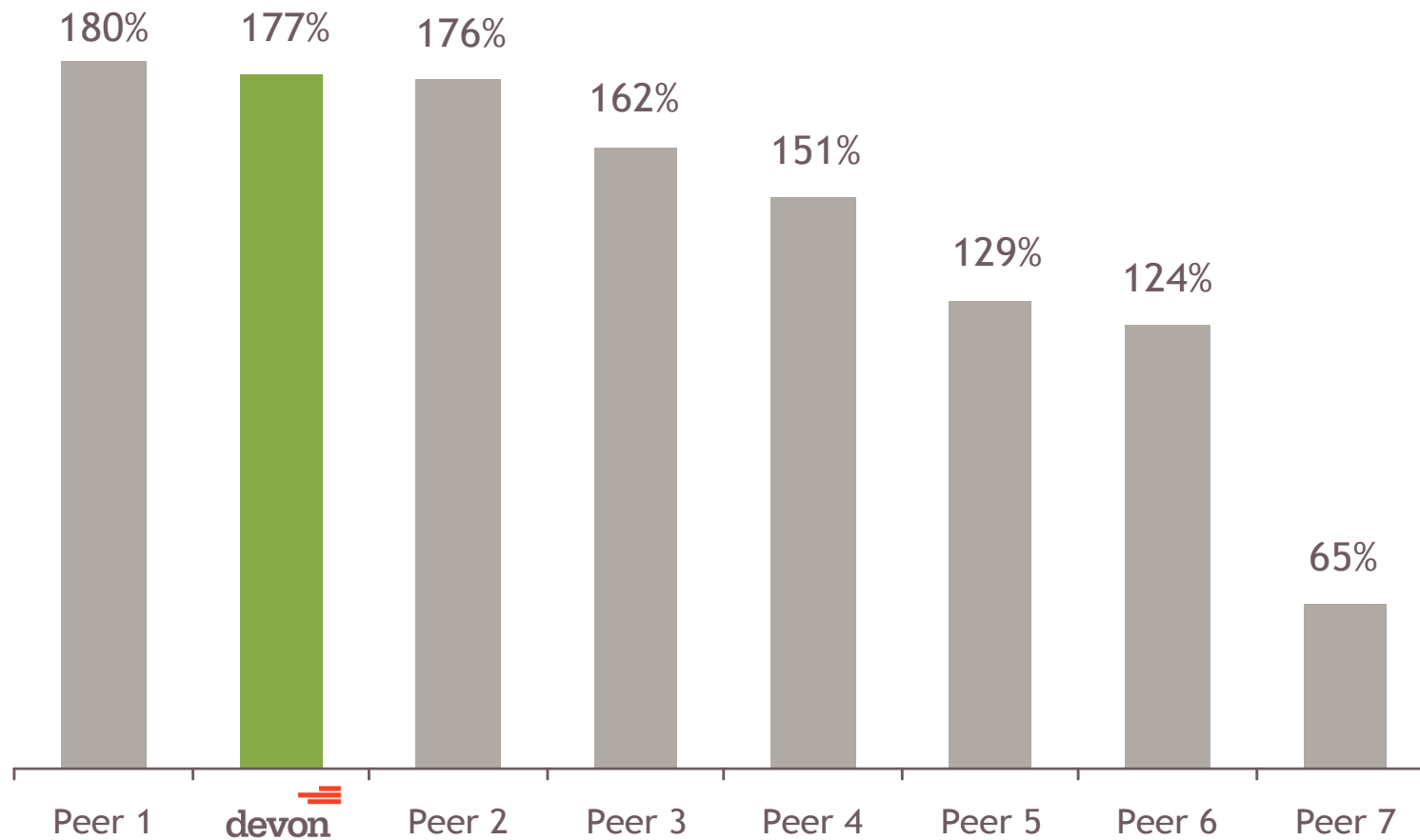
	\$ Per BOE
Revenue (excluding hedges)	\$ 36.90
Cash costs ⁽¹⁾	(12.78)
Midstream capital	(1.39)
<hr/>	
Cash margin per BOE	\$ 22.73
3-yr drilling F&D (includes performance revisions)	\$ 12.87
Unit cash margin / F&D	177%

Note: Includes a non-GAAP measure, see appendix for required disclosures.

(1) Cash costs include LOE, taxes other than income, G&A, interest expense and current taxes.

Recycle Ratio Excluding Hedges

Full-Year 2011 Results

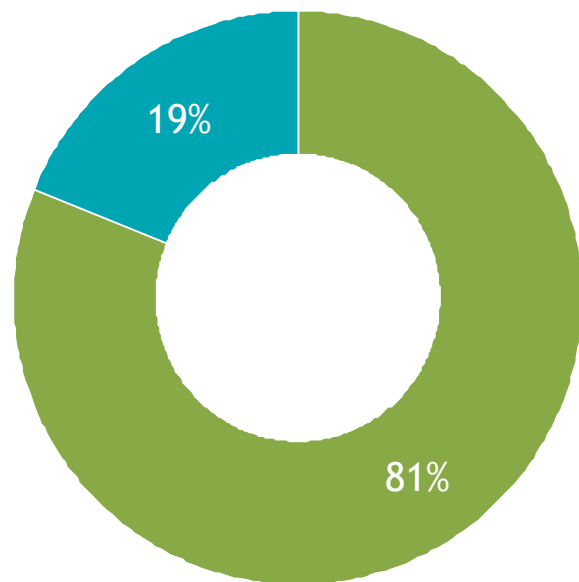


Note: Peer group includes APA, APC, CHK, ECA, EOG, NBL and NFX
Source: SEC filings and company disclosures

Devon's Risked Resource Base

High-Quality and Balanced

16.2 BBOE Risked Resource
(31.8 BBOE Unrisked)



■ Proved Reserves (26% PUD)
 ■ Additional Risked Potential

Note: Includes 12/31/11 proved reserves of 3.0 BBOE.

Risked Resource By Product (BBOE)

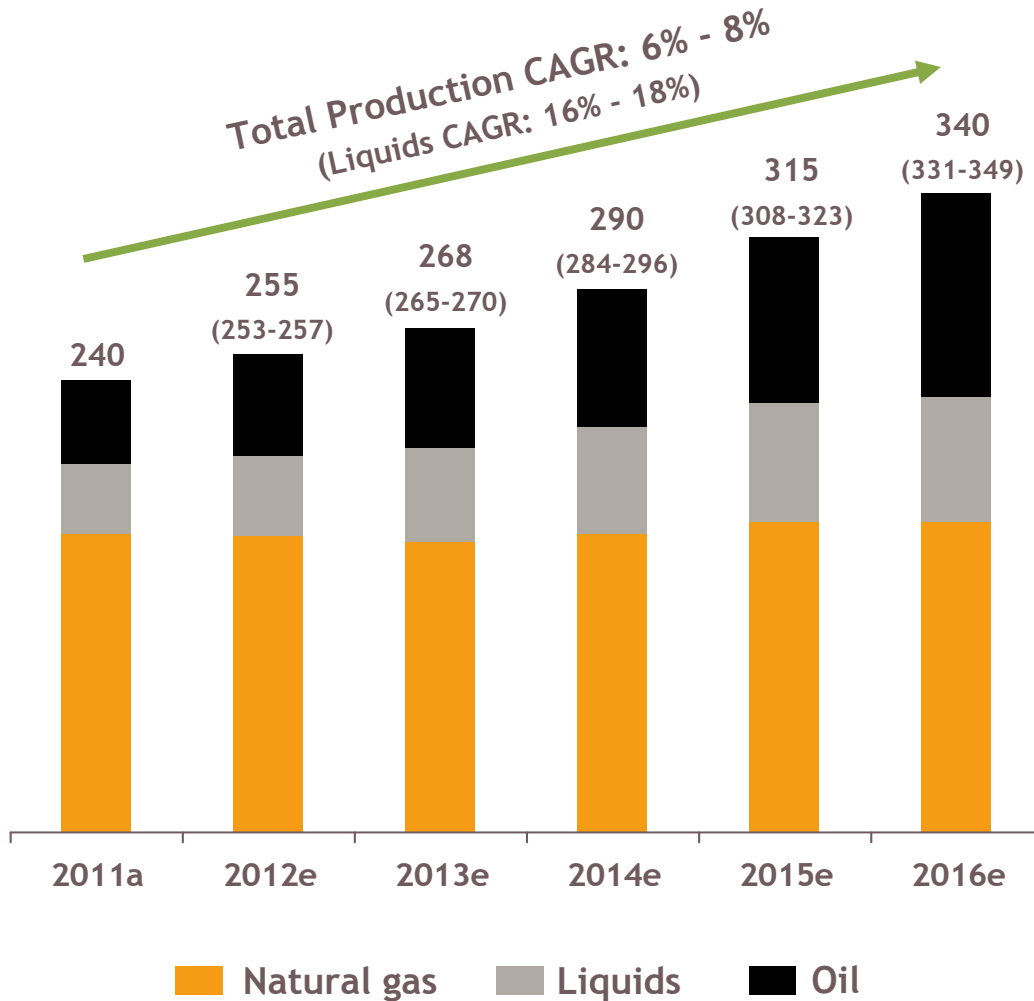
Oil (29%)	4.7
NGLs (19%)	3.1
Gas (52%)	8.4
Total	16.2

Oil-focused exploration provides upside to risked resource

Long-Term Outlook

Robust Oil & Liquids Production Growth

Production Data in MMBOE



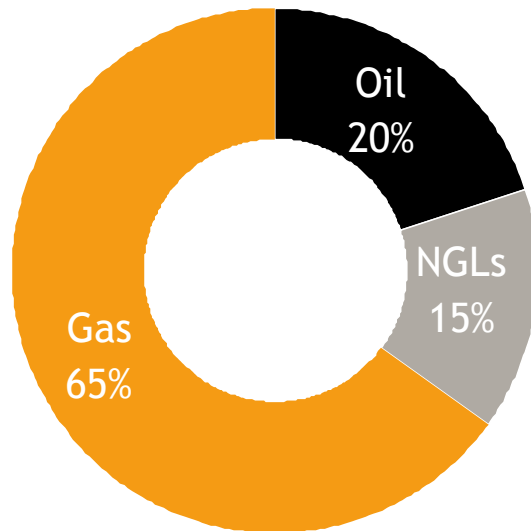
5-Year Production CAGR By Product

Oil	19%
Liquids	13%
Natural gas	1%
Total (BOE)	≈7%

Long-Term Outlook

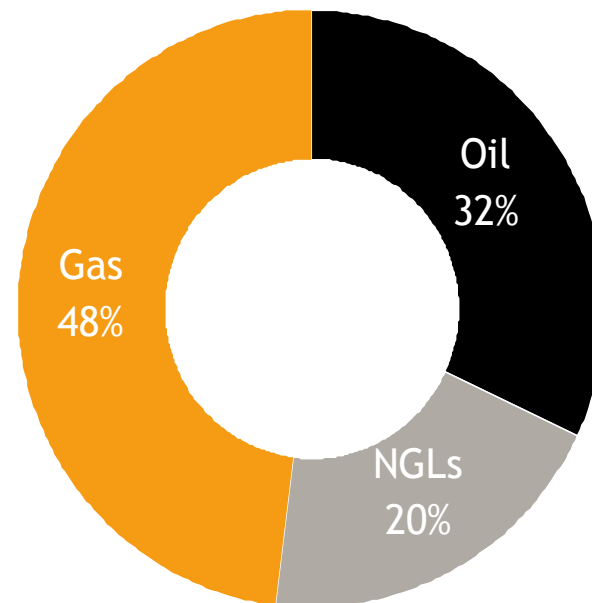
Robust Oil & Liquids Production Growth

Q4 2011



680 MBOED
(35% Liquids)

2016



905-955 MBOED
(>50% Liquids)

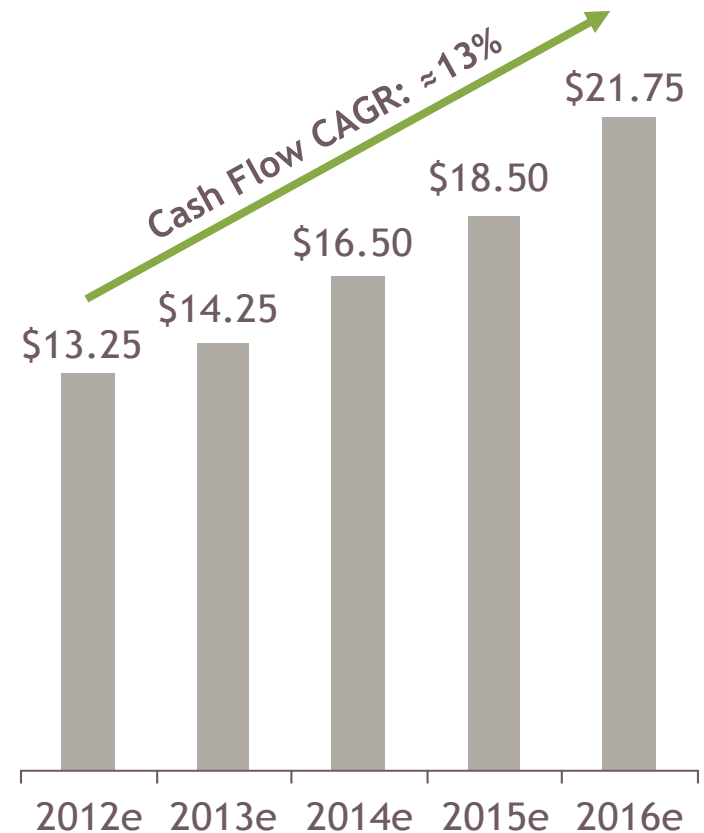
Long-Term Outlook

Strong Cash Flow Growth

Operating Cash Flow
(\$ Billions)



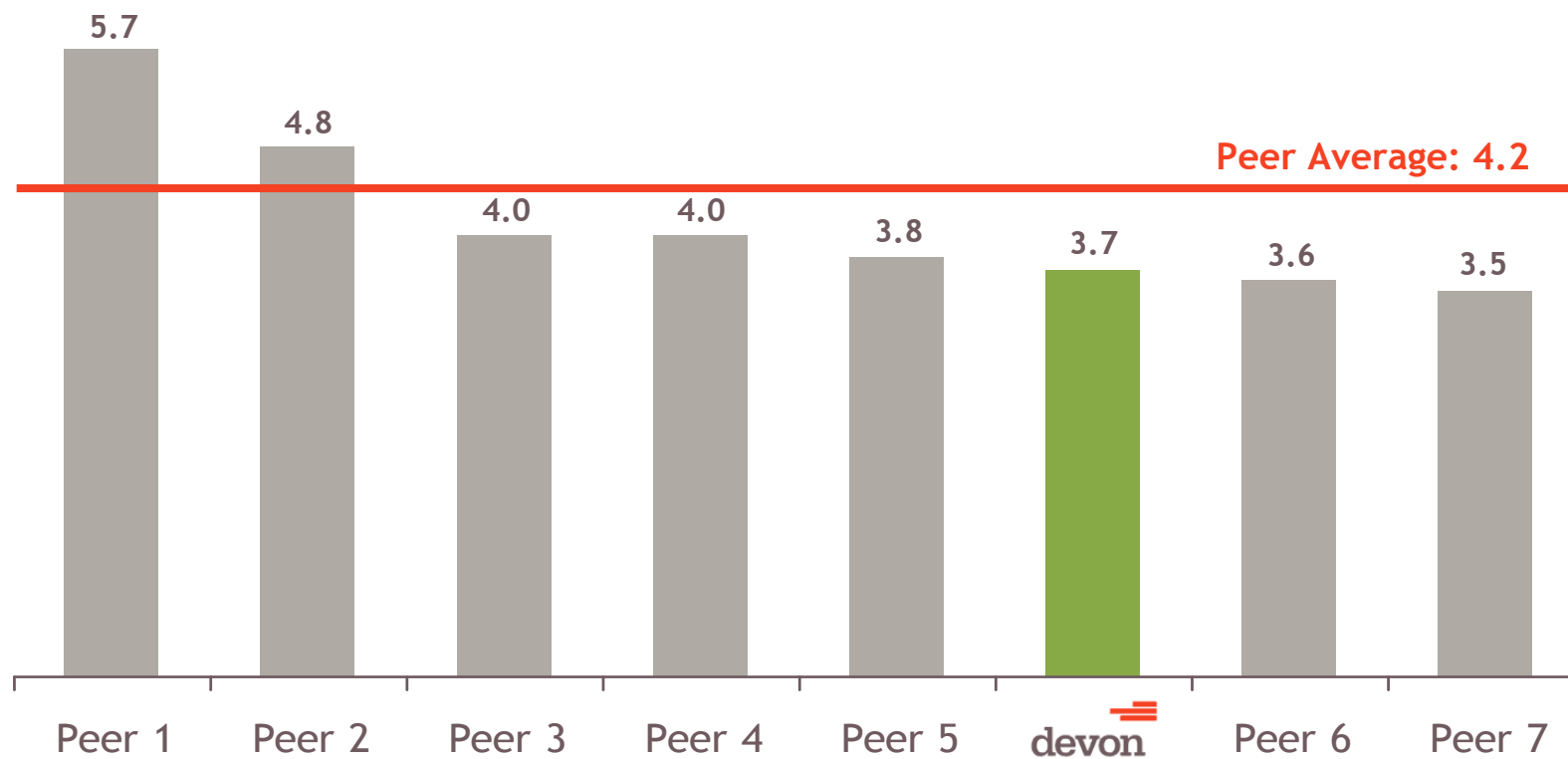
Cash Flow Per Debt-Adjusted Share
(\$ Per Share)



Note: Cash flow per debt-adjusted share calculation assumes Devon's share price trades at current multiple to cash flow (4.2x).

Devon's Compelling Valuation

Enterprise Value to 2013e EBITDA Multiple



Note: Peer group includes APA, APC, CHK, ECA, EOG, NBL and NFX
Source: Deutsche Bank 3-26-12

DVN trades at a 12% discount to peer group average



Misconceptions About Devon

- Natural gas focused with minimal liquids exposure
 - 42% of proved reserves are liquids (Oil ≈60% of liquids reserves)
 - Production >50% liquids by 2016
- Key assets are maturing
 - 3 out of 4 focus areas are in high growth mode
(Driving liquids production CAGR of 16%-18% through 2016)
 - Capturing high-impact new venture opportunities at low costs
- Risk of dilutive M&A activity
 - Disciplined focus on debt-adjusted metrics

What About the Cash?

Deployment of \$7.1 Billion of Cash

- Reinvestment in E&P projects
 - Accelerate existing projects
 - Large-scale new ventures
- Repurchase of shares
- Reduction of debt



Why Own Devon?

- Committed to delivering:
 - Top quartile per share results
 - Strong full-cycle returns
- Deep inventory of repeatable opportunities in current environment
- Strong, highly-visible oil and liquids growth
- Significant upside from exploration prospects
- Compelling valuation

E&P Overview

Dave Hager

Executive Vice President, E&P

E&P Strategy

Goal: Maximize return on investment

- Assemble large, concentrated positions
- Build inventory with early mover positions
- Balance resource capture and resource development
- Current investment focus on oil & liquids-rich opportunities
(Maintain a balanced portfolio)
- Focus on operational excellence
- Optimize margins (revenues, costs & midstream)

Portfolio Management

Goal: Optimize depth, diversity, and quality of drilling inventory

- Harvesting mature and lower return assets
(Since 2002 divested ≈\$17 billion of assets)
- New leasehold capture
(Since 2009 invested >\$4 billion into leasehold capture and exploration)
- Joint ventures / farm-ins
(Recent \$2.5 billion Sinopec transaction)

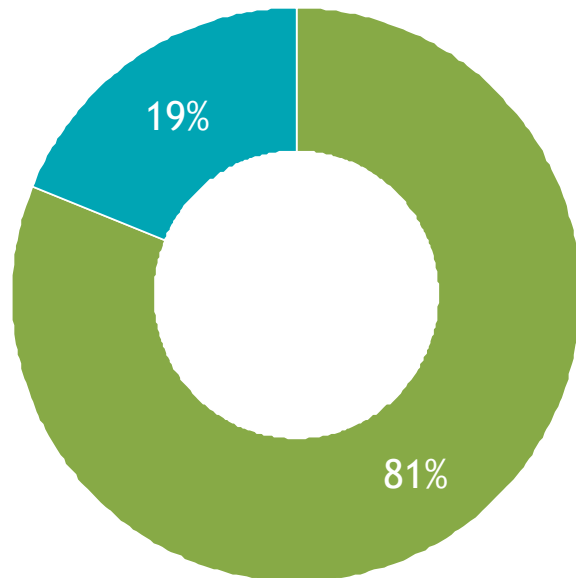
Devon's Resource Base

Petroleum Reserves Classification Framework

- Uniform classification system for petroleum resource estimates
 - Adopted by Society of Petroleum Engineers (SPE)
 - Supported by widely respected professional organizations (AAPG, WPC, SPEE, SEG)
- Based on the range of uncertainty and chance of commerciality
- Referenced in recent SEC ruling for reserve determination

Devon's Risked Resource Base

16.2 BBOE Risked Resource
(31.8 BBOE Unrisked)



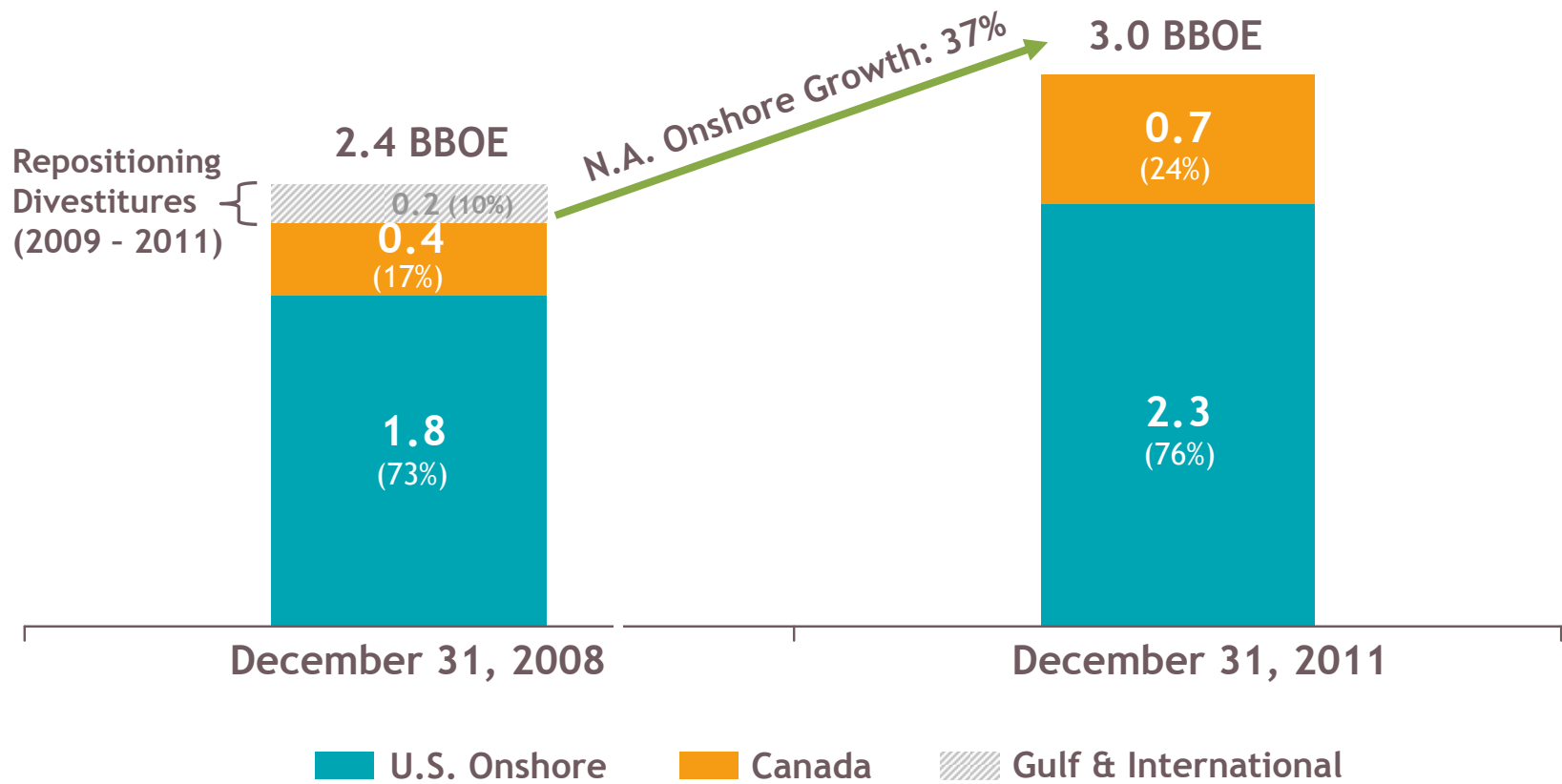
■ Proved Reserves (26% PUD) ■ Additional Risked Potential

Devon's Risked Resource Base

- High quality reserves: 3.0 BBOE (26% PUD)
- Deep inventory of economic drilling opportunities
- Recent acreage capture provides significant exploration upside

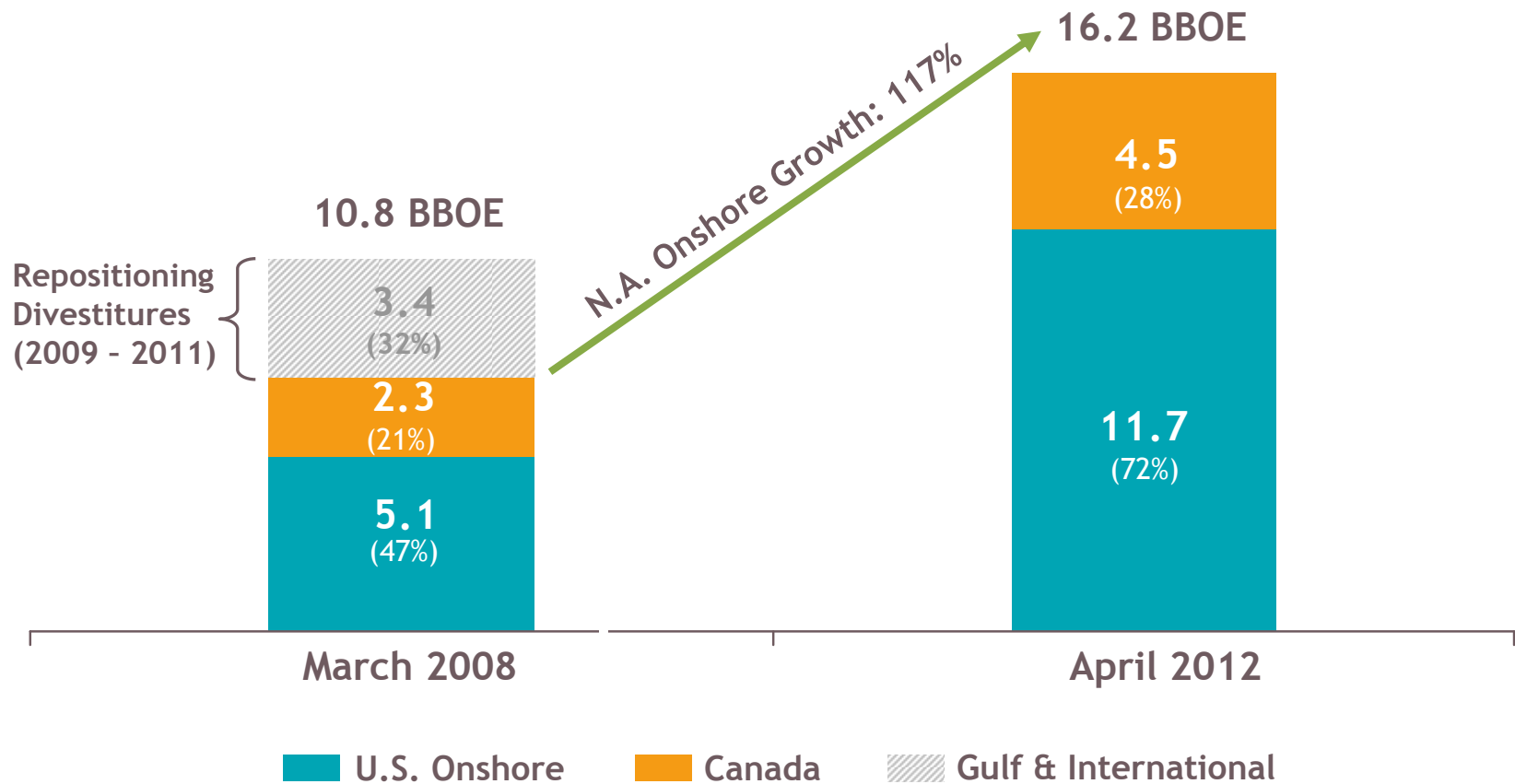
Proved Reserves

History of Growth



Risked Resource Base

History of Growth



Resource By Asset

Strong Foundation for Growth

Data in BBOE

	Unrisked Resource	Proved Reserves	+	Additional Risked Potential	=	Total Risked Resources
Permian Basin	7.6	0.2		2.6		2.8
Barnett Shale	4.3	1.2		1.3		2.5
Cana Woodford Shale	2.8	0.3		1.6		1.9
Canadian Oil Sands	2.1	0.5		0.9		1.4
East Texas/Gulf Coast	0.9	0.2		0.6		0.8
Other U.S.	4.6	0.4		1.7		2.1
Other Canada	3.3	0.2		1.8		2.0
Horn River	1.4	-		1.1		1.1
Sinopec JV Assets (net)	4.8	-		1.6		1.6
Total	31.8	3.0		13.2		16.2

Note: Includes 12/31/11 proved reserves of 3.0 BBOE.

Slide 33



Growing the Resource Base

New Ventures Exploration



Assembled 1.4 million net acres in five high-impact plays

Targeting oil and liquids-rich opportunities

Low acreage costs and low royalty rates

Early stages of evaluation

2011/2012 activity: Drill \approx 125 wells

2012 net DVN capital: \approx \$170 million
(\approx \$620 million gross)

Joint Venture Agreement

Deal Structure and Rationale

Announced January 3, 2012

Deal Structure

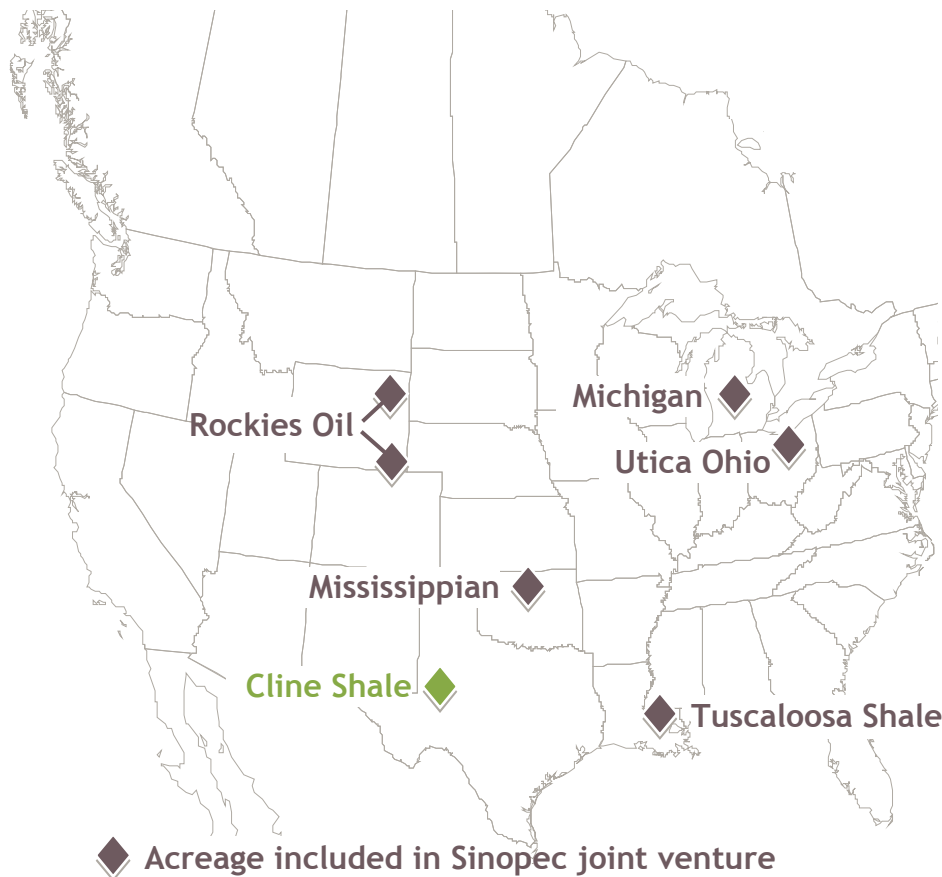
- \$2.5 billion transaction with Sinopec (\$900 million cash and \$1.6 billion carry)
- Sinopec receives 33% of Devon's interest in five new venture plays (Mississippian, Utica, Tuscaloosa, Rockies Oil and Michigan Basin)
- Devon serves as operator

Rationale

- Improves capital efficiency
- Accelerates de-risking and commercialization
- Mitigates exploration risk
- Provides additional cash flow for development projects
- Flexibility to generate new prospects

Growing the Resource Base

New Ventures Exploration



Cline Shale

- Net acreage: 500,000 (closed & committed)
- 2012 plans: Drill 15 wells (4 rigs by year-end)
- Attractive attributes:
 - Permian Basin oil play
 - Low entry costs
 - Multiple pay zones

Undisclosed Opportunities

- Building significant position in an additional undisclosed oil play (captured 250,000 net acres; targeting 500,000)
- Initiating positions in new oil-focused opportunities

2012 Exploration & Leasehold Budget Reconciliation

\$ Millions

Original 2012 exploration & leasehold budget \$530

Undisclosed oil play #1 500
(Captured 250,000 net acres; targeting 500,000 net acres)

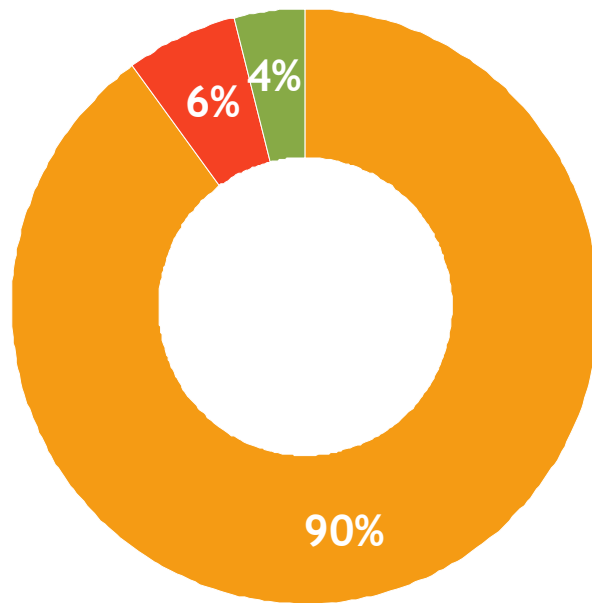
Cline Shale 350

Other undisclosed oil plays 220

Revised 2012 exploration & leasehold budget \$1,600

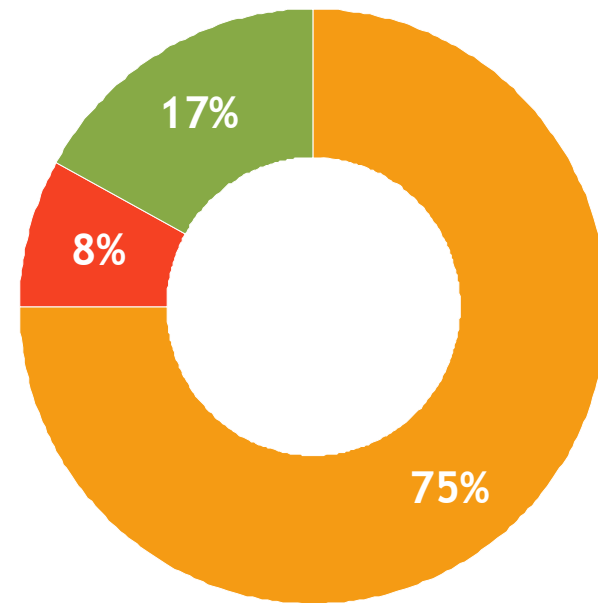
2012 E&P Capital Allocation

Original Budget



\$5.1 - \$5.5 Billion

Revised Budget



\$6.1 - \$6.5 Billion

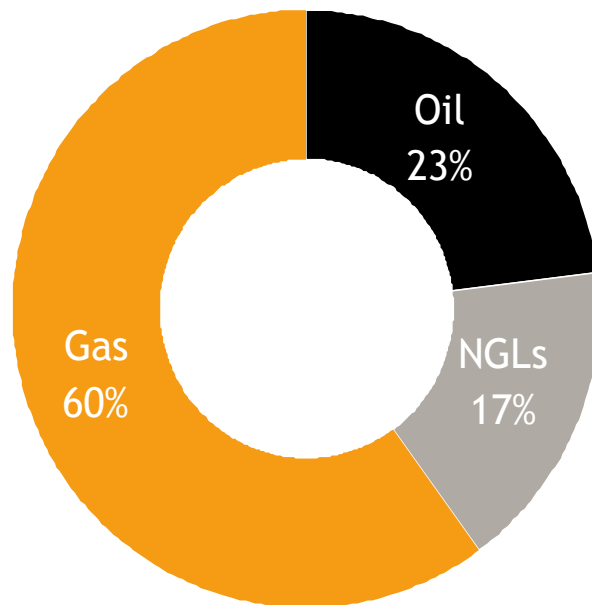
- Development activity
- Exploration activity
- Leasehold capture

≈100% of capital allocated towards oil and liquids-rich projects

2012 Capital Program

Delivering Strong Oil & Liquids Growth

2012 Exit Rate



>710 MBOED
(40% Liquids)

Oil production

- Annual growth rate: 22% - 24%
- Driven by Jackfish and Permian
- ≈25% of total company volumes

NGLs production

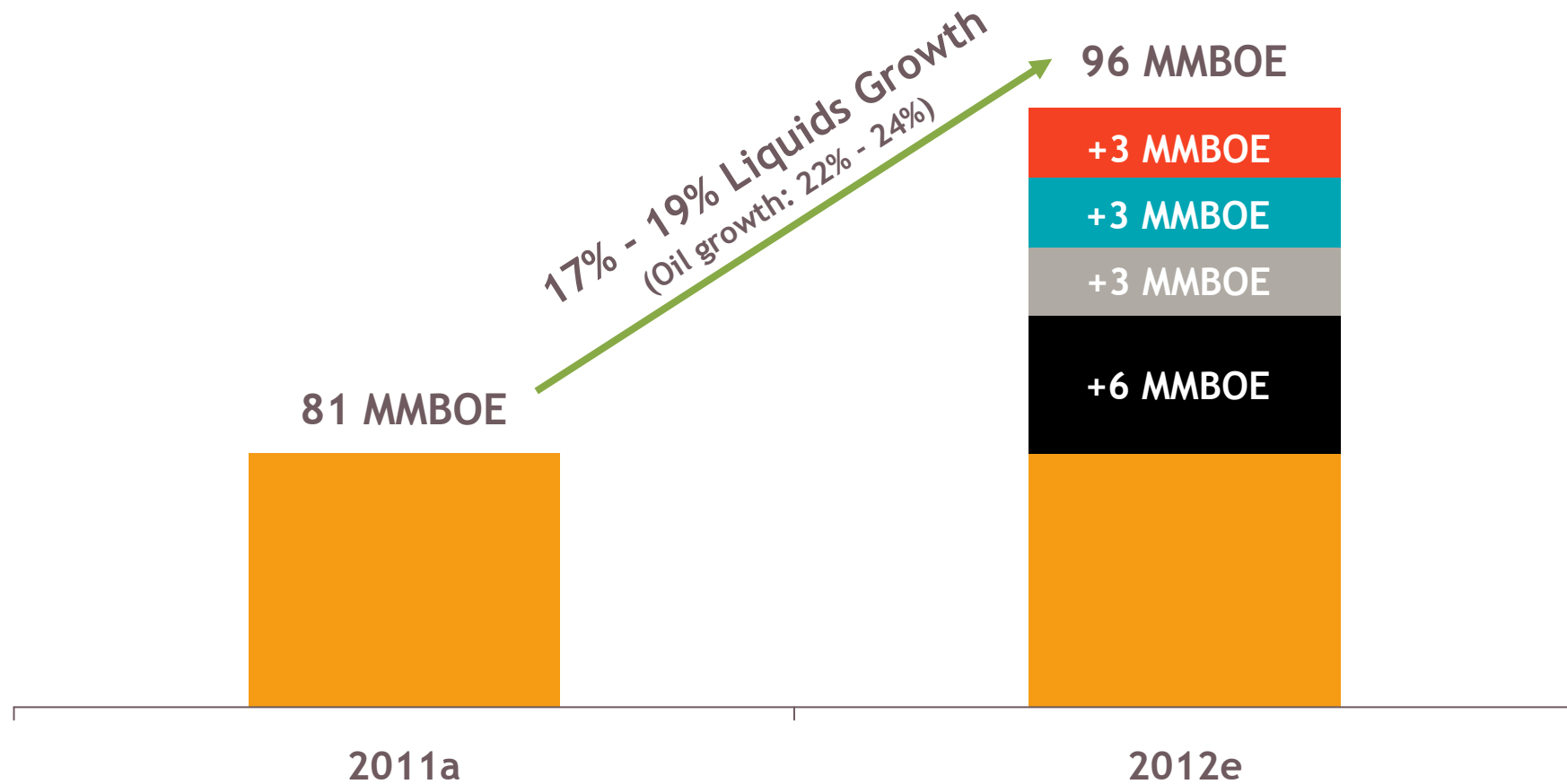
- Annual growth rate: 11% - 13%
- Driven by Cana and Barnett activity
- NGLs have access to Mont Belvieu

Natural gas production

- Expect minor declines
- No dry gas rigs running
- No significant lease expirations

2012 Liquids Growth

By Key Asset



■ Base Production ■ Thermal ■ Permian ■ Cana ■ Barnett

2012 F&D Target

E&P capital	\$6.1 - \$6.5 billion
Capitalized G&A and interest	\$0.4 billion
Drill-bit capital	\$6.5 - \$6.9 billion
Drill-bit reserve additions ⁽¹⁾	360 - 390 MMBOE
F&D ⁽¹⁾	≈\$16 - \$19/BOE
Reserve replacement ⁽¹⁾	≈150%

(1) Excludes price revisions

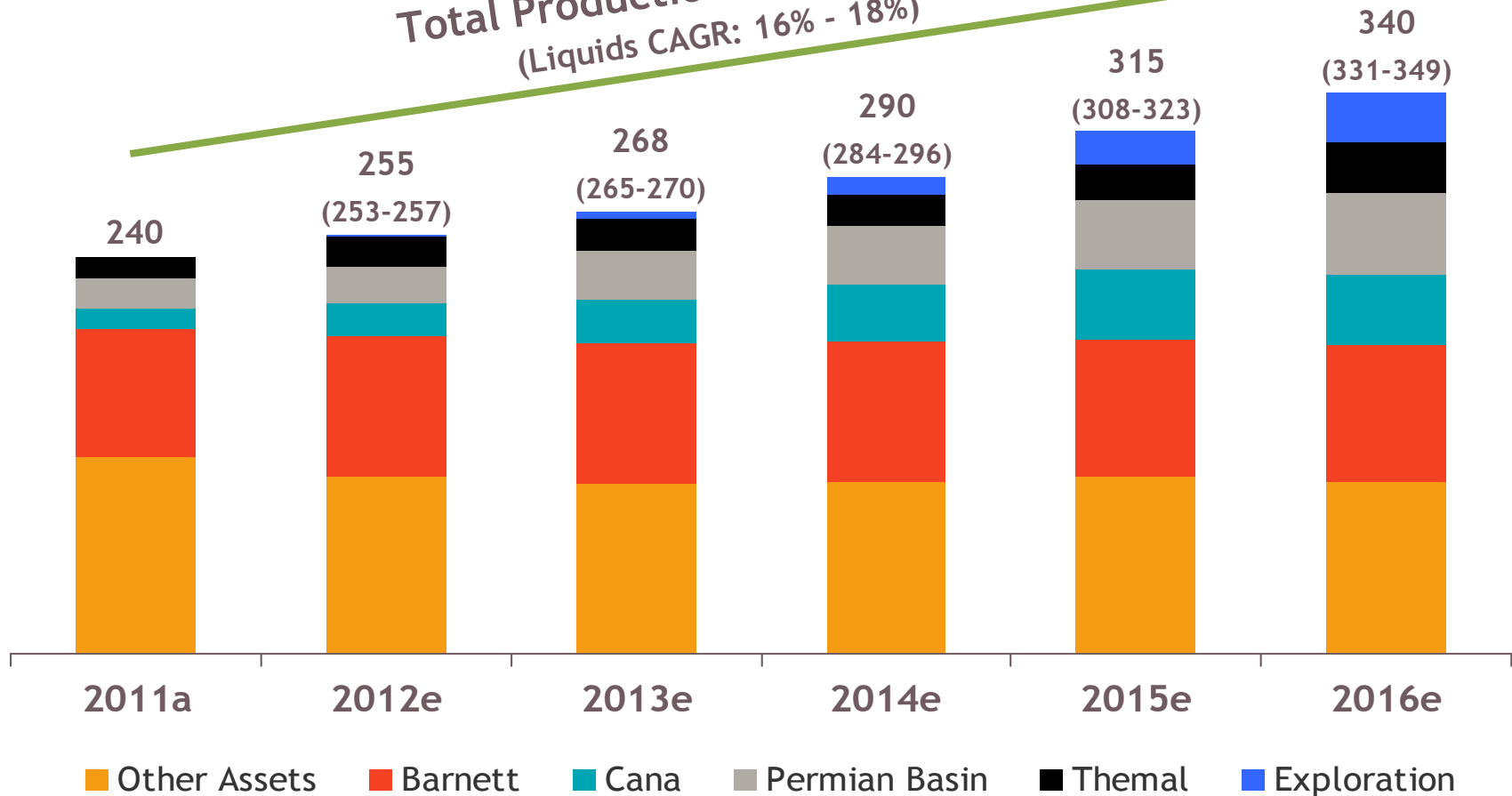
Notes: F&D equals drill-bit capital divided by drill-bit reserve additions
Includes a non-GAAP measure, see appendix for required disclosures.

Long-Term Outlook

Production By Key Asset

Production Data in MMBOE

Total Production CAGR: 6% - 8%
(Liquids CAGR: 16% - 18%)



Other Assets Barnett Cana Permian Basin Themal Exploration

Summary

- Committed to:
 - Maximizing return on investment
 - Maintaining a balanced portfolio
 - Optimizing depth and quality of portfolio
- Deep inventory of opportunities in current environment
- Robust oil-focused leasehold capture
- Strong, highly-visible oil and liquids production growth

New Ventures

Dave Hager

Executive Vice President, E&P

New Ventures/Exploration

Well Resourced

- Technical expertise
- Budget

Objectives/Strategy

- Establish material positions in new high-margin plays (oil current focus)
- Be an early mover (reasonable acreage costs and royalty burdens)
- Focus on regions with manageable operating environments
- Utilize partnerships to improve capital efficiency
- Continuous, efficient resource capture

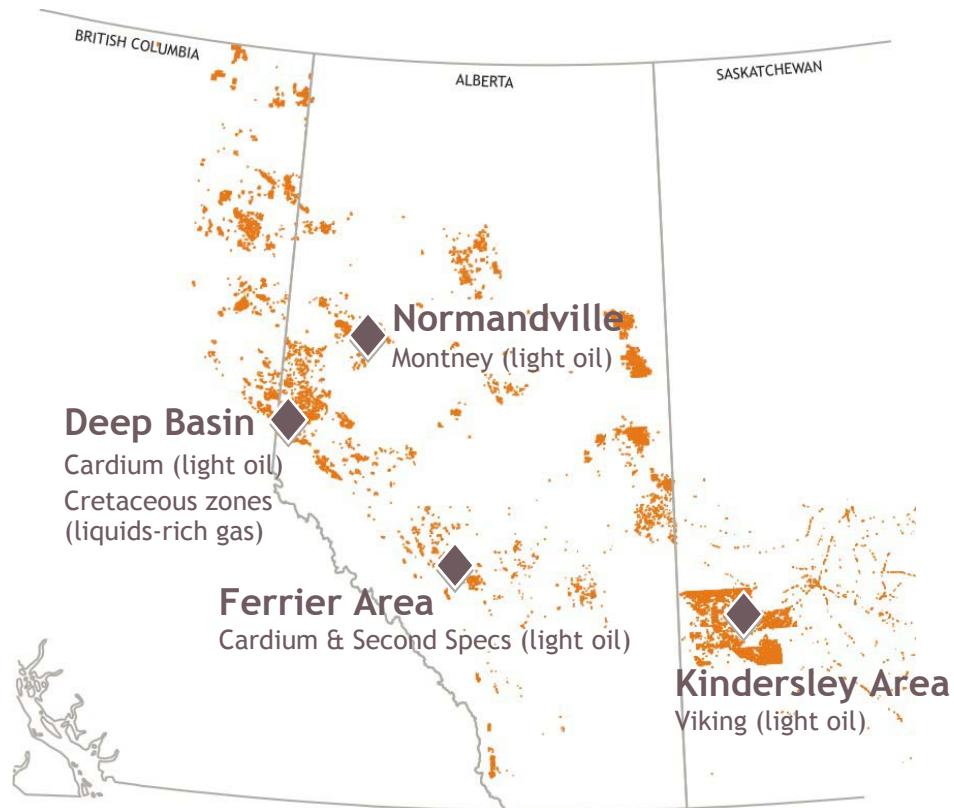
New Ventures/Exploration Process

Unlocking Significant Potential

- Methodical exploration
- Initial assessment
 - Oil in place
 - Permeability
 - Rock properties
 - Cost to develop
- Lease best plays
- Test commerciality
- Expand position

	Unrisked Resource (BBOE)
New ventures (Sinopec JV & Cline Shale)	8.4
Other U.S. exploration	5.8
Canada exploration	2.2
Development & exploitation assets	15.4
<hr/>	
Total Unrisked Resource	31.8

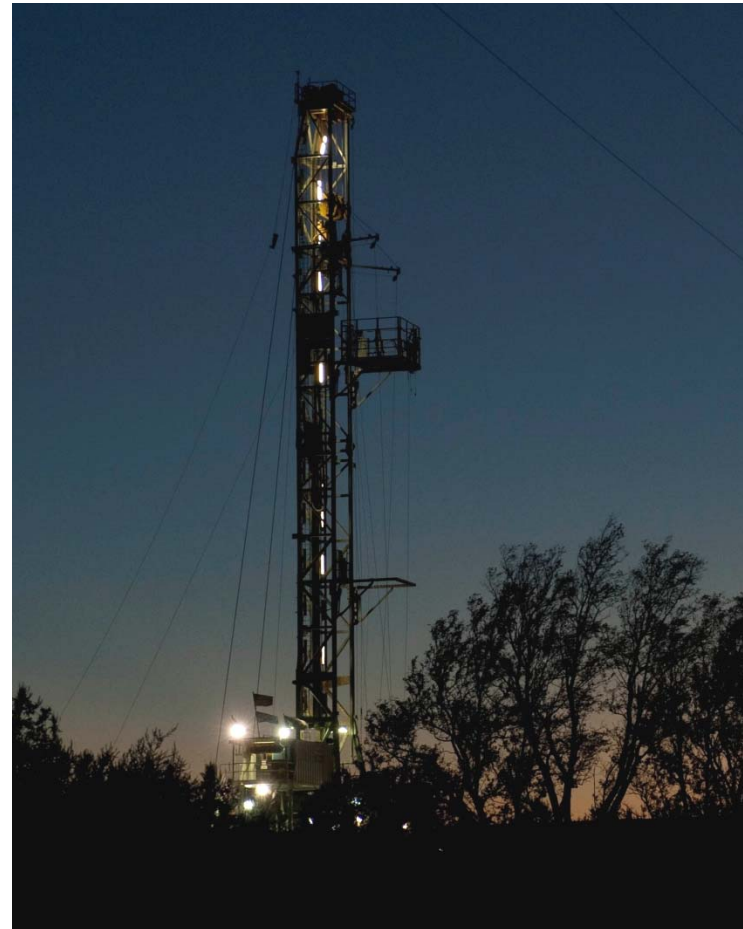
Canada Exploration Oil & Liquids Opportunities



- Net prospective acres: >4 million
- Net unrisks resource: 2.2 BBOE
- 2012 plans: Drill 90 wells
- Testing >10 new play types including:
 - Viking (Shallow targets; good economics)
 - Cardium (Ferrier area IP's up to 940 BOED)
 - Second Specs (Early stages of evaluation)
 - Montney (Light-oil exploration prospect)
 - Cretaceous zones (Exploiting multi-stacked pay)

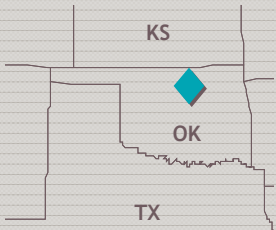
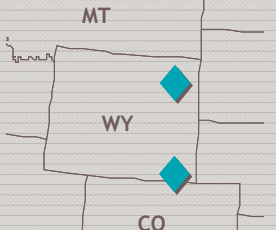



Other U.S. Exploration Oil & Liquids Opportunities

- Net prospective acres: 1.3 million
- Net unrisks resource: 5.8 BBOE
- Focus on oil opportunities
- Targeting tight carbonates/clastics and shale
- Currently evaluating 16 different exploration concepts across our existing asset base
 - 2012 Plans: Drill ≈15 wells

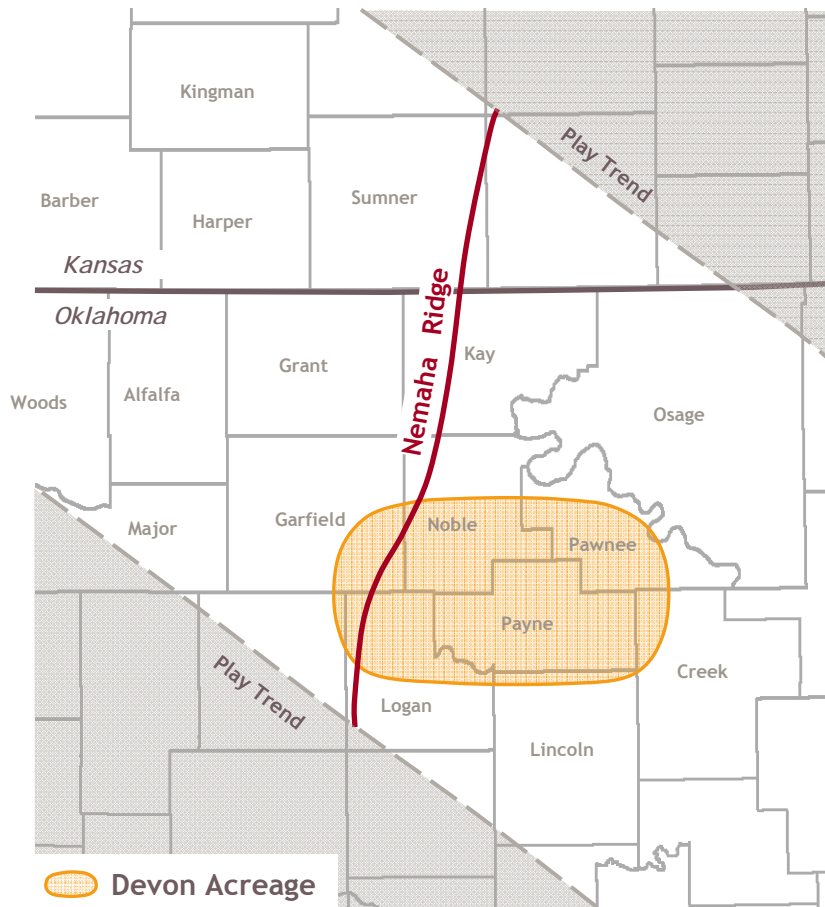


Initial New Venture Positions

Five Oil and Liquids-Rich Plays Partnered with Sinopec

	Mississippian	Rockies Oil	Utica Ohio	Tuscaloosa	Michigan
Net Acres Assembled	230,000	320,000 • 220,000 PRB • 100,000 DJ Basin	235,000	285,000	360,000
Location					
Average Royalty	20%	18%	16%	21%	17%
Play Type	Oil in matrix and fractured carbonate zone	Oil in matrix and fractured carbonate zone	Oil in carbonate rich shale zone	Oil and gas in silica rich shale zone	Oil and gas in shale and carbonate zones
Targets	Mississippian Lime & Woodford Shale	Niobrara, Turner, Codell, Mowry & Frontier	Utica Shale	Tuscaloosa Marine Shale (Silica-rich shale)	A1 Carbonate & Utica Shale
Depth	4,500' - 6,500'	6,000' - 12,000'	3,000' - 6,000'	11,000' - 15,000'	7,500' - 10,500'
2011 & 2012 Activity	Drill/participate in ~50 wells	Drill/participate in ~35 wells	Drill/participate in ~15 wells	Drill/participate in ~10 wells	Drill/participate in ~15 wells

Mississippian Overview

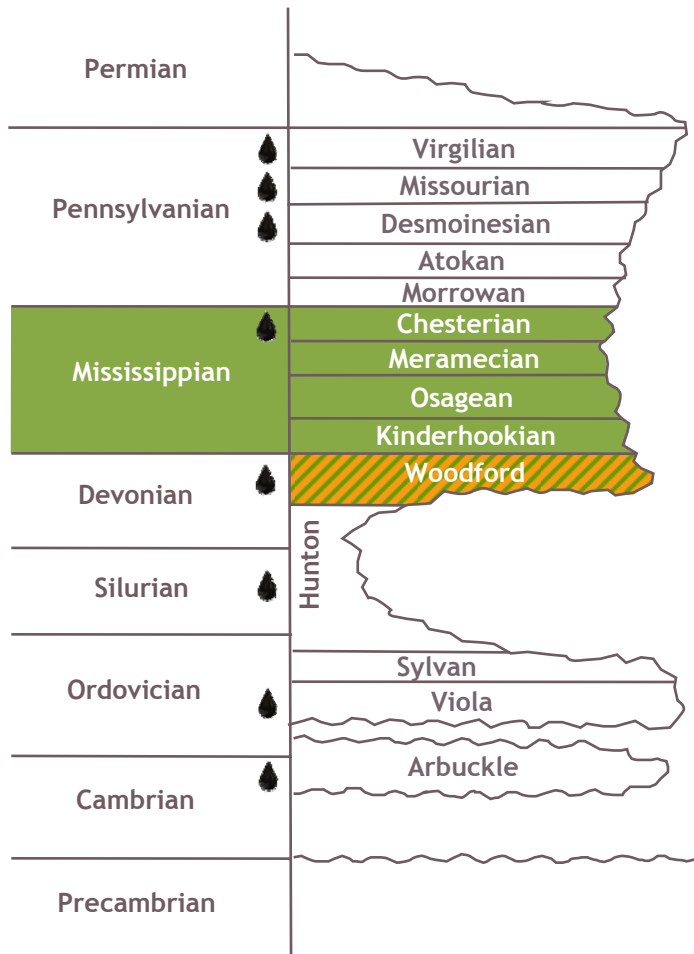


	DVN (net)	JV (gross)
Net acres:	153,000	230,000
Unrisked res.	560 MMBOE	840 MMBOE
2012 capital:	\$26 MM	\$90 MM
2011/12 plans:	Drill ≈ 50 wells	

Attractive Attributes

- 40° API sweet crude
- Existing well control and industry activity significantly derisking play
- Opportunities to expand position
- Can utilize smaller and more available rigs
- Stacked pay potential (Woodford)

Mississippian Stratigraphic Section

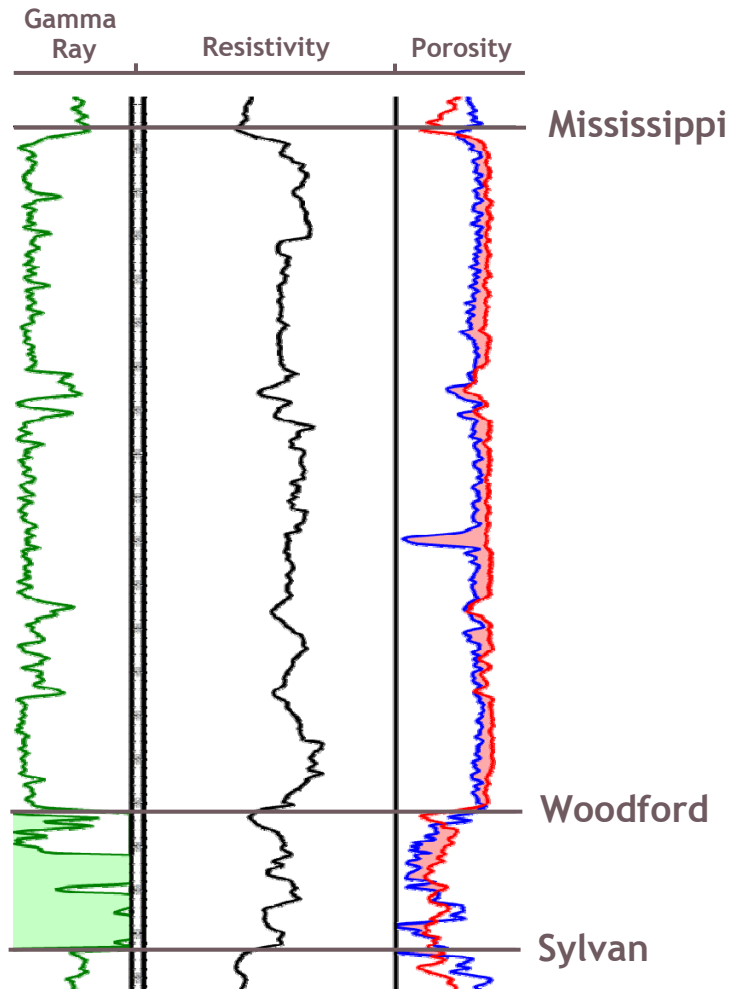


- Multiple prolific lithologies
 - High porosity chert
 - Siliceous limestone with medium porosity
 - Fractured limestone with lower porosity
- Significant open fractures
- Woodford TOC up to 10% is a great source rock



Productive Zones
 Primary Objective
 Secondary Objective

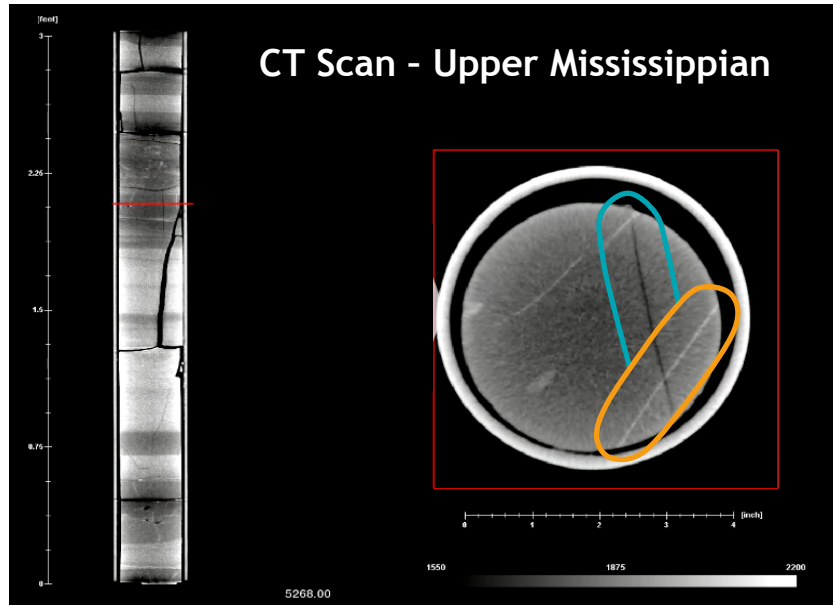
Mississippian Type Log



- Widespread shelf setting with minimal relief
- Gross thickness: 100' - 300'
- Oil window with 39 - 42 degree gravity and 4,000 GOR average
- Microdarcy permeability system
- Healed fractures reopened by frac job

Mississippian Fractures Within Interval

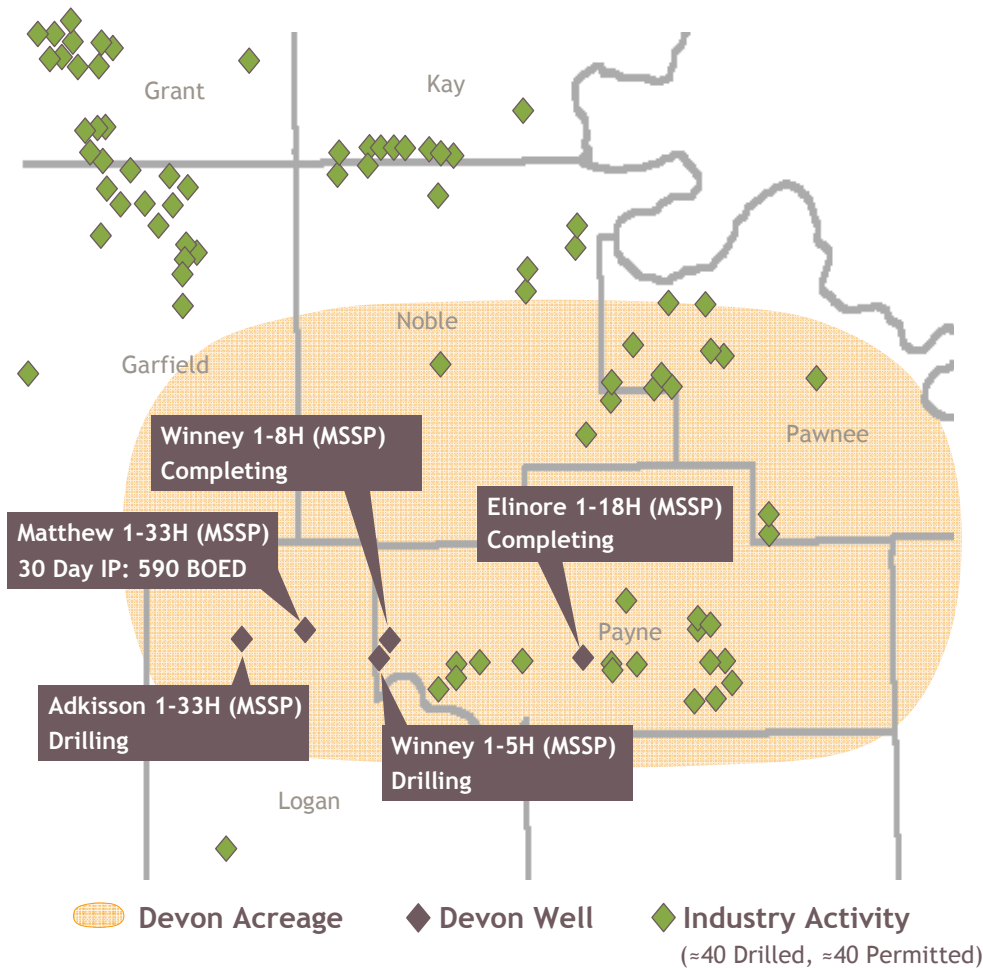
Frank 1-33



- Mineralized fractures (white)
- Healed to fully open fractures (black)
- Both fracture types improve effectiveness of fracture stimulation

Mississippian

Results to Date & Targets



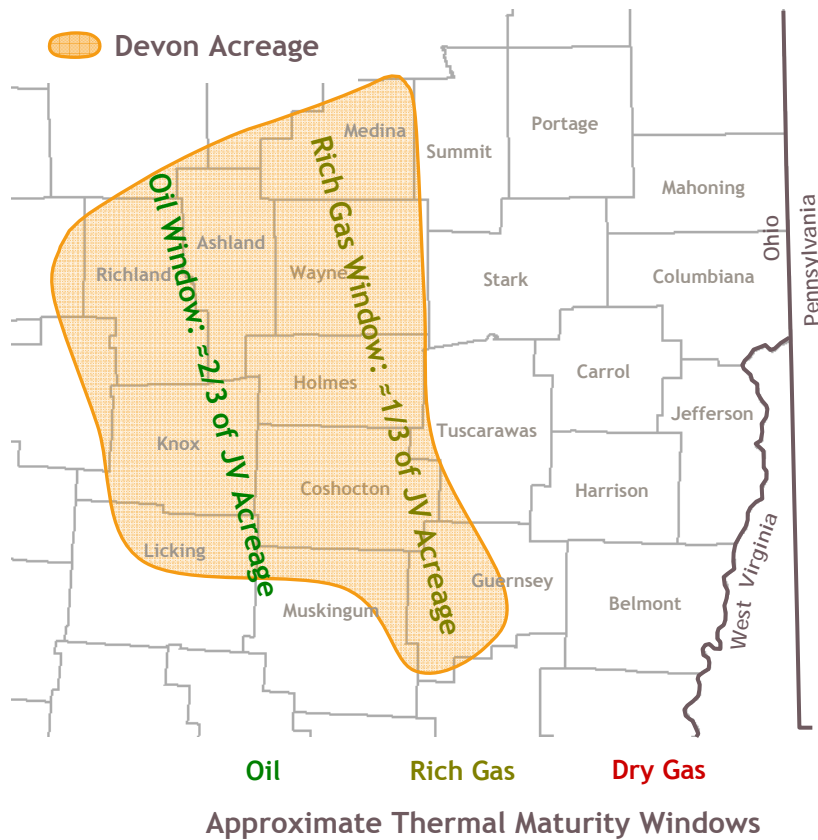
Target Well Economics

- Drill & complete cost: \$3.0 - 3.5 million
- EUR: 300 - 400 MBOE (80% liquids)
- IP rate (1st month avg): 275 - 325 BOED
- Average royalty: 20%

Keys Going Forward

- Matrix vs. fracture contribution
- Drilling and completion cost optimization
- Long lateral and larger stage completions not yet tested

Ohio Utica Overview

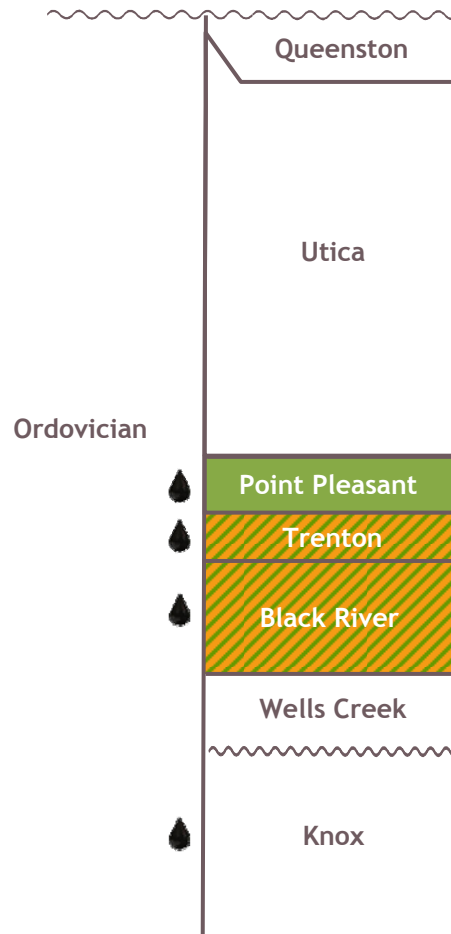


	DVN (net)	JV (gross)
Net acres:	157,000	235,000
Unrisked res.	640 MMBOE	950 MMBOE
2012 capital:	\$26 MM	\$100 MM
2011/12 plans:	Drill ≈ 15 wells	

Attractive Attributes

- Positive industry results to date
- Conventional oil and gas area
- Abundant well control
- Favorable subsurface (TOC, porosity, perm)

Ohio Utica Stratigraphic Section

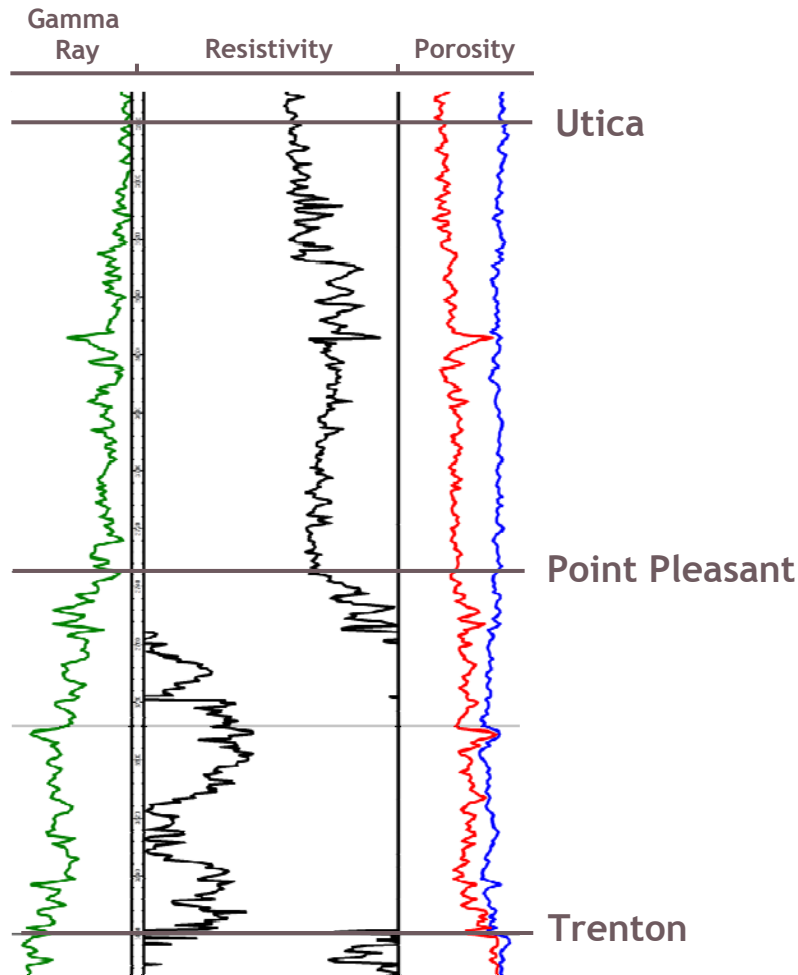


- Hybrid unconventional resource
- Lithology consists of laminated limestone-mudstone
- In-situ fractures
- Frac barriers above and below (no wet zones)
- Prolific source rock and reservoir
- Potential upside from fractured Trenton/Black River

Productive Zones Primary Objective Secondary Objective

Ohio Utica

Type Log

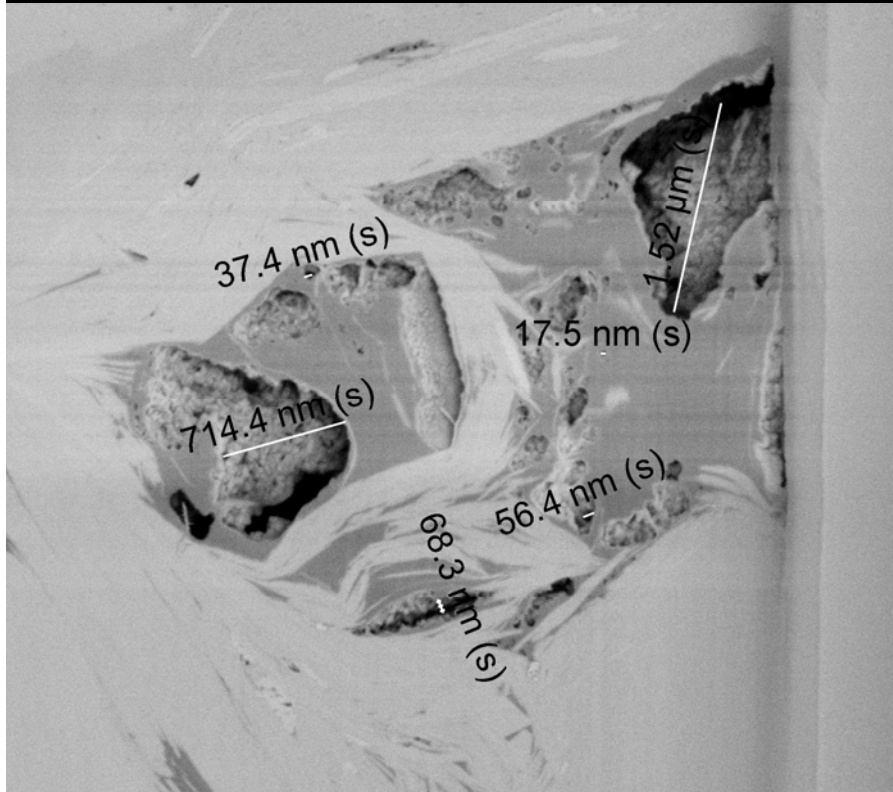


- Point Pleasant primary reservoir
- Gross thickness: 100' - 140'
- Consistent interval thickness
- Low structural relief
- Play spans dry gas to oil window
- Microdarcy permeability system

Ohio Utica

Permeability Analysis

Fixed Ion Beam Scanned Electron Microscope (FIBSEM Analysis)



nm = nanometers
(Oil molecules range from 0.5 - 3.0 nm)

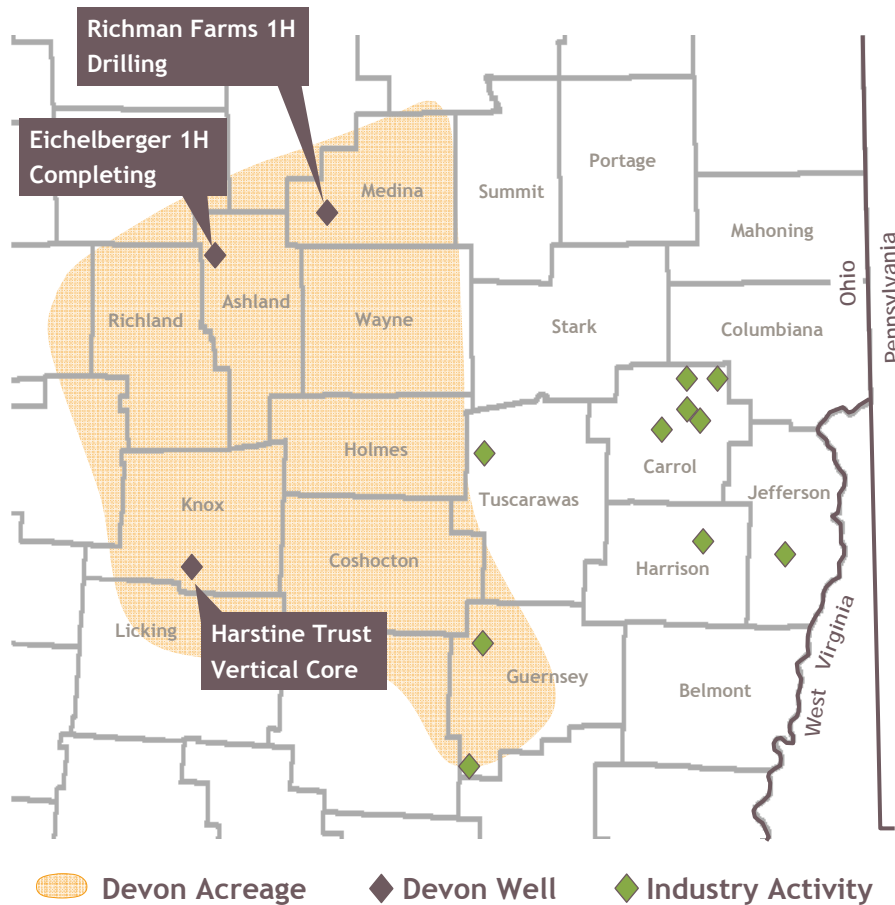
- FIBSEM analysis enables imaging of connected pores
- Significant size pores present
- Indicates potential to move liquids
- Top-tier permeability:

Permeability (microdarcy, μD)

DVN Harstine Well	Up to 30
Barnett Shale:	0.2 to 0.3
Marcellus:	0.7 to 1.3
Eagleford:	0.7 to 1.5
Bakken:	6.7 to 13.3

Ohio Utica

Results to Date & Targets



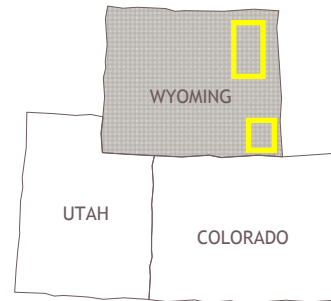
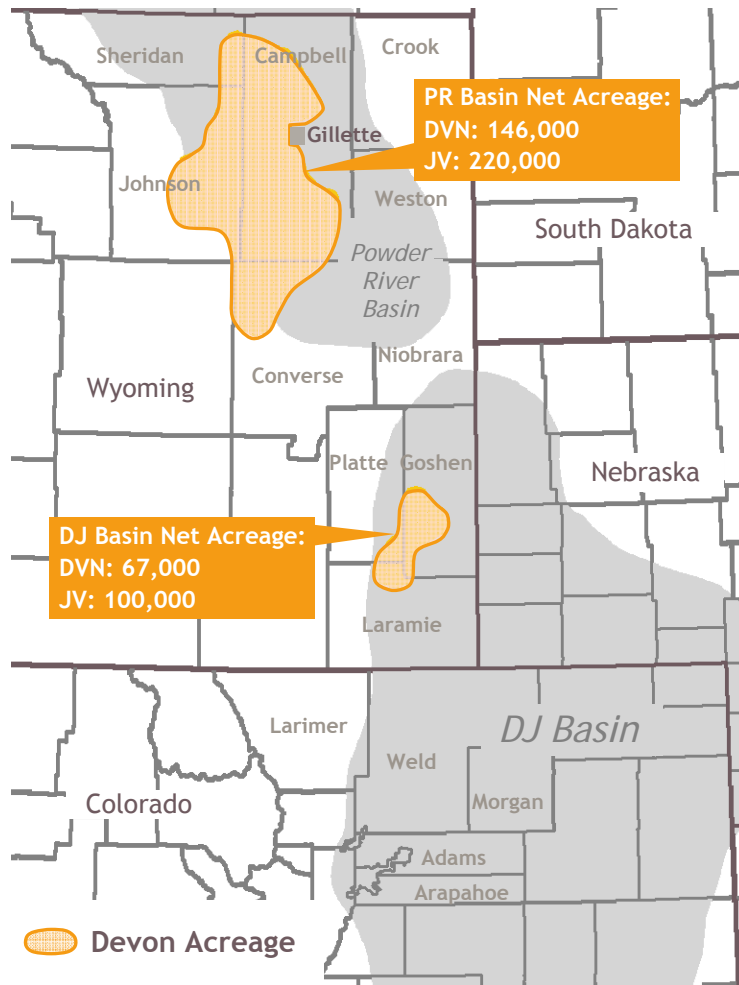
Target Well Economics

- Drill & complete cost: \$3.0 - 5.0 million
- EUR: 200 - 300 MBOE (85% liquids)
- IP rate (1st month avg): 200 - 250 BOED
- Average royalty: 16%

Keys Going Forward

- Flow properties of oil window
- Variations in permeability
- Gas/oil ratio
- Maturity variation across position
- Overpressured trend

Rockies Oil Overview



	DVN (net)	JV (gross)
Net acres:	213,000	320,000
Unrisked res.	890 MMBOE	1,330 MMBOE
2012 capital:	\$40 MM	\$152 MM
2011/12 plans:	Drill ≈ 35 wells	

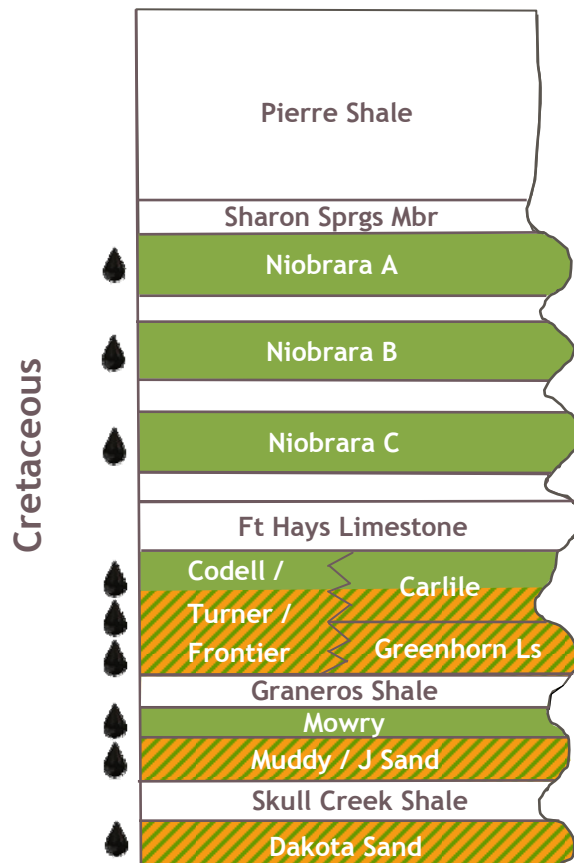
Attractive Attributes - Powder River Basin

- Stacked oil targets - Niobrara, Turner, Frontier, Greenhorn Mowry & Muddy
- Economic results in multiple intervals
- Significant operational expertise in basin

Attractive Attributes - DJ Basin

- Stacked oil targets - Niobrara, Codell, Greenhorn & J Sand
- Favorable thermal maturity for oil generation
- Thick Codell sand with oil shows in core and logs

Rockies Oil Stratigraphic Section



Powder River Basin

- Primary targets: Niobrara and Mowry
- High total organic content in Mowry and Niobrara
- Secondary targets: Turner, Muddy, Dakota and Frontier
- Deeper Paleozoic prospective

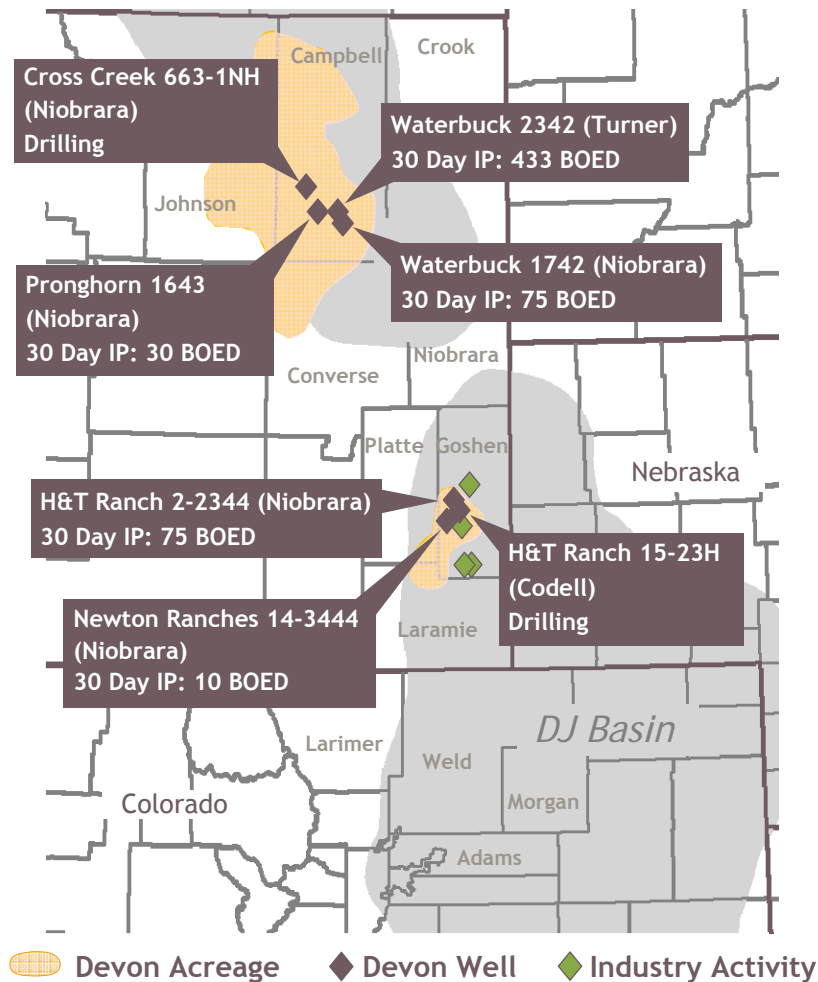
DJ Basin

- Primary targets: Niobrara and Codell
- Niobrara and Mowry source of significant lower Cretaceous production
- Multiple Niobrara chalk benches; B main target across play
- Viable secondary objectives: Greenhorn and J Sand

Productive Zones
 Primary Objective
 Secondary Objective

Rockies Oil

Results to Date & Targets



Target Well Economics - PR Basin

- Drill & complete cost: \$5.5 - 6.0 million
- EUR: 300 - 400 MBOE (90% liquids)
- IP rate (1st month avg): 450 - 500 BOED
- Average royalty: 20%

Target Well Economics - DJ Basin

- Drill & complete cost: \$4.7 - 5.2 million
- EUR: 200 - 300 MBOE
- IP rate (1st month avg): 250 - 300 BOED
- Average royalty: 17%

Rockies Oil

Learnings to Date

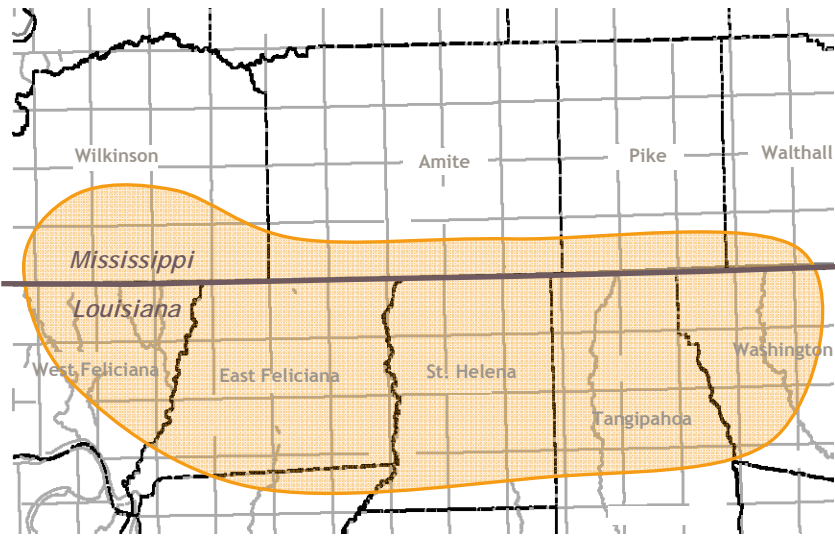
What We Know

- Fractures in Niobrara are key - initial wells had lower fracture intensity
- Deeper areas in PRB with higher GOR performing better in Niobrara
- Encouraging initial results from other zones with meaningful potential
(Turner, Codell, Mowry, Frontier and Greenhorn)

Keys Going Forward

- 3D seismic targeting fractures to improve Niobrara performance
- Define extent of secondary objectives

Tuscaloosa Overview



 Devon Acreage



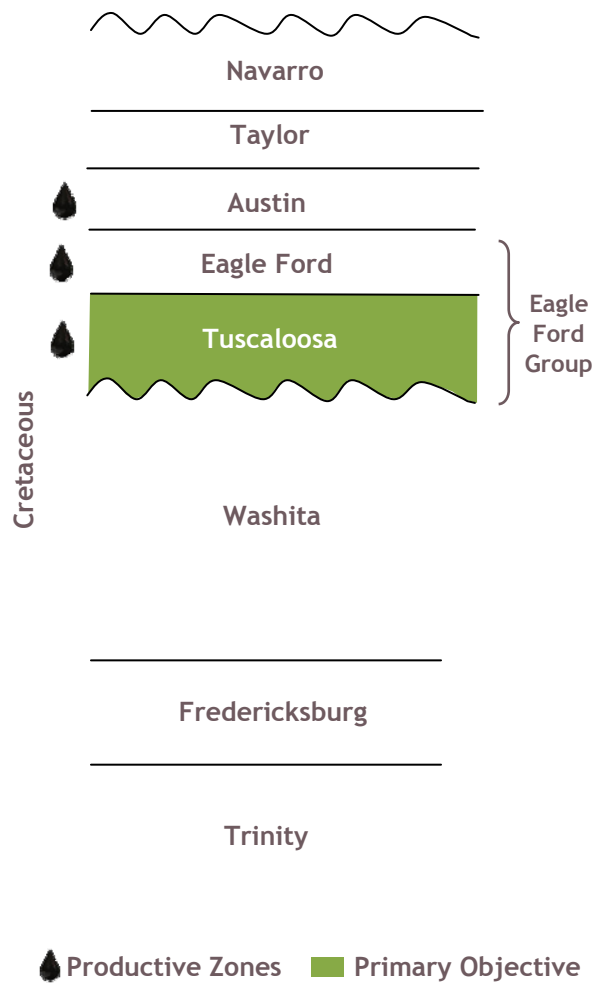
	DVN (net)	JV (gross)
Net acres:	190,000	285,000
Unrisked res.	1,150 MMBOE	1,730 MMBOE
2012 capital:	\$44 MM	\$167 MM
2011/12 plans:	Drill ≈ 10 wells	

Attractive Attributes

- Proven capacity to flow oil; existing production
- Highly over-pressured reservoir
- Low-cost acreage
- Well-established regulatory environment
- Existing infrastructure

Tuscaloosa

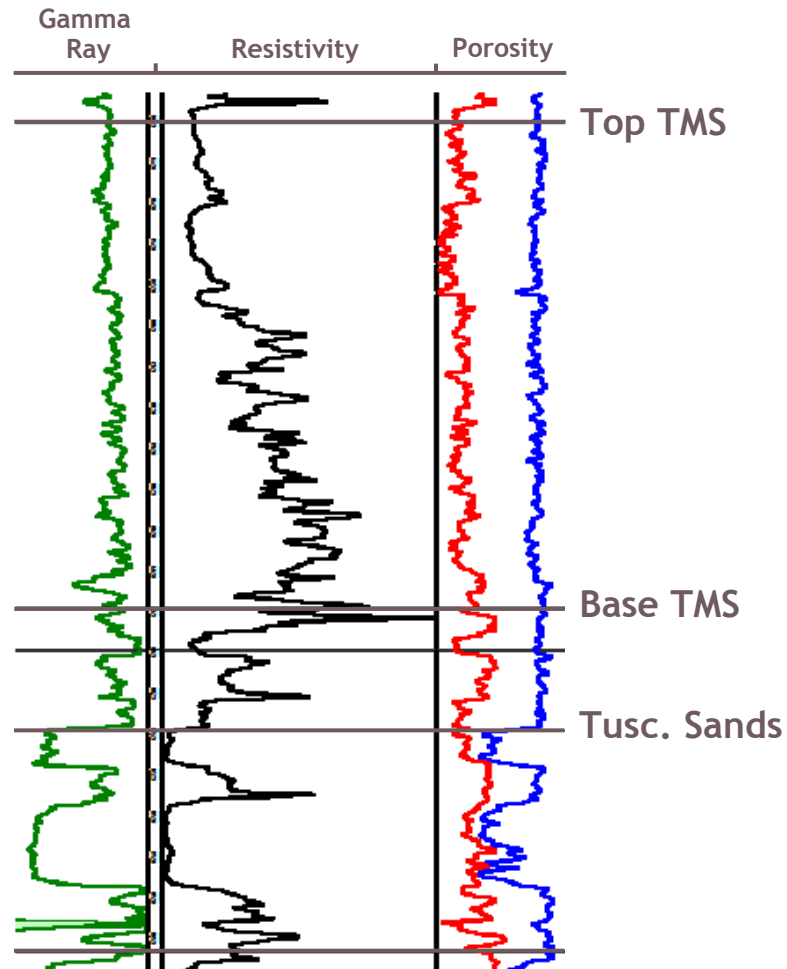
Stratigraphic Section



- Highly laminated lithology
- Brittle intervals of sand, siltstone and limestone
- Significant fracture system
- Several historical oil pay zones throughout the stratigraphic section

Tuscaloosa

Type Log



- Widespread shelf setting; low structural relief
- Gross thickness: 100' - 250'
- High resistivity
- Highly overpressured: >0.7 psi/ft
- Frac barriers above and below
- Fractures present in cores and image logs

Tuscaloosa

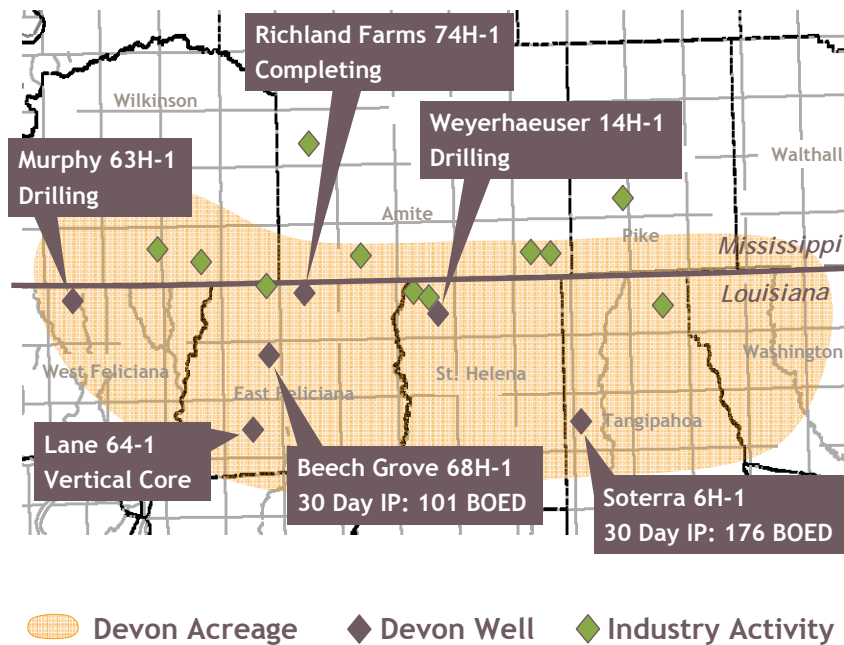
Significant Fracture System



- Fractures are dominant component
- Very dense fractures
- Closely spaced fractures will improve permeability
- Challenges for drilling

Tuscaloosa

Results to Date & Targets



Target Well Economics

- Drill & complete cost: \$12 - 14 million
- EUR: 400 - 600 MBOE (90% liquids)
- IP rate (1st month avg): 700 - 900 BOPD
- Average royalty: 21%

Keys Going Forward

- Optimization of drilling and completion techniques and costs
- Testing of longer laterals with 15 - 20 stage fracs
- Establish repeatable commercial rates

Michigan



 Devon Acreage

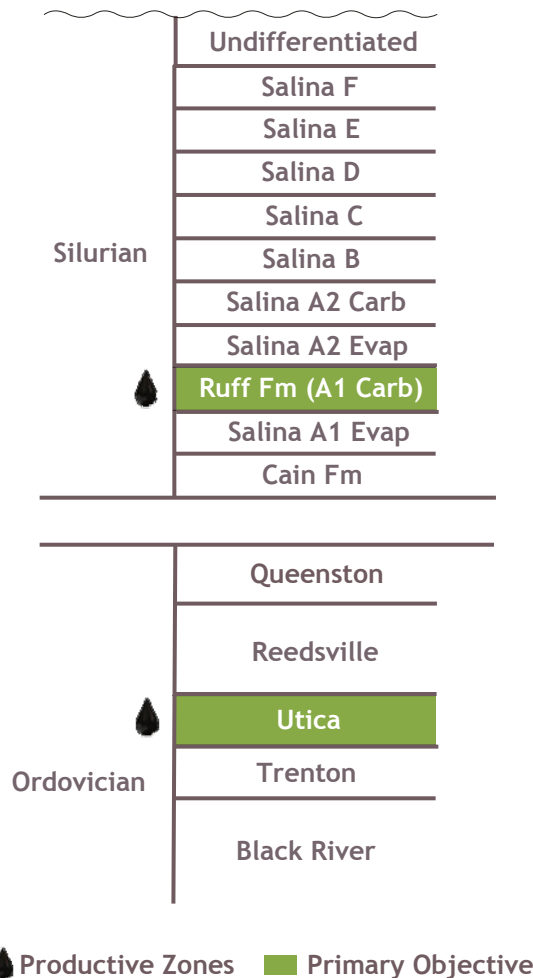


	DVN (net)	JV (gross)
Net acres:	240,000	360,000
Unrisked res.	1,530 MMBOE	2,290 MMBOE
2012 capital:	\$34 MM	\$108 MM
2011/12 plans:	Drill ≈ 15 wells	

Attractive Attributes

- Rich gas to oil maturity exposure
- Large resource potential
- Multi-zone potential
- Conventional oil and gas production
- 8 - 10 year leases

Michigan Stratigraphic Section



A1 Carbonate

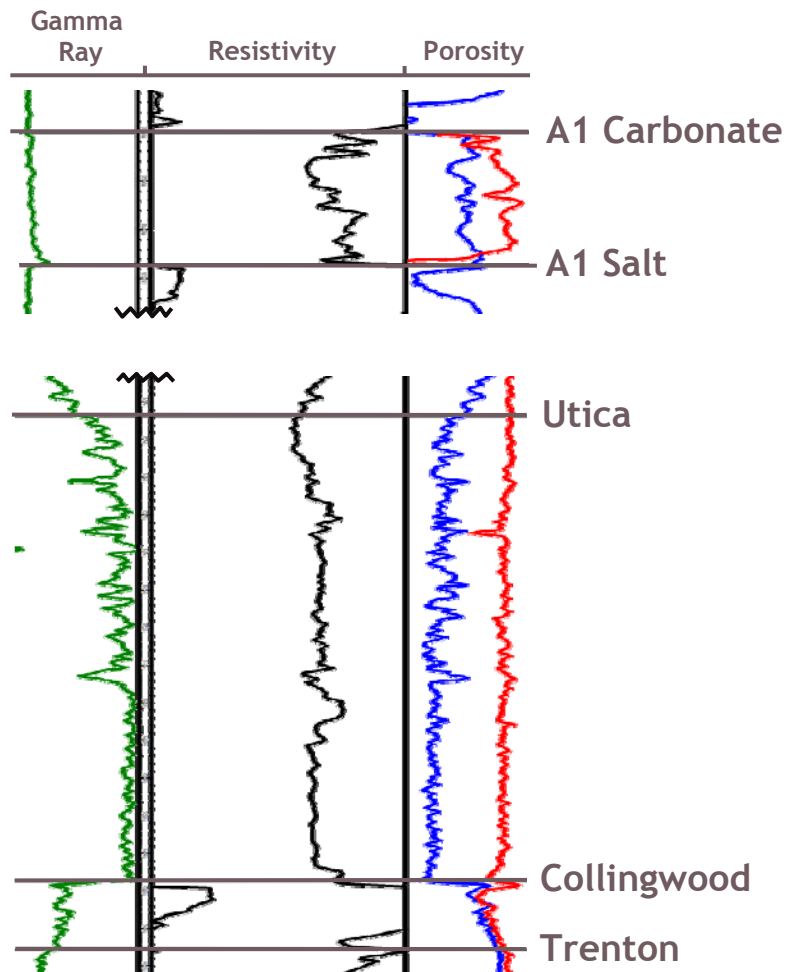
- Laminated organic-rich argillaceous limestone/ dolomite
- Gross thickness: 45' - 65'
- A1 is hydrocarbon source for the Michigan Basin reef trend

Utica Shale

- Laminated mudstone with silty carbonate-rich intervals
- Gross thickness: 250' - 400'
- Cores show fractures in both A1 and Utica

Michigan

Type Log



A1 Carbonate

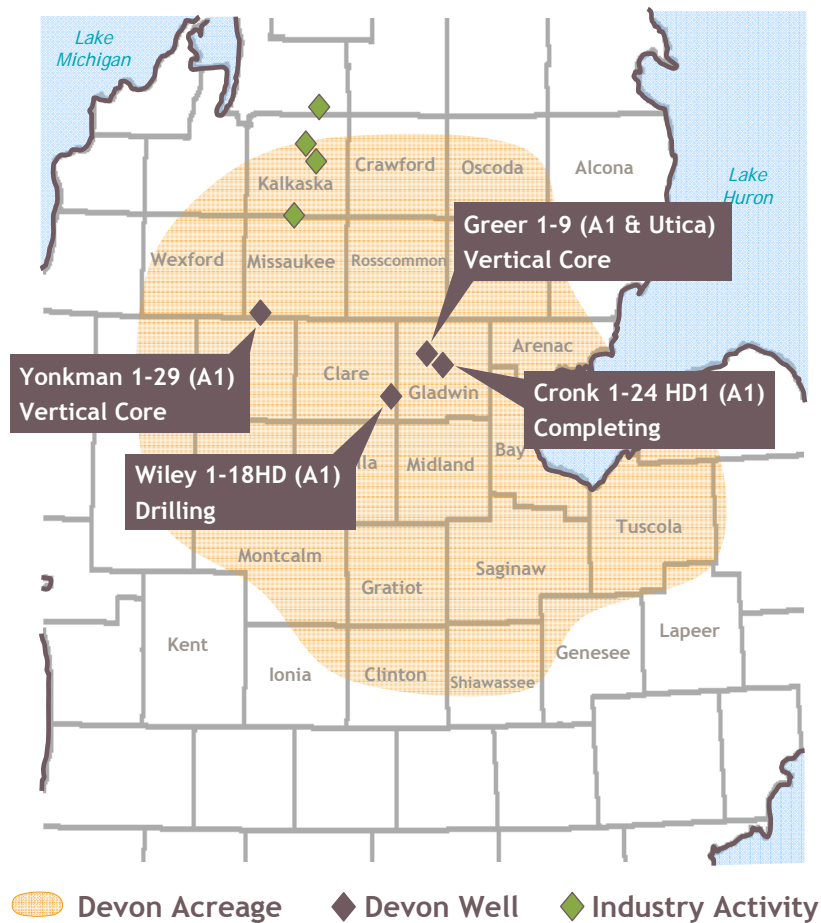
- Dolomitic limestone
- Vuggy porosity
- Cores show fracture development
- Highly fractured and overpressured

Utica Shale

- Silty, carbonate-rich
- Silty intervals provide higher perm
- Carbonate component contributes to brittleness (fractures)

Michigan

Results to Date & Targets



Target Well Economics - A1

- Drill & complete cost: \$5.5 - 8.0 million
- EUR: 800 - 900 MBOE (55% liquids)
- IP rate (1st month avg): 800 - 900 BOED
- Average royalty: 17%

Keys Going Forward

- Maturity in the A1 and Utica
- Pressure regime and mechanical implications
 - 1 psi per foot
- Understanding significant fracture system
 - 50 fractures/ft (average is 5)

JV New Venture Plays Summary

	DVN Net Acres	Unrisked Resource (MMBOE)	% Liquids
Mississippian	153,000	560	80%
Ohio Utica	157,000	640	85%
Rockies Oil	213,000	890	90%
Tuscaloosa	190,000	1,150	90%
Michigan	240,000	1,530	55%
Total	953,000	4,770	80%



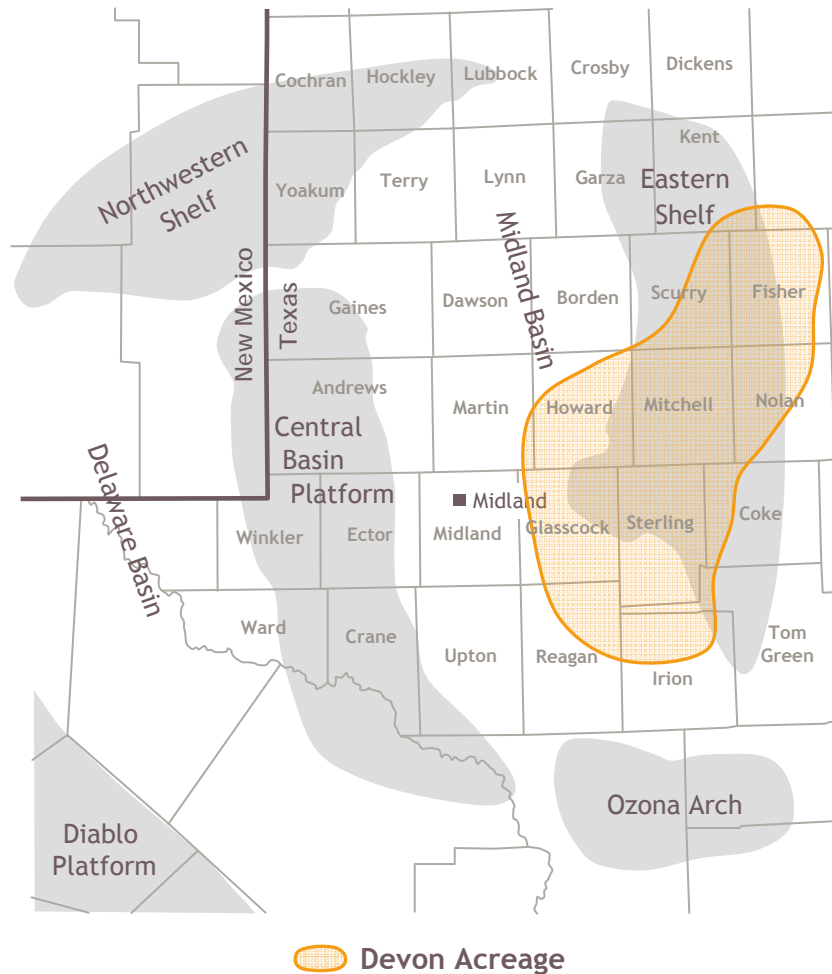
Additional New Ventures

Emerging Play Exposure Continues

	Net Acreage		Unrisked Resource (MMBOE)
	Closed or Committed	Target	
Cline Shale	500,000	500,000	3,600
Undisclosed oil play #1	250,000	500,000	2,700
Total	750,000	1,000,000	6,300

Note: Undisclosed play is not included in Devon's 31.8 BBOE of unrisked resource potential.

Cline Shale Overview



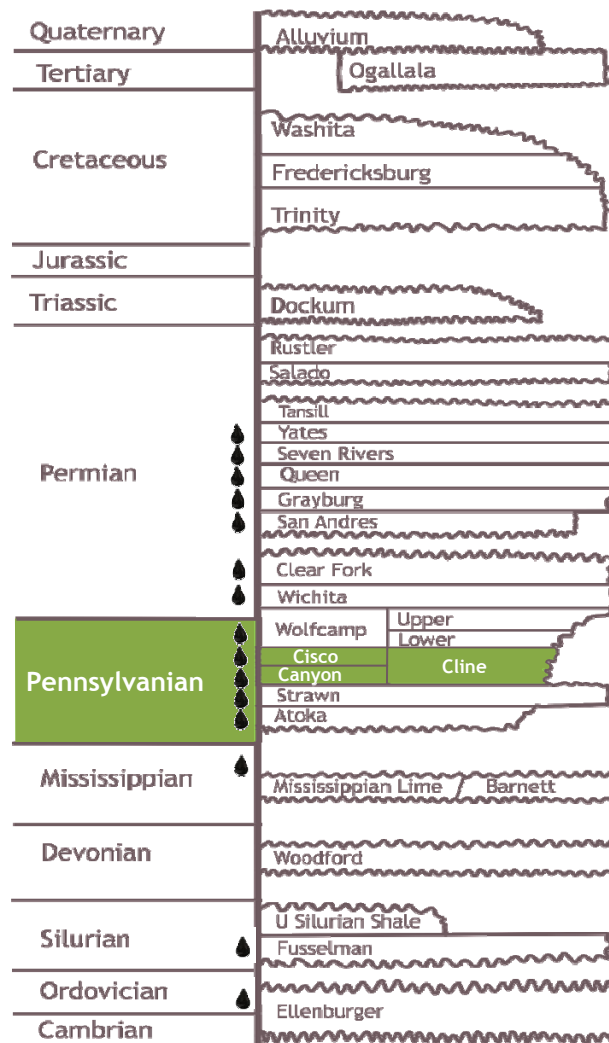
Net acres:	500,000
Unrisked res.	3.6 BBOE
2012 capital:	≈\$350 MM
2012 plans:	Drill ≈15 wells

Attractive Attributes

- High-impact resource play
- Existing well control and increasing industry activity derisking play
- Stacked pay potential
- Favorable regulatory and above ground environment

Cline Shale

Stratigraphic Section

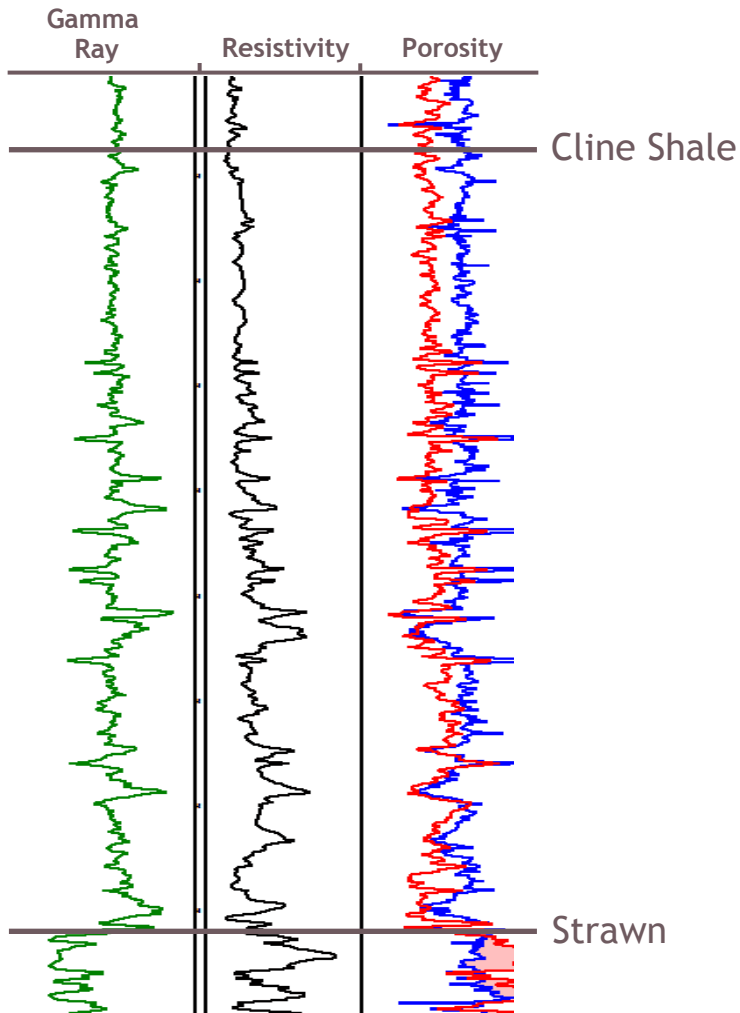


Productive Zones
 Primary Objective

- Organic-rich shale
- Mixed silt and sand interbeds
- Gross thickness: 200' - 550'
- Total organic content: 1 - 8%
- Frac barriers above and below

Cline Shale

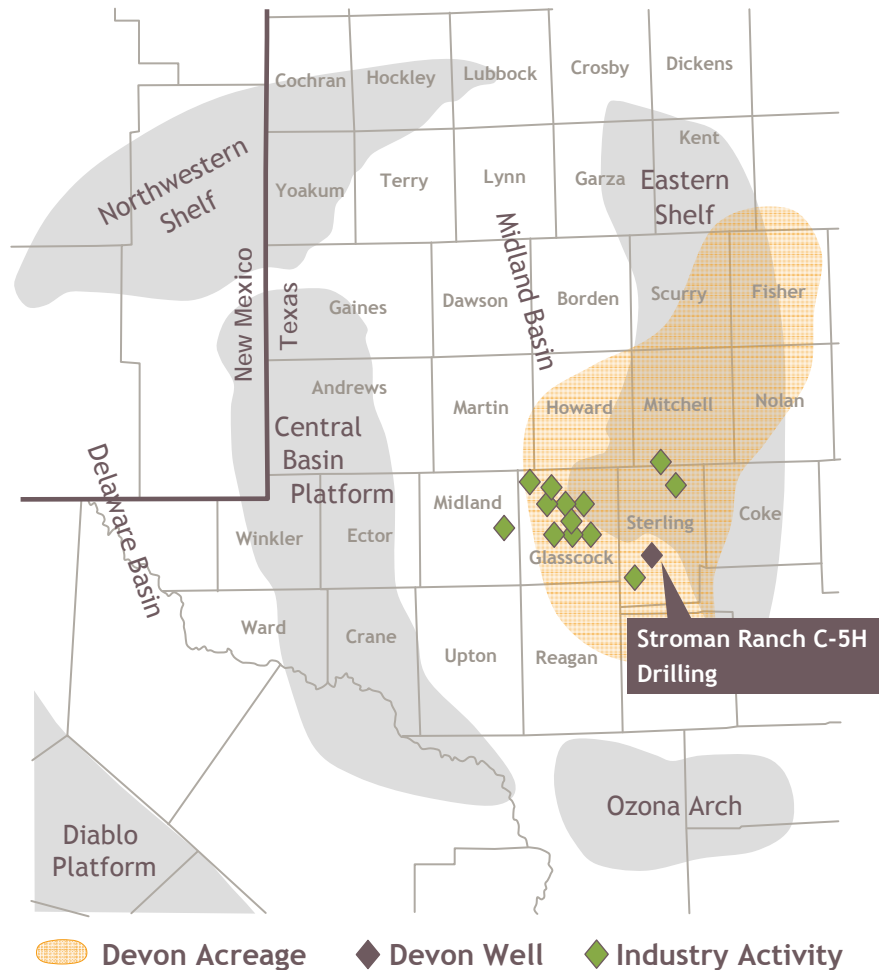
Type Log



- Broad shelf setting with minimal relief
- Oil window with 38 - 42 gravity and 2,500 to 3,000 GOR
- Excellent porosity: 6 - 12%
- Microdarcy permeability

Cline Shale

Results to Date & Targets



Target Well Economics

- Drill & complete cost: \$6.5 million
- EUR: 570 MBOE (85% liquids)
- IP rate (1st month avg): 600 BOED
- Average royalty: 25%

Keys Going Forward

- Capture additional core data
- Continuity of attractive reservoir properties
- Optimization of drilling and completion techniques
- Performance of longer laterals
- Evaluate stacked pay potential

New Ventures/Exploration Key Messages

- Well-funded, technically-capable new venture group
- Significant exploration potential on existing asset base
- Material new venture positions in oil plays
- Utilizing partnerships to improve capital efficiency
- Aggressive and efficient oil-focused resource capture



Q&A

Permian Basin

Andy Coolidge

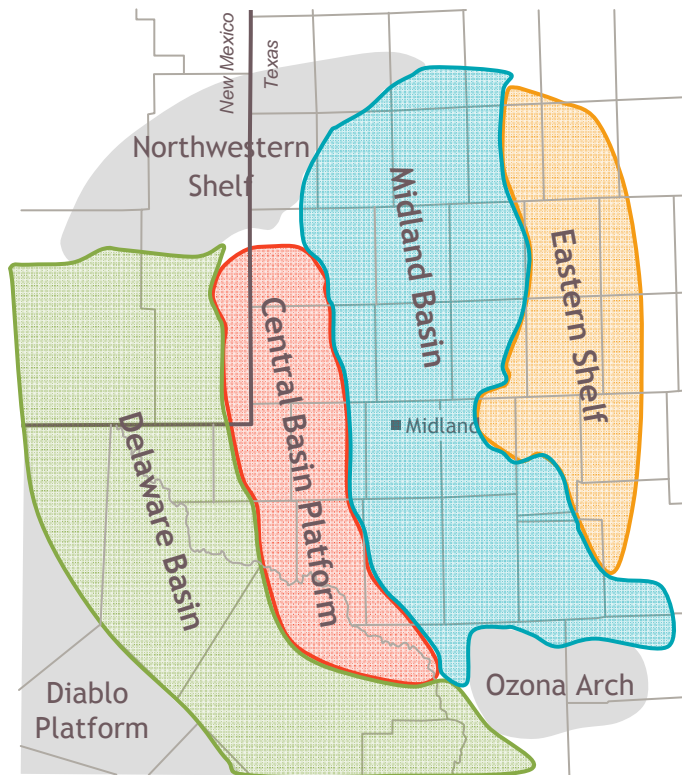
Business Unit Vice President,
Permian Basin

Permian Basin Key Messages

- Industry leader in basin
 - 1.5 million net acres with stacked-pay potential
 - Currently #1 horizontal driller
- Deep inventory of low-risk oil development projects
- Significant positions in emerging, high-impact oil plays
- Many additional play types to evaluate
- Highly economic & robust production growth

Geology Overview

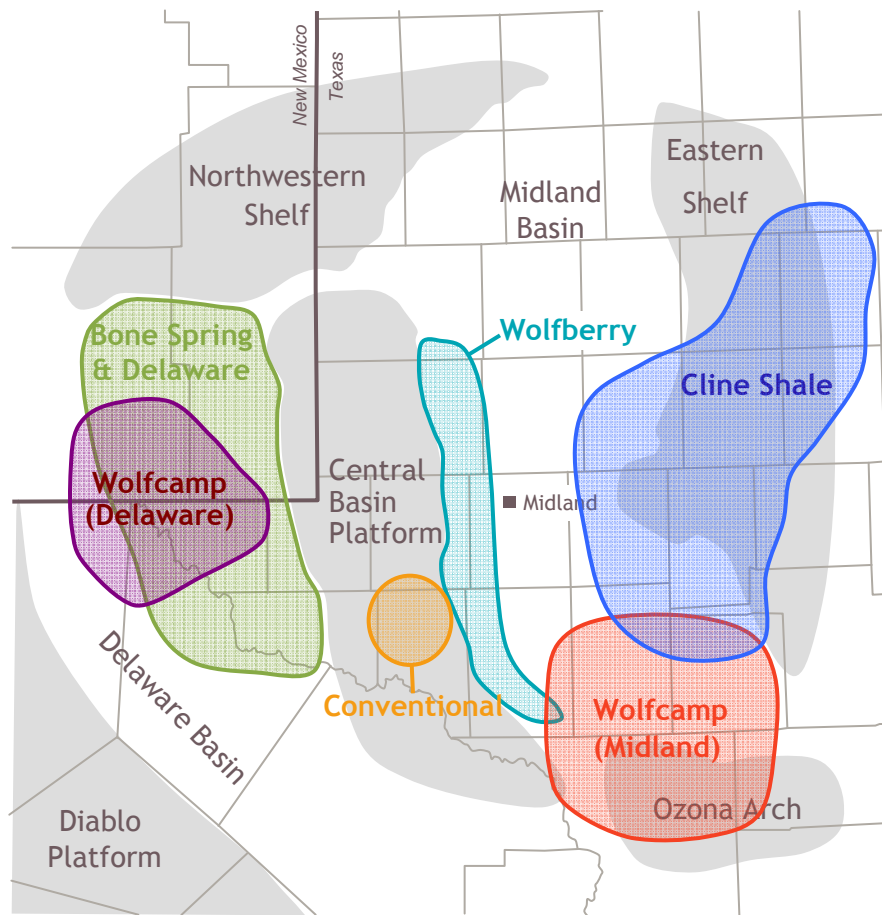
Low-Risk Development Plays



AGE	Delaware Basin	Central Basin Platform	Midland Basin	Eastern Shelf	
PERMIAN	Delaware Sand Group	Artesia Group	Artesia Group	Artesia Group	
		San Andres	San Andres	San Andres	
		Glorieta	Glorieta	San Angelo	
	Bone Spring	1st / Avalon	Clear Fork ^{Tubb}	Clear Fork	Clear Fork
		2nd	Wichita - Albany	Spraberry	Wichita - Albany
		3rd		Dean	
	Wolfcamp	Wolfcamp	Wolfcamp	Wolfcamp	
PENNSYLVANIAN	Cisco	Cisco	Cline	Cline	
	Canyon	Canyon	Cisco	Cisco	
	Strawn	Strawn	Canyon	Canyon	
	Atoka	Bend		Strawn	
	Morrow	Bend		Strawn	
MISSISSIPPIAN	Miss. Ls. Barnett	Miss. Ls. Barnett	Miss. Ls. Barnett	Miss. Ls. Barnett	

Note: Targeted formations are shaded.

Permian Basin Overview



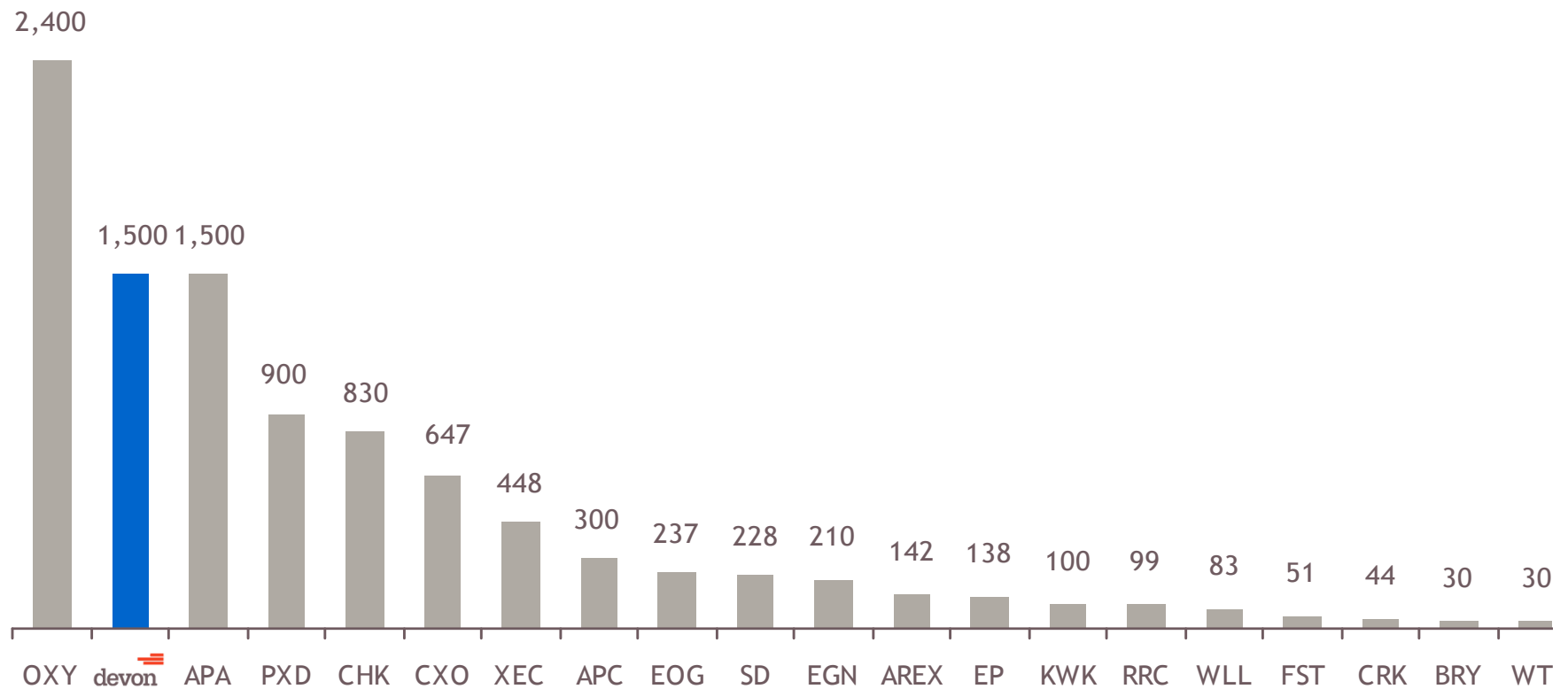
Net acres: 1.5 million
Net unrisks resource: 7.6 BBOE
Net risks resource: 2.8 BBOE
Risks locations: >8,000

- Significant exposure to oil & liquids plays
- 21 operated rigs (24 by year-end)
- Q4 2011 net production: 53 MBOED
- Oil and liquids content \approx 75% of production

Permian Basin

Independent E&P Acreage Positions

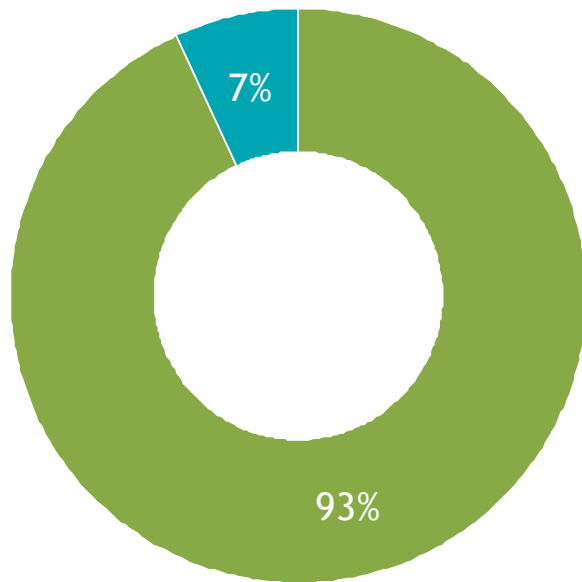
Net Acres (In Thousands)



Source: Howard Weil and company disclosures

Permian Risked Resource

2.8 BBOE Risked Resource
(7.6 BBOE Unrisked)



■ Proved Reserves (9% PUD) ■ Additional Risked Potential

Note: Includes 12/31/11 proved reserves of 189 MMBOE.

Risked Resource By Product (BBOE)

Oil (45%)	1.3
NGLs (29%)	0.8
Gas (26%)	0.7
<hr/>	
Total	2.8

Includes only those play types characterized to date

Slide 86

Additional Permian Resource Upside

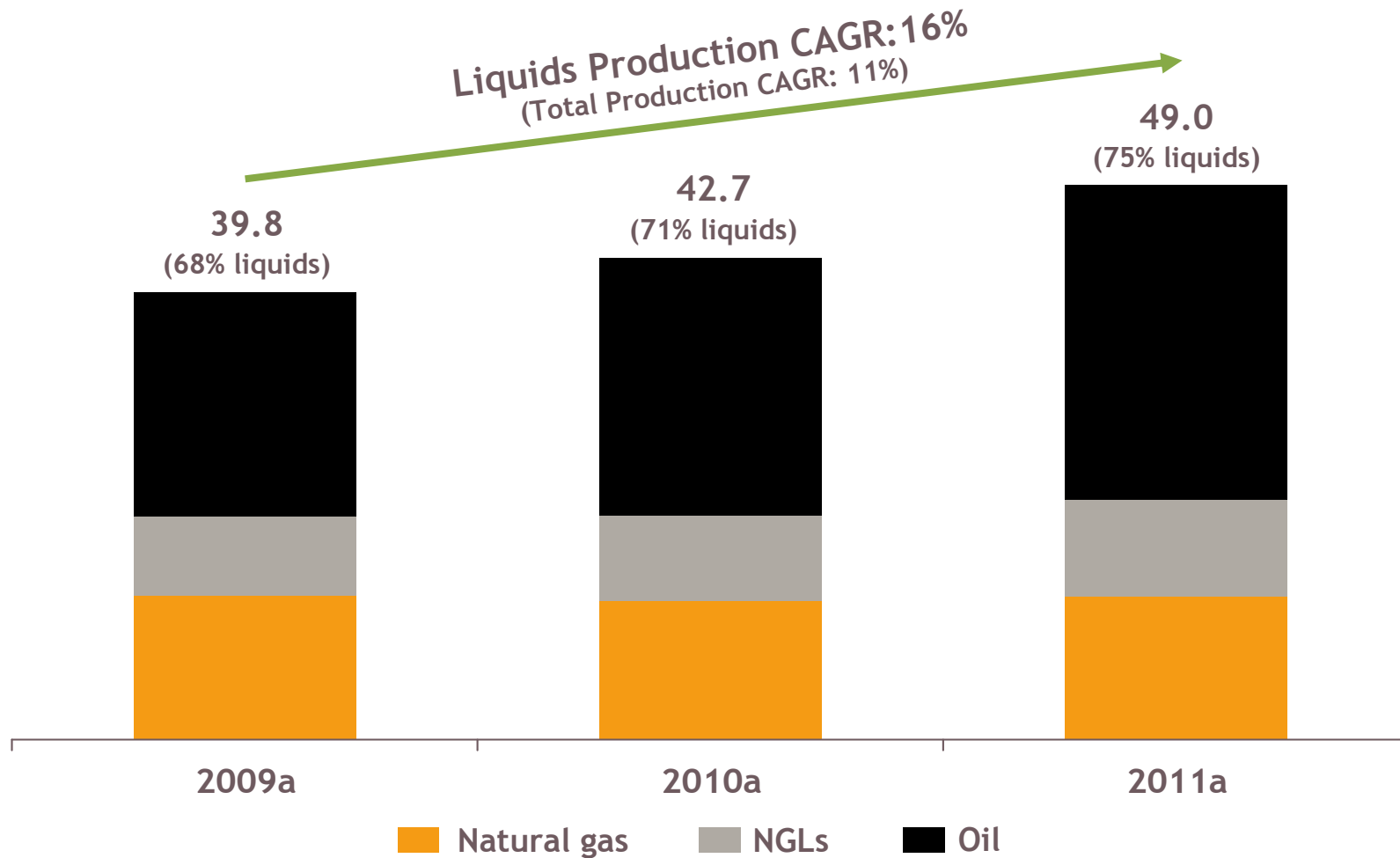
Uncharacterized Plays

- Devon has broad exposure across basin
- >50 potential play types in basin
- Horizontal potential in early stages of evaluation
- Many play types yet to be characterized
- Devon's risked resource likely understated

Permian Basin

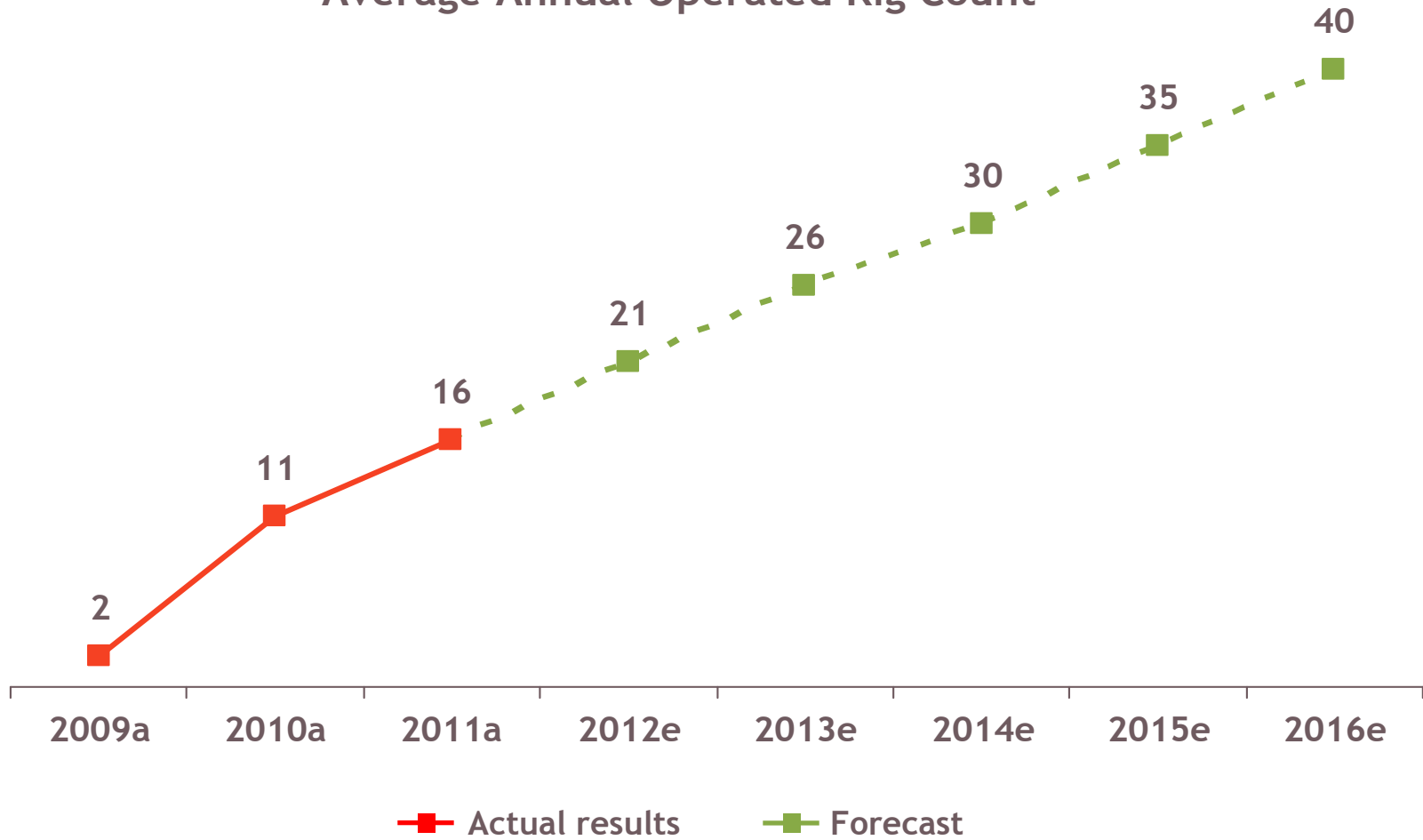
Delivering Strong Oil and Liquids Production

Production Data in MBOED



Permian Basin Operated Rig Count

Average Annual Operated Rig Count

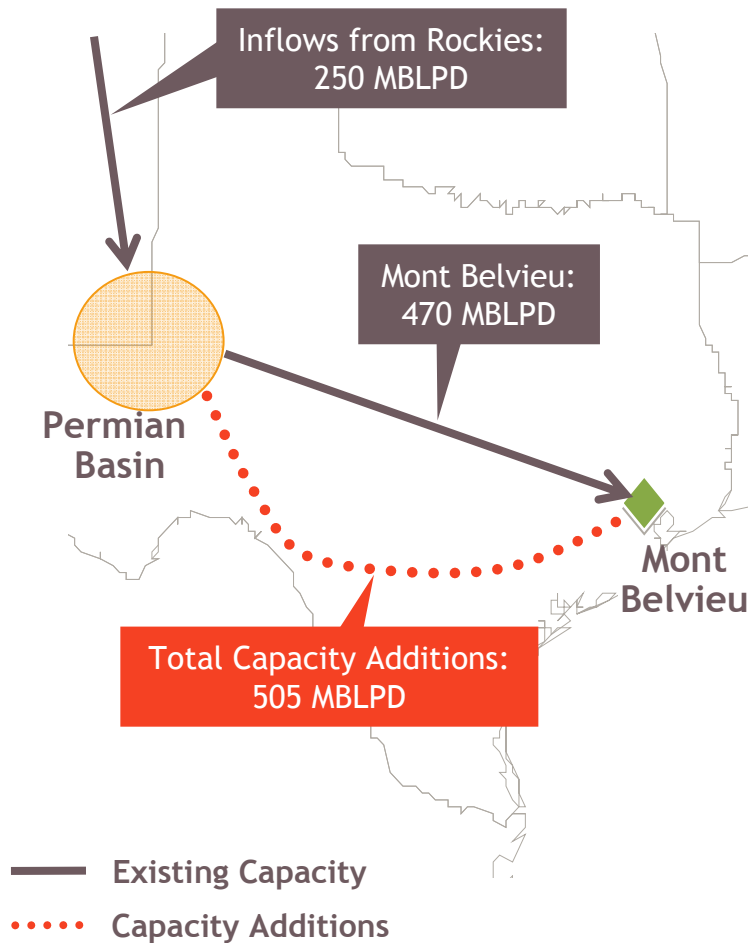


Permian Basin

Devon's Ability to Execute

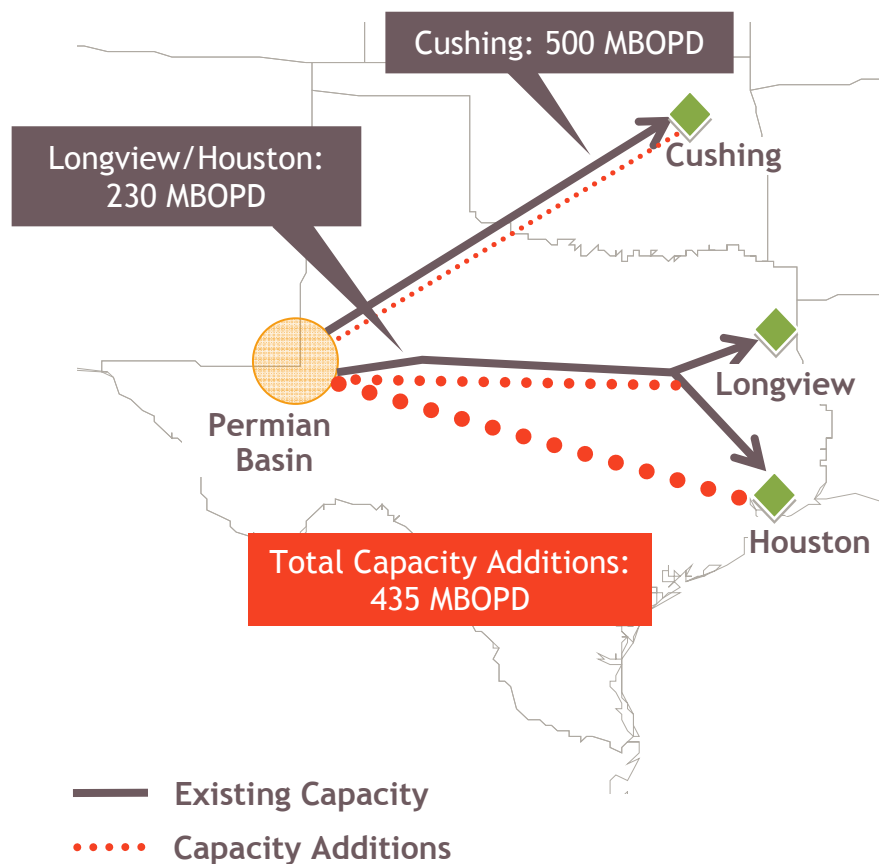
- Largely derisked and moving into development mode
- Strong relationships with service providers
- Significant operating presence in basin
- Well-established regulatory regime
- Industry leader in water management

Permian Basin NGL Takeaway Capacity



- Existing NGL pipelines at capacity
- Additional capacity expected by mid-2013
 - LoneStar Gateway (210 MBLPD - Q2 2013)
 - Texas Express (70 MBLPD - Q2 2013)
 - DCP Sandhills (225 MBLPD - Q3 2013)

Permian Basin Oil Takeaway Capacity



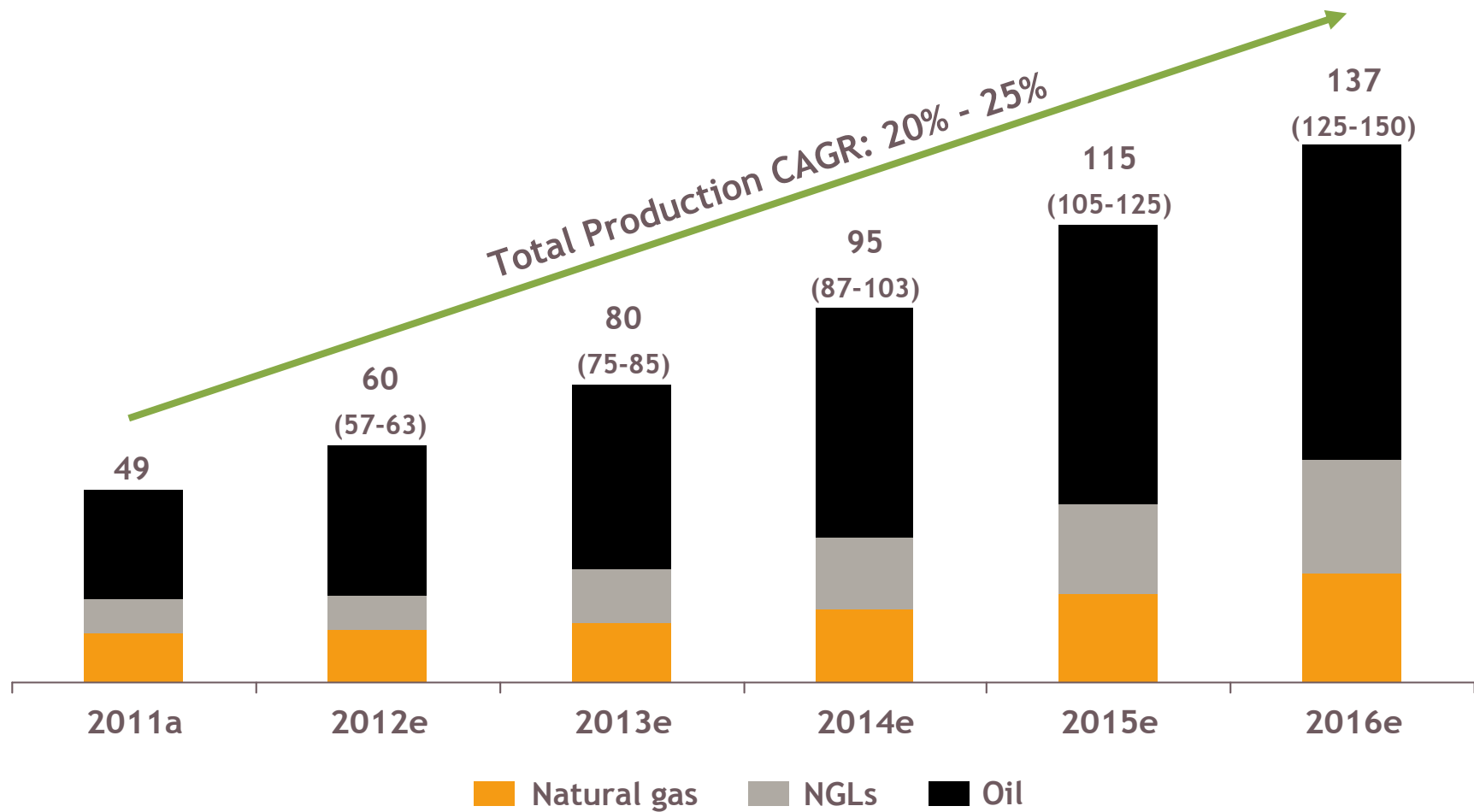
- Oil takeaway is near capacity
- Capacity additions

- Basin (50 MBOPD - Q2 2012)
- West Texas Gulf (160 MBOPD - Q1 2013)
- Longhorn (225 MBOPD - Q2 2013)

Long-Term Production Outlook

Permian Basin

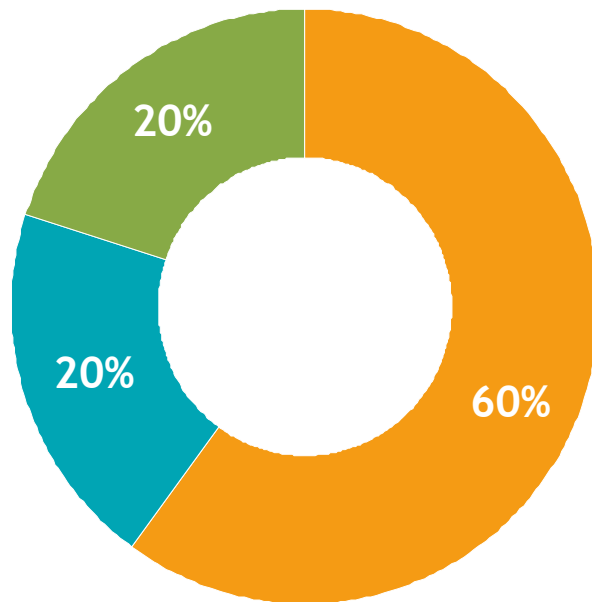
Production Data in MBOED



2012 Capital Objectives

Permian Basin

2012 Budget



≈ \$1.4 Billion

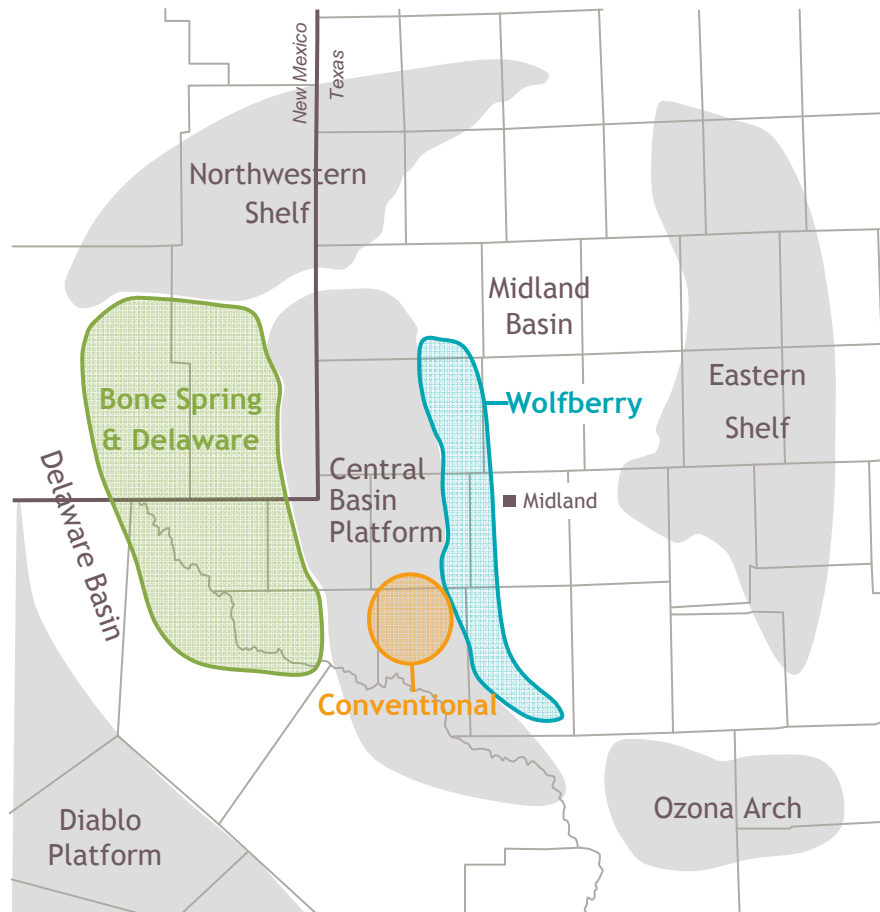
- Development
- Emerging plays
- Leasehold capture

2012 Targets

- 2012 plans: Drill >300 wells
- 24 operated rigs by year-end
- ≈25% liquids production growth
 - Driven by >30% oil growth
- Accelerate exploration activity
- Capture additional oil leasehold

Permian Basin

Current Development Activity



Net acres: $\approx 420,000$

Risked resource: 470 MMBOE

Risked locations: $\approx 1,800$

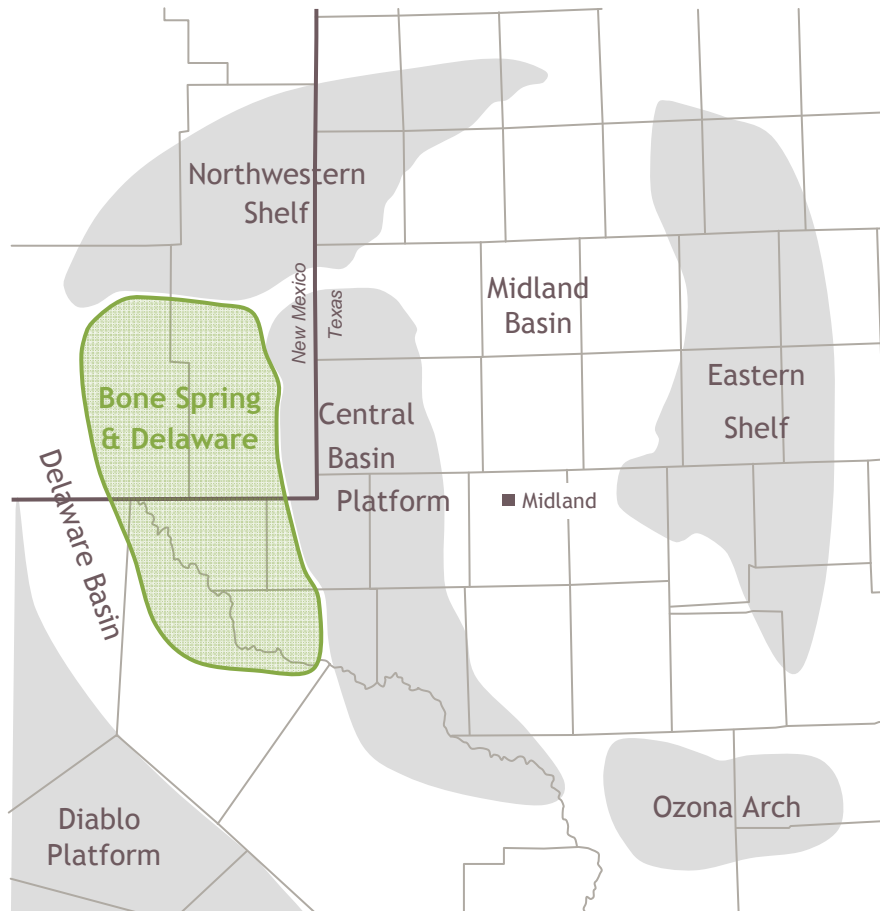
2012 capital: $\approx \$800$ million

2012 plans: Drill >250 wells

- Low-risk, high-margin oil plays
- Multi-year drilling inventory
- Oil and liquids content $\approx 85\%$
- Delivering >30% oil growth in 2012
- Legacy position enhances full-cycle returns

Bone Spring & Delaware

Current Development Activity



Net acres: 185,000

Risked resource: 140 MMBOE

Risked locations: 550

2012 capital: ≈\$350 million

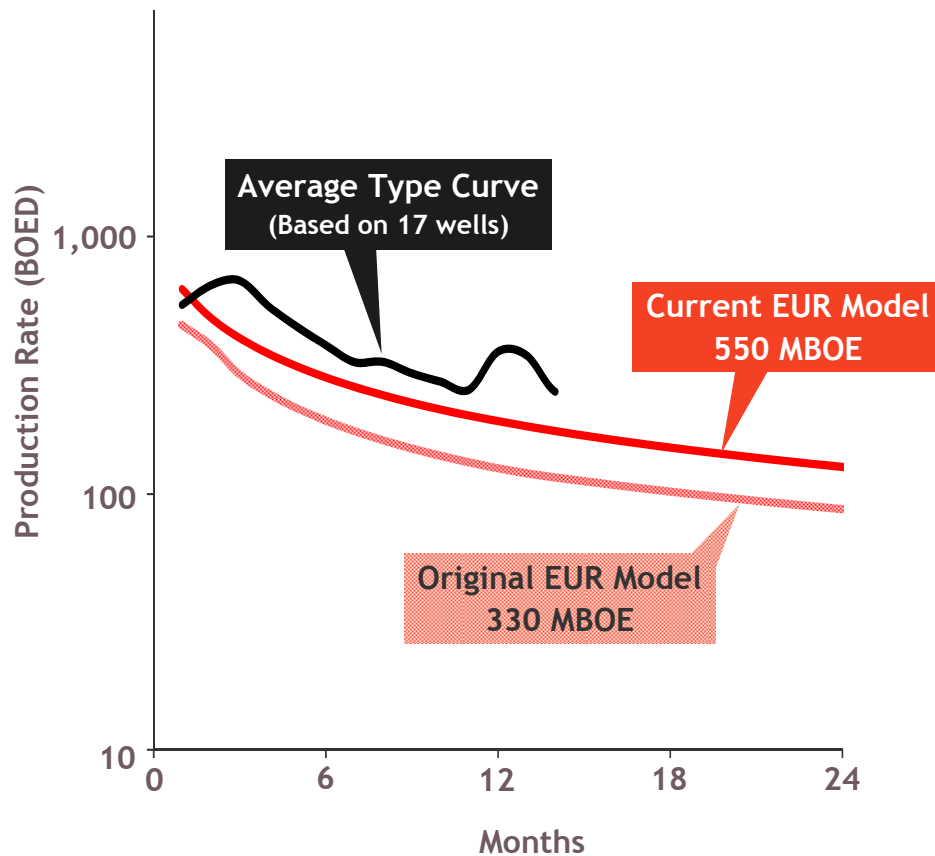
2012 plans: Drill 110 wells

- Stratigraphic/structural, tight-sand oil play
- Revitalized by horizontal drilling
- Drilling depth: 7,000' - 8,000' (Delaware)
8,000' - 10,500' (Bone Spring)
- High-impact wells (Best wells: IP's >1,000 BOED)
- Q4 2011 net production: 13 MBOED
- Well performance exceeding expectations

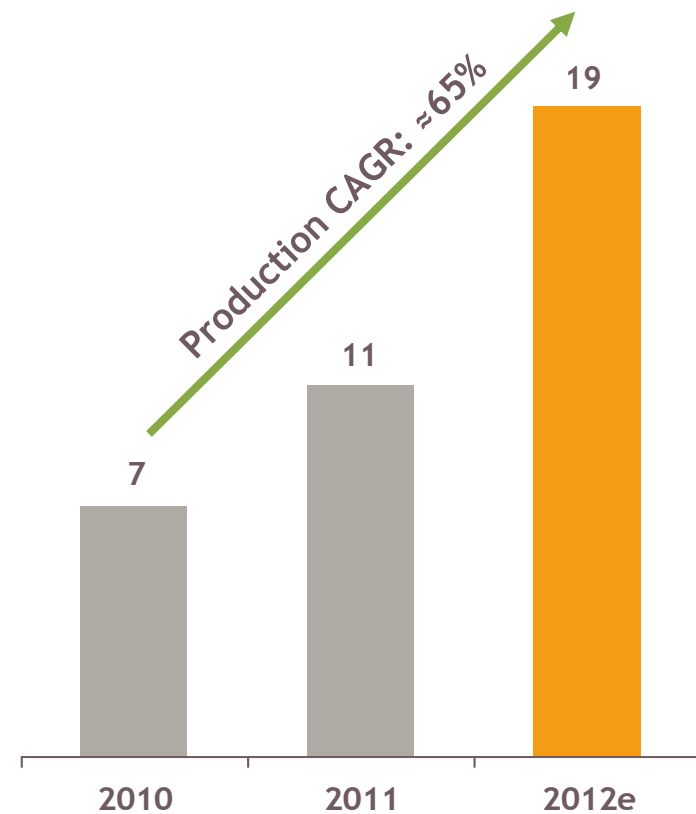
Bone Spring & Delaware

Continuous Improvement

Performance Exceeds Expectations
(Bone Spring Type Curve)

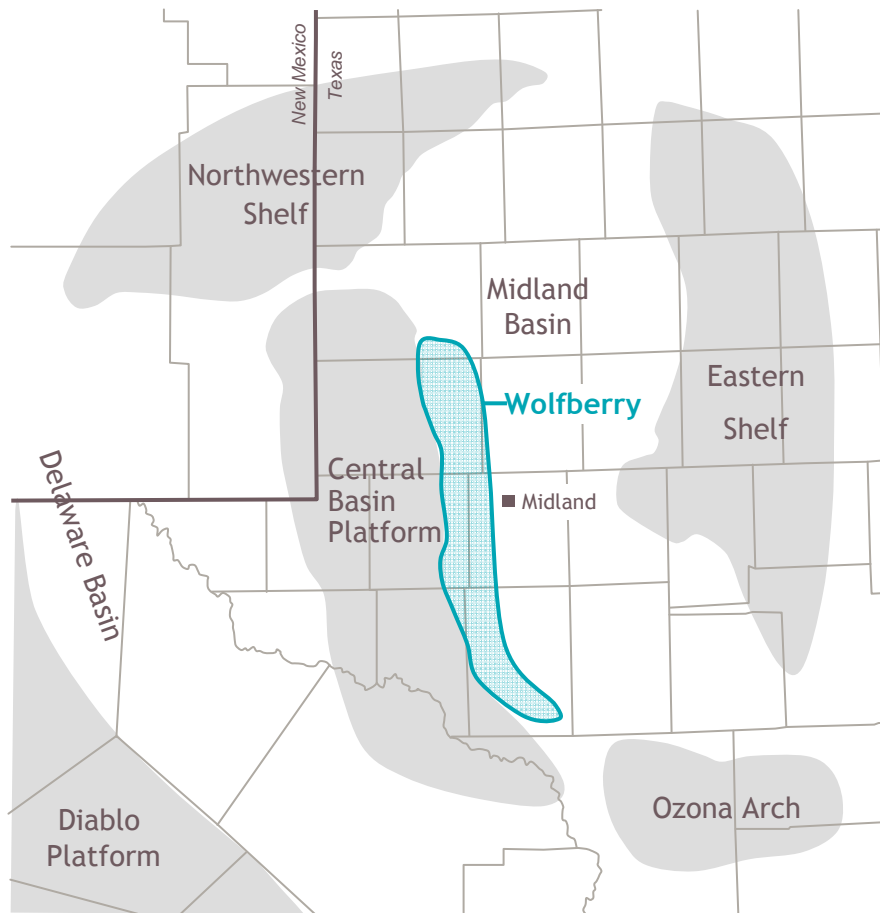


Net Production - MBOED
(Bone Spring & Delaware)



Wolfberry

Current Development Activity



Net acres: 160,000

Risked resource: 120 MMBOE

Risked locations: \approx 1,000

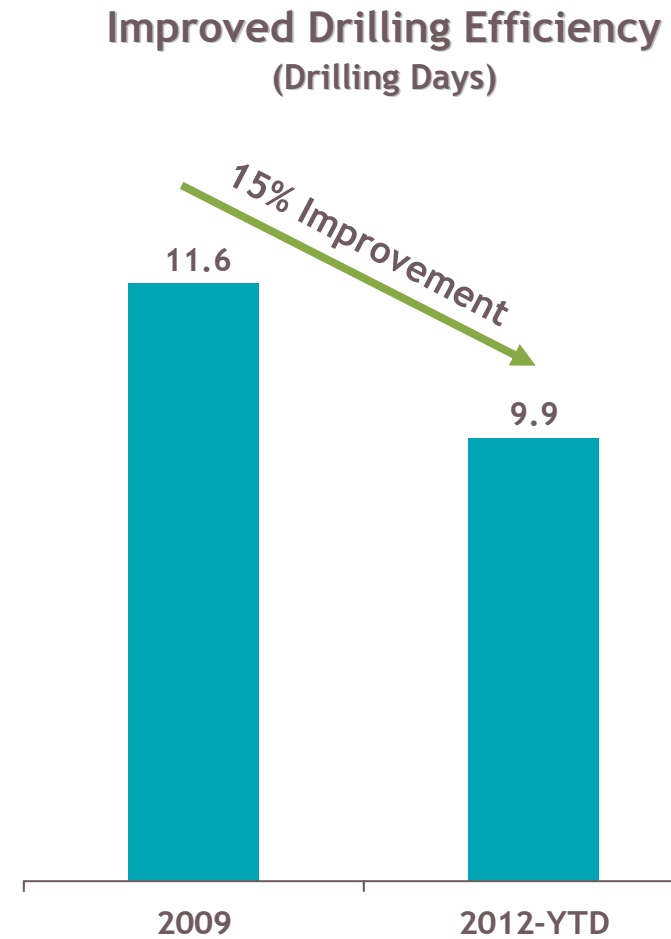
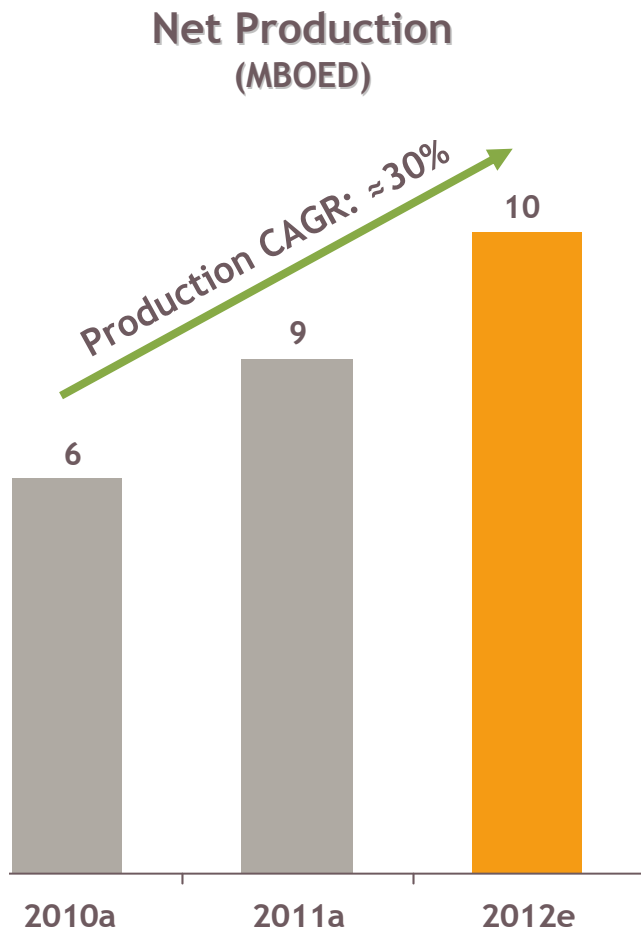
2012 capital: \approx \$275 million

2012 plans: Drill \approx 100 wells

- Predominantly vertical program
- Targets Sprayberry & Wolfcamp formations
- Repeatable results
- Drilling depth: 10,000' - 11,000'
- Q4 2011 net production: 9 MBOED
- 20 acre downspacing underway
- Upside: Horizontal exploitation

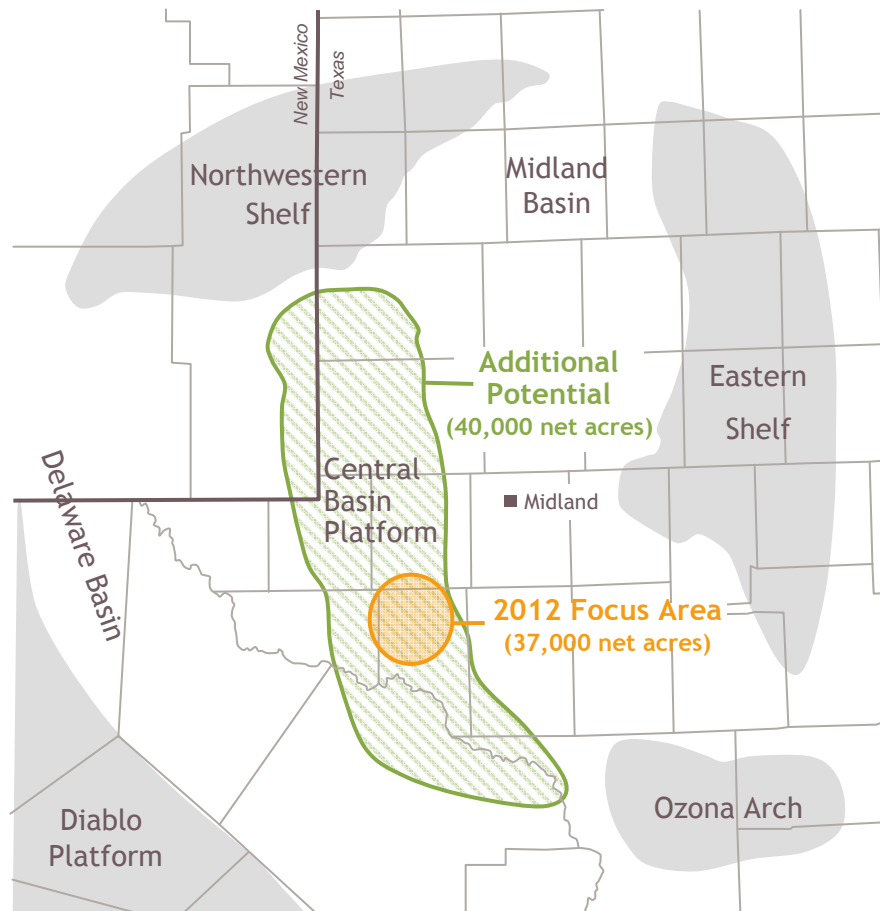
Wolfberry

Current Development Activity



Central Basin Platform

Current Development Activity



Net acres: 77,000

Risked resource: 210 MMBOE

Risked locations: >200

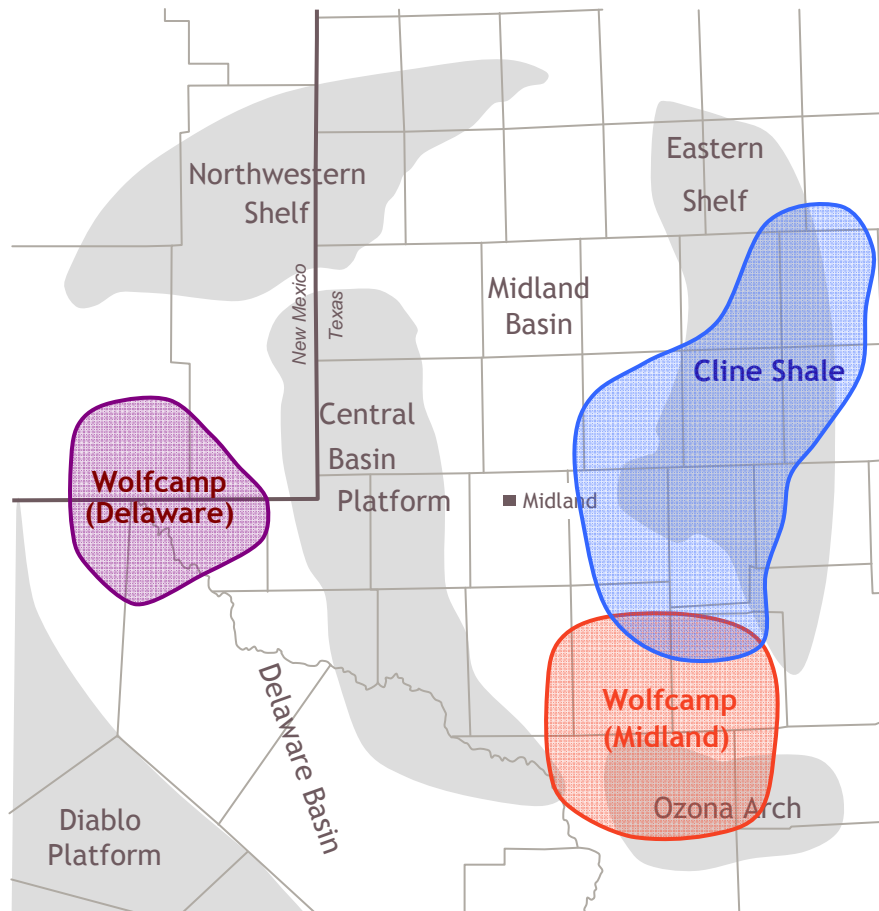
2012 capital: ≈\$175 million

2012 plans: Drill 45 wells

- Stacked oil pays
(Tubb, Wichita-Albany, Strawn, Clear Fork, & others)
- Low-risk, high-margin inventory
- Drilling depth: 4,000' - 6,000'
- Q4 2011 net production: 8 MBOED
(2010 - 2012e production CAGR: 21%)
- Additional zones to evaluate
- Testing longer horizontals

Permian Basin

Emerging Opportunities



Net acres: >800,000

Unrisked resource: 4.9 BBOE

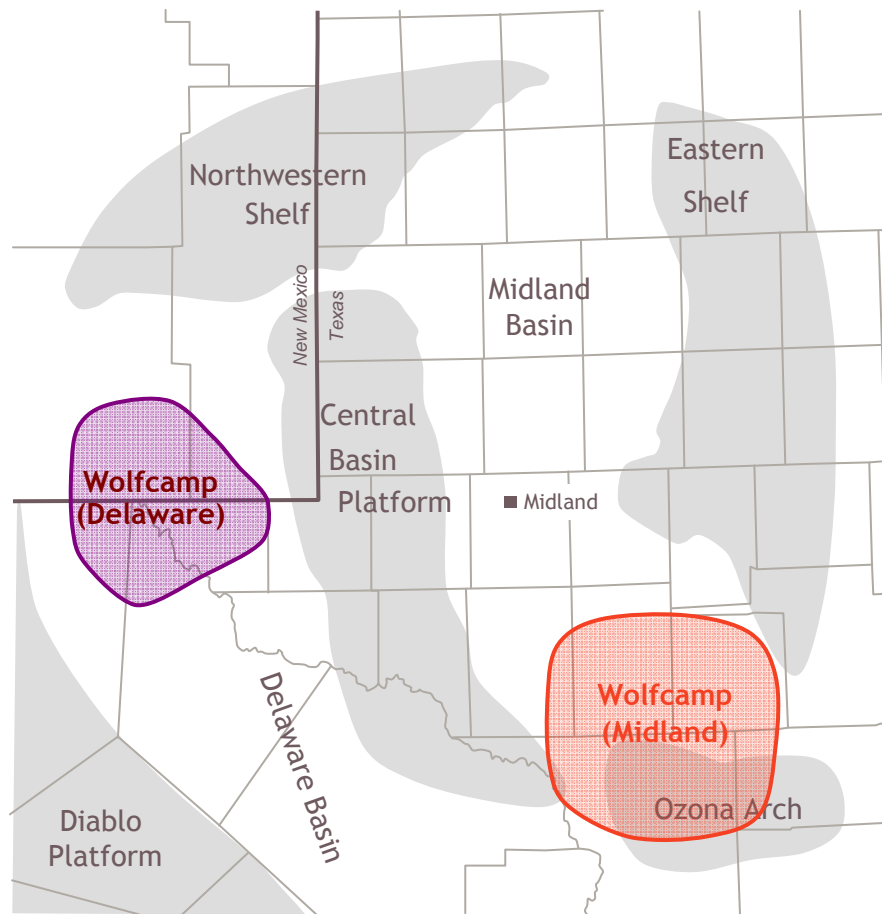
2012 capital: ≈\$575 million

2012 plans: Drill ≈50 wells

- Oil-focused opportunities
- High-impact targets
- Potential resource plays
- Multi-pay formations
- Early results encouraging (DVN & Industry)

Wolfcamp Shale

Emerging Opportunity



Net acres: 92,000 (Midland)
240,000 (Delaware)

Unrisked resource: 1.3 BBOE

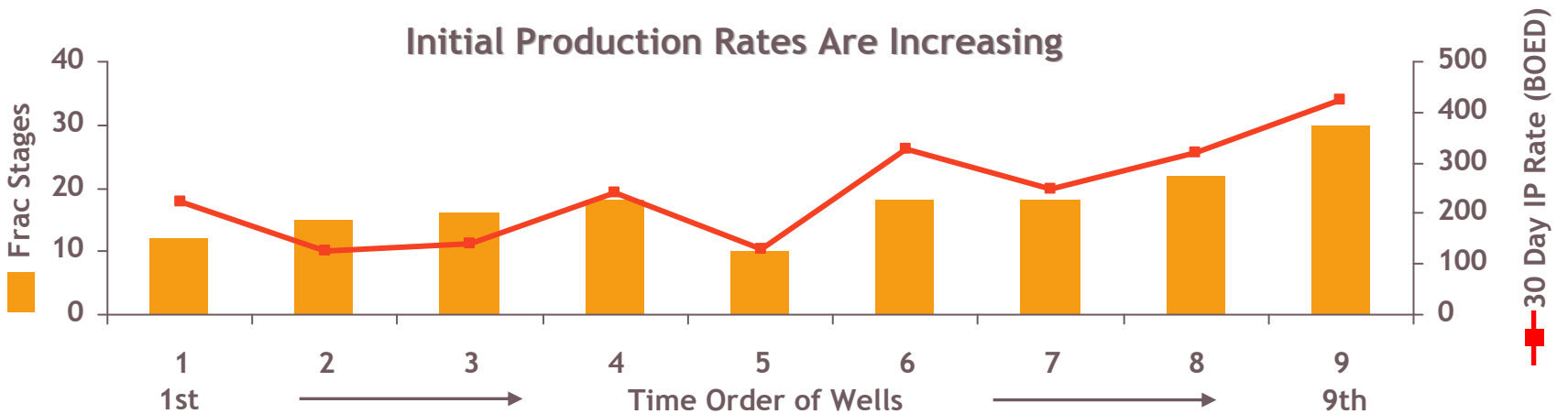
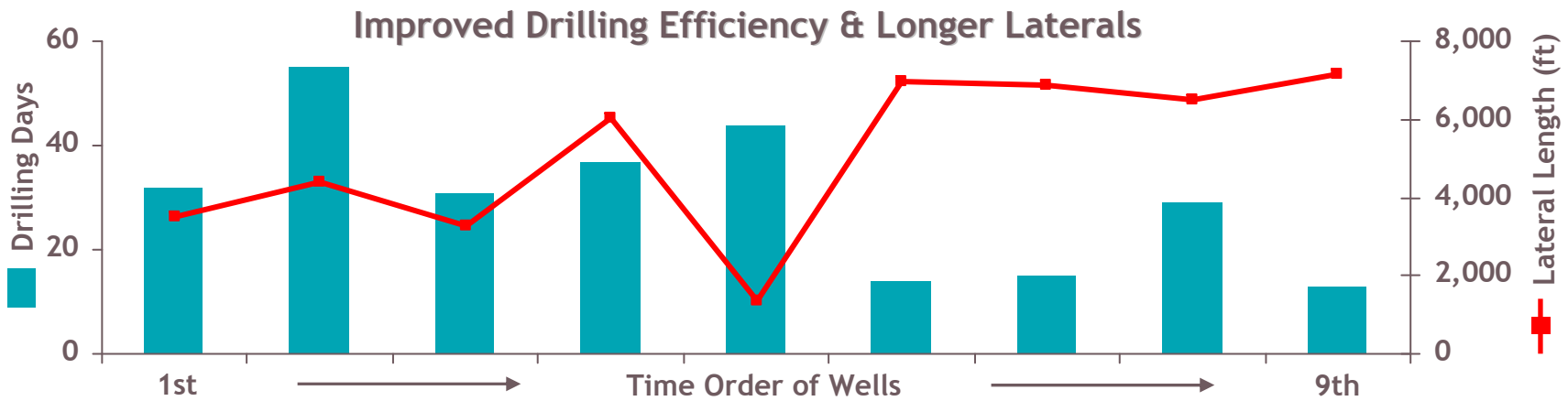
2012 capital: ≈\$225 million

2012 plans: Drill 35 wells

- Focus on Wolfcamp Midland (light oil, resource play)
- Multiple producing zones in Wolfcamp
- Drilling depth: 5,000' - 8,500' (Midland)
8,000' - 10,500' (Delaware)
- Midland Basin results improving
- Testing long laterals (Extending to >7,000')

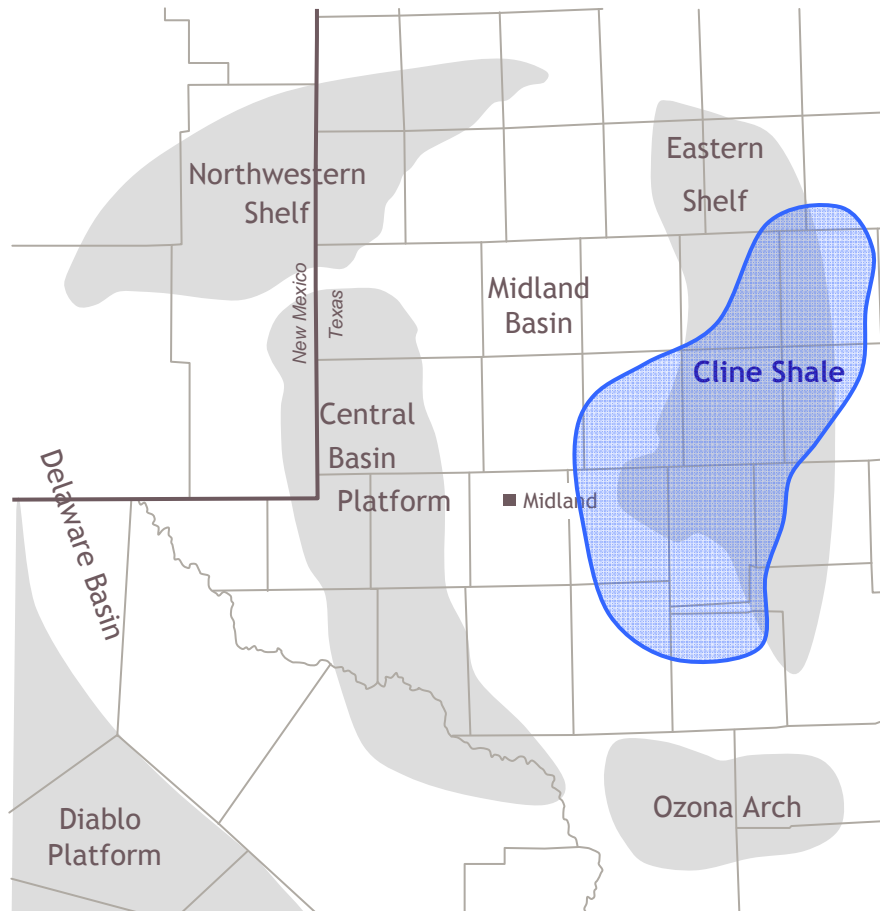
Wolfcamp Midland

Continuous Improvement



Cline Shale

Emerging Opportunity



Net acres: 500,000

Unrisked resource: 3.6 BBOE

2012 capital: ≈\$350 million

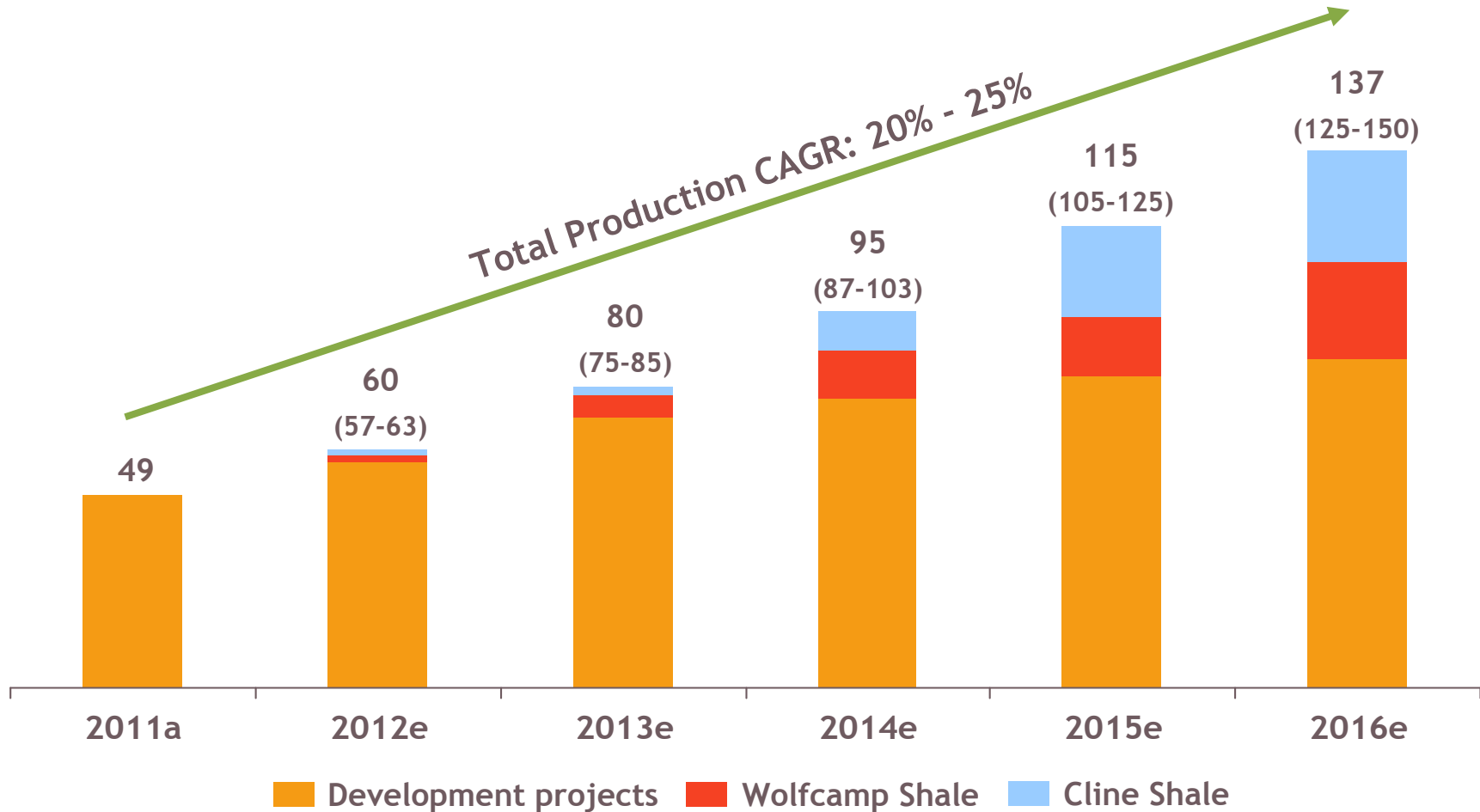
2012 plans: Drill 15 wells

- High-impact opportunity
- Potential resource play
- Stacked pay potential
- Drilling depth: 5,000' - 8,500'
- Early stages of evaluation
- 4 operated rigs running by year-end

Long-Term Production Outlook

Permian Basin

Production Data in MBOED



Note: Development projects include: Bone Spring, Delaware, Wolfberry and Central Basin Platform conventional

Permian Basin Key Messages

- Industry leader in basin
 - 1.5 million net acres with stacked-pay potential
 - Currently #1 horizontal driller
- Deep inventory of low-risk oil development projects
- Significant positions in emerging, high-impact oil plays
- Many additional play types to evaluate
- Highly economic & robust production growth

Canadian Thermal Oil

Chris Seasons

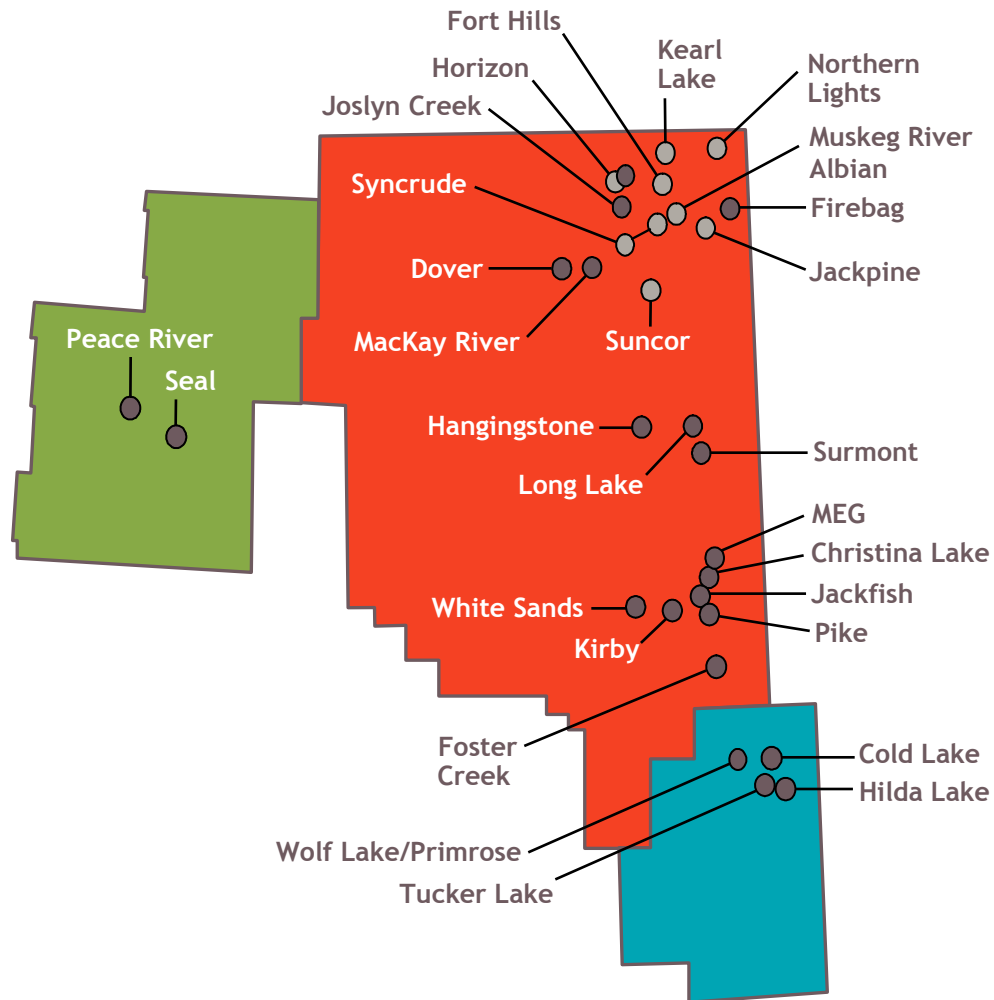
President, Devon Canada

Canadian Thermal Oil Key Messages

- World-class SAGD oil position
- Visible, low-risk oil production growth
- Strong returns enhanced by low natural gas prices
- Upside potential to resource estimates

Canadian Oil Sands

Industry Overview



Project Type

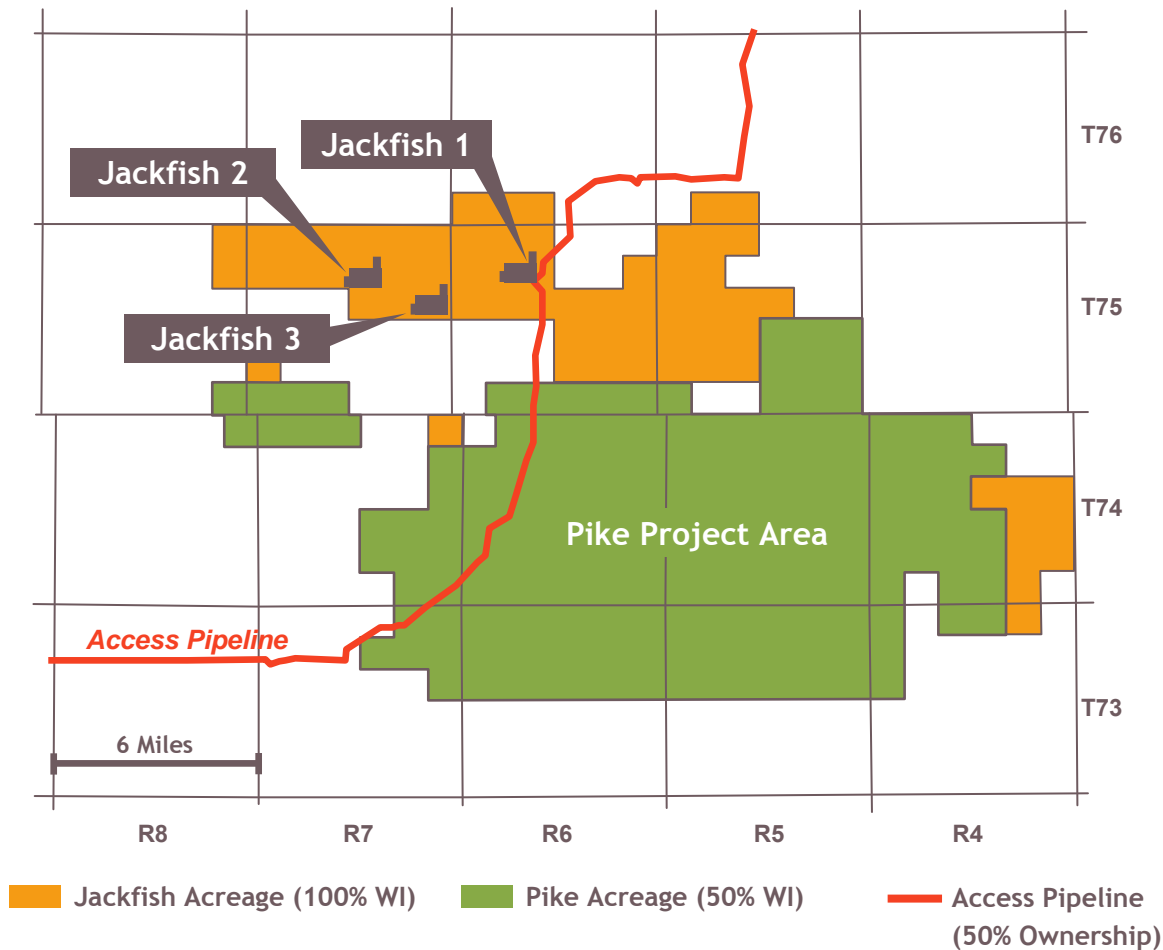
- In-Situ Projects
- Mining Projects

Oil Sands Region

- Athabasca
- Peace River
- Cold Lake



Devon's SAGD Today

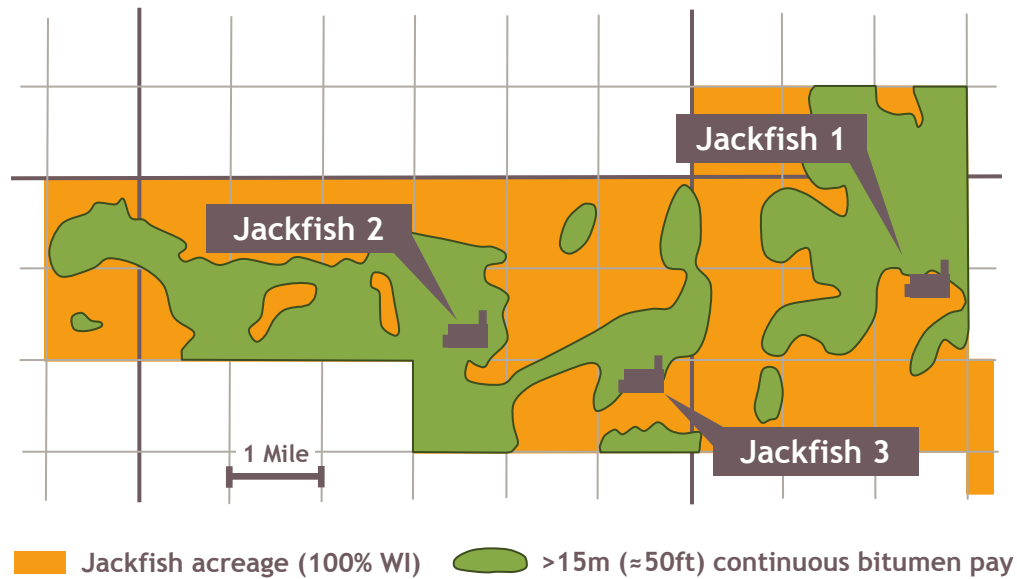


Devon's SAGD characteristics

- Low F&D
- Low geologic risk
- High reservoir quality
- Flat production profile
- Long reserve life \approx 25 years



Jackfish Projects Overview

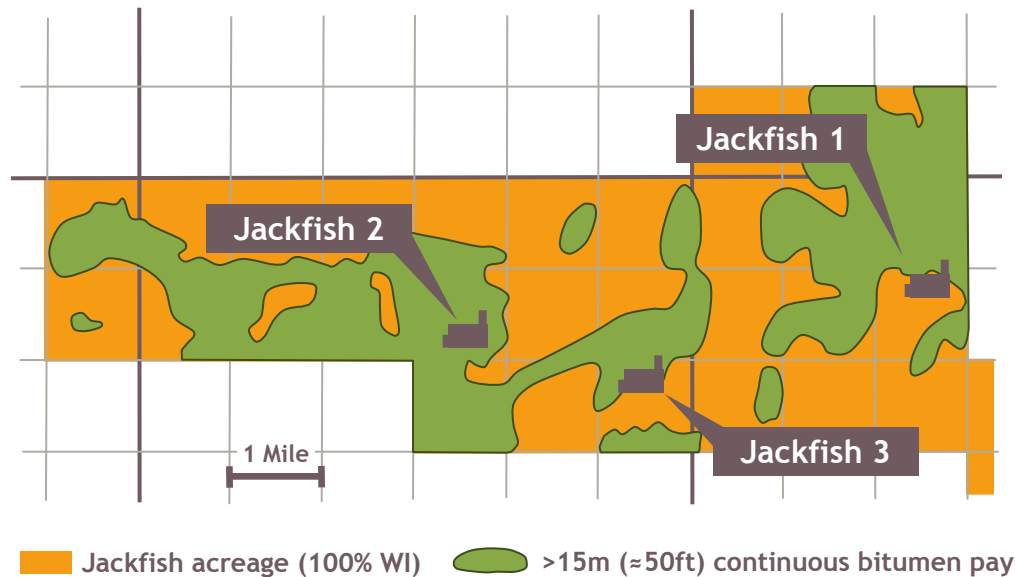


- Each Jackfish project:
 - 300 MMBO EUR (≈260 MMBO net)
 - 35 MBOPD of production (≈30 MBOPD net)
 - Working interest: 100%

- Proved reserves 12/31/11: 457 MMBO



Jackfish Projects Overview



Jackfish 1

- Top-tier operating performance
 - Steam to oil ratio: 2.6
 - Capacity utilization: 96%
 - Non-fuel operating costs: \$7/BBL
- Q4 2011 net production: 31 MBOPD

Jackfish 2

- Q4 2011 production exit rate: 14 MBOPD
- Production ramp-up throughout 2012

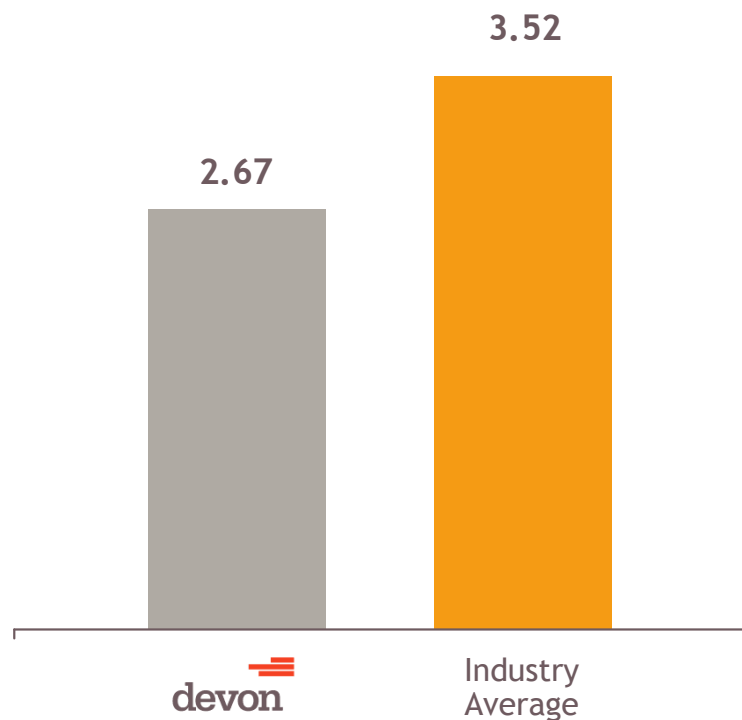
Jackfish 3

- Regulatory application approved
- Field construction started in January
- Construction >20% complete

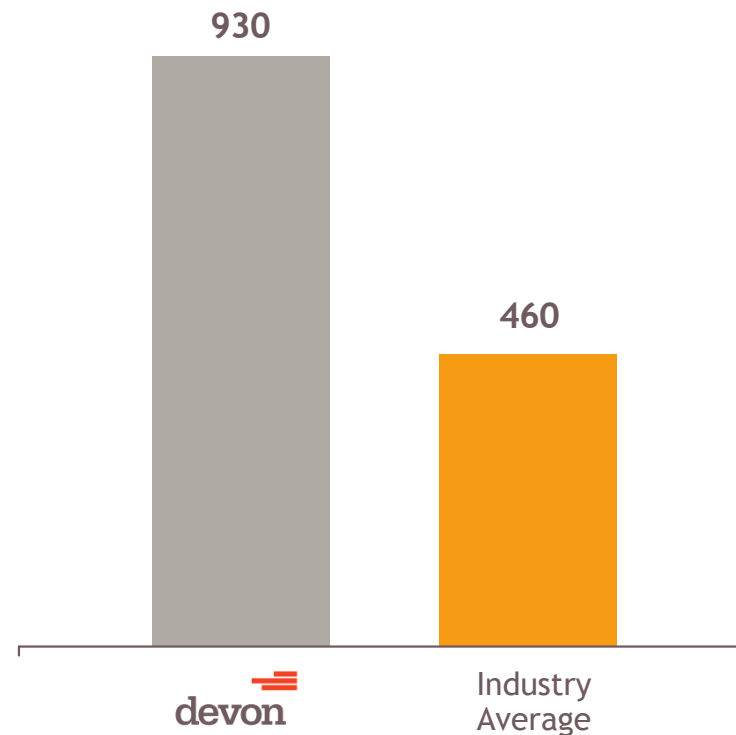
Jackfish 1 Performance Comparison to Industry SAGD Projects

51 Months After Project Startup

Cumulative Steam Oil Ratio (SOR)



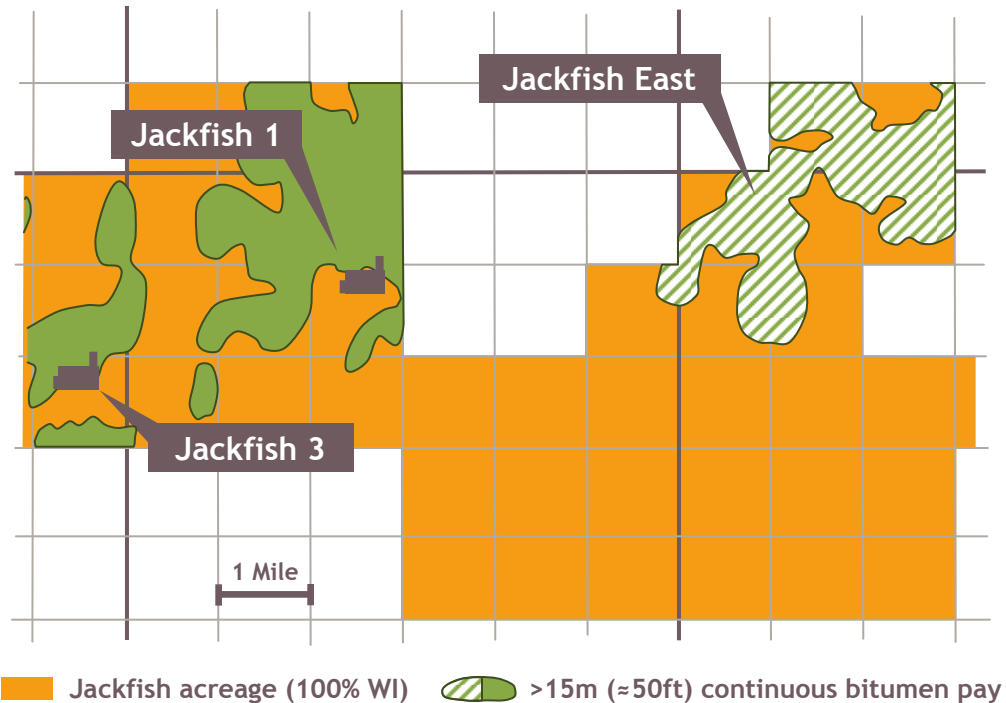
Production Per Well (BOPD)



Note: Industry average includes: Bolney-Celtic, Christina Lake, Firebag, Foster Creek, Great Divide, Hangingstone, Hilda Lake, Long Lake, MacKay River, Orion, Senlac, Surmont, Tangleflags, and Tucker

Source: FirstEnergy Capital and company disclosures

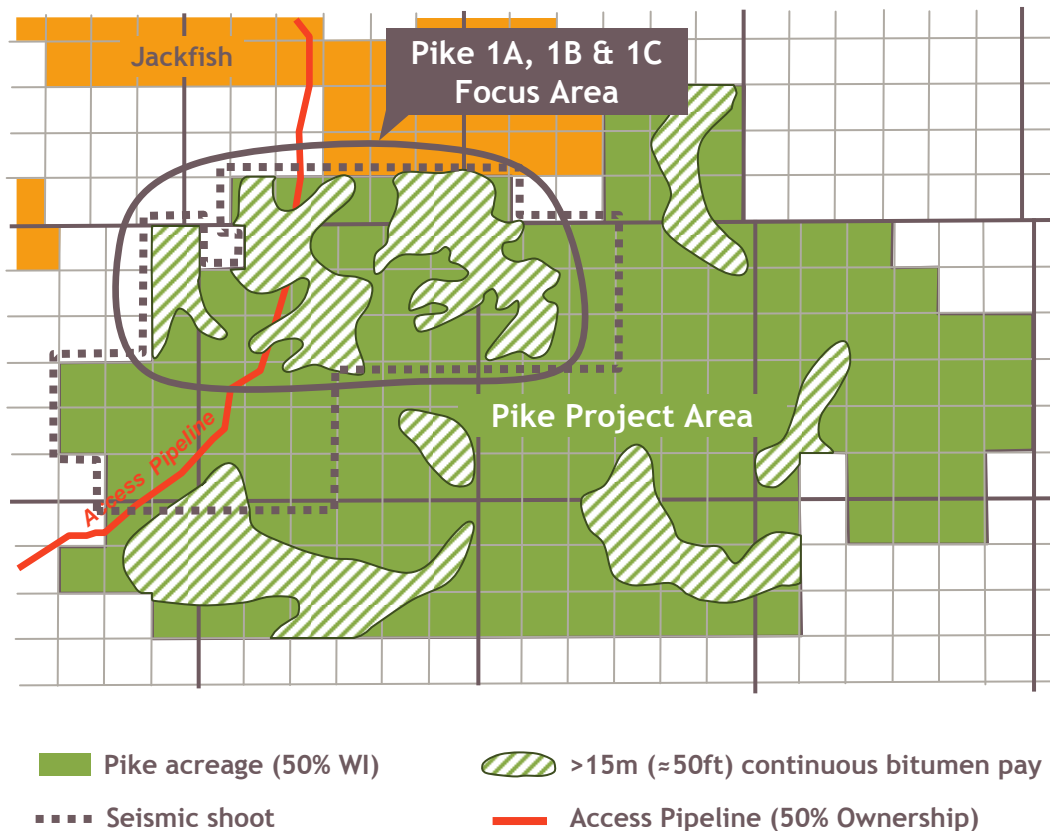
Jackfish East



- Jackfish expansion phase
- 150 MMBO EUR (≈130 MMBO net)
- 20-25 MBOPD of production (≈17-21 MBOPD net)
- Similar reservoir quality with minimal bottom water
- Delineation program to be completed Q1 2013

	2015	2016	2017	2018	2019
Regulatory Application & Review	█				
Engineering	█	█			
Plant Construction		█	█	█	
Plant Start-up				█	█

Pike Project Overview



Pike leasehold

- 50% operated working interest
- Similar reservoir characteristics to Jackfish
- Up to five 35 MBOPD SAGD development phases

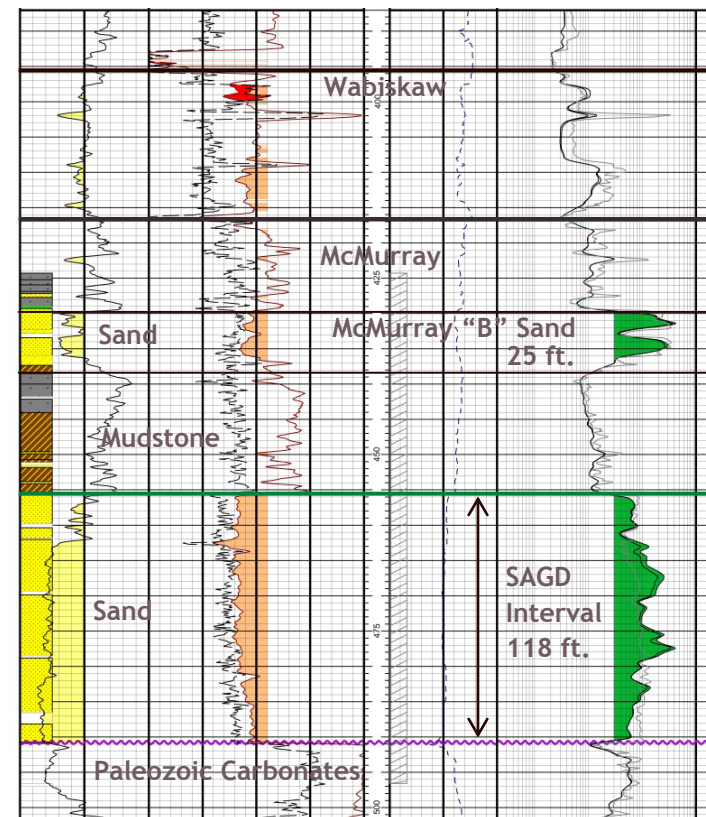
Potential Pike 1 development

- Single plant pad
- Three 35 MBOPD projects
- Developed concurrently
- Regulatory filing expected in 2012

Pike Delineation Drilling Confirms High-Quality Reservoir

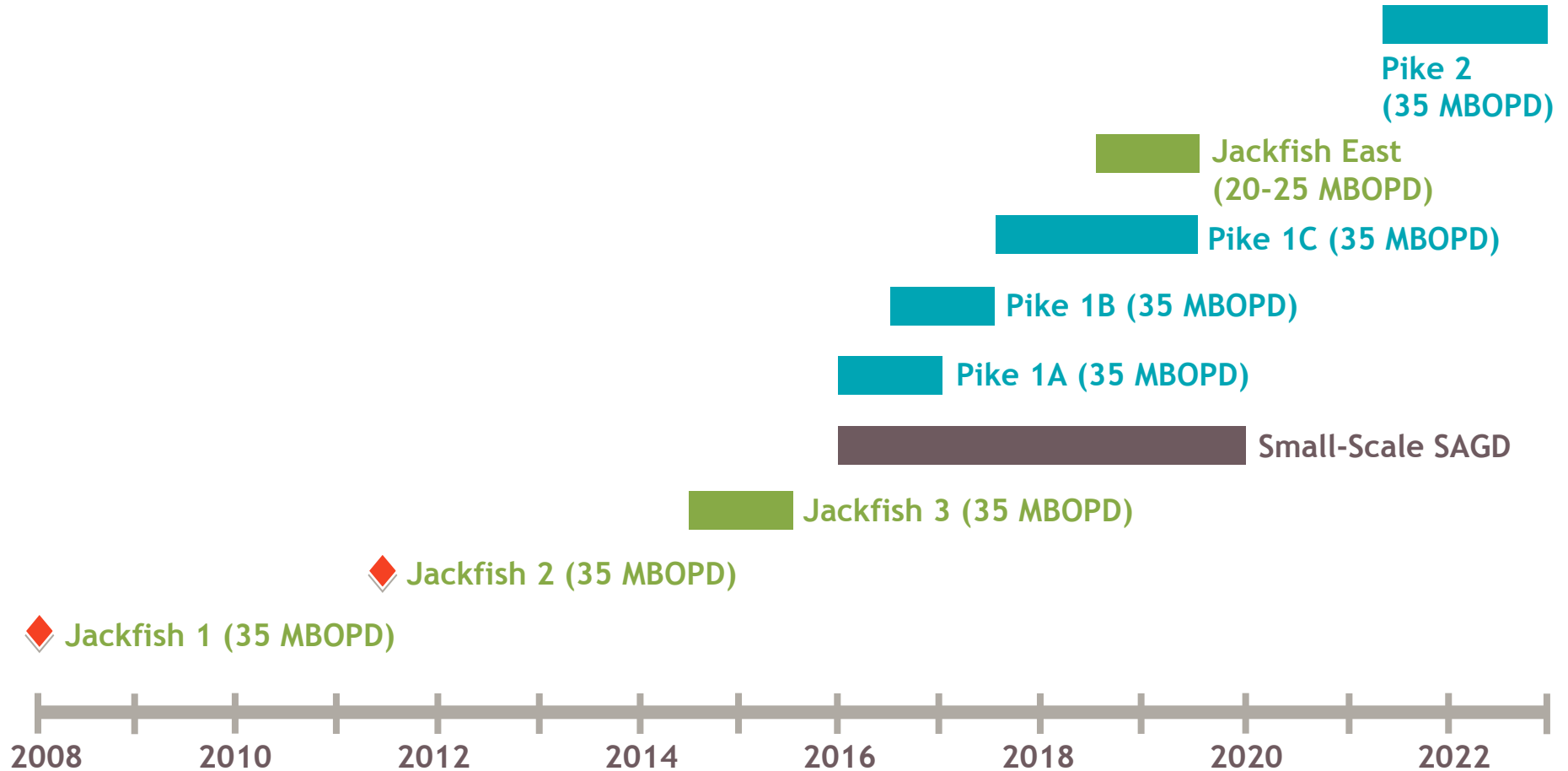
	Pike	Jackfish
Depth (Ft, TVD)	1,400 - 1,560	1,320 - 1,380
Pay Thickness (Ft)	49 - 144	49 - 164
Porosity (%)	30 - 35	30 - 33
Permeability (Darcies)	2 - 10	2 - 10
Oil Saturation (%)	60 - 90	60 - 90
Original Pressure (KPa)	2,900	2,800
Original Temperature (°C)	15	15

Pike Type Log



Proposed Timeline

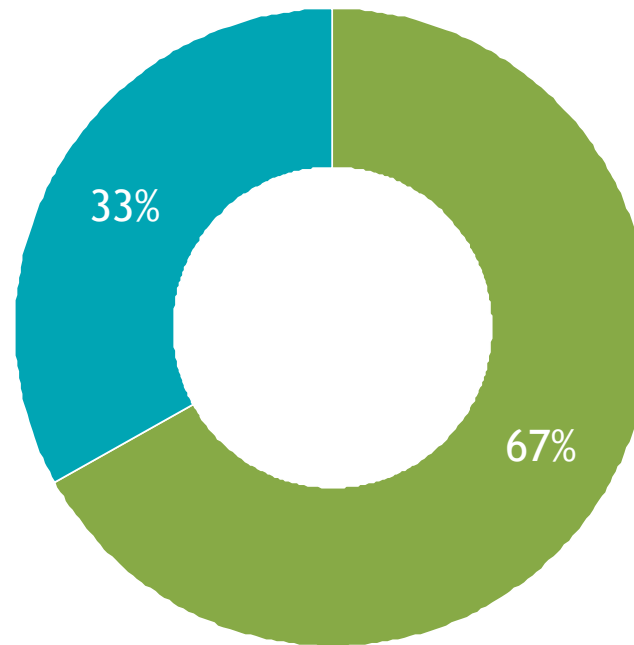
Timing Range of Expected Plant Start-Up



Thermal Risked Resource

Strong Foundation for Growth

1.4 BBO Risked Resource
(2.1 BBO Unrisked)

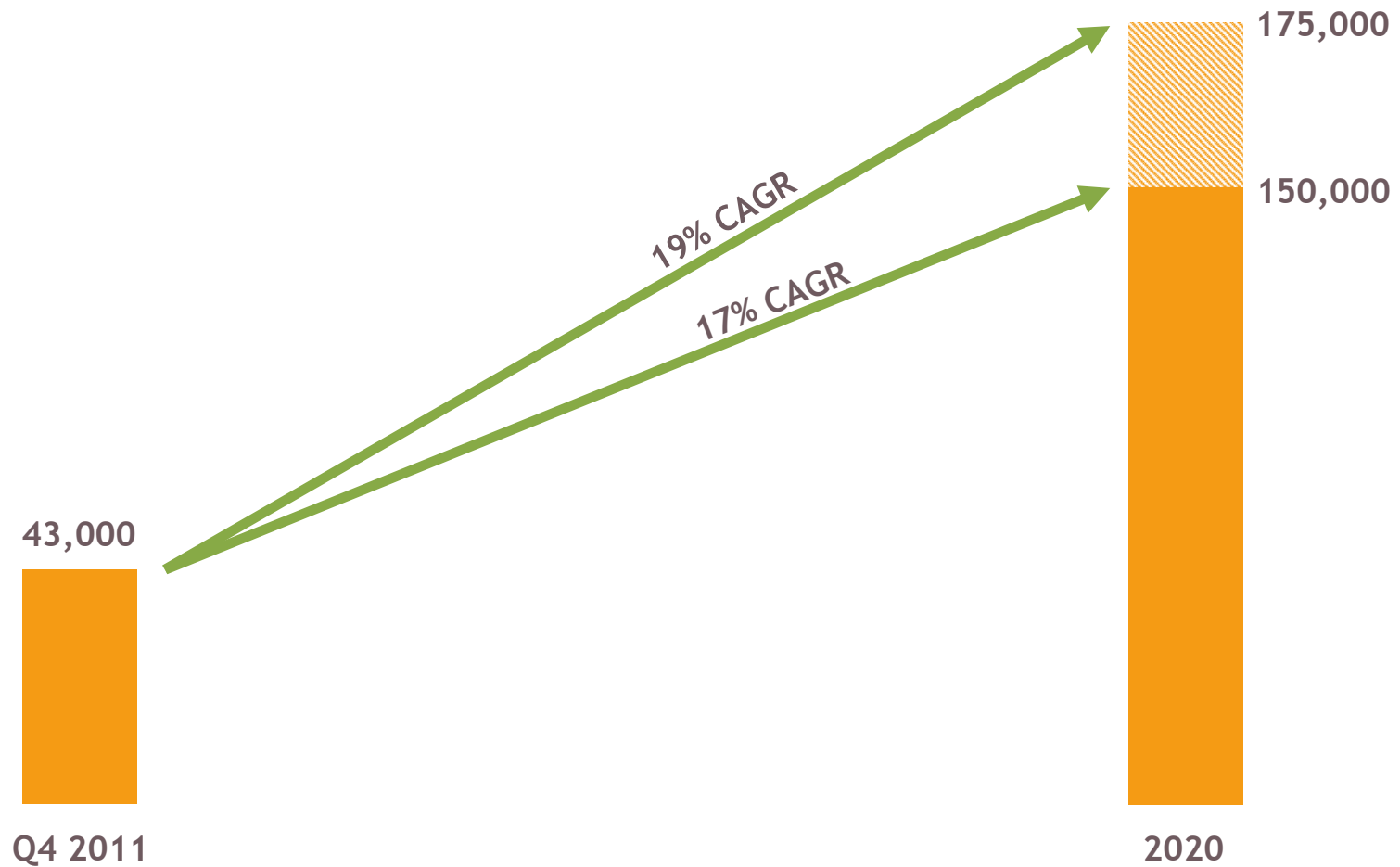


■ Proved Reserves (457 MMBO) ■ Additional Risked Potential

Long-Term Production Outlook

Thermal Oil

Net Barrels Per Day



Rate of Return Matrix

Jackfish 1

Capital Through Start-up: \$620 Million

Natural Gas Price	WTI-NYMEX Price			
	\$60.00	\$80.00	\$100.00	\$120.00
\$2.00	23%	29%	35%	39%
\$4.00	22%	28%	34%	37%
\$6.00	20%	27%	33%	37%

Assumptions:

- 1) Blended price realizations are 70% of WTI-NYMEX oil price
- 2) Condensate price is equivalent to WTI-NYMEX price
- 3) Non-fuel operating costs are \$7.00 per barrel
- 4) One Mcf of gas utilized for every barrel of bitumen produced
- 5) Maintenance capital is assumed to be \$75 million annually
- 6) WTI and natural gas pricing points are constant for the entire life of the project

Rate of Return Matrix

Jackfish 2

Capital Through Start-up: \$1.0 Billion

Natural Gas Price	WTI-NYMEX Price			
	\$60.00	\$80.00	\$100.00	\$120.00
\$2.00	16%	22%	26%	29%
\$4.00	15%	21%	25%	28%
\$6.00	13%	20%	24%	28%

Assumptions:

- 1) Blended price realizations are 70% of WTI-NYMEX oil price
- 2) Condensate price is equivalent to WTI-NYMEX price
- 3) Non-fuel operating costs are \$7.00 per barrel
- 4) One Mcf of gas utilized for every barrel of bitumen produced
- 5) Maintenance capital is assumed to be \$75 million annually
- 6) WTI and natural gas pricing points are constant for the entire life of the project

Upside to Economics

- Technology should improve future recovery rates
- More efficient facility design for future phases
- Improvements in fuel efficiency
- Additional exploitation through small-scale SAGD developments
- Solvents could improve SOR



Solvents

Potential Benefits

- Increases production rates per well and plant production capacity
- Lower steam-oil ratios (15% - 50% decrease)
- Reduces plant emissions

Risks

- Access to solvent
- Solvent recovery

Devon Status

- 1st pilot program: Q4 2012

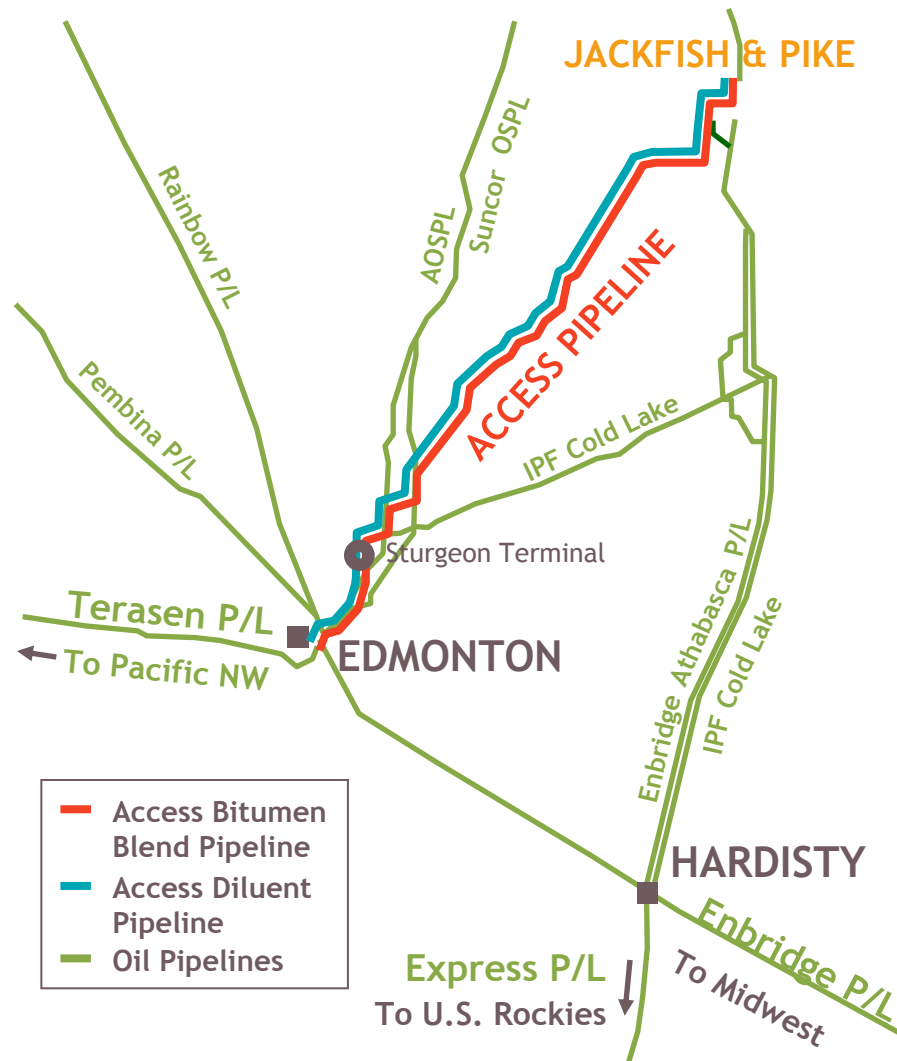


Small-Scale SAGD

- Reusable SAGD facilities designed to exploit smaller accumulations of bitumen (4 prospects indentified)
 - Targeted resource: 35-70 MMBO per project
 - Peak production rates up to 10 MBOPD per project
 - Less upfront capital commitments
(30% of the capital required for traditional SAGD projects)
 - Earlier return on capital
(1st oil sale ≈25 months after sanctioning)

Heavy Oil Midstream Infrastructure

Access Pipeline



- ≈200 mile dual pipeline from Edmonton to Devon's thermal acreage
- Devon ownership: 50%
- Capacity net to Devon
 - Blended bitumen: ≈80,000 BOPD
 - Condensate: ≈35,000 BPD
- Application to double system capacity: 2012
- Access to Edmonton condensate, synthetic crude and light oil markets
- Flexibility enhances economics

Heavy Oil Blend Refinery Expansions

Operator	Location	In Service Date	Capacity Increase (BOPD)
Conoco Phillips	Wood River, Illinois	2012	130,000
Marathon	Detroit, Michigan	2012	80,000
BP	Whiting, Indiana	2013	260,000
Northwest Upgrading	Edmonton, Alberta	2015	80,000
Total			550,000

550,000 BOPD of refinery expansions by 2015

Heavy Oil Blend Pipeline Expansions



— Existing pipelines

..... Flanagan South: Chicago to USGC

- Capacity: 585 MBOPD
- Estimated in service by mid-2014

..... Keystone XL: Hardisty to USGC

- Capacity: 830 MBOPD
- Estimated in service by 2015

..... TMPL: Edmonton to Vancouver

- Incremental capacity: 400 MBOPD
- Estimated in service by 2017

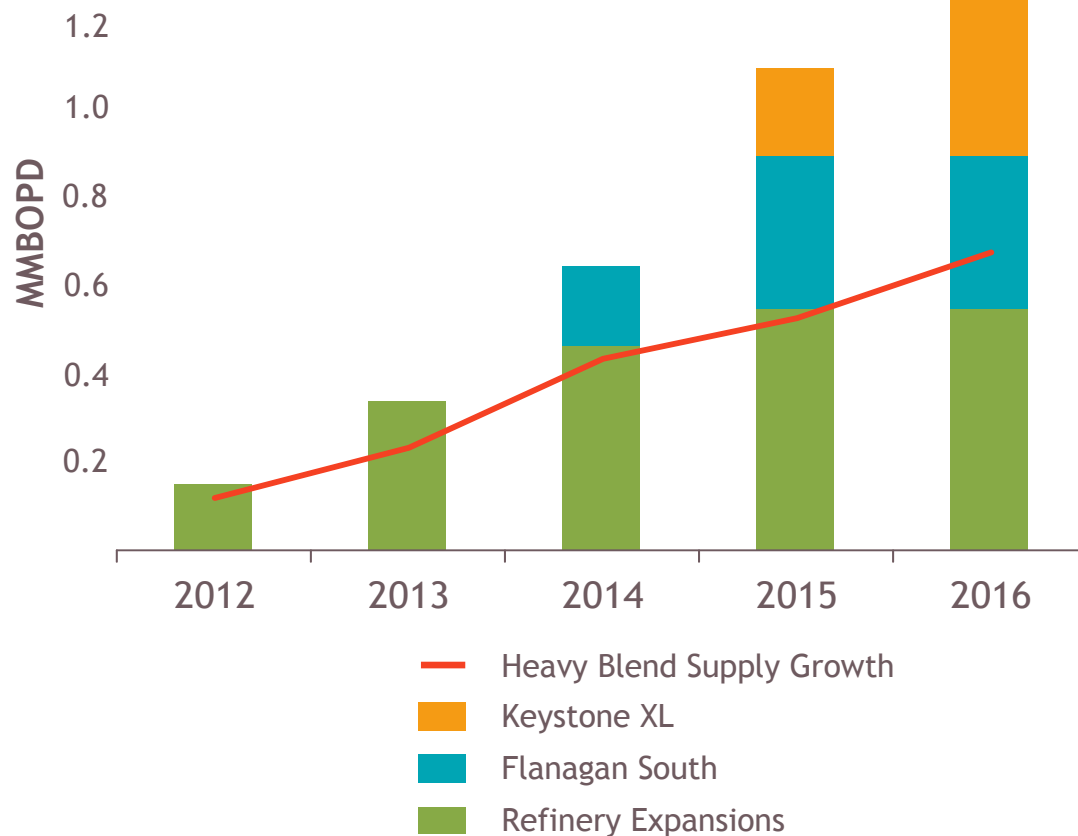
..... Gateway: Edmonton to Kitimat

- Capacity: 525 MBOPD
- Estimated in service by 2018

Note: Proposed pipeline projects pending commercial and regulatory approval

Incremental Heavy Oil Blend Supply/Demand Growth Summary

Incremental Heavy Oil Blend Supply/Demand



Market currently balanced

Excess capacity from 2013 - 2016

- Refinery expansions complete
- Enbridge Flanagan South and Keystone XL expected to be online

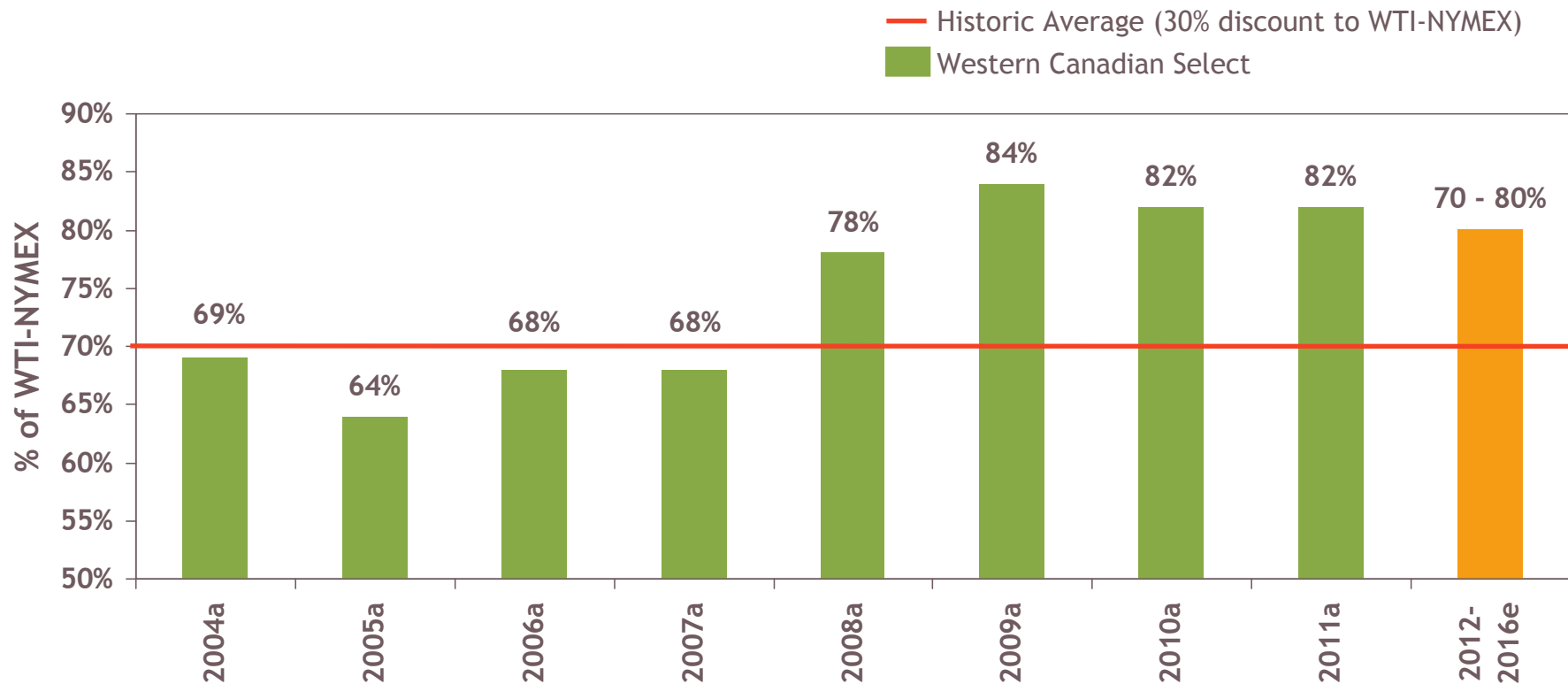
Positive indicators for Devon

- Strong demand for heavy oil blend
- Adequate access to markets
- Refinery and pipeline expansions
- Narrow differentials

Heavy Oil Blend

Historical & Forecasted Prices

Strong demand for heavy oil should keep realizations strong over the medium term



Canadian Thermal Oil Key Messages

- World-class SAGD oil position
- Visible, low-risk oil production growth
- Strong returns enhanced by low natural gas prices
- Upside potential to resource estimates



Q&A

Barnett Shale

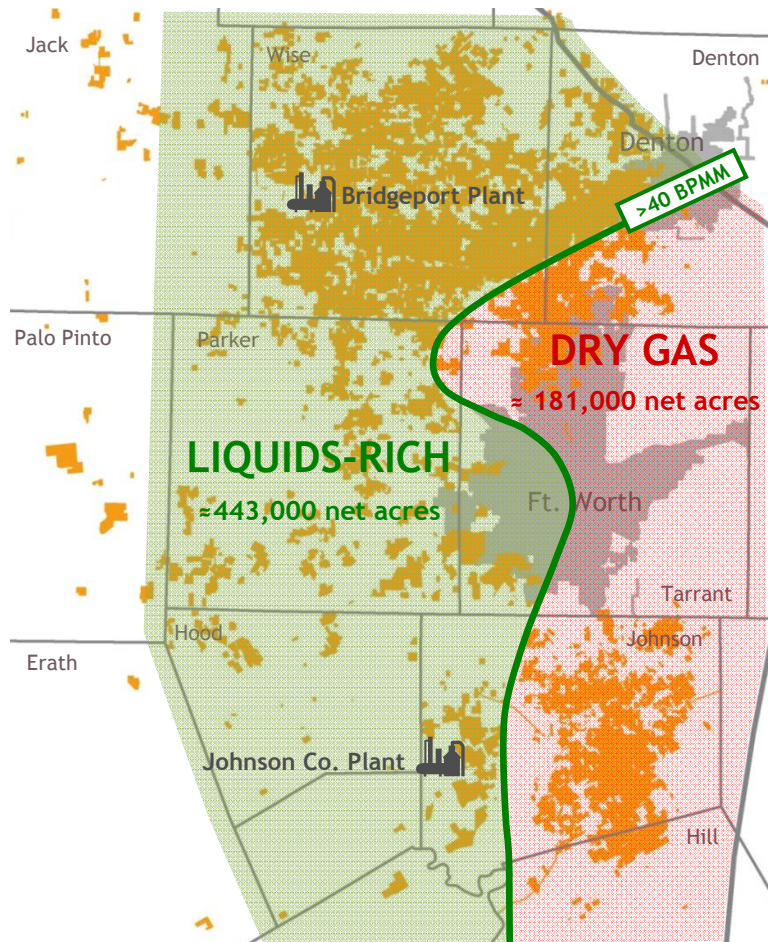
Brad Foster

Senior Vice President,
Mid-Continent Division

Barnett Shale Key Messages

- Advantaged early mover position
- Attractive multi-year, liquids-rich inventory
- Significant free cash flow
- Strategic midstream presence
- Emerging oil and liquids expansion area

Barnett Shale Overview



Net risked resource: 14.8 TCFE

Risked locations: \approx 5,000

2012 capital: \approx \$950 million

2012 plans: Drill \approx 300 wells

- Net acres: 624,000
- Enviable land position: 71% in liquids window
- Q4 2011 net production: 1.32 BCFED (21% liquids)
- Low-risk production with continued free cash flow generation
- Economics enhanced by midstream business

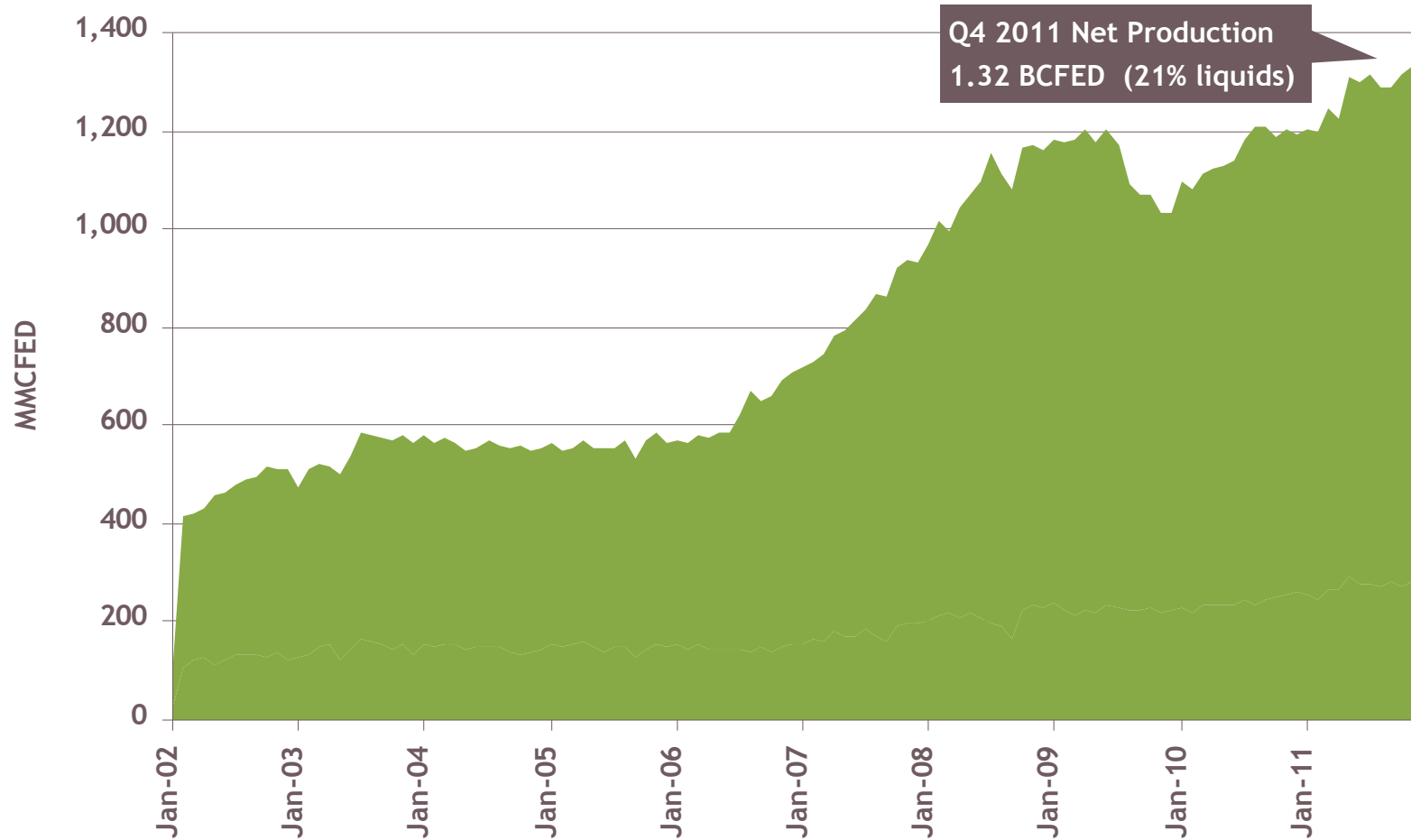
First-Mover Advantage

Barnett Shale

- Best acreage position (71% in liquids-rich areas)
- Significant economies of scale
- Low cost of entry (royalty burden & acreage costs)
- Strategic midstream presence
- Enhanced economics

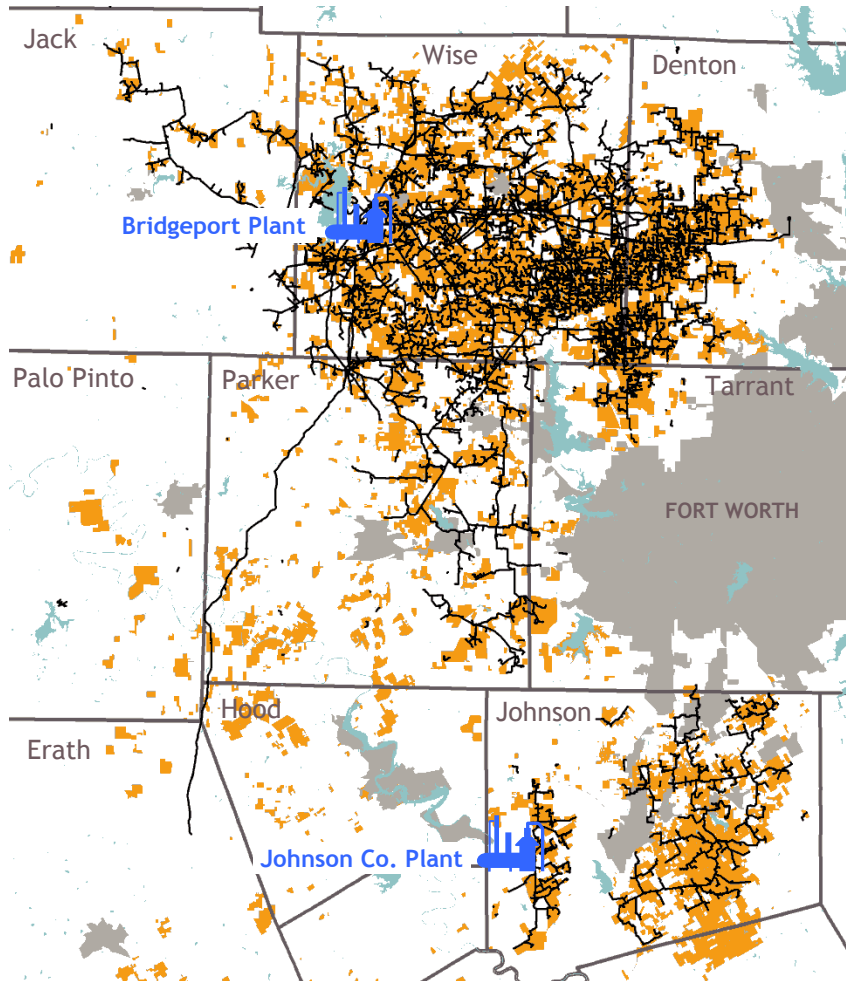
Devon's Barnett Production

Net Equivalent



Strategic Midstream Presence

Barnett Shale

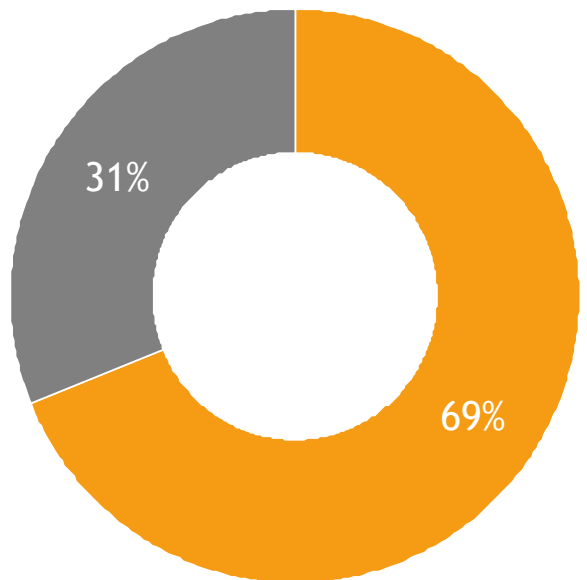


- Provides operating and marketing flexibility to maximize product value
- Ensures timely flow of production
- 100% ownership in over 3,300 miles of gas gathering system
- 100% ownership in 2 gas processing plants
 - Bridgeport: 650 MMCFD capacity
(After 1Q13 expansion: 790 MMCFD / 65 MBLPD)
 - Johnson County: 100 MMCFD capacity
- NGLs tied to Mt. Belvieu pricing

2012 Drilling Program

Barnett Shale

2012 Drilling Program
Production Mix



■ Liquids ■ Natural gas

- 2012 plans: Drill ~300 wells
- 12 operated rigs (going to 10 in Q2)
- ~80% of program is pad drilling
- Average cost per well: \$3.1 million
- Average EUR per well: 3.4 BCFE
- Targeting liquids-rich portions of field
 - Liquids >30% of production

Rate of Return Matrix

Barnett Shale 2012 Drilling Program

WTI-NYMEX Price	Henry Hub Natural Gas Price			
	\$2.50	\$3.00	\$3.50	\$4.00
\$80.00	12%	22%	30%	35%
\$90.00	15%	24%	33%	37%
\$100.00	17%	28%	35%	39%

Assumptions:

- WTI and natural gas pricing points are constant for life of project
- NGL benchmark price is 47% of WTI
- LOE: \$4.30 per BOE

Free Cash Flow Generation

Barnett Shale 2012 Drilling Program

	\$ Millions
Revenue ⁽¹⁾	\$2,100
Operating costs ⁽²⁾	(\$400)
<hr/>	
Operating margin	\$1,700
E&P & midstream capital	(\$1,100)
<hr/>	
Free cash flow	\$600

(1) Includes midstream operating profit. Excludes hedges.

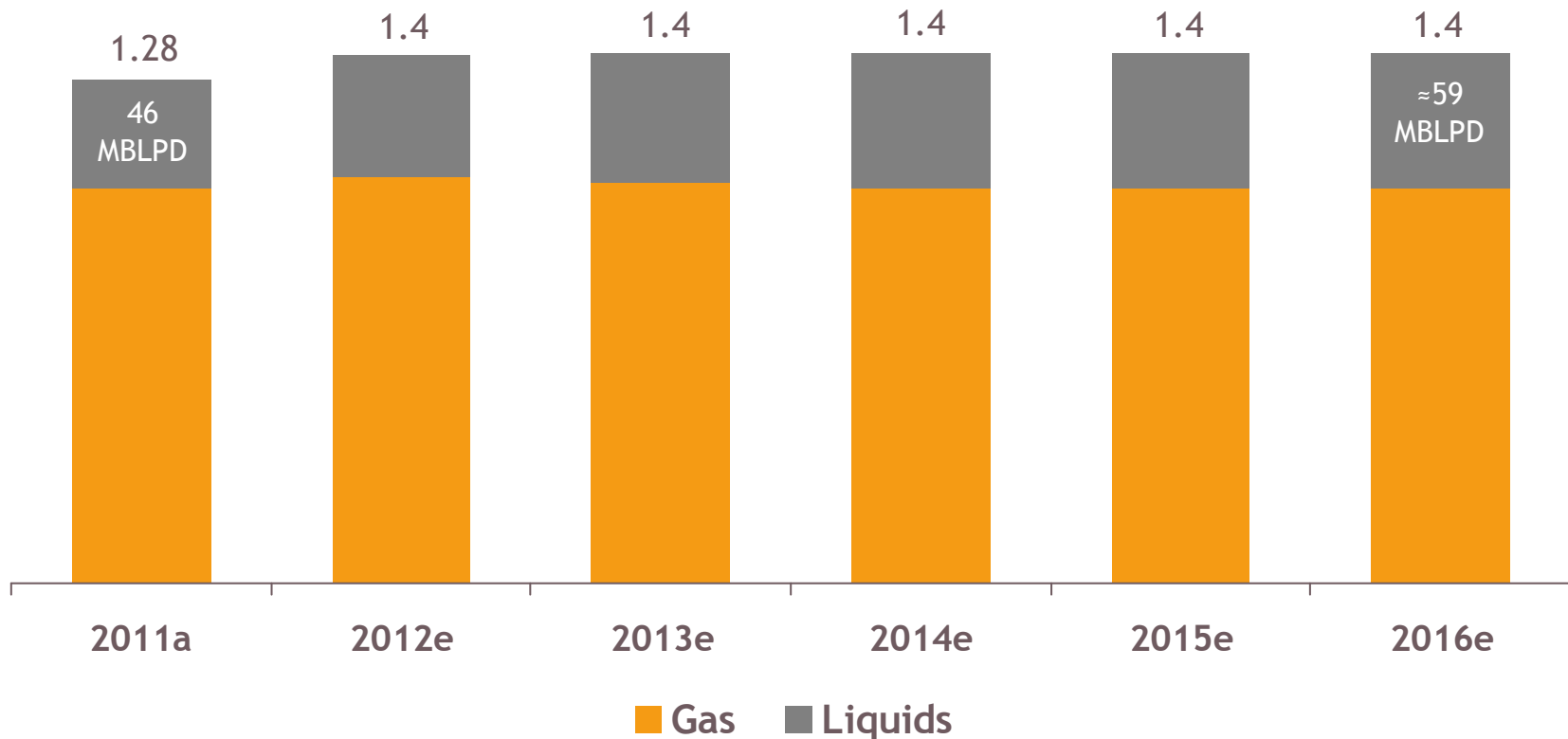
(2) Operating costs include LOE and taxes other than income.



Long-Term Production Outlook

Barnett Shale

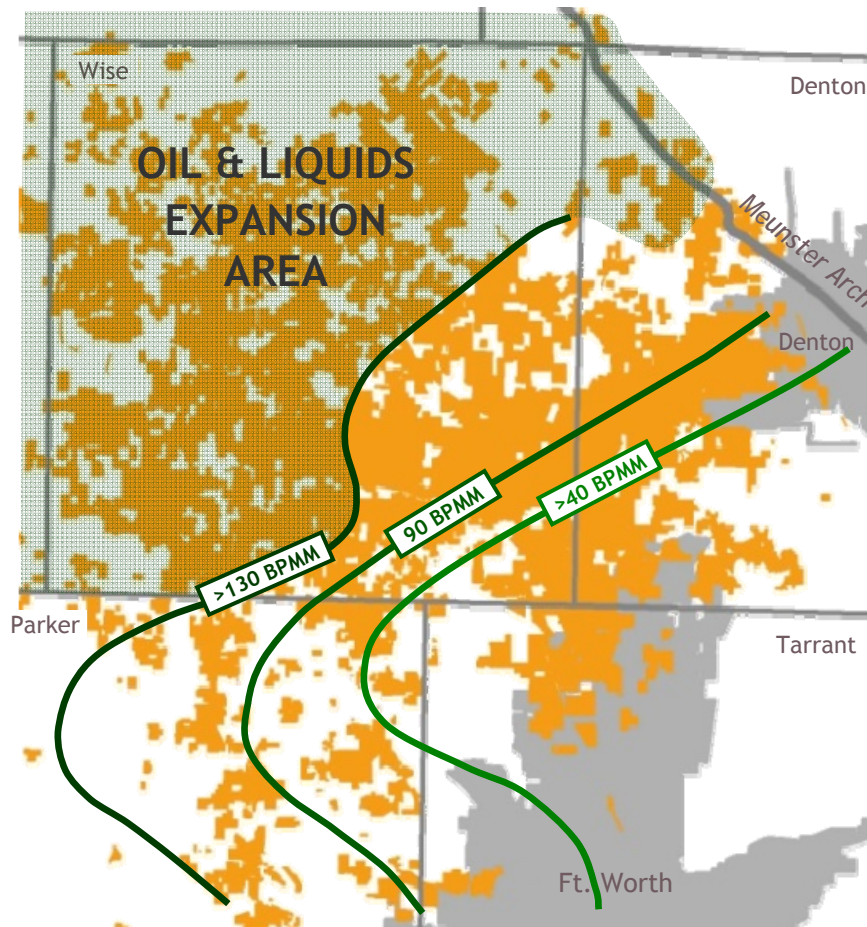
Production Data in BCFED



≈30% liquids production growth through 2016

Slide 141

Barnett Oil & Liquids Expansion Area



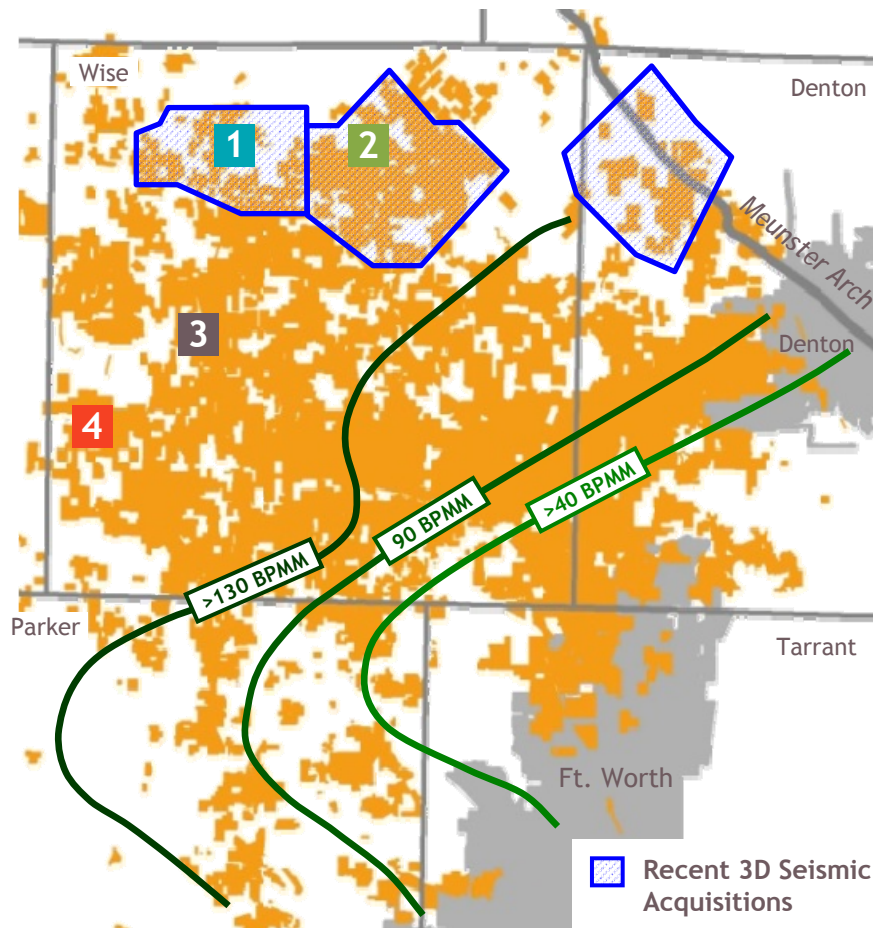
Net prospective acres: 200,000

Net unrisks resource: 600 MMBOE

- Legacy leasehold held by production
- Targeting Barnett, Strawn and Caddo formations
- Structural play, geologically complex
- Condensate and super-rich gas (up to 160 BPMM)
- Encouraging initial results

Barnett Oil & Liquids Expansion Area

Results and Plans



Initial drilling results:

- 1** Tinney
30 Day IP: 341 BOED (33% oil, 32% NGLs)
- 2** Parsons
30 Day IP: 408 BOED (50% oil, 24% NGLs)
- 3** Fitzgerald
30 Day IP: 516 BOED (9% oil, 40% NGLs)
- 4** Forrest Lindsay
30 Day IP: 485 BOED (42% NGLs)

- Seismic evaluation and mapping underway
- Drilling 28 wells in this area in 2012

Barnett Continuous Improvement Drilling

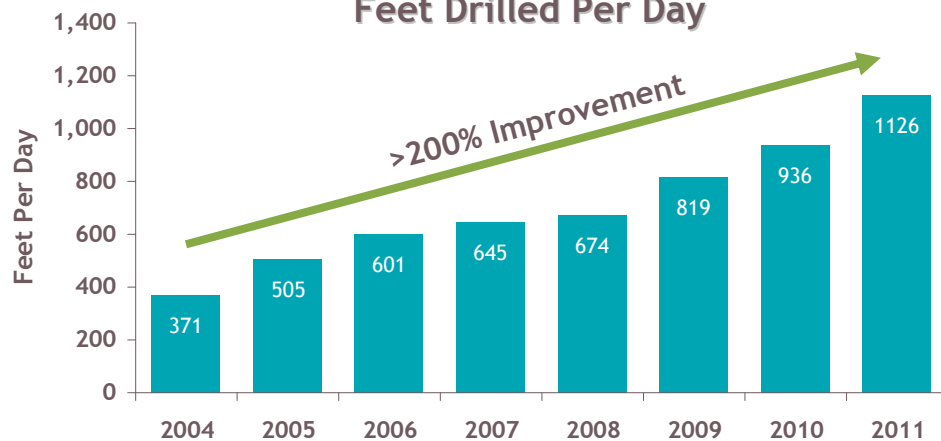
Spud to Rig Release & Lateral Length



- Spud to rig release days decreased 30% since 2008 while lateral lengths have increased 65%

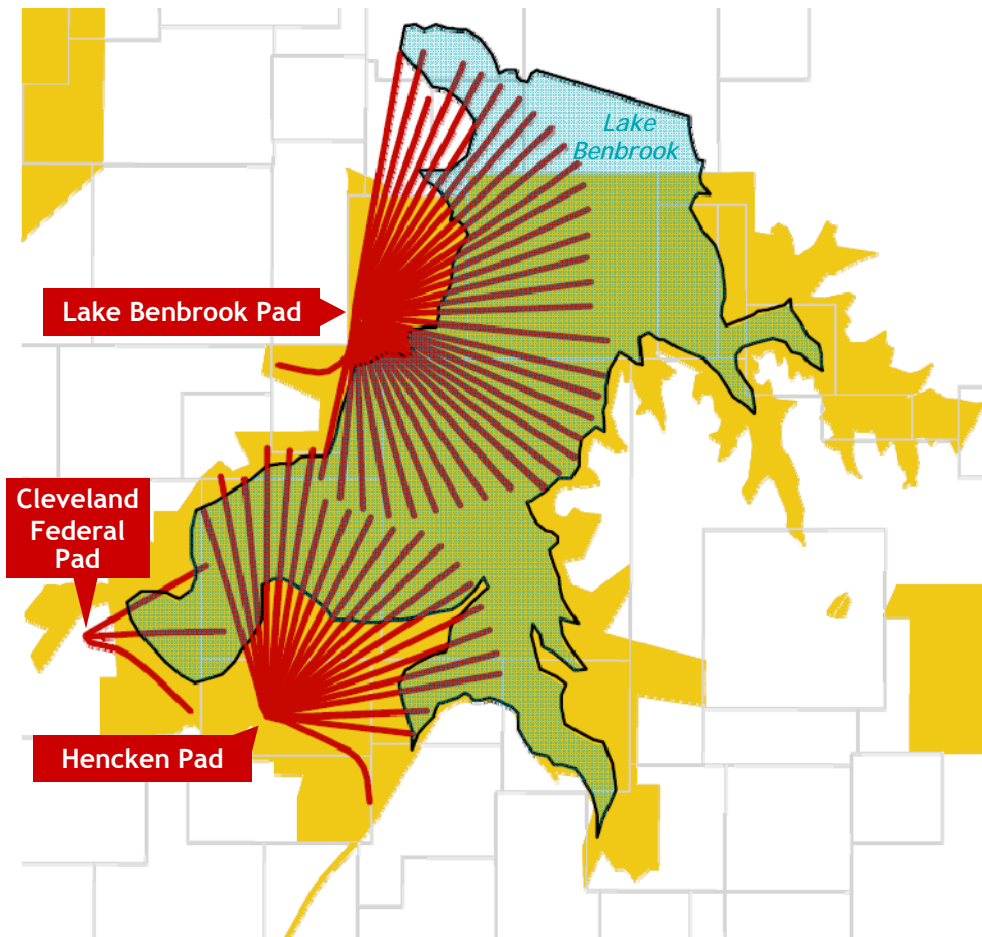
- Feet drilled per day has improved >200% since 2004

Feet Drilled Per Day



- Improvements include:
 - Drilling practices
 - Multi-well pad drilling
 - Equipment reliability

Lake Benbrook Pad Drilling Example



Lake Benbrook Pad

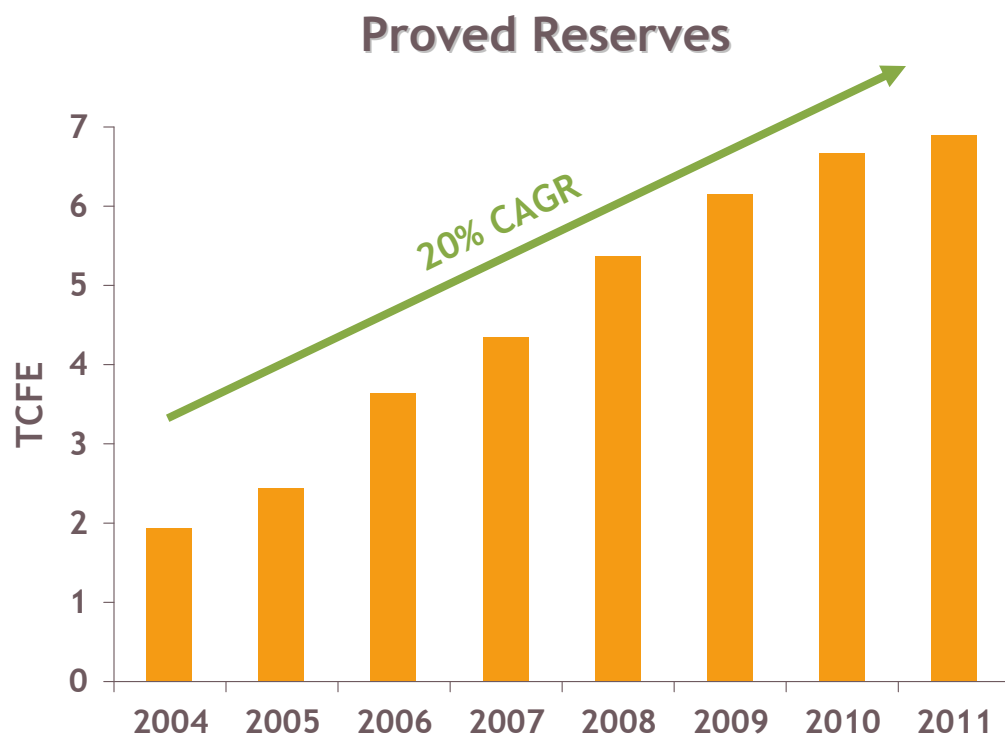
- 36 wells drilled in 2011
- Spud to rig release: 11 days
- First 24 wells online at 80 MMCFD
- 80 BPMM yield or >6,000 BLPD
- Pad SWD lowers operating expense

Hencken Pad

- 22 wells online in 2011
- Spud to rig release: 10 days
- 30 day IP: 60 MMCFD
- 90 BPMM yield or >5,000 BLPD

Outstanding Reserve Growth

Barnett Shale



	<u>TCFE</u>
Purchased at 1/24/02	1.8
Produced through 12/31/11	(3.0)
Reserve additions	8.1
<hr/>	
Proved reserves 12/31/11	6.9
▪ 22% liquids	
▪ 14% PUD	

Performance Reserve Revisions

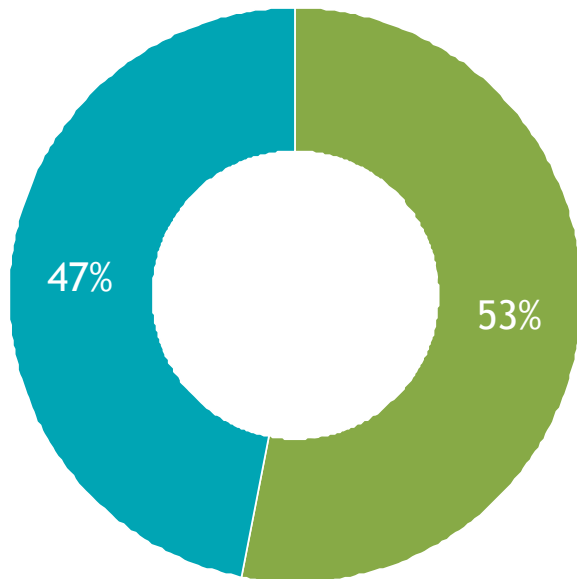
Barnett Shale

Year	Performance Reserve Revisions (BCFE)
2004	+186
2005	+366
2006	+30
2007	+240
2008	+132
2009	+288
2010	+156
2011	+30

Barnett Risked Resource

High-Quality and Balanced

14.8 TCFE Risked Resource (25.7 TCFE unrisked)



■ Proved Reserves (14% PUDs) ■ Additional Risked Potential

Note: Includes 12/31/11 proved reserves of 6.9 TCFE.

Barnett Resource Overview

- ≈5,000 undrilled risked locations
 - ≈2,500 liquids locations
- ≈8 years of liquids drilling inventory
- Oil and liquids expansion area
 - Unrisked potential: 600 MMBOE

Barnett Shale Key Messages

- Advantaged early mover position
- Attractive multi-year, liquids-rich inventory
- Significant free cash flow
- Strategic midstream presence
- Emerging oil and liquids expansion area

Cana Woodford Shale

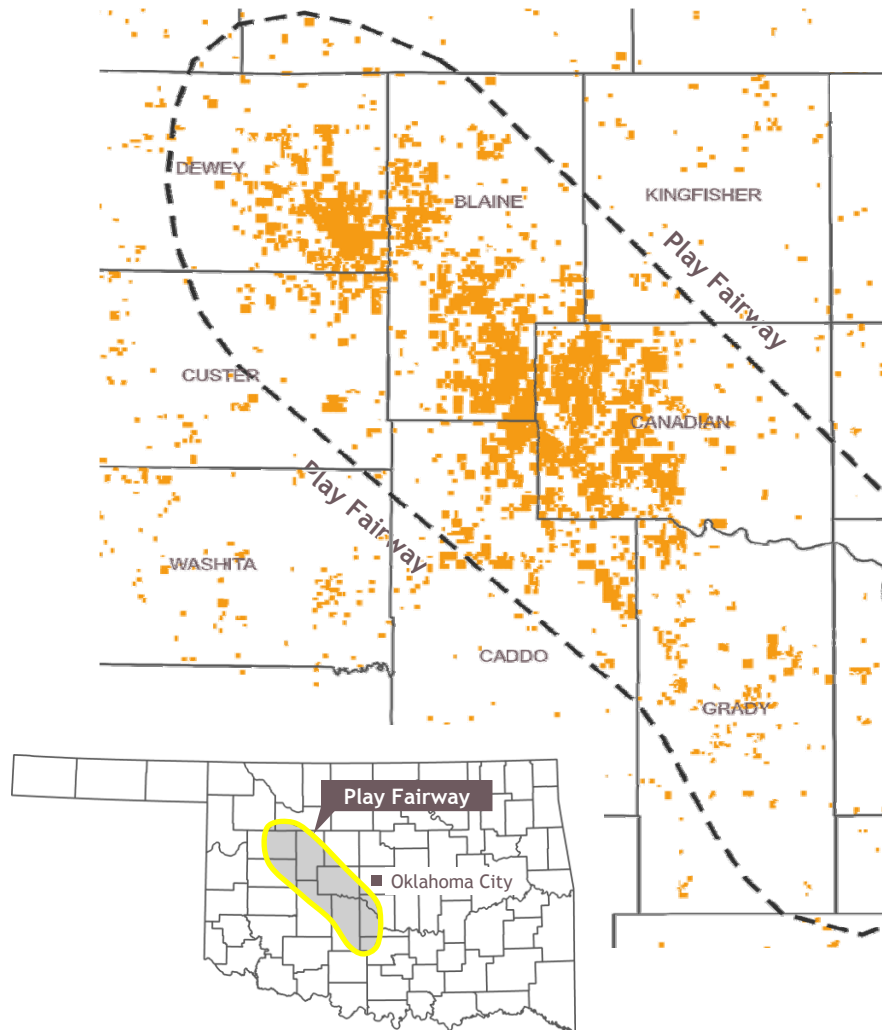
Kris Goforth

Business Unit Vice President,
Anadarko Basin

Cana Woodford Key Messages

- Significant resource with dominant and best position
- Strong oil and liquids-rich growth
- Multi-year inventory with solid returns
- Low execution risk environment
- Strategic midstream presence
- Additional upside

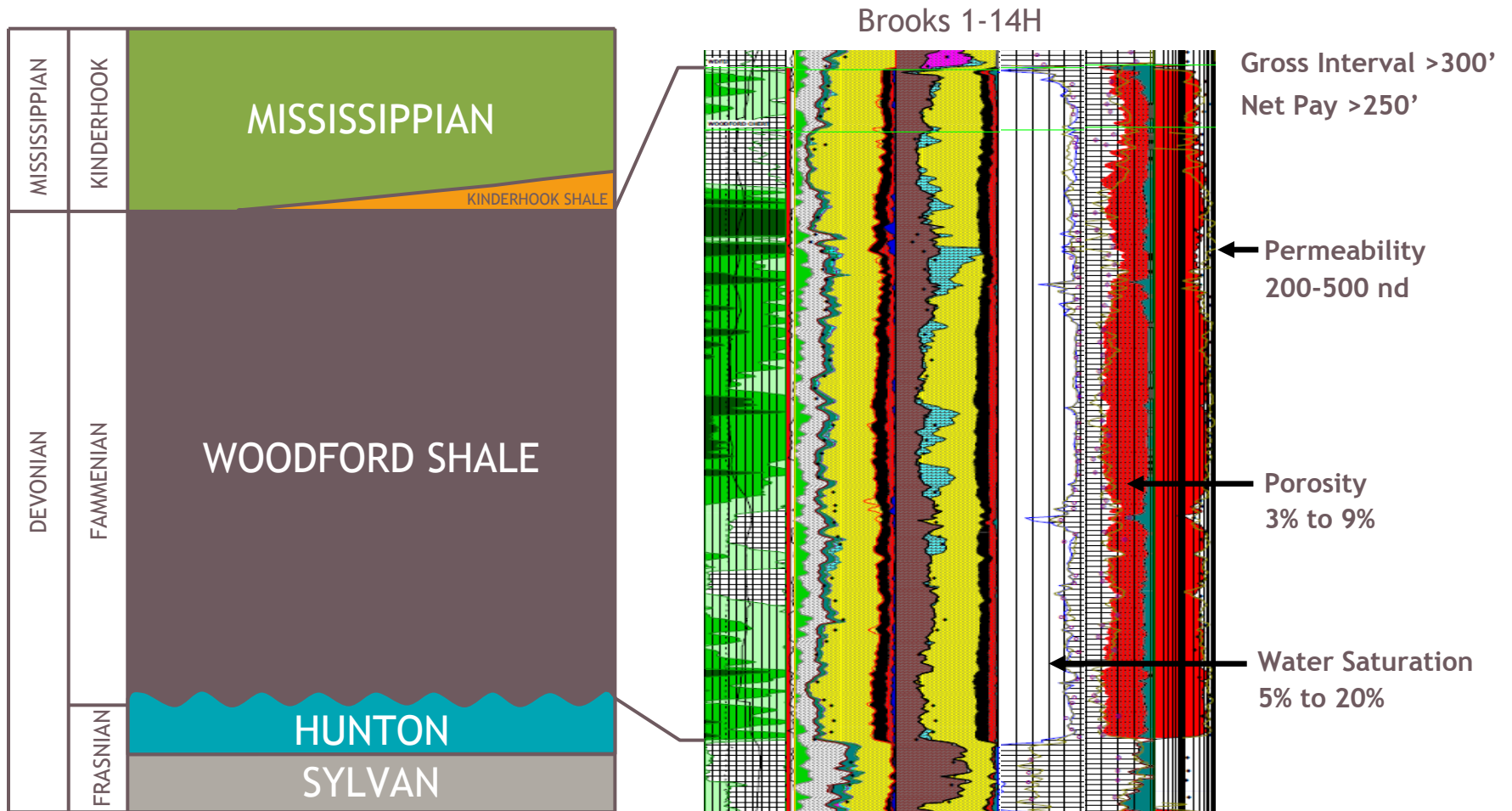
Cana Woodford Shale Overview



- Estimated play resource in place: 50-220 BCFE per square mile
- Oil and liquids-rich gas play
- Low above ground risk (markets, topography, regulatory environment)
- Industry rigs running: 46
- Producing wells: ≈500

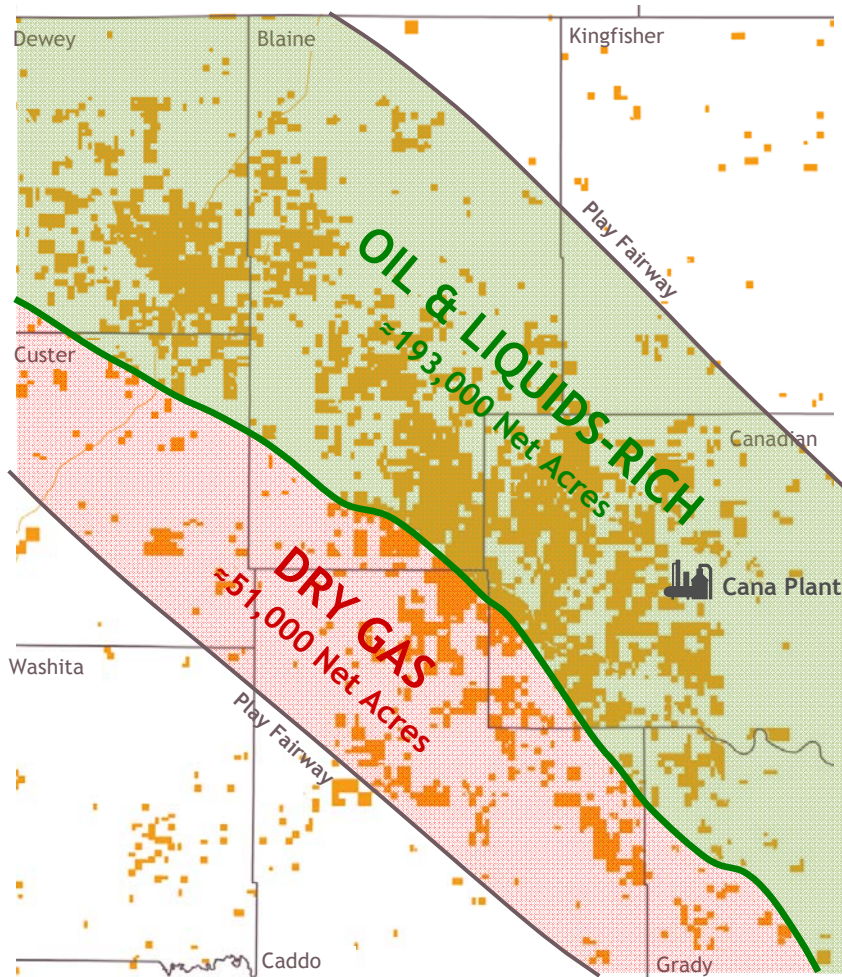
Cana Woodford Geology

Petrophysical Log Evaluation



Cana Woodford Shale

Devon's Position



Net risked resource: 11.4 TCFE

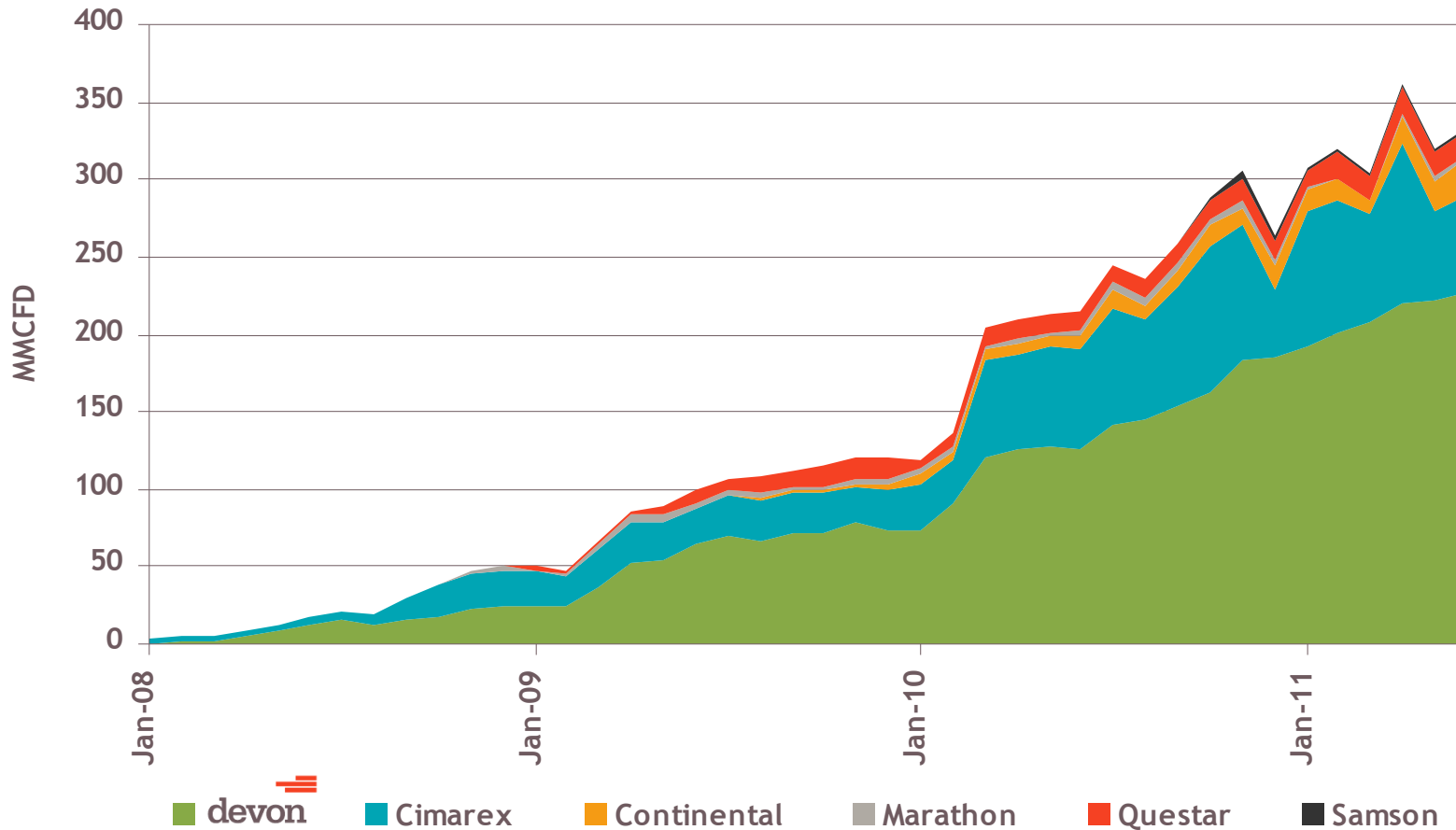
Risked locations: ≈5,400

2012 capital: \$870 million

2012 plans: Drill ≈200 wells

- Net acres: 244,000 (Essentially all HBP)
- 79% in oil and liquids-rich window
- Low acreage costs and royalty burden
- Q4 2011 net production: 250 MMCFED
- Economics enhanced by midstream business

Industry Cana Woodford Production Gross Wellhead Since Inception



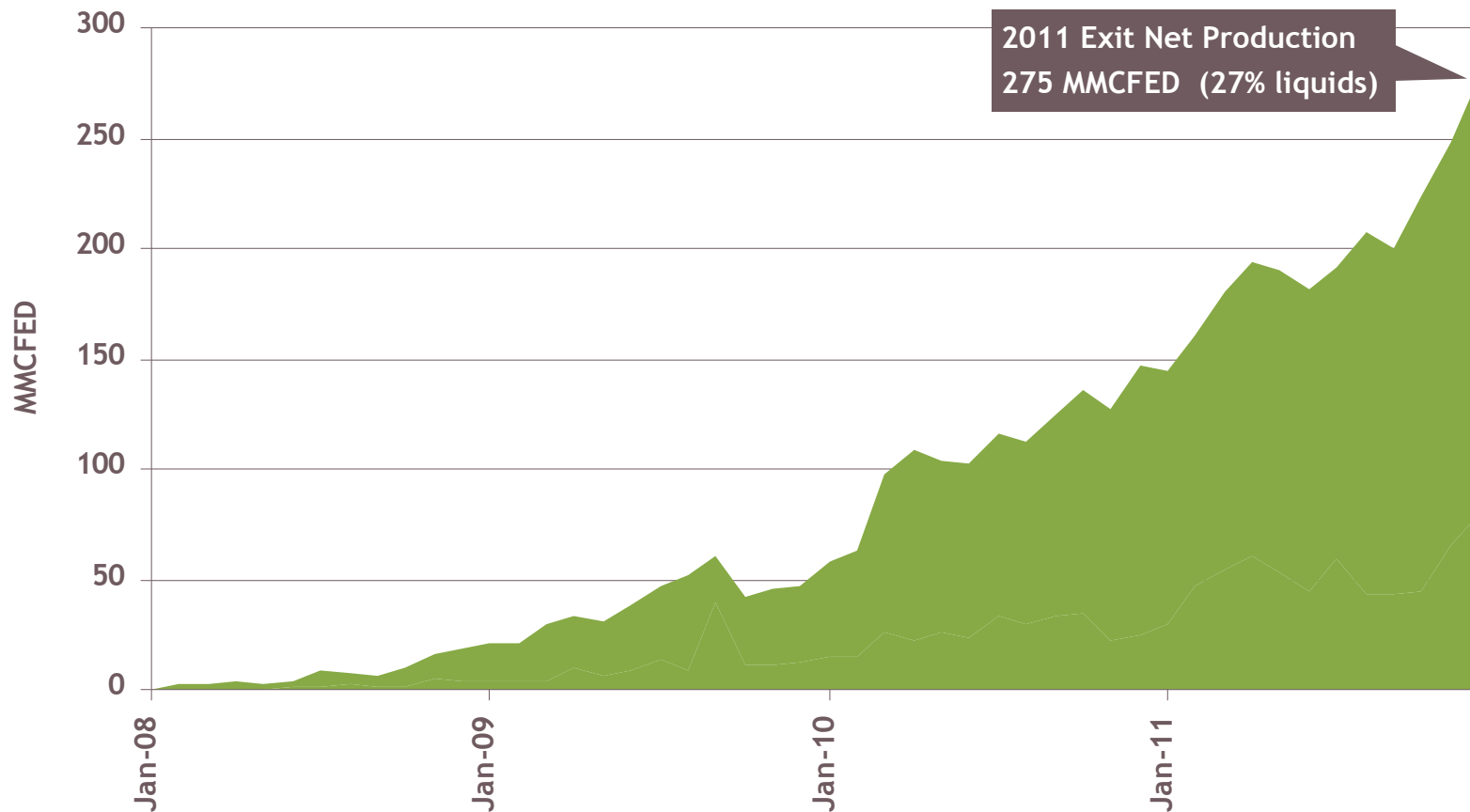
Source: IHS Energy. Gross wellhead production by operator as of June 2011.

First mover advantage yields dominant position

Slide 155

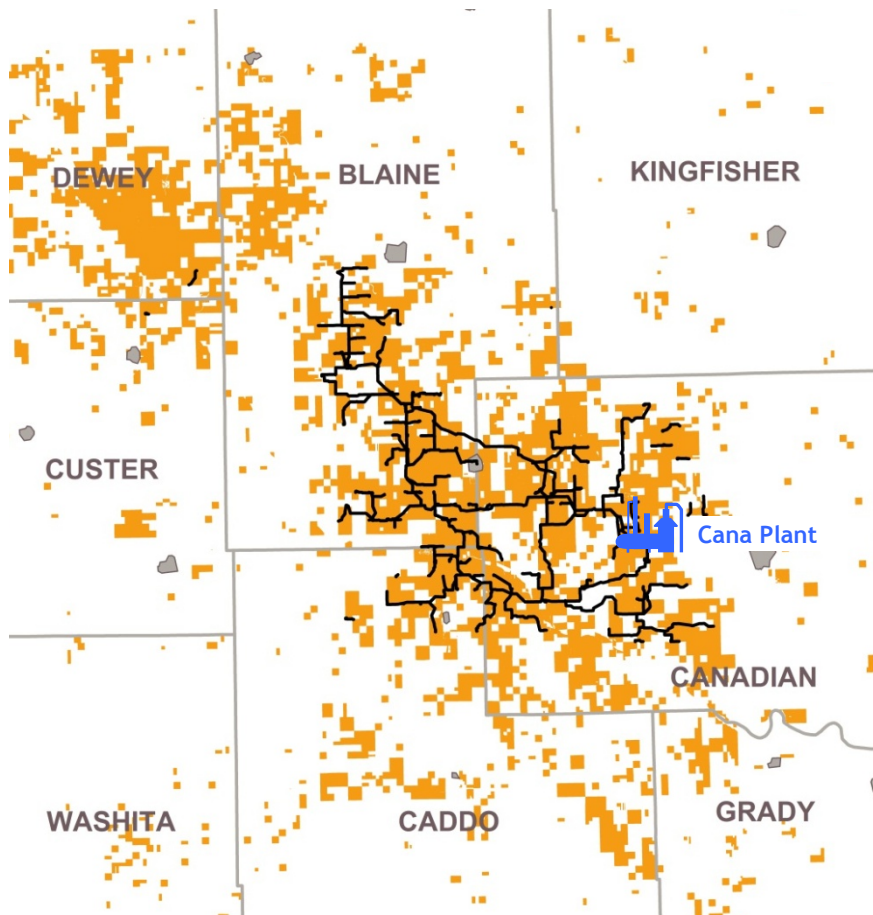


Devon's Cana Woodford Production Net Equivalent



Strategic Midstream Presence

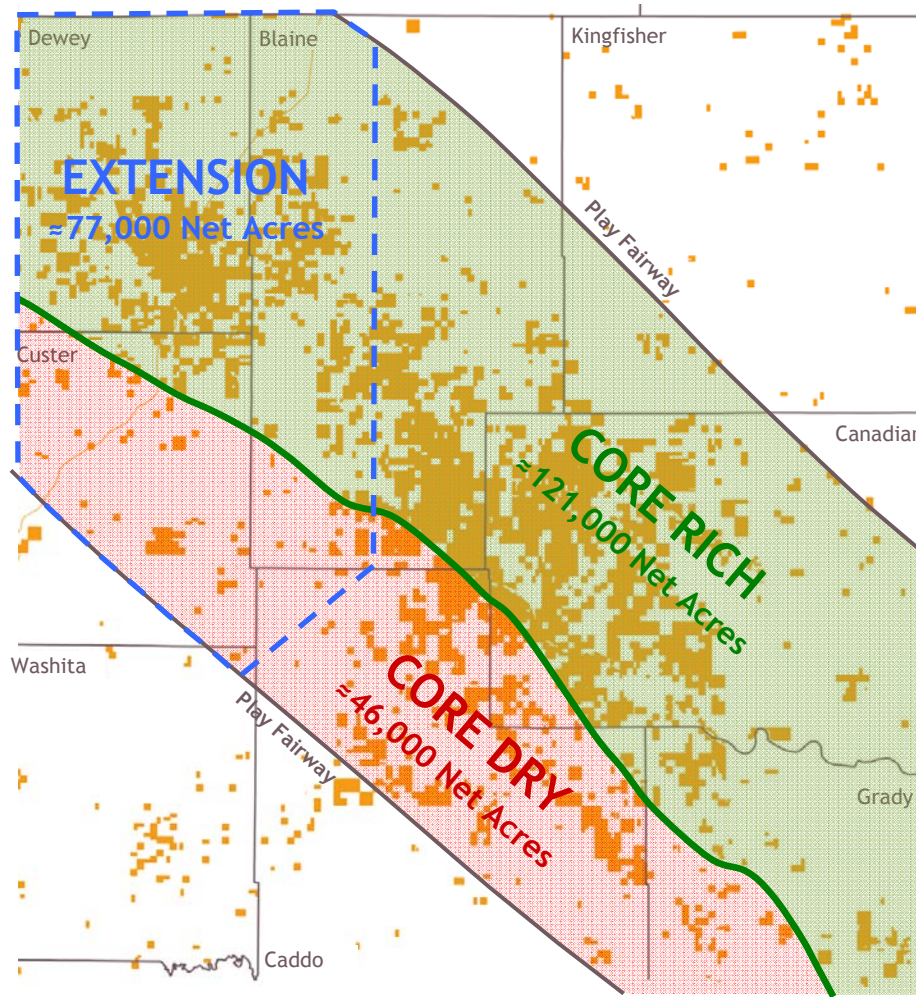
Canva Woodford



- Provides operating and marketing flexibility, maximizes product value
- Ensures timely flow of production
- 100% ownership in over ~300 miles of gas gathering system
- 100% ownership in Canva processing plant
 - 200 MMCFD capacity
(After 1Q13 expansion: 350 MMCFD / 30 MBLPD)
- NGLs tied to Mt. Belvieu pricing

Cana Woodford Play Characterization

Based On Drilling Results To Date



Core Rich Area

- Net acres: 121,000
- Gross pay: 100' to 320'
- High oil and liquids content: up to 300 barrels per MMCF

Core Dry Area

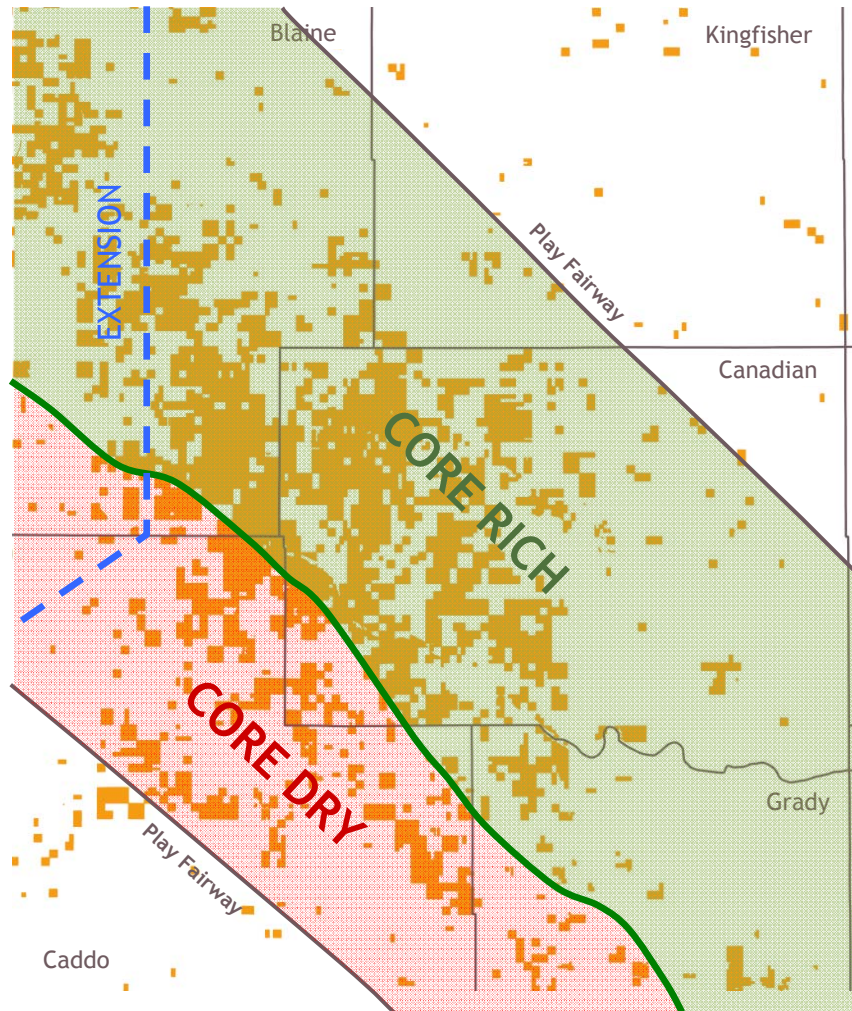
- Net acres: 46,000
- Gross pay: 100' to 250'
- Over-pressured reservoir

Extension Area

- Net acres: 77,000
- Gross pay: <150' Woodford plus Mississippian contribution

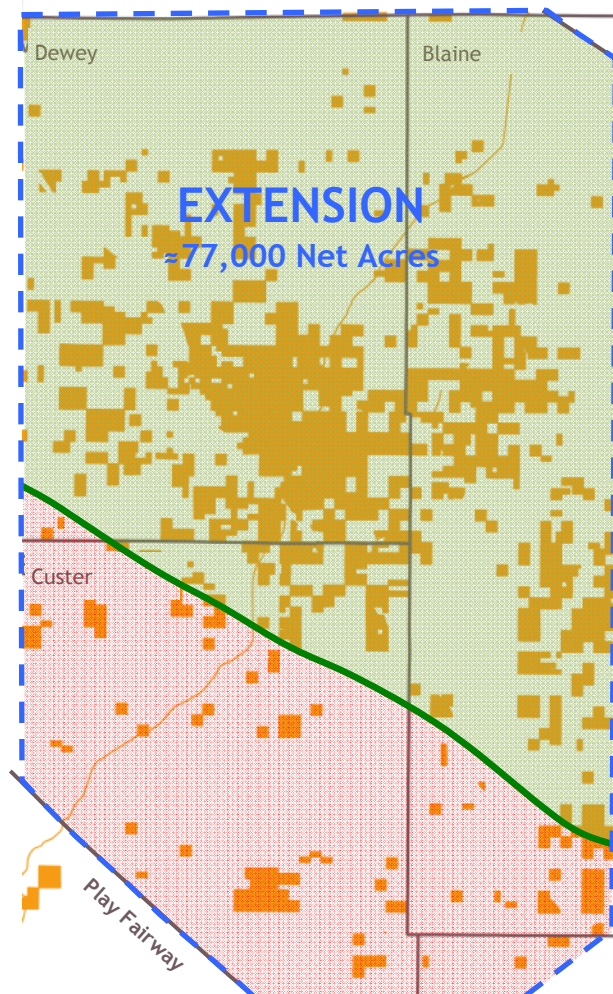
Cana Woodford Core

World-Class Shale



- 9.4 TCFE of risked resource in total core area
 - 8.3 TCFE in core rich
- ≈3,000 oil and liquids-rich drilling locations (Based on 5,000' lateral length)
- Strong economics in current environment
- Infill development program underway
- Testing 10,000' multi-section laterals

Cana Woodford Extension

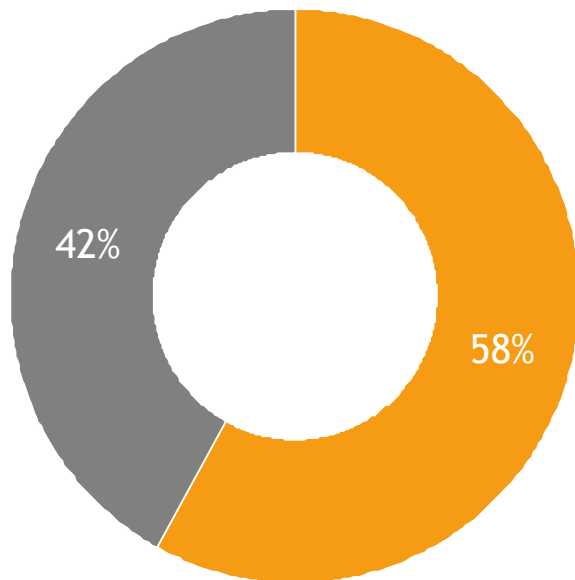


- Greater geologic complexity
- Additional Mississippian contribution
- Technical evaluation ongoing

2012 Drilling Program

Cananda Woodford Shale

2012 Drilling Program
Production Mix



■ NGLs & condensate ■ Natural gas

- 2012 plans: Drill ≈200 wells
- 16 operated rigs
- Average cost per well: \$8.1 million
- Average EUR per well: 8.3 BCFE
- Focused in core rich portion of field
 - Oil and liquids >40% of production

Rate of Return Matrix

Cana Woodford 2012 Drilling Program

WTI-NYMEX Price	Henry Hub Natural Gas Price			
	\$2.50	\$3.00	\$3.50	\$4.00
\$80.00	20%	22%	28%	31%
\$90.00	23%	29%	31%	35%
\$100.00	27%	32%	34%	38%

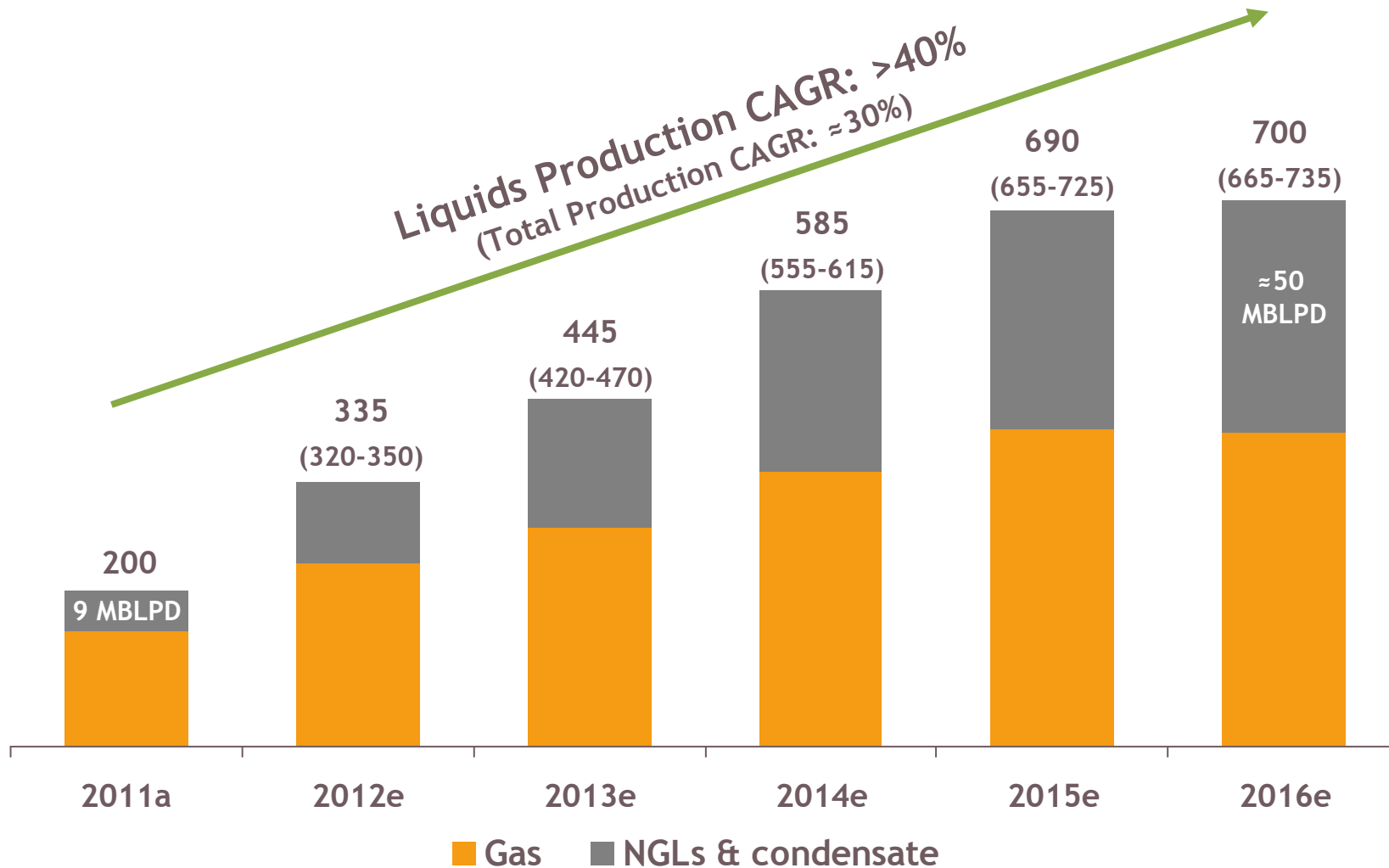
Assumptions:

- WTI and natural gas pricing points are constant for life of project
- NGL benchmark price is 47% of WTI
- LOE: \$3.90 per BOE

Long-Term Production Outlook

Cananda Woodford

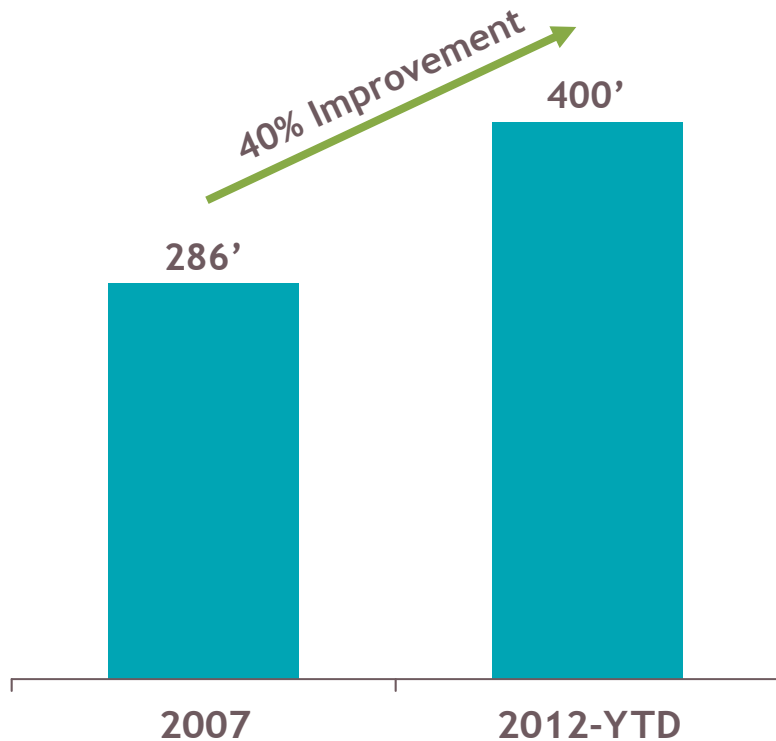
Production Data in MMCFED



Cana Continuous Improvement

Drilling

Improved Drilling Efficiency (Average Feet Drilled Per Day)

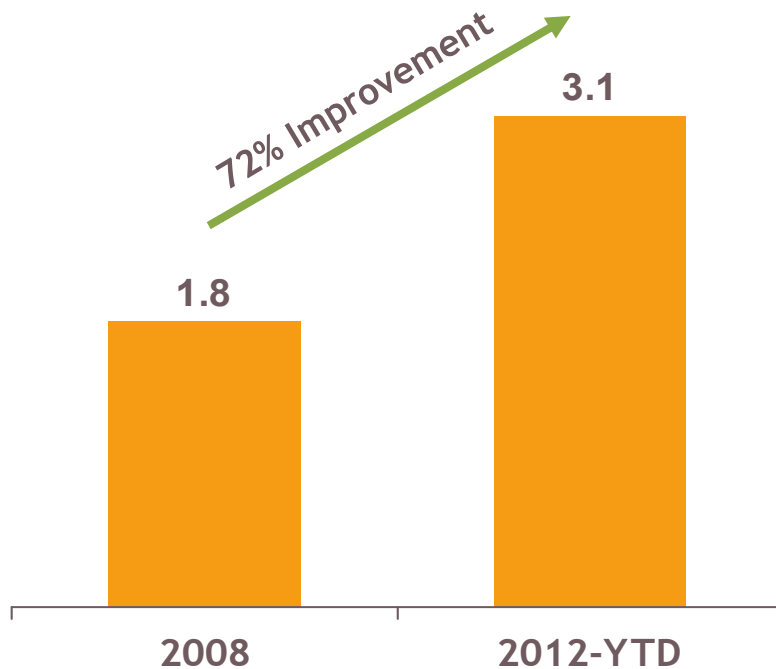


- Feet drilled per day has improved 40% since 2007
- Improvements include:
 - Rig technology
 - Improved bit design and performance
 - Drilling practices
 - Improved geo-steering

Cana Continuous Improvement

Completion Practices

Improved Completion Efficiency (Average Frac Stages Per Day)

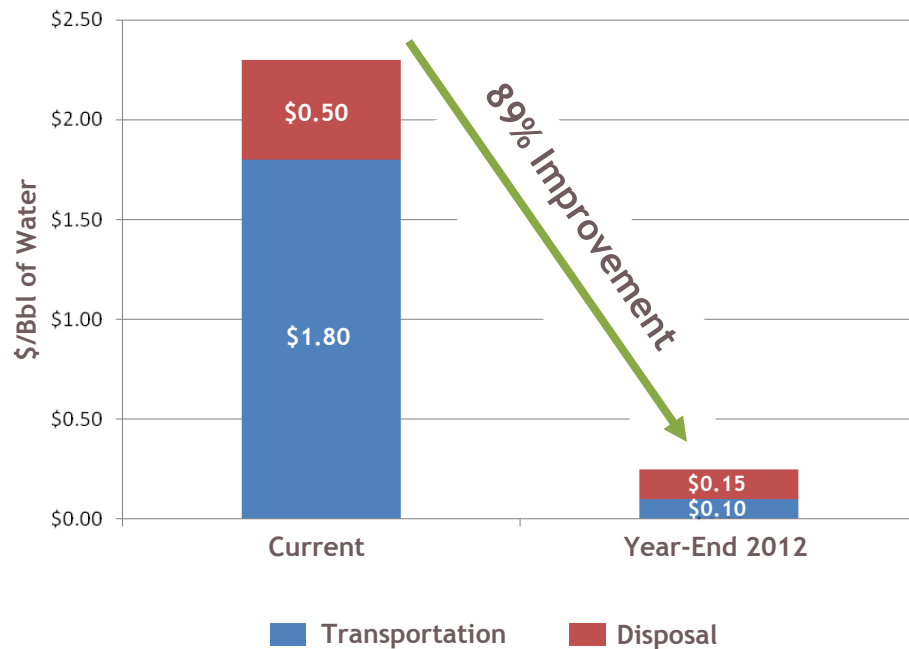


- Frac stages per day has improved 72% since 2008
- Improvements include:
 - Execution efficiencies in multi-stage completions
 - Better completion designs
 - Less downtime

Cana Continuous Improvement

Water Recycling

Improved Water Handling Costs
Cana Recycling Project
 (\$/Bbl of Water)



Project Details

- 38 miles of dedicated water recycling pipeline to service 30 section drilling program
- 500,000 barrel, fully-automated water holding facility

Impact

- 89% decrease in water handling costs in initial project area
- Additional cost savings with full implementation
- Expected ROR: ~35%

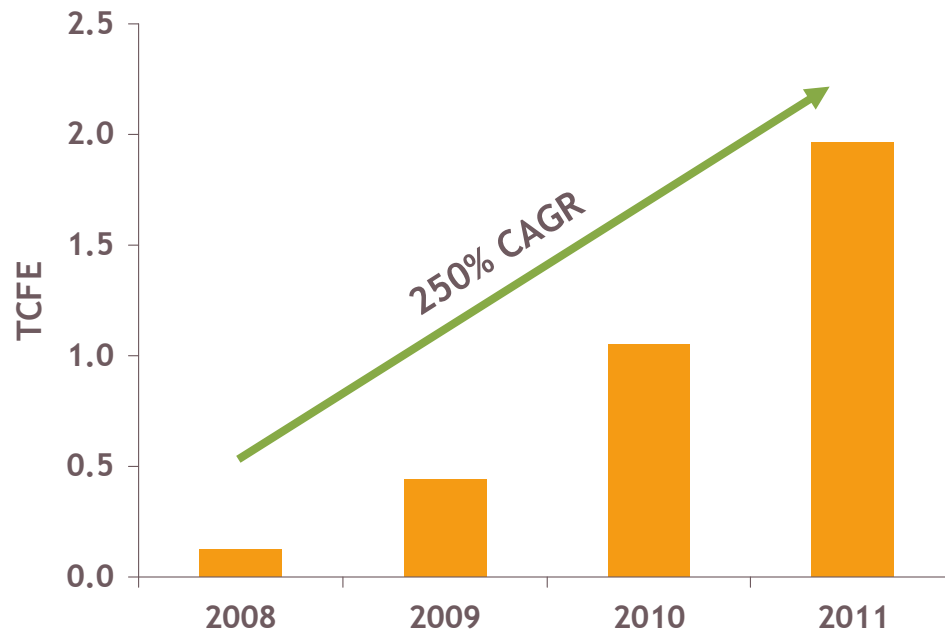
Water Conservation

- 2.3 million barrels to be recycled in 2012
- 7.5 million barrels recycled annually by 2014

Outstanding Reserve Growth

Cananda Woodford

Proved Reserves



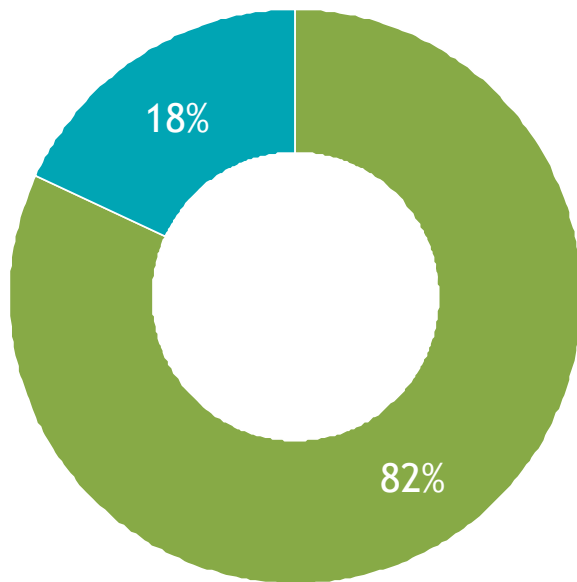
TCFE

Year-end 2008	0.1
Produced through 12/31/11	(0.1)
Reserve additions	2.0
<hr/>	
Proved reserves 12/31/11	2.0
▪ 36% liquids	

Cana Woodford Risked Resource

High-Quality and Balanced

11.4 TCFE Risked Resource (16.8 TCFE unrisked)



■ Proved Reserves (51% PUD) ■ Additional Risked Potential

Note: Includes 12/31/11 proved reserves of 2.0 TCFE.

Cana Resource Overview

- >80% of resource located in core area
- ≈5,400 undrilled locations
 - ≈3,000 oil and liquids locations in core rich
- ≈15 years of oil and liquids drilling inventory

Cana Woodford Key Messages

- Significant resource with dominant and best position
- Strong oil and liquids-rich growth
- Multi-year inventory with solid returns
- Low execution risk environment
- Strategic midstream presence
- Additional upside

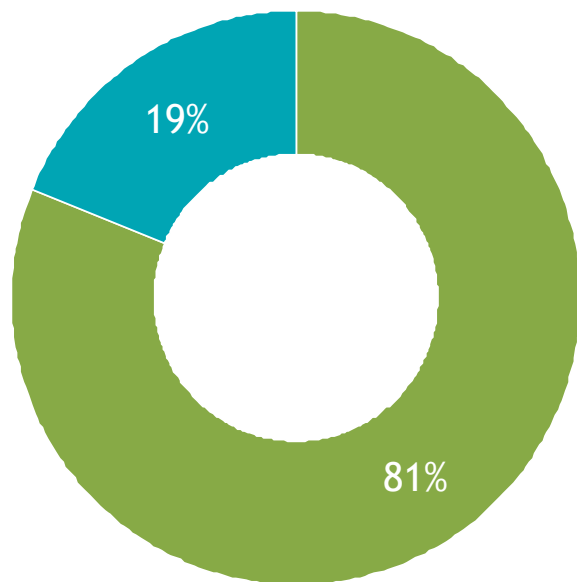
Summary

John Richels
President & CEO

Devon's Risked Resource Base

High-Quality and Balanced

16.2 BBOE Risked Resource
(31.8 BBOE Unrisked)



■ Proved Reserves (26% PUDs)
 ■ Additional Risked Potential

Note: Includes 12/31/11 proved reserves of 3.0 BBOE.

Risked Resource By Product (BBOE)

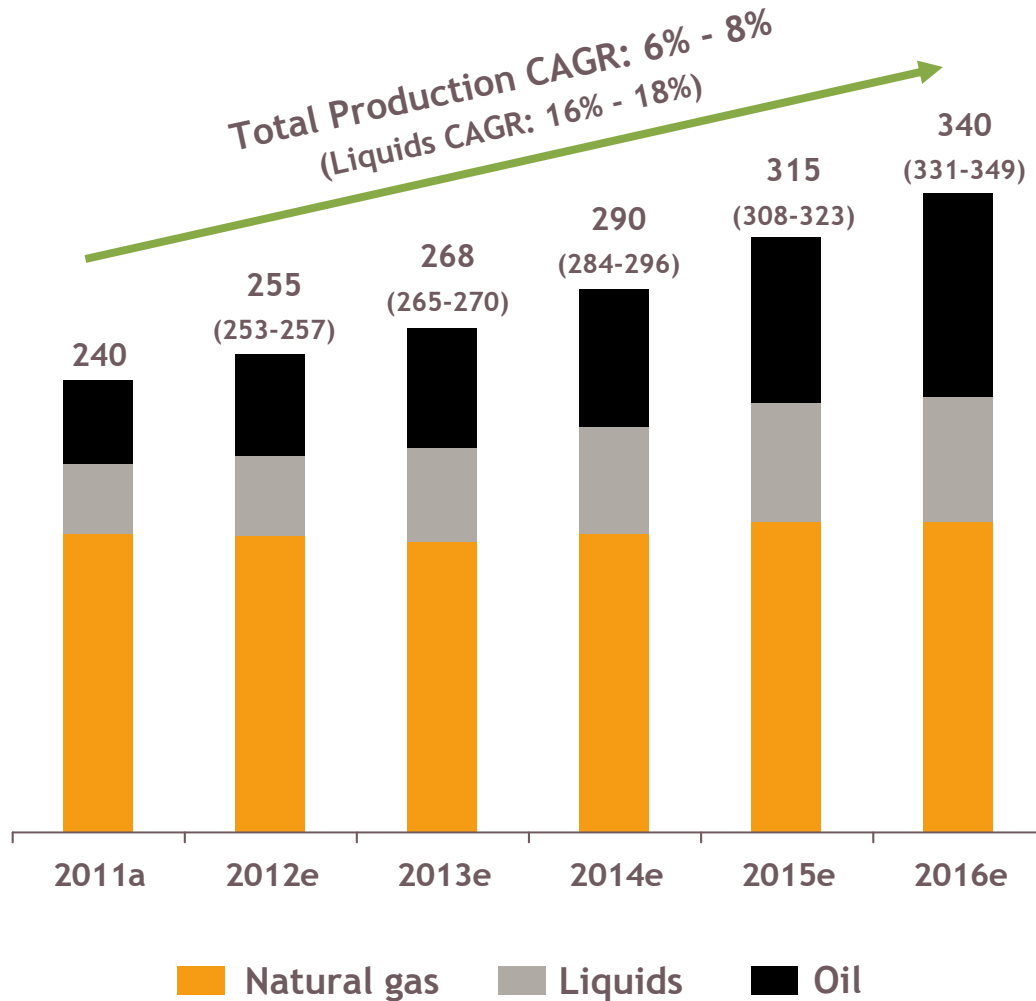
Oil (29%)	4.7
NGLs (19%)	3.1
Gas (52%)	8.4
Total	16.2

Oil-focused exploration provides upside to risked resource

Long-Term Outlook

Robust Oil & Liquids Production Growth

Production Data in MMBOE



5-Year Production CAGR By Product

Oil	19%
Liquids	13%
Natural gas	1%
<hr/>	
Total (BOE)	≈7%

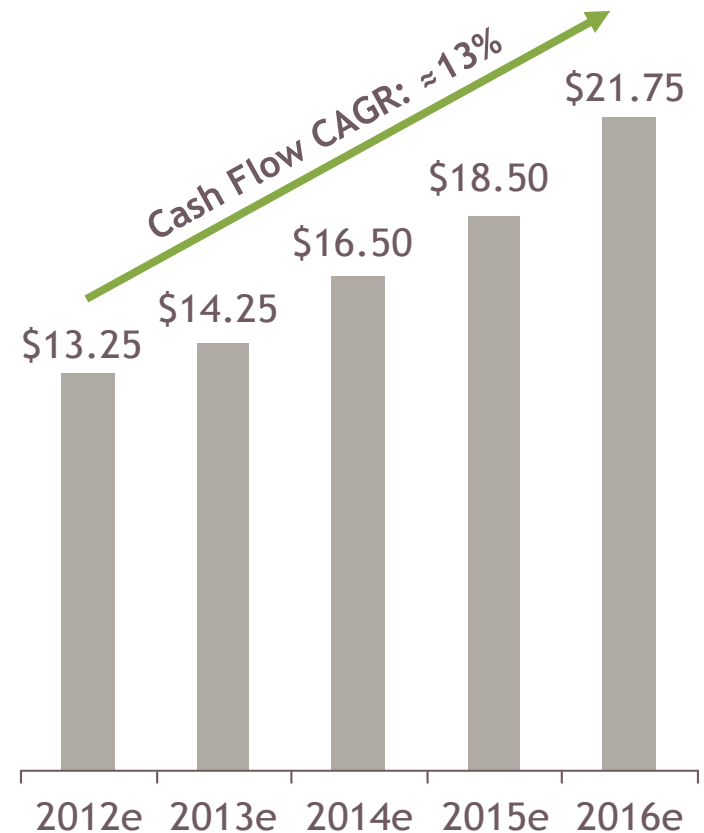
Long-Term Outlook

Strong Cash Flow Growth

Operating Cash Flow
(\$ Billions)



Cash Flow Per Debt-Adjusted Share
(\$ Per Share)



Note: Cash flow per debt-adjusted share calculation assumes Devon's share price trades at current multiple to cash flow (4.2x).

Summary

- Committed to delivering:
 - Top quartile per share results
 - Strong full-cycle returns
- Deep inventory of repeatable opportunities in current environment
- Strong, highly-visible oil and liquids growth
- Significant upside from exploration prospects
- Superior financial strength and flexibility



Q&A



Thank You

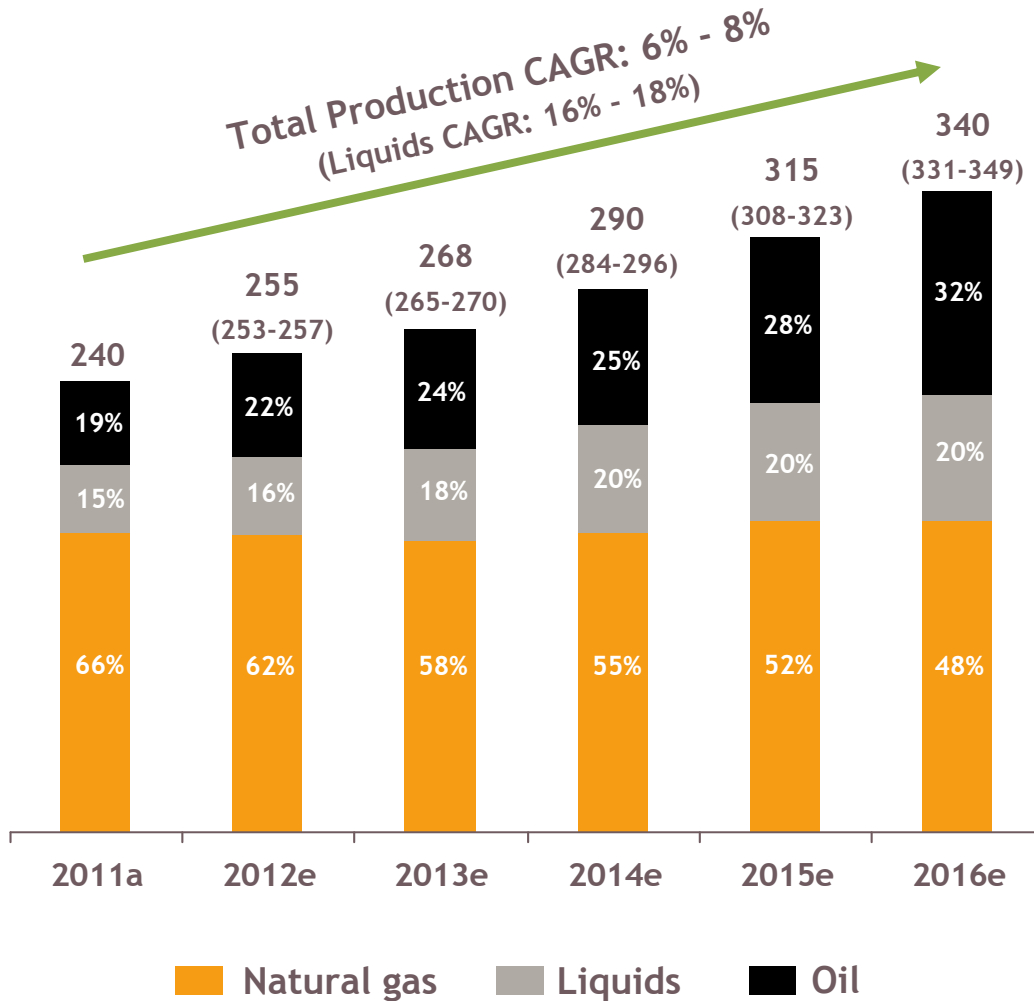


Appendix

Long-Term Outlook

Robust Oil & Liquids Production Growth

Production data in MMBOE



NYSE: DVN

www.devonenergy.com

5-Year Production CAGR By Product

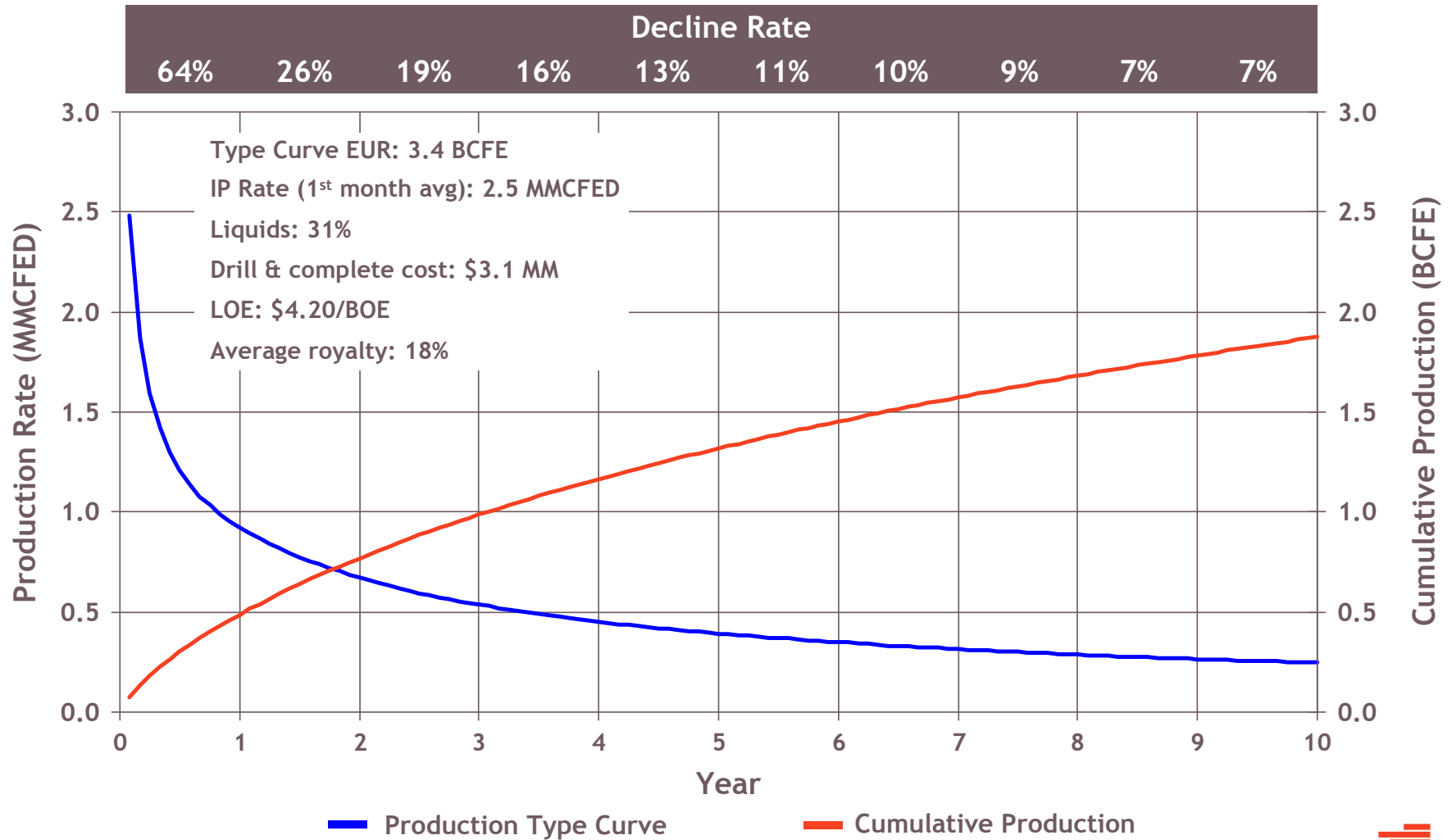
Oil	19%
Liquids	13%
Natural gas	1%
Total (BOE)	≈7%

Slide 178



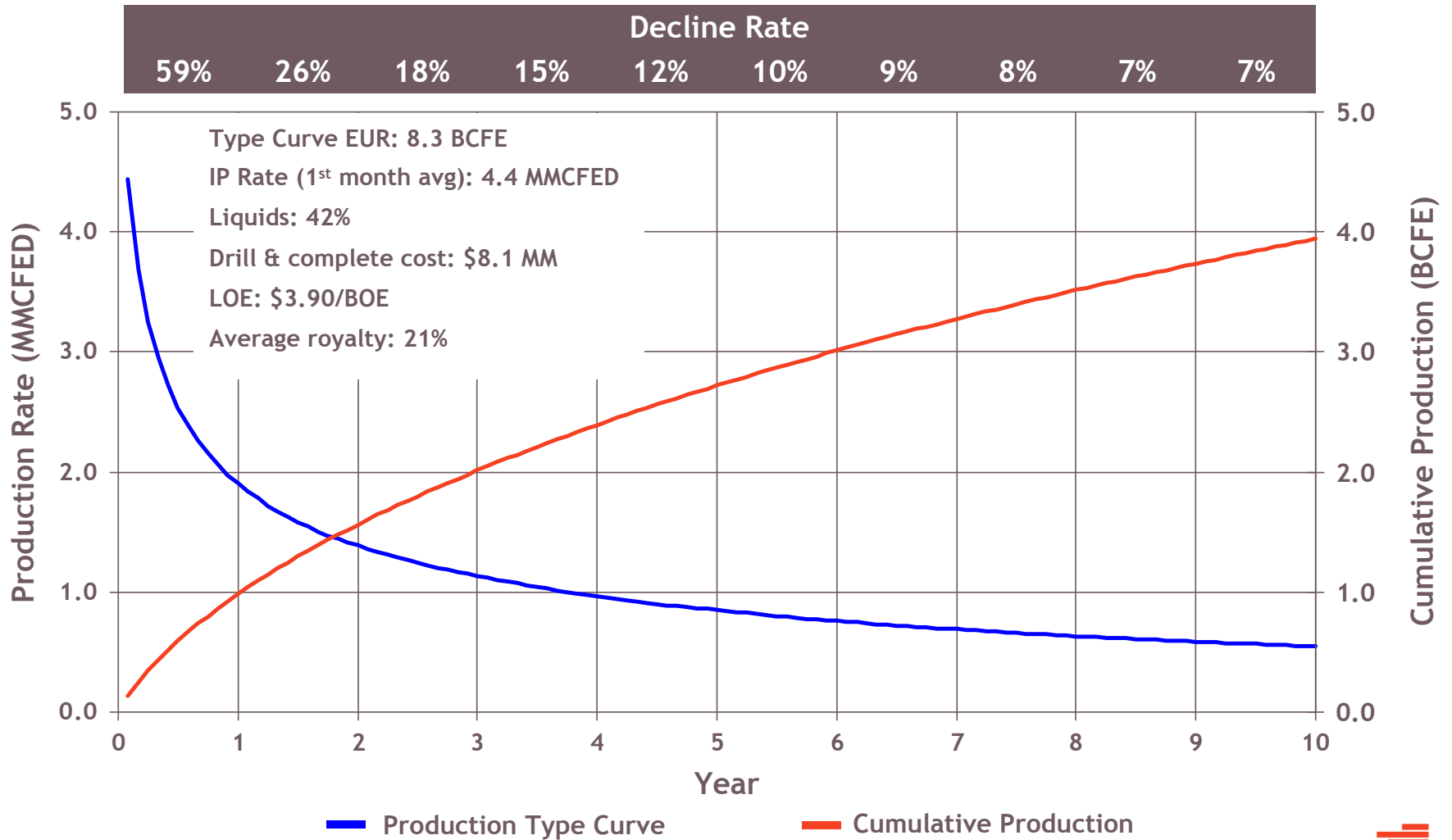
Barnett Modeling Statistics

Based on 2012 Drilling Program



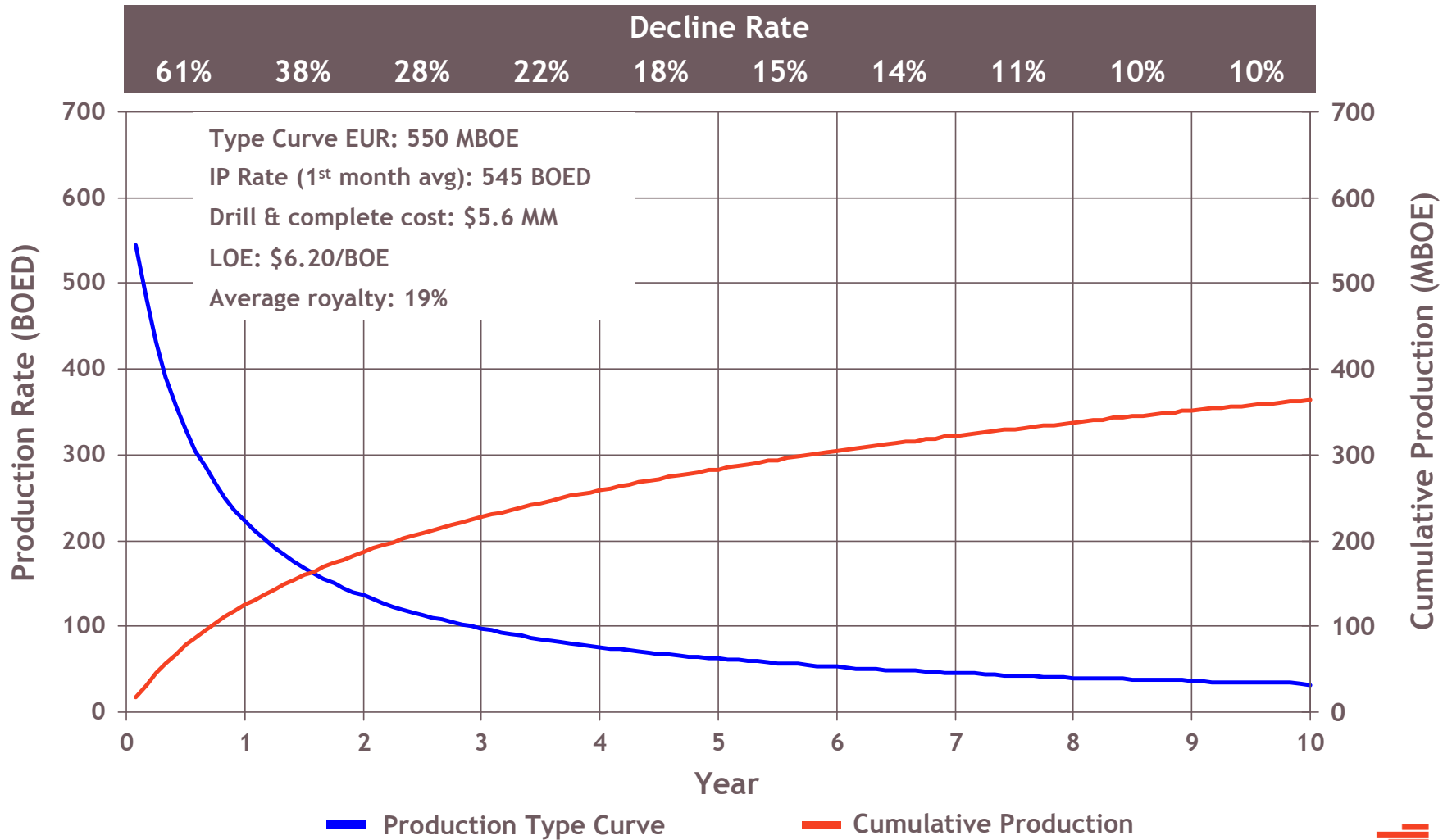
Cana Woodford Modeling Statistics

Based on 2012 Drilling Program



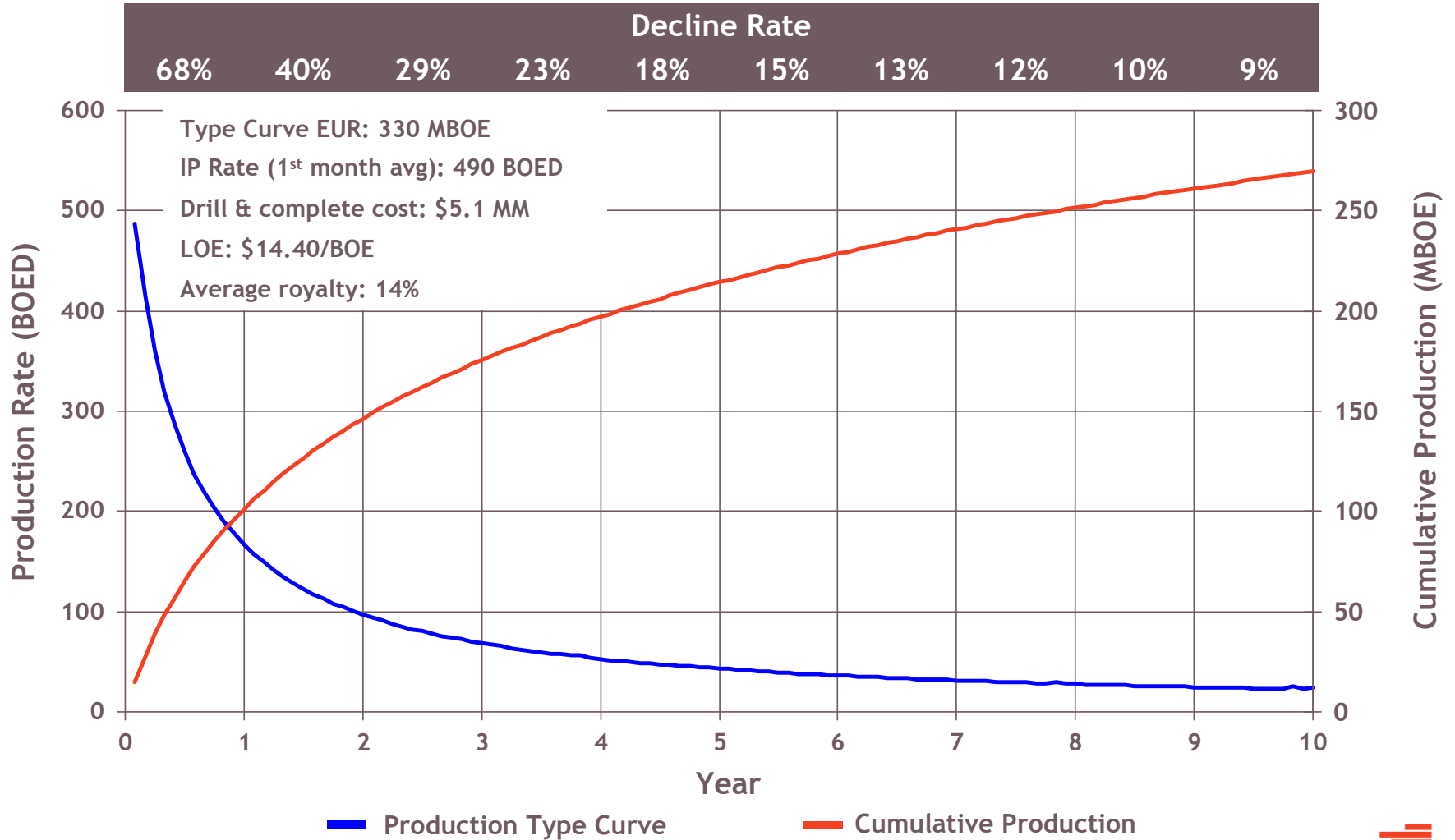
Bone Spring

Based on 2012 Drilling Program



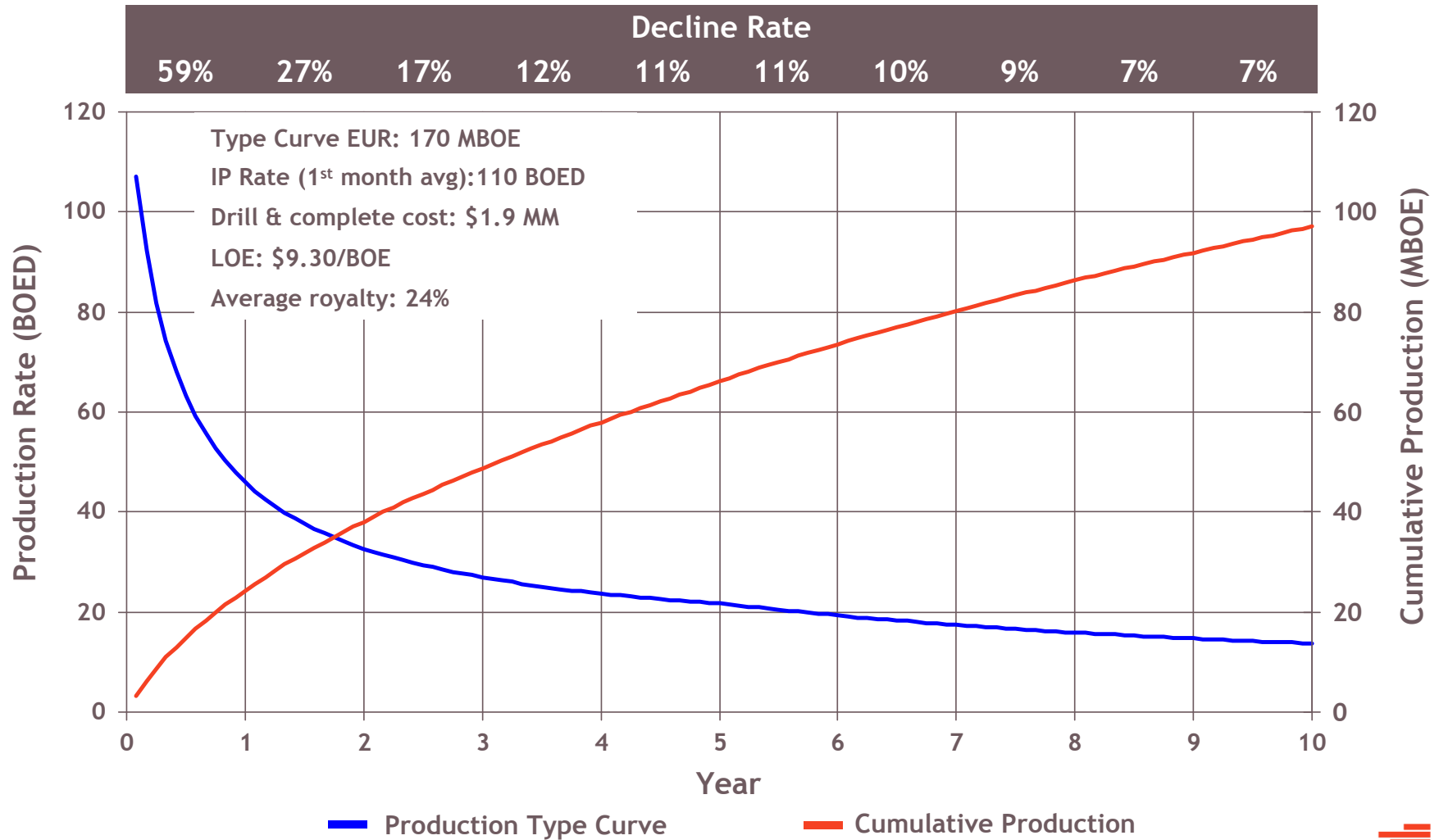
Delaware

Based on 2012 Drilling Program



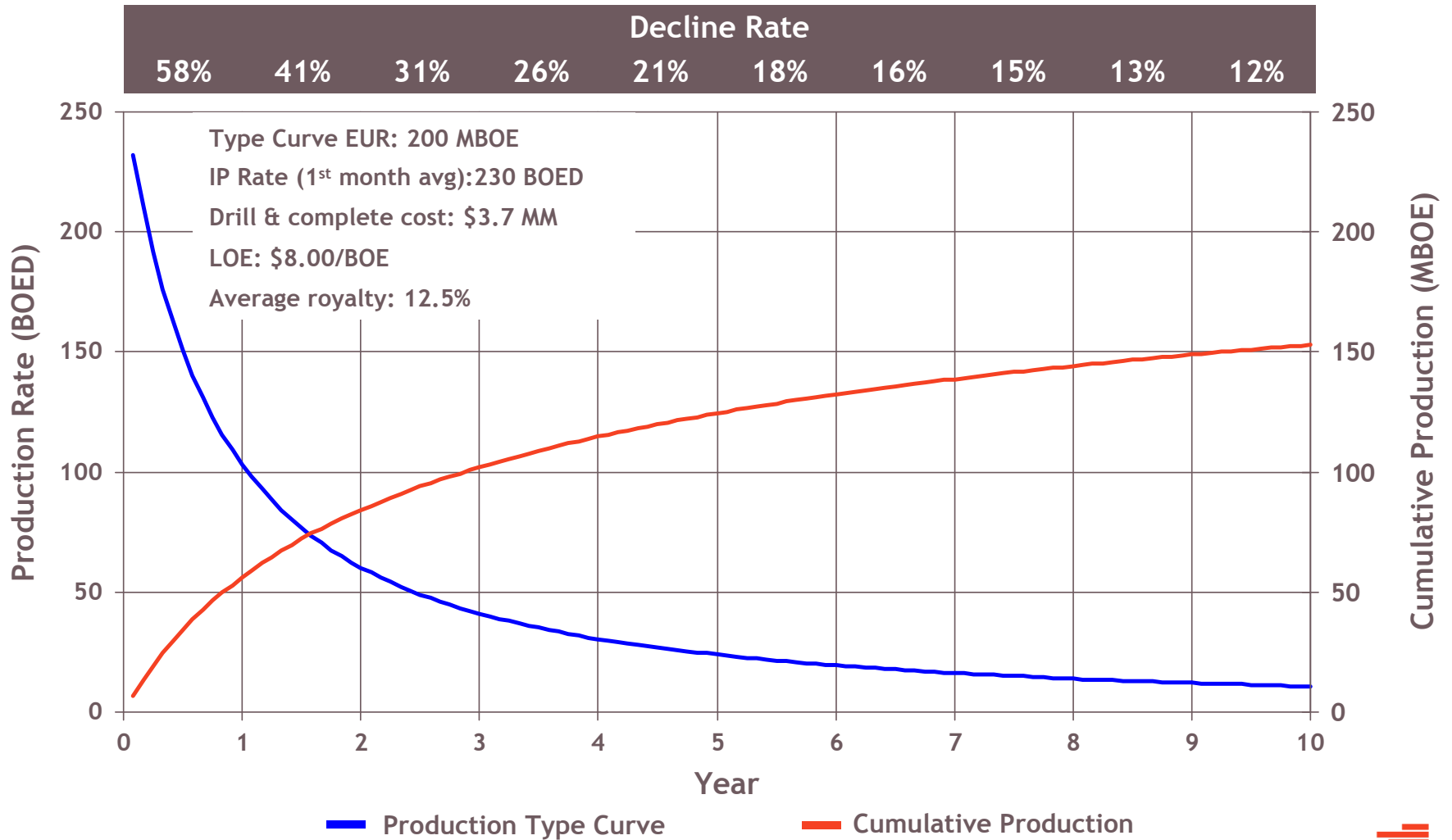
Wolfberry

Based on 2012 Drilling Program



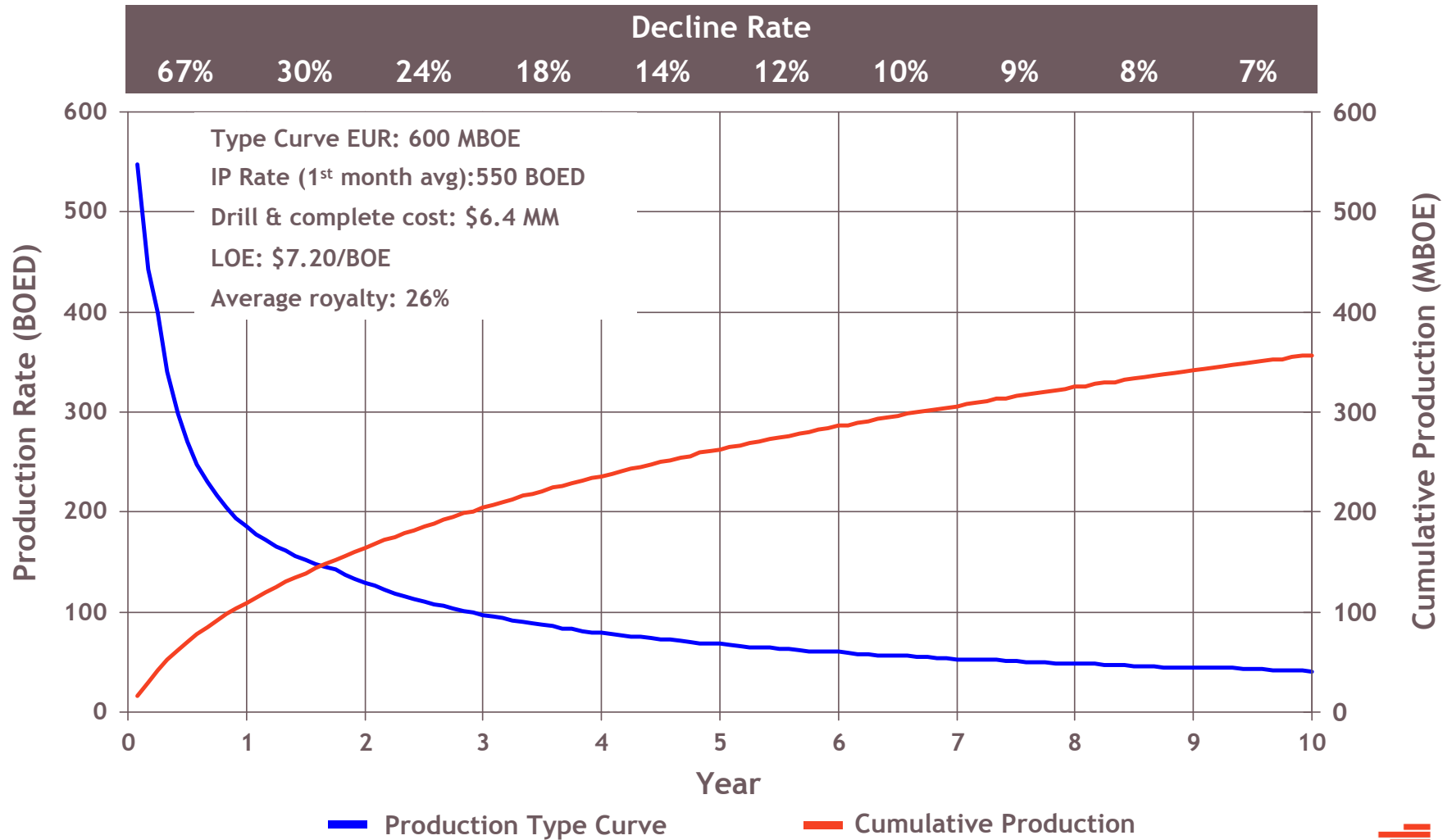
Central Basin Platform

Based on 2012 Drilling Program



Wolfcamp Midland

Based on 2012 Drilling Program



Canadian Thermal Oil

How We Report Our Results

Reported production is bitumen, no diluent

Production is net of royalties

Oil revenue is only bitumen, no diluent

Fuel and transportation costs are recorded in lease operating expenses (LOE)

LOE does not include the cost of diluent



Canadian Thermal Oil

Key Drivers of SAGD Economics

Capital costs

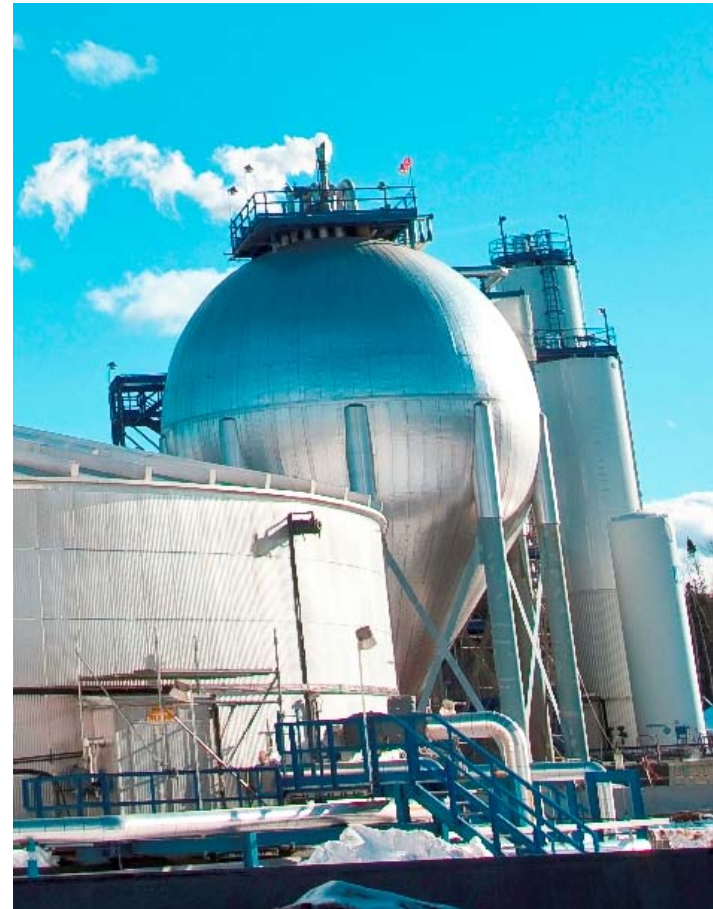
- Facility construction
- Future development capital

Bitumen realizations

Operating expenses

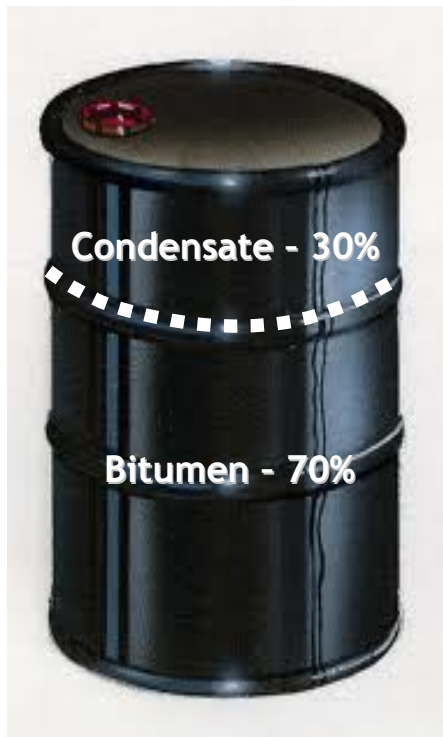
- Natural gas prices
- Non-fuel operating costs

Sliding scale royalties



Canadian Thermal Oil

Bitumen Realizations



WTI-NYMEX market price	\$100.00
------------------------	----------

Price differential	30%
--------------------	-----

Blended barrel realization	\$70.00
----------------------------	---------

Less: Diluent value	(\$30.00)
30% of blended barrel x condensate price	

Bitumen realization	\$40.00
0.7 barrels of bitumen production	

Divided by:	0.7 barrels
-------------	-------------

Bitumen realization	\$57.14
1 barrel of bitumen production	

Note: Condensate price is assumed to be equivalent to the WTI-NYMEX price

Canadian Thermal Oil

Operating Costs & Royalties

Operating Costs

Non-fuel operating expenses

- ≈\$7.00 per barrel

Fuel operating expenses

- Plant steam-to-oil ratio (SOR) is designed at 2.6
- Facility utilizes ≈1 Mcf of natural gas for every barrel produced

Sliding Scale Royalties

Base royalty rate begins at \$55 per barrel

Maximum royalty rate is at \$120 per barrel

Pre-project payout royalties range from 1% - 9%

Post-project payout royalties range from 25% - 40%

Canadian Thermal Oil

Cash Margin Per Barrel

	Pre-Payout	Post-Payout
Bitumen realization	\$57.14	\$57.14
Non-fuel operating costs	(\$7.00)	(\$7.00)
Fuel operating costs	(\$2.50)	(\$2.50)
Royalties	(\$3.74)	(\$14.07)
Cash operating margin	\$43.90	\$33.57

Assumptions:

- 1) WTI-NYMEX oil price is \$100 per barrel
- 2) Blended price realizations are 70% of WTI-NYMEX oil price
- 3) Condensate price is equivalent to WTI-NYMEX price
- 4) One Mcf of gas utilized for every barrel of bitumen produced