November 2016

Investor Presentation

Forward-Looking / Cautionary Statements

Forward-Looking Statements

This presentation contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this presentation that address activities, events or developments that the Company expects, believes or anticipates will or may occur in the future are forward-looking statements. Without limiting the generality of the foregoing, forward-looking statements contained in this presentation specifically include the expectations of plans, strategies, objectives and anticipated financial and operating results of the Company, including the Company's drilling program, production, derivative instruments, capital expenditure levels and other guidance included in this presentation. These statements are based on certain assumptions made by the Company based on management's experience and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. These include, but are not limited to, the Company’s ability to integrate acquisitions into its existing business, changes in oil and natural gas prices, weather and environmental conditions, the timing of planned capital expenditures, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as the Company's ability to access them, the proximity to and capacity of transportation facilities, and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting the Company's business and other important factors that could cause actual results to differ materially from those projected as described in the Company's reports filed with the SEC.

Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

Cautionary Statement Regarding Oil and Gas Quantities

The SEC requires oil and gas companies, in their filings with the SEC, to disclose proved reserves, which are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions (using unweighted average 12-month first day of the month prices), operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The SEC also permits the disclosure of separate estimates of probable or possible reserves that meet SEC definitions for such reserves; however, we currently do not disclose probable or possible reserves in our SEC filings.

In this presentation, proved reserves at December 31, 2015 are estimated utilizing SEC reserve recognition standards and pricing assumptions based on the trailing 12-month average first-day-of-the-month prices of $50.16 per barrel of oil and $2.63 per MMBtu of natural gas. The reserve estimates for the Company at December 31, 2015, 2014, 2013, 2012, 2011 and 2010 presented in this presentation are based on reports prepared by DeGolyer and MacNaughton (“D&M”).

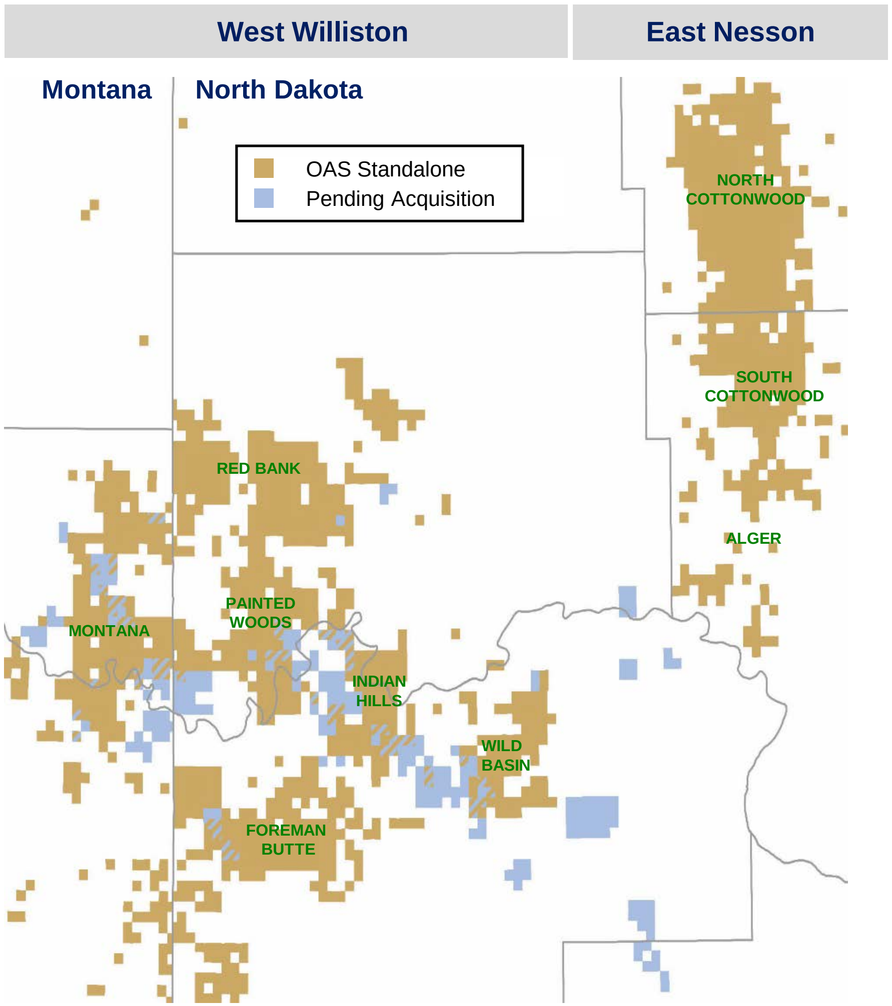
We may use the terms "unproved reserves," "EUR per well" and "upside potential" to describe estimates of potentially recoverable hydrocarbons that the SEC rules prohibit from being included in filings with the SEC. These are the Company’s internal estimates of hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques. These quantities may not constitute "reserves" within the meaning of the Society of Petroleum Engineer’s Petroleum Resource Management System or SEC rules and do not include any proved reserves. EUR estimates and drilling locations have not been risked by Company management. Actual locations drilled and quantities that may be ultimately recovered from the Company’s interests will differ substantially. There is no commitment by the Company to drill all of the drilling locations which have been attributed to these quantities. Factors affecting ultimate recovery include the scope of our ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals and other factors; and actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of unproved reserves, per well EUR and upside potential may change significantly as development of the Company’s oil and gas assets provide additional data.

Our production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.

Top Pure Play in the Williston Basin[1]

- **Top tier asset position**
  - Concentrated position - 485k net acres
    - 91% held by production
    - 97% operated
  - 395 operated DSUs
  - Significant economic inventory: ~25 years / >1,300 locations economic > $40 WTI
  - Pending acquisition of ~55,000 net acres expected to close 12/1/16
    - ~12 MBoepd Dec. 2016 estimated production
- **Improving capital efficiency**
  - Continued success with high intensity completions
  - Active testing program
  - Wild Basin EURs: ~1.55 MMBOE
  - >50% reduction in well costs
- **Improving balance sheet and leverage metrics**
  - Free cash flow positive by $43MM for last seven quarters combined (2)
- **Well positioned for growth in 2017 and beyond**

Premier Position in Williston Basin



1) As of 12/31/15 unless otherwise noted
2) Free Cash Flow defined as Adjusted EBITDA less cash interest and CapEx (excluding capitalized interest, which is included in cash interest). Non-GAAP reconciliation can be found on our website www.oasispetroleum.com.

Recent Accomplishments & Highlights

Driving EUR Performance Higher	▪ Wild Basin Bakken type curves increasing to ~1.55 MMBoe EURs (from ~1.2 MMBoe) ▪ Completion design testing yielding positive results ▪ Likely increasing proppant intensity in base completion styles
Lowering Well and Operating Costs	▪ >10% further reduction to well costs to $5.2 million (down >50% since 2014 @ $10.6 million) ▪ Potential to continue to go lower ▪ 2016 LOE range of **$7.00 to $7.50** per Boe from over $10 per Boe in 2014
Infrastructure Delivering Increased Margins	▪ Better oil differentials/realizations ▪ Higher gas capture and gas realizations ▪ Wild Basin infrastructure to pay dividends
Multiplying Success through Core Bolt-on Acquisition	▪ Basin leading completion designs driving EUR performance ▪ Low cost operator ▪ Leverage benefits of legacy Oasis infrastructure within operations areas ▪ Oasis advantages transferable to Williston Acquisition

Improving capital efficiency & operational performance

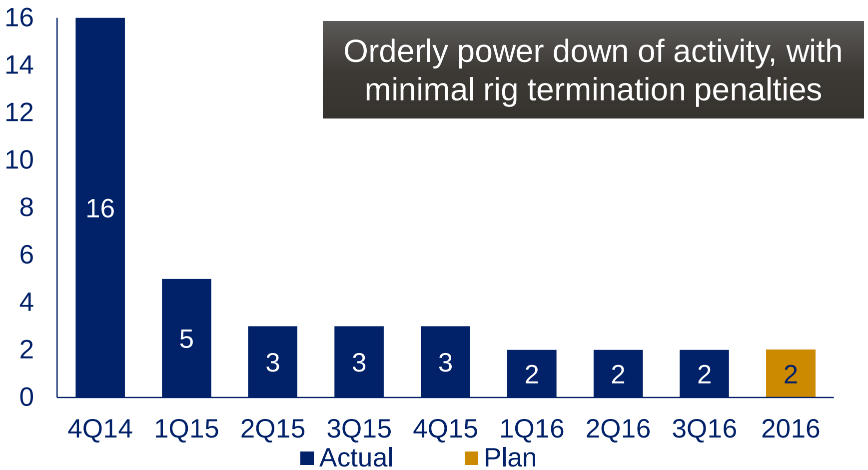
October 2016 $785MM Pending Acquisition

Acquisition Highlights

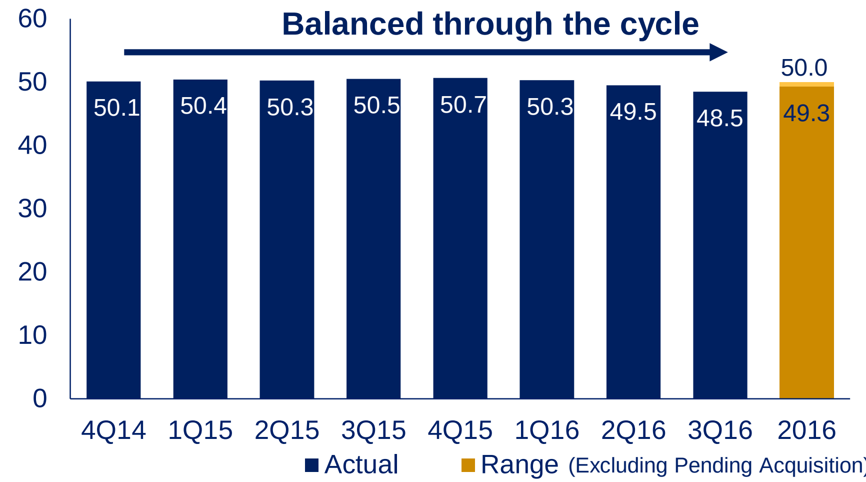
- **Bolt-on core inventory position**
  - ~55k net acres in the heart of the Williston Basin
  - 34 operated DSUs
  - ~25% increase to OAS core inventory position
- **Strong production base**
  - ~12 MBoepd Dec. 2016 estimated production
  - ~78% oil; 22% gas
  - Generates free cash flow for reinvestment
- **Ability to leverage OAS core competencies**
  - High EUR/completion efficiency
  - Low capital and operating cost structure
  - OWS/OMS benefits
- **Accretive to cash flow, production and NAV at strip prices**
- **Expected to close on December 1, 2016**

Capital Discipline, Optimization and Efficiency

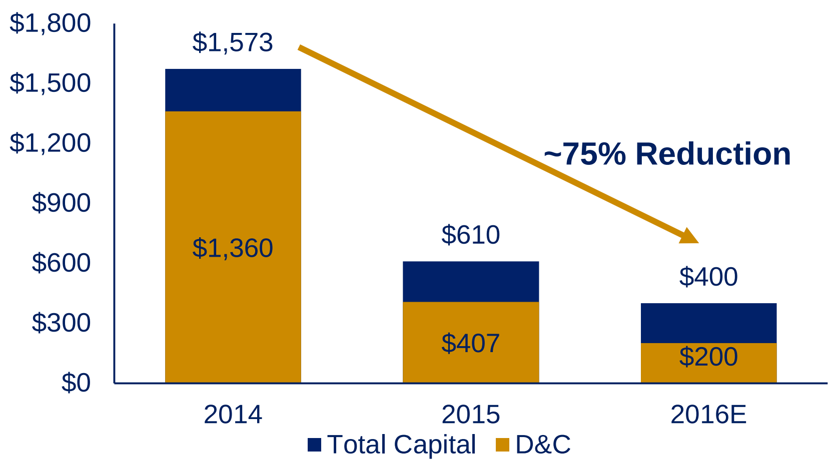
Rigs Running in Williston Basin



Average Daily Production (Mboepd)



CapEx ($MM)

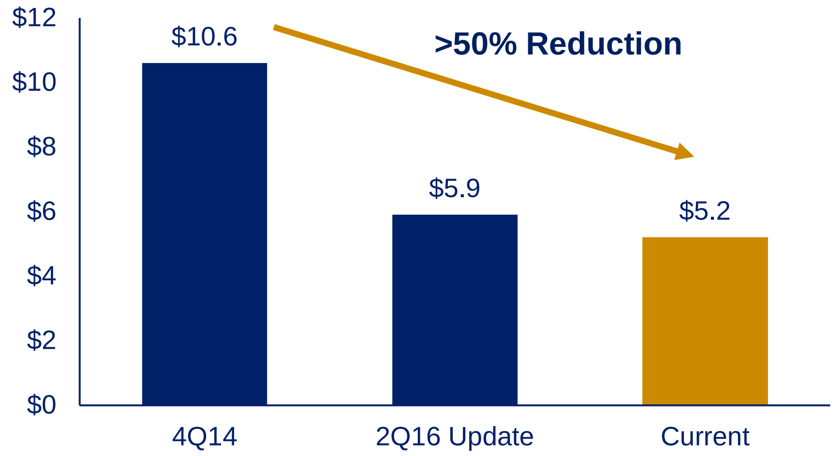


Highlights

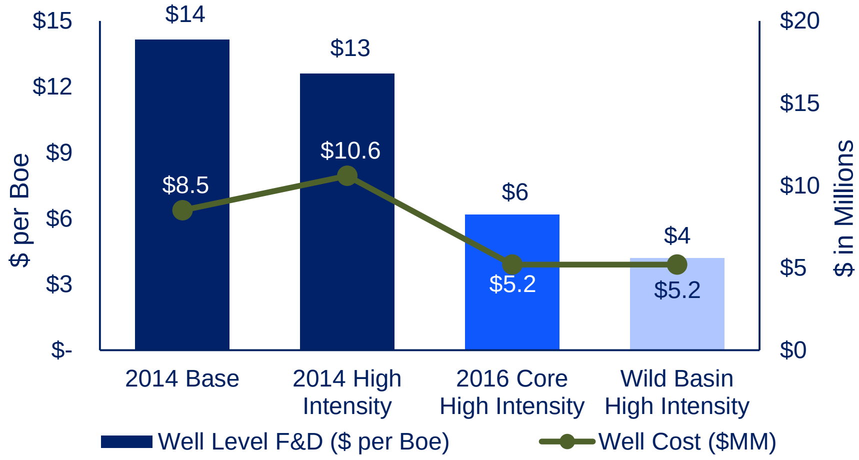
- Transitioned activity to core of Williston Basin
- Driven down well costs by >50%
- Reduced D&C CapEx by 85%
- Kept production basically flat
- Discipline stability leaves us well positioned to grow in 2017 and beyond

Improving Capital Efficiency through Reduced Well Costs

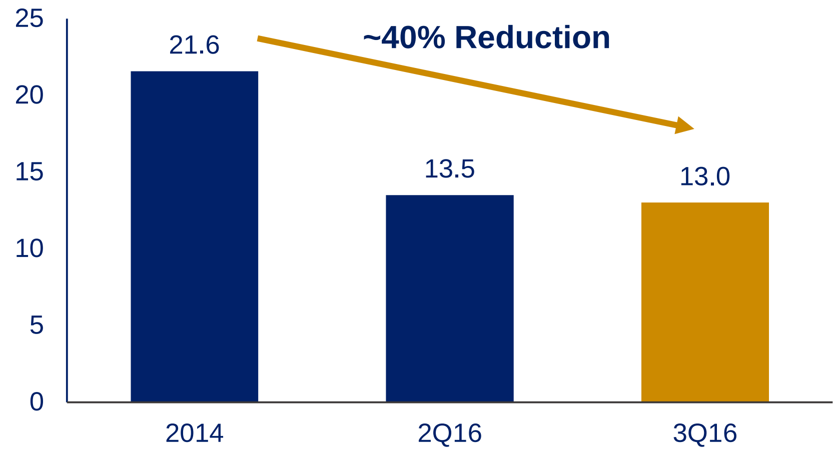
Slickwater Well Cost ($MM)



Substantially Improving Capital Efficiency in Core[(1)]



Average Spud to Rig Release (Days)



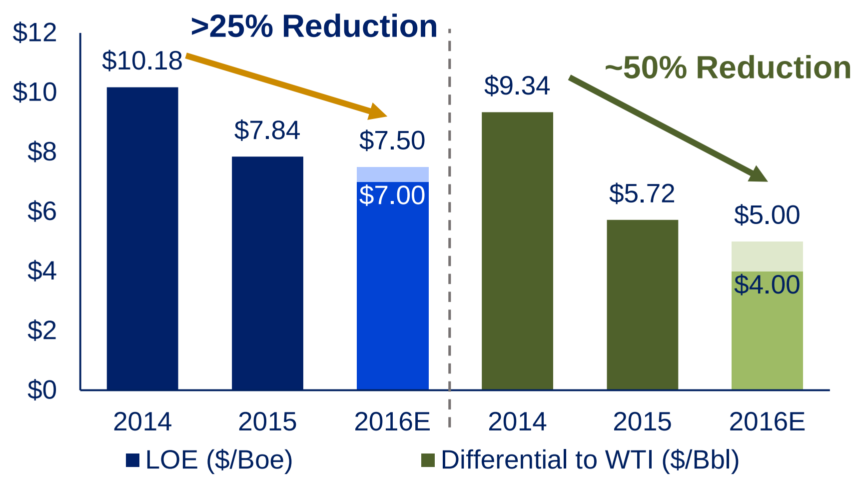
Highlights

- Well cost and EUR improvements combined to bring single well F&D costs into the $4-5 per Boe range in Wild Basin
  - Reduction of 38% vs. beginning of 2016
- Ability to maintain cost reductions
  - Increased reliance on Oasis Well Services
  - Significant operational efficiency gains across both drilling and completion activities
  - Supply chain improvements

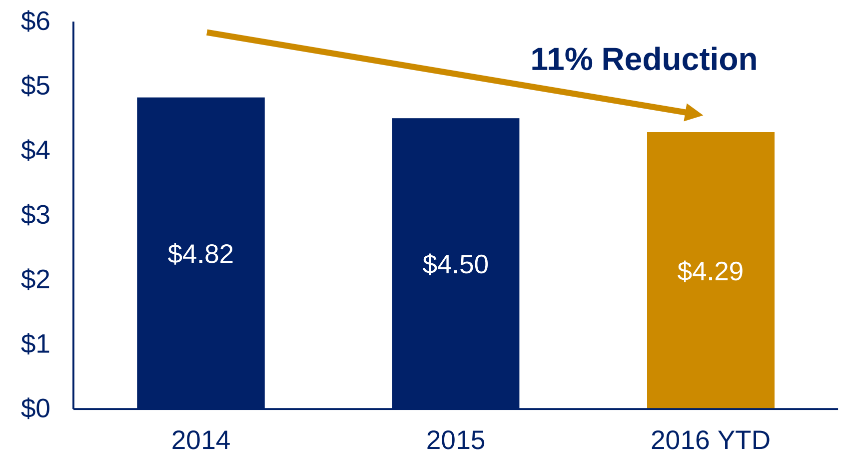
1) Well level EUR assumes 750Mboe for 2014 base design Bakken wells in the core and 1,050Mboe for high intensity design Bakken wells in the core. Wild Basin high intensity wells are consistent with the revised 1,550 Mboe Bakken EURs depicted on slide 11. Analysis assumes a 20% royalty burden in all cases.

Operational Excellence: Lowering Operating Cost Structure

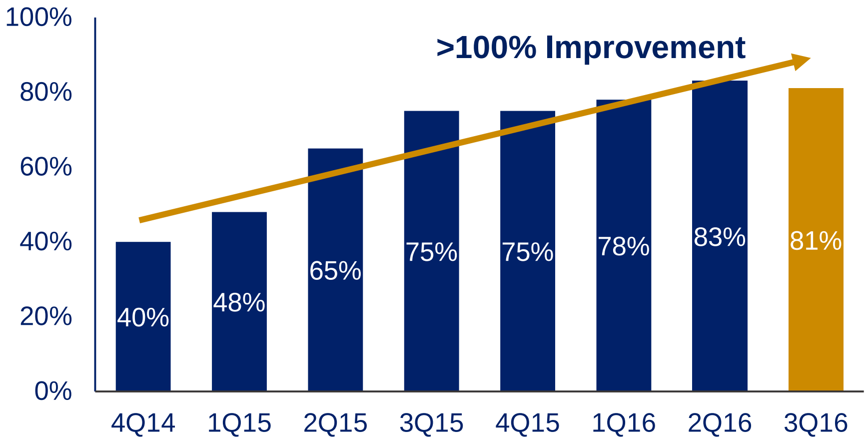
Improving Operating Cost Structure



Steady E&P G&A Improvements ($/Boe)



Growing Utilization of Saltwater Pipelines



Highlights

- Substantial LOE improvements during last three years across all operating cost types
- Increasing utilization of infrastructure lowers operating costs and decreases production downtime
- Continuing to realize efficiencies throughout our operations and the entire organization

Growth within Cash Flow

Path to Continued Growth

Base plan: 2 rig program drilling in Wild Basin

Pending Acquisition expected to add ~12 MBoepd to YE 2016 production

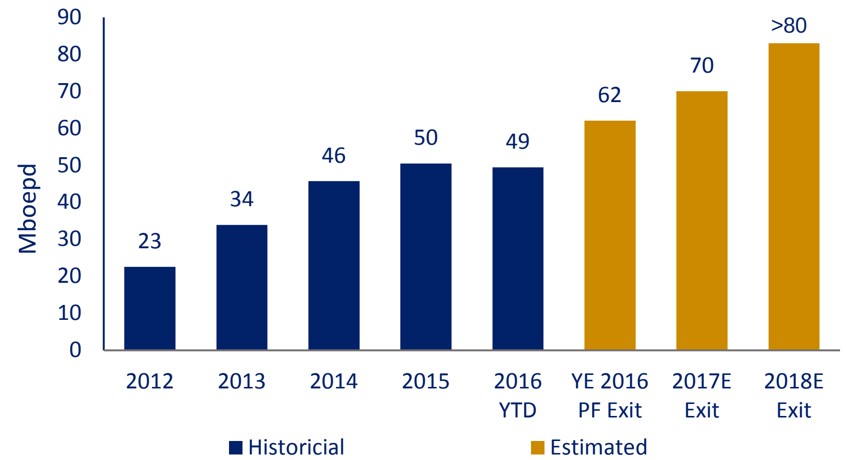
Runway for production growth within cash flow

- Plans to add up to two additional rigs in 2017 if WTI prices are at or above $50 WTI
- Expect to add a 5th rig in 2018
- Opportunity to grow OMS and OWS

Mid-teens production growth CAGRs through 2018

- Absolute production growth of >65% 3Q16 to YE 2018

Production Growth Profile



Upside to Plan

Active completion testing program with potential for increased recoveries and improved capital efficiency

Currently focused on:

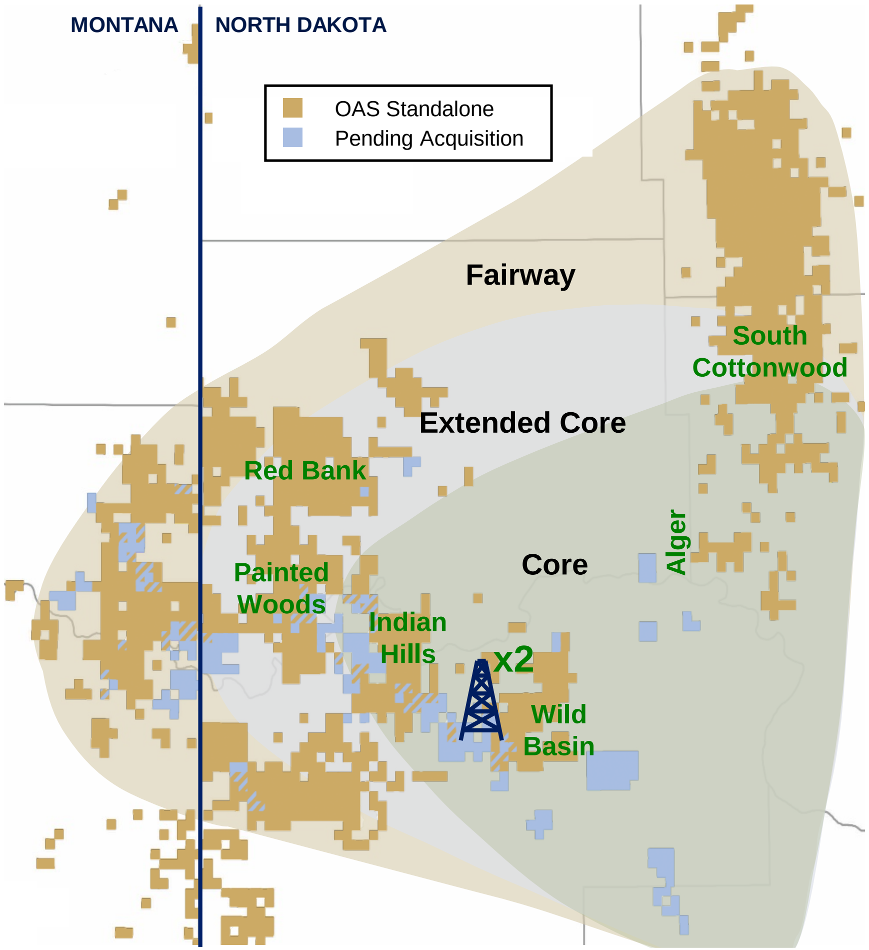
- Higher sand loadings
- Improved proppant placement (precision fracs, increased stage counts, proppant suspension)

~80 gross operated Drilled Uncompleted (“DUC”) Wells as of 9/30/16

- Wells set up for high intensity completions
- Wells are highly economic at current strip (~$3.5MM completion cost)
- ~80% of DUCs in core

Robust Inventory in the Heart of the Williston Basin

Inventory in the Heart of the Play



Depth of Inventory Across Play

Area	DSUs	Remaining Gross Op Locations[1]	EUR (Mboe)[2]	Break-even ($WTI)
Oasis Standalone				
Core	72	607	1,050	$27+
Extended Core	104	711	575-750	$40+
Fairway	219	1,665	450-625	$50+
Total OAS	**395**	**2,983**		
Pending Acquisiton				
Core	22	130		
Extended Core	9	72		
Fairway	3	24		
Total Acquisition	**34**	**226**		

Depth of Inventory in Core & Extended Core (1)

72 operated DSUs across core:
- Indian Hills – 31 DSUs
- Wild Basin – 23 DSUs
- Alger – 18 DSUs
- 22 additional core DSUs from Pending Acquisition

Pro forma for Pending Acquisition, OAS has >1,500 remaining locations in core & extended core
- Economic at current prices

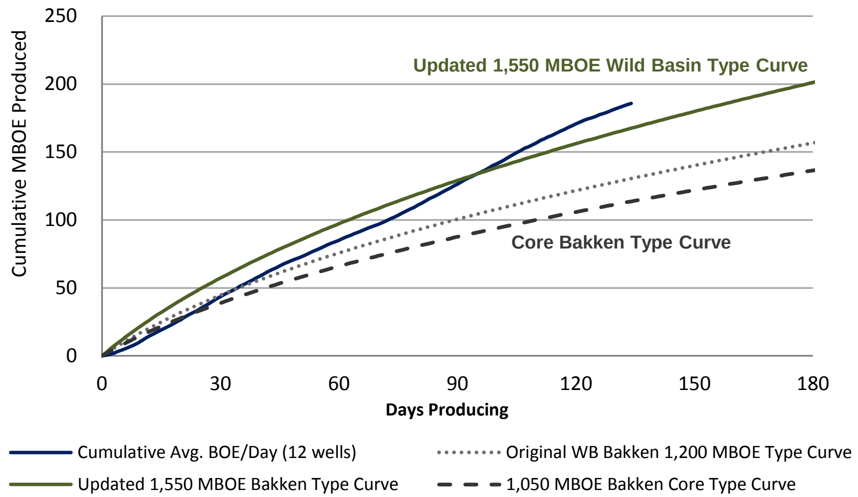
Current pace of completions: 55 gross operated/year
- Bakken and TFS1 represent >25 years of remaining inventory at WTI >$40 per barrel

Further upside in fairway with recovering oil price environment

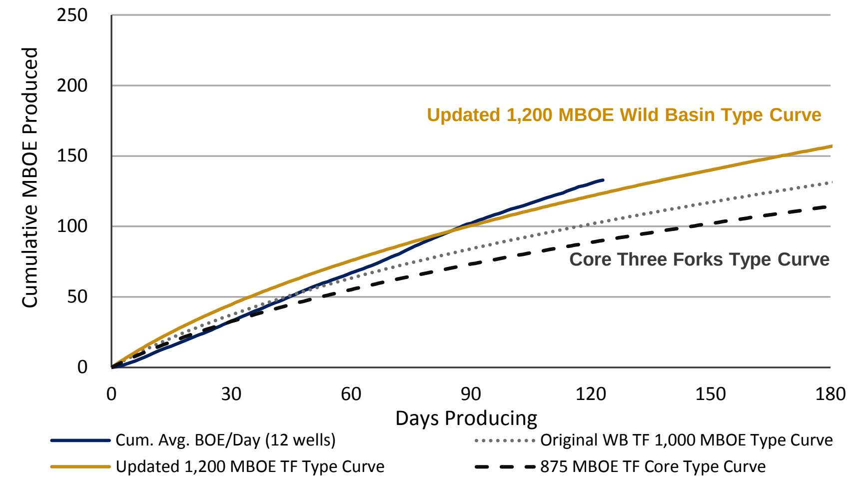
1) As of 12/31/15
2) EUR based on high intensity Bakken completion design in all areas except Cottonwood. Core EURs not updated for the Wild Basin well performance improvements mentioned on page 11

Wild Basin High Intensity Type Curve and Performance Update

Wild Basin Bakken Well Performance



Wild Basin Three Forks Well Performance



Wild Basin Type Curve Statistics (1)

	Core: Bakken	Core: Three Forks
EUR (Mboe)	**1,550**	**1,200**
Initial Production		
IP – 7 day midpoint (Boepd)	2,304	1,795
1st 30 days -average (Boepd)	1,912	1,490
2nd 30 days - average (Boepd)	1,331	1,037
Cumulative (Mboe)		
30 day	57	45
60 day	97	76
180 day	201	157
365 day	302	235

Highlights

- Single well IRRs in excess of 100% for both Bakken and Three Forks at strip pricing
  - Assuming $5.2MM current well costs
- Remaining upside from ongoing completion testing program
- Substantial portion of remaining core inventory

1) Type curve parameters: Qi=varies, b=1.6, initial decline 82%, terminal decline 6%, 2,500 gas / oil ratio

Financial Strength & Balance Sheet Protection

Free Cash Flow Positive [1]

- Free Cash Flow positive by $43MM thru 2015 & YTD2016 combined
- Free Cash Flow neutral in third quarter

Long Term Debt

- No near-term debt maturities
- Current balance of $2,053MM
- Average interest rate across 5 issues of 6.2%
- Current ratings of notes:
  - S&P: B+
  - Moody's: B2 (upgraded in October)

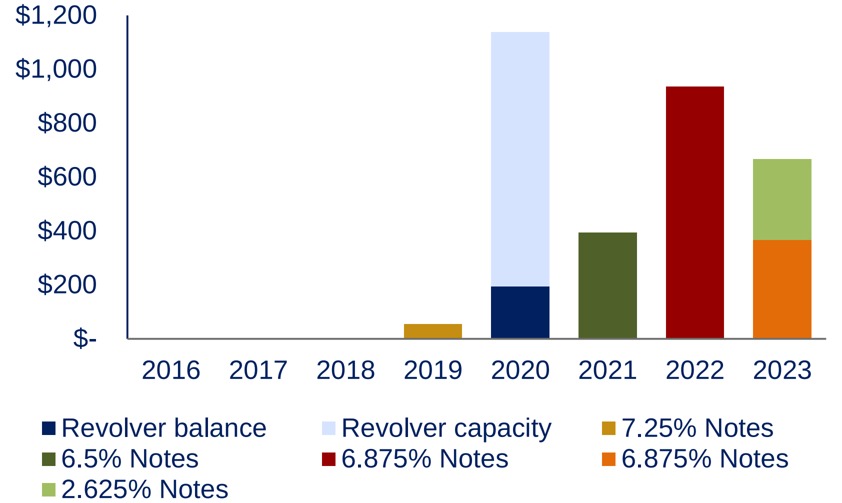
Strong Borrowing Base & Liquidity

- Borrowing Base of $1.15Bn, reaffirmed on 10/14/16
- $195MM drawn under revolver at 9/30/16
  - $12.3MM of LCs
- Interest coverage is only financial covenant:
  - Covenant of 2.5x (3.6x LTM 3Q16)

Hedge Protection

- Approximately 80+% of 2016 oil volumes hedged at $49 per Bbl
- ~27.0 MBopd hedged in 2017

No Near-Term Debt Maturities ($MM) (as of 9/3016)



Strong Hedge Protection

	Weighted Average Prices ($/Bbl)			Volume
	Sub-Floor	Floor	Ceiling	(BOpD)
2016				
4Q16 Swaps (Oct - Dec)		$49.20	$49.20	33,000
2017				
1H17 Swaps (Jan - June)		$48.57	$48.57	16,000
2H17 Swaps (July - Dec)		$49.08	$49.08	14,000
FY2017 Two-way Collars		$45.00	$53.95	6,000
FY2017 Three-way Collars	$31.67	$45.83	$59.94	6,000
2018				
1H18 Swaps (Jan - June)		$54.32	$54.32	4,000
2H18 Swaps (July - Dec)		$54.45	$54.45	3,000
Natural Gas				
2017 Swaps (MMBTUpD)		$3.21	$3.21	6,000

1) Free Cash Flow defined as Adjusted EBITDA less cash interest and CapEx (excluding capitalized interest, which is included in cash interest). Non-GAAP reconciliation can be found on our website www.oasispetroleum.com.

Controlling Strategic Infrastructure

Asset Highlights

Saltwater gathering lines (over 300 miles)

- Increased volume flowing through gathering lines from 40% at YE14 to 81% in 3Q16

Saltwater disposal (SWD) wells (25)

- Increased volume disposed in company wells from 60% at YE14 to 90% in 3Q16

Strategic Value

- Lowers LOE & increases operational efficiency
- Removes trucks from road & minimizes weather impacts

3Q16 Adjusted EBITDA of $18.2MM / YTD of $57.3MM[1]

Wild Basin Project

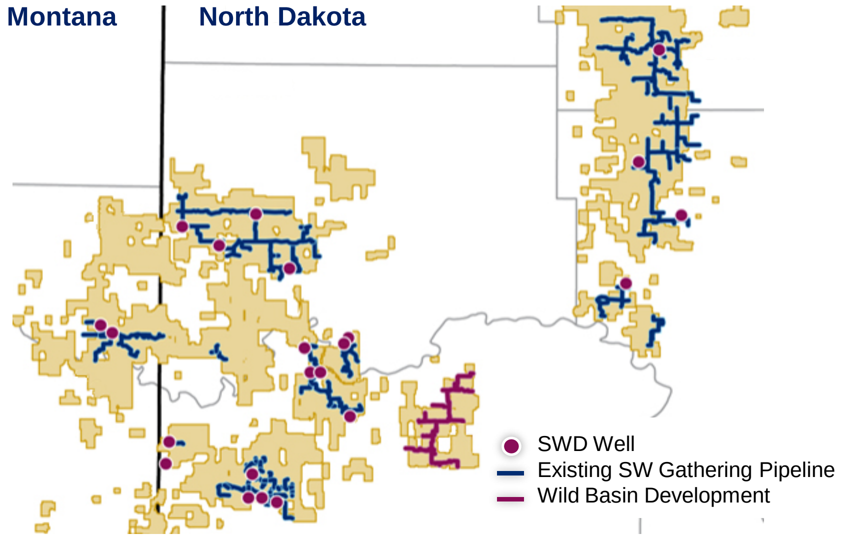
Assets in Wild Basin are Online

- Natural gas gathering & processing
  - 80MMscf/d Gas Plant
- Oil gathering, stabilization and storage
- Saltwater gathering and disposal wells
- Synergy with Williston Basin Acquisition

2016 Activity

- Began completing wells in Wild Basin in Summer 2016
- Wells choked back until infrastructure commissioned in September/October 2016
- 4Q16 LOE and overall Oasis margins improve

Saltwater Gathering & Disposal Infrastructure



Wild Basin Gas Plant & Crude Storage

1) Non GAAP Adjusted EBITDA Reconciliation can be found on the Oasis website at www.oasispetroleum.com

Oil and Gas Infrastructure Development

3rd Party Infrastructure Highlights

Crude oil gathering

- Realized $4.39/bbl differential in 3Q16
- Signing longer term contracts at fixed differentials
- Provides marketing flexibility to access to 4 pipeline and 10 different rail connection points
- ~75% gross operated oil production currently flowing through pipeline systems

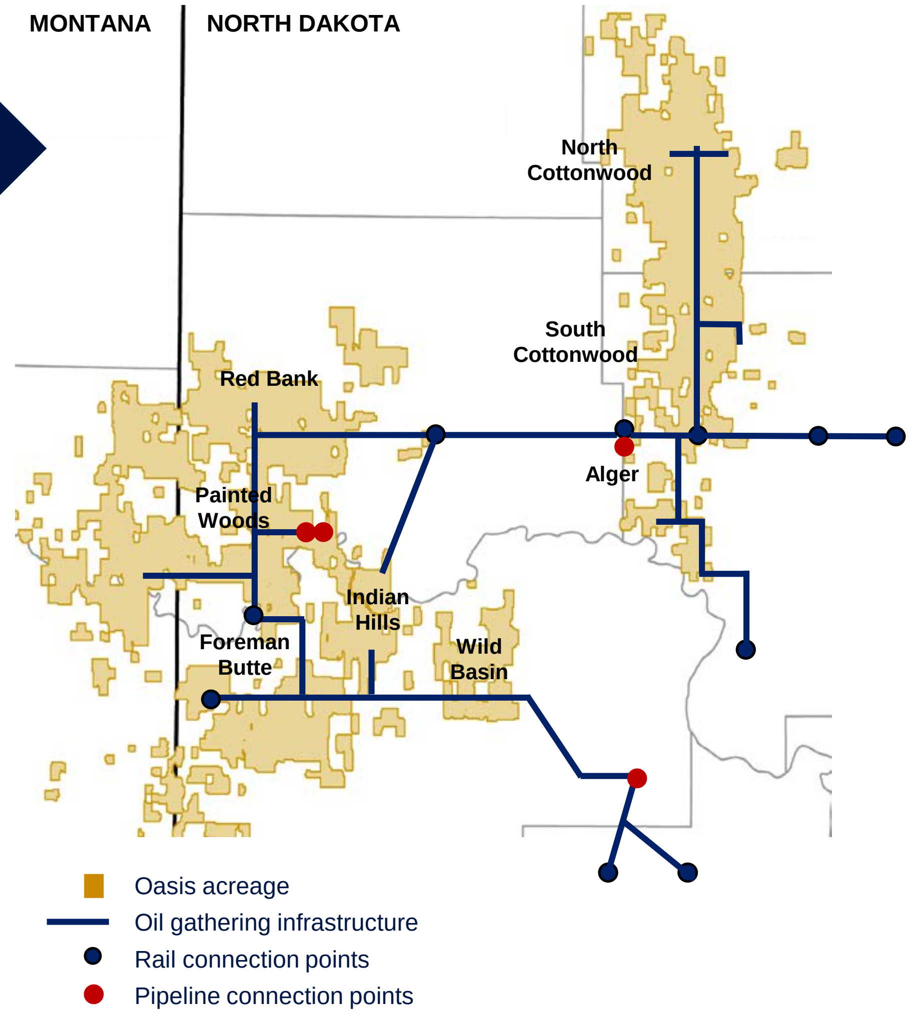
Gas gathering and processing (3rd party systems)

- Average realization of $1.84/mcf in 3Q16
- ~98% of wells connected to gathering system
- 92% gas production currently being captured, vs. North Dakota goal of 80%

Infrastructure considerations

- Drives higher oil and gas realizations
- Provides surety of production when all infrastructure in place
- Need infrastructure in place when wells come on-line
- Regulatory environment

Crude Oil Gathering Infrastructure



Investment Highlights

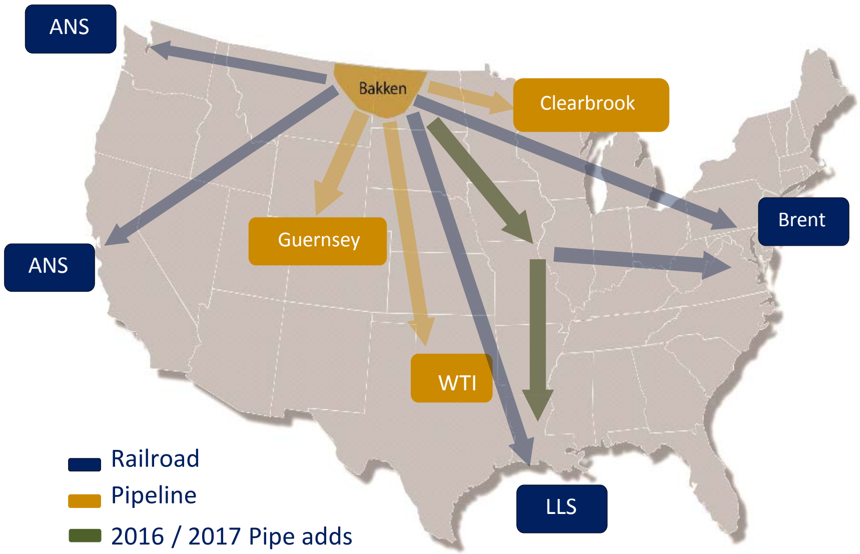
- **Improving capital efficiency & operational performance**
  - **Lowering well costs while increasing EURs**
- **Prudently managing balance sheet while being one of the first E&P companies to become free cash flow positive**
  - **$1.15Bn revolver**
- **Focusing on the "Core of the North American Core"**

Appendix

OASIS PETROLEUM

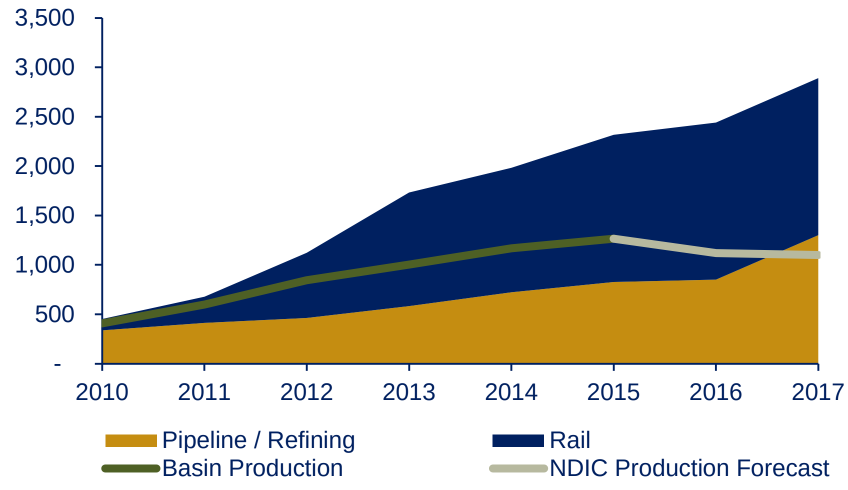
Expanding Takeaway Capacity out of Williston Basin

Takeaway Options



- Pipeline and rail provide multiple destinations for Bakken crude
- Oasis can ship crude via rail or pipe to achieve the highest realizations
- New pipelines provide excellent optionality for low cost transportation
- Given the pipe and rail options, there is ample capacity for Bakken crude production

Takeaway Capacity (Mbopd) (1)



	Current Capacity	Additions	
(MBopd)	**YE2015**	**2016**	**2017**
Pipeline / Local refining	827	24	450
Rail	1,420	100	-
Additions in Year		124	450
Total Takeaway	**2,247**	**2,371**	**2,821**
Current Production	**1,109**		
% of Production on Rail	*33%*		

1) Source: North Dakota Pipeline Authority

Key Metrics & Inventory Detail

Key metrics	3Q16
Net acreage (000s) [1]	485
Estimated net PDP - MMBoe [1]	147.6
Estimated net PUD - MMBoe [1]	70.7
Estimated net proved reserves - MMBoe [1]	**218.2**
Percent developed [1]	68%
Operated rigs running [2]	2
Operated wells waiting on completion [2]	80
3Q16 production (Mboe/d)	48.5

Bakken/TFS well counts	Producing @ 3Q16	2016 Plan
Gross operated	774	55
Net operated	596	35.3
Working interest in operated wells	*77%*	*64%*
Net non-operated	26.2	0.6
Total net wells	**622.4**	**35.9**

Key acreage acquisitions (Net acres / Boepd then current)	West Williston	East Nesson
$83MM in June 2007	175,000 / 1,000	
$16MM in May 2008		48,000 / 0
$27MM in June 2009		37,000 / 800
$11MM in September 2009		46,000 / 300
$82MM in 4Q 2010	26,700 / 500	
$1,542MM in 3Q/4Q 2013	136,000 / 9,000	25,000 / 300
$785MM in October 2016 (Pending)	55,000 / 12,000	

Remaining Operated Locations [1]

Area	Wells/DSU	Gross	Net
Core	~15	607	367
Extended Core	~10	711	531
Fairway	~7	1,665	1,210
Total operated		**2,983**	**2,107**

Inventory Categories

Core	- Highest recoveries - Best infrastructure access - Optimal development plan established
Extended Core	High recovery, Middle Bakken and possible TFS
Fairway	Shallowest part of the basin, resource can be recovered through Middle Bakken wells

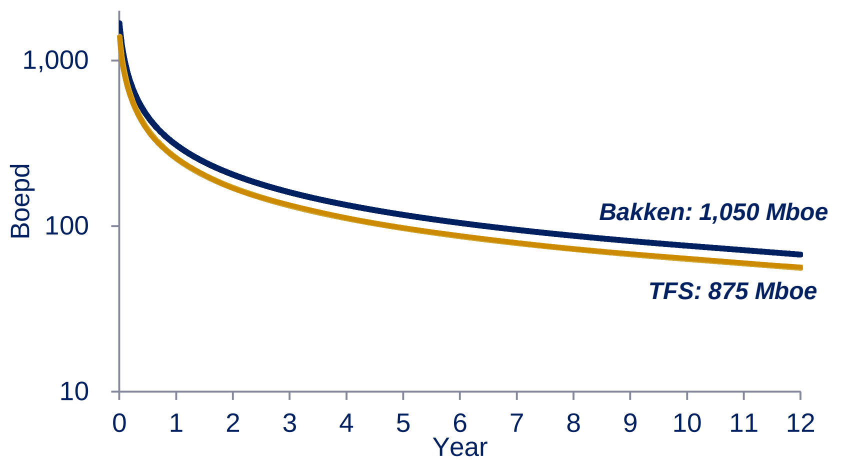
Type Curve Metrics for Extended Core & Fairway [3]

	Low End	High End
Gross Reserves (MBoe)	**450**	**750**
IP – 7 day average (Boepd)	536	873
1st 60 days - average (Boepd)	415	675
2nd 30 days - average (Boepd)	359	584
Cumulative (Mboe)		
30 day	14	23
60 day	25	41
180 day	55	89
365 day	85	138

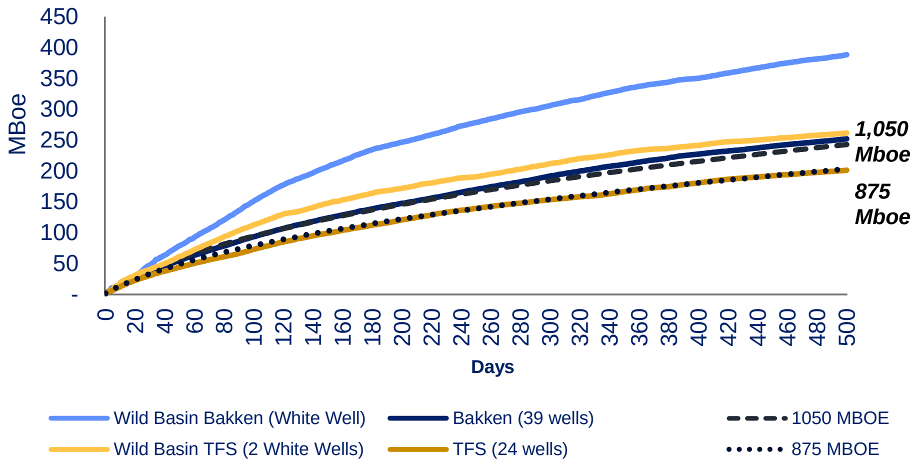
1) As of 12/31/15. Excludes Pending Acquisition
2) As of 9/30/2016
3) Type curve parameters: Qi=varies, b=1.6, initial decline 76%, terminal decline 6%

Core High Intensity Type Curve and Performance

Core High Intensity Type Curve



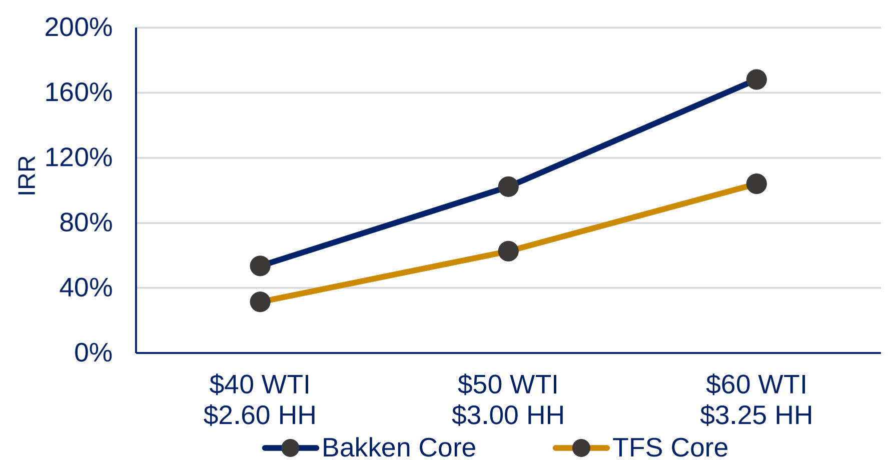
Core Bakken & TFS High Intensity Well Performance



Core Type Curve Statistics [1]

	Core: Bakken	Core: Three Forks
EUR (Mboe)	**1,050**	**875**
Initial Production		
IP – 7 day midpoint (Boepd)	1,572	1,307
1st 30 days -average (Boepd)	1,305	1,085
2nd 30 days - average (Boepd)	908	755
Cumulative (Mboe)		
30 day	39	33
60 day	66	55
180 day	137	114
365 day	206	172

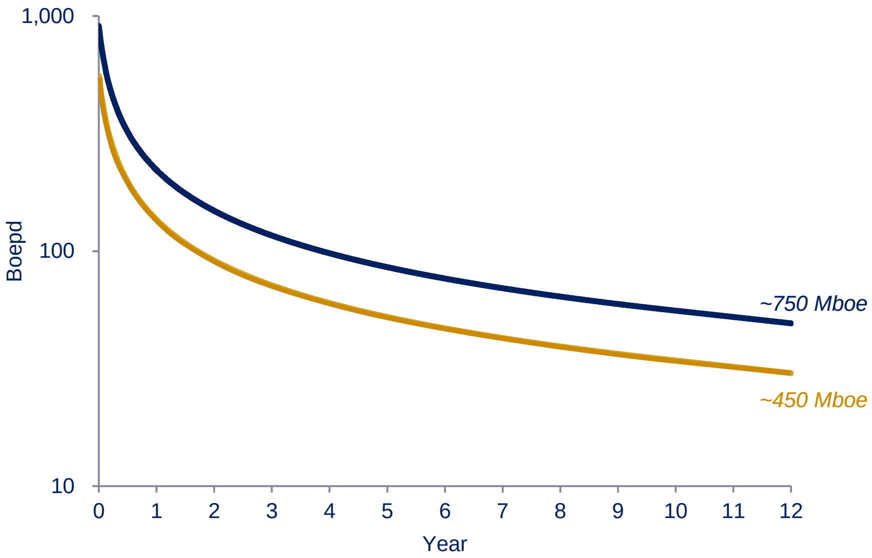
Core Economics by Commodity Price [1]



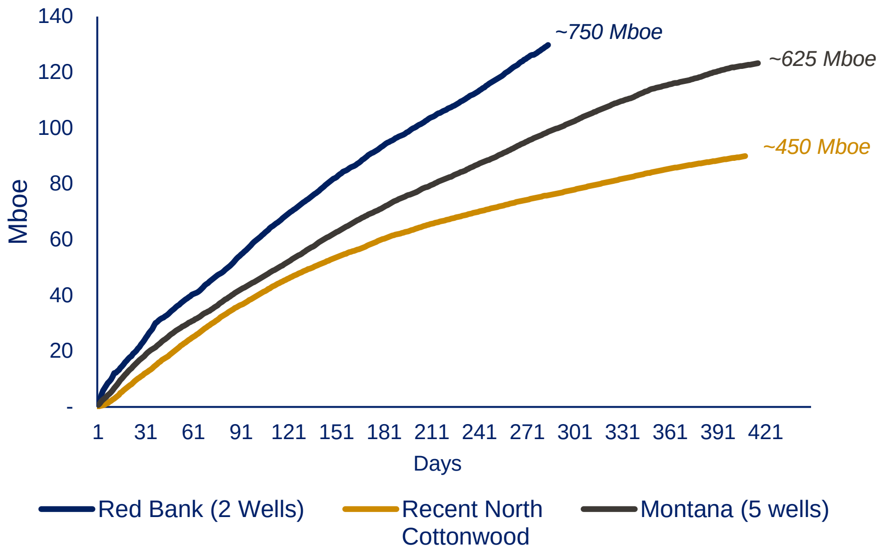
1) Type curve parameters: Qi=varies, b=1.6, initial decline 82%, terminal decline 6%

Extended Core & Fairway Type Curves and Economics

Extended Core & Fairway Type Curves



Recent Well Performance



Inventory Depth & Growth Opportunity

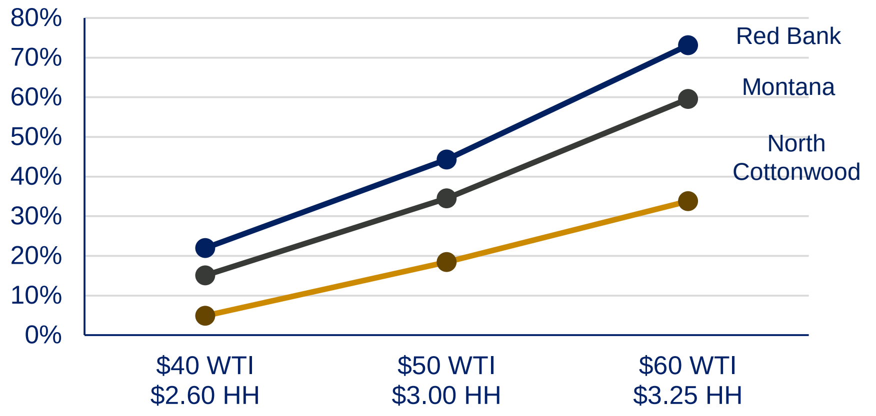
711 extended core locations

- Economic at WTI > $40
- Red Bank, Painted Woods and South Cottonwood are key areas to add rigs in a rising oil price environment

1,665 fairway locations

- Economic at WTI > $50
- Potential for further well cost reduction in North Cottonwood
- Favorable tax regime in Montana

Economics[1,2]



1) Type curve parameters: Qi=varies, b=1.6, initial decline 76%, terminal decline 6%
2) Well cost of $5.9MM for Red Bank & Montana and $4.2MM for North Cottonwood

Financial and Operational Results / Guidance

Select Operating Metrics	FY12	FY13	FY14	1Q 15	2Q 15	3Q 15	4Q 15	FY15	1Q 16	2Q 16	3Q 16	Guidance[1] FY16
Production (MBoepd)	22.5	33.9	45.7	50.4	50.3	50.5	50.7	50.5	50.3	49.5	48.5	49.3 - 50.0
Production (MBopd)	20.6	30.5	40.8	44.7	44.0	44.3	43.3	44.1	42.5	41.2	39.4	
% Oil	92%	90%	89%	89%	88%	88%	86%	87%	85%	83%	81%	
WTI ($/Bbl)	$93.39	$98.05	$92.07	$48.58	$57.93	$46.43	$42.07	$48.75	$33.59	$45.66	$44.94	
Realized oil prices ($/Bbl) [2]	$85.22	$92.34	$82.73	$40.73	$52.04	$41.61	$37.77	$43.04	$28.74	$40.81	$40.54	
Differential to WTI	9%	6%	10%	16%	10%	10%	10%	12%	14%	11%	10%	
Realized natural gas prices ($/Mcf)	$6.52	$6.78	$6.81	$3.23	$1.63	$1.63	$1.97	$2.08	$1.44	$1.42	$1.84	
LOE ($/Boe)	$6.68	$7.65	$10.18	$8.62	$8.26	$7.67	$6.85	$7.84	$6.78	$7.00	$8.00	$7.00 - $7.50
Cash marketing, transportation & gathering ($/Boe)	$1.04	$1.52	$1.61	$1.60	$1.68	$1.63	$1.57	$1.62	$1.60	$1.55	$1.58	$1.55 - $1.65
G&A ($/Boe)	$6.95	$6.09	$5.54	$5.14	$4.70	$4.81	$5.43	$5.02	$5.32	$4.86	$5.12	
Production Taxes (% of oil & gas revenue)	9.4%	9.3%	9.8%	9.6%	9.6%	9.5%	9.9%	9.6%	9.2%	9.0%	9.3%	~9.2%
DD&A Costs ($/Boe)	$25.14	$24.81	$24.74	$26.10	$26.07	$26.61	$26.59	$26.34	$26.74	$27.19	$25.08	
Select Financial Metrics ($ MM)												
Oil Revenue	$642.0	$1,028.1	$1,231.2	$163.8	$208.6	$169.7	$150.4	$692.5	$111.2	$152.9	$147.1	
Gas Revenue	27.0	50.5	72.8	10.0	5.5	5.6	8.0	29.2	$6.1	$6.4	$9.2	
Bulk Purchase of Oil Revenue	1.5	5.8	-	-	-	-	-	-	-	-	1.9	
OWS and OMS Revenue	16.2	57.6	86.2	6.5	16.0	22.0	23.6	68.1	13.0	19.7	19.1	
Total Revenue	**$686.7**	**$1,142.0**	**$1,390.2**	**$180.4**	**$230.0**	**$197.2**	**$182.1**	**$789.7**	**$130.3**	**$179.1**	**$177.3**	
LOE	54.9	94.6	169.6	39.1	37.8	35.7	31.9	144.5	31.1	31.5	35.7	
Cash marketing, gathering & transportation [3]	8.6	18.8	26.8	7.3	7.7	7.6	7.3	29.9	7.3	7.0	7.0	
Production Taxes	63.0	100.5	127.6	16.6	20.6	16.7	15.7	69.6	10.8	14.4	14.6	
Exploration Costs & Rig Termination	3.2	2.3	3.1	1.9	3.9	0.3	0.1	6.3	0.4	0.3	0.5	
Bulk purchase of oil cost and non-cash valuation adjustment [3]	0.7	7.2	2.3	0.0	0.1	0.9	1.0	1.8	1.2	(0.5)	1.8	
OWS and OMS expenses	11.8	30.7	50.3	2.0	7.4	10.0	8.7	28.0	4.4	8.9	8.2	
G&A	57.2	75.3	92.3	23.3	21.5	22.4	25.3	92.5	24.4	21.9	22.8	$88 - $92
Adjusted EBITDA [4]	**$512.3**	**$821.9**	**$952.8**	**$208.9**	**$245.4**	**$189.2**	**$176.7**	**$820.2**	**$132.9**	**$132.2**	**$104.4**	
DD&A costs	206.7	307.1	412.3	118.5	119.2	123.7	123.9	485.3	122.4	122.5	111.9	
Interest expense	70.1	107.2	158.4	38.8	37.4	36.5	36.9	149.6	38.7	35.0	31.7	
E&P CapEx [5]	1,111.7	916.7	1,505.9	261.3	145.6	71.8	83.9	562.6	82.8	126.0	73.4	340.0
Non E&P CapEx	36.9	26.2	66.7	9.8	24.8	6.2	6.6	47.4	5.2	5.3	5.0	60.0
Total CapEx [5]	$1,148.6	$942.9	$1,572.6	$271.1	$170.4	$78.1	$90.4	$610.0	$88.0	$131.3	$78.5	$400.0
Select Non-Cash Expense Items ($ MM)												
Impairment of oil and gas properties	$3.6	$1.2	$47.2	$5.3	$19.5	$0.1	$21.1	$46.0	$3.6	-	$0.4	
Amortization of restricted stock [6]	10.3	12.0	21.3	7.6	6.1	6.0	5.6	25.3	6.7	6.2	5.8	$24 - $26
Amortization of restricted stock ($/boe) [6]	$1.26	$0.97	$1.28	$1.68	$1.32	$1.28	$1.21	$1.37	$1.47	$1.39	$1.30	

1) Guidance was provided in 2/24/16 press release and updated in the 10/18/16 press release. Guidance does not include contributions from our Pending Acquisition, announced 10/18/2016
2) Average sales prices for oil are calculated using total oil revenues, excluding bulk oil sales of $1.9 million, divided by oil production.
3) Excludes marketing expense associated with non-cash valuation change on our pipeline imbalances and line fill inventory. These items are included under "Bulk Purchase of Oil Cost and non-cash valuation adjustment."
4) Non GAAP Adjusted EBITDA Reconciliation can be found on the Oasis website at www.oasispetroleum.com.
5) Excludes capital for acquisitions in 2013 of $1,563MM. OMS capital included in E&P CapEx.
6) Non-Cash Amortization of Restricted Stock is included in G&A.

Key Company Facts / External Support

Oasis Petroleum Inc.	
Exchange / Ticker	NYSE / OAS
Shares Outstanding (as of 11/2/16)	236.4 MM
Share Price (close on 11/7/16)	$10.81 per share
Approximate Equity Market Capitalization	$2,555MM

External Support	
Independent Registered Public Accounting Firm	PricewaterhouseCoopers
Legal Advisors	DLA Piper LLP / Vinson & Elkins LLP
Reserves Engineers	DeGolyer and MacNaughton