OASIS PETROLEUM

August 2015

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, 2014 are estimated utilizing SEC reserve recognition standards and pricing assumptions based on the trailing 12-month average first-day-of-the-month prices of $95.28 per barrel of oil and $4.35 per MMBtu of natural gas. The reserve estimates for the Company at December 31, 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

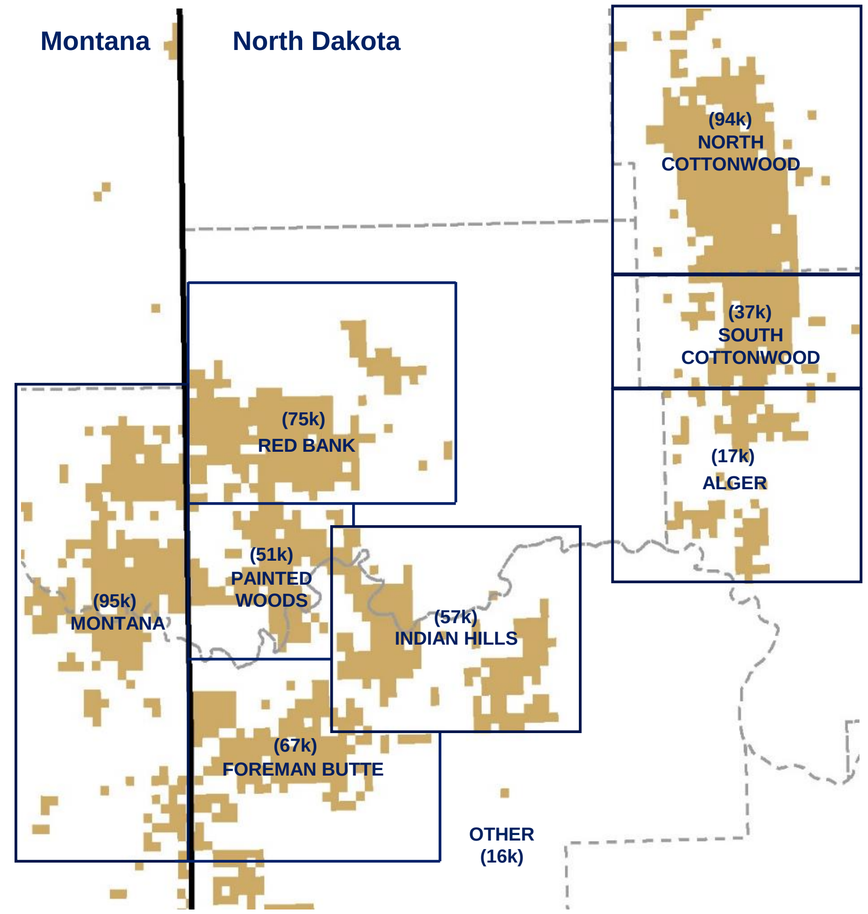
- 506k net acres
  - 86% held by production
  - 97% operated
- 405 operated DSUs
- 3,046 gross operated locations
  - 825 locations in the core
  - Highly economic inventory outside core
- 2Q15 production of 50.3 Mboepd / 88% oil
- Proved Reserves 272 MMBoe with PV-10 of $5.5 billion

Solid outlook in a low price environment

- Driving down well costs and focusing on capital efficiency
- Currently running 3 rigs in the core where:
  - High intensity completions are driving significant production and value uplift
  - Existing infrastructure drives down LOE
- Growing Oasis Midstream Services (OMS) → improving operational & financial performance
- Completing 100% of Oasis' wells with Oasis Well Services (OWS) → improving operating efficiency

Premier Position in Williston Basin[2]

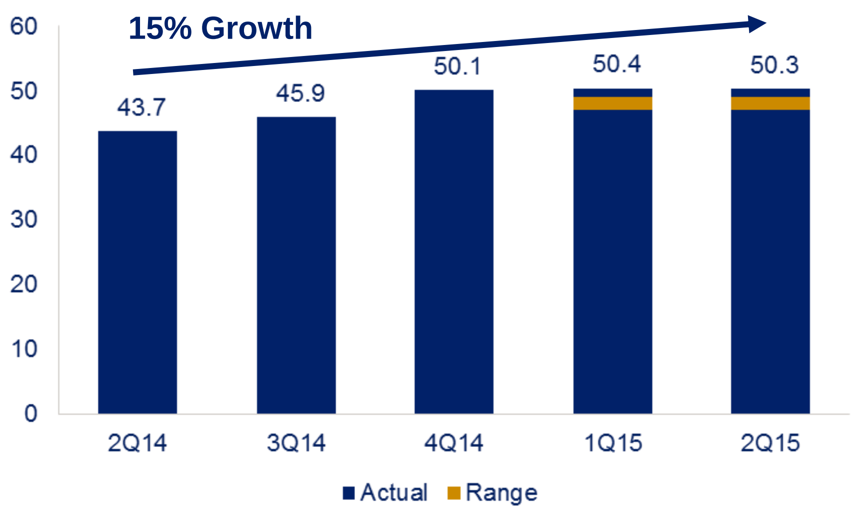
West Williston (358k acres)	East Nesson (148k)



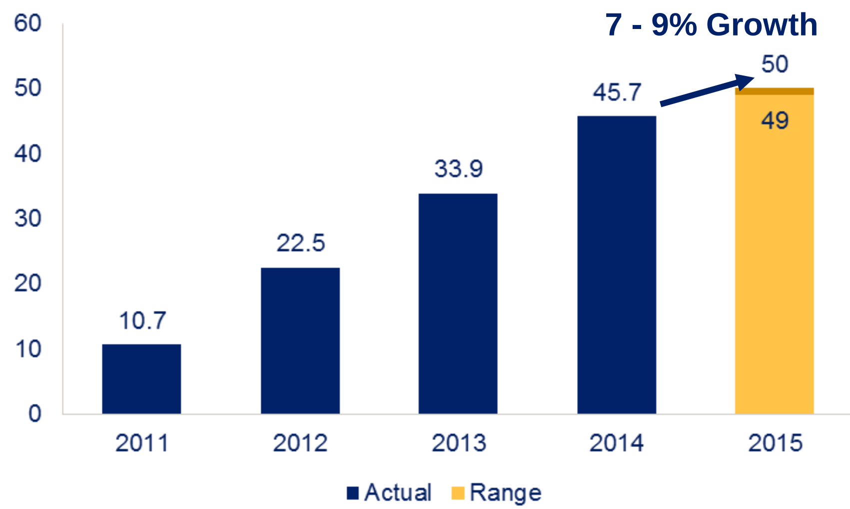
1) As of 12/31/14 unless otherwise noted
2) Acreage in parenthesis

Increasing Production with Less Capital

Solid Quarterly Production (Mboepd) Growth



Annual Average Daily Production (Mboepd)

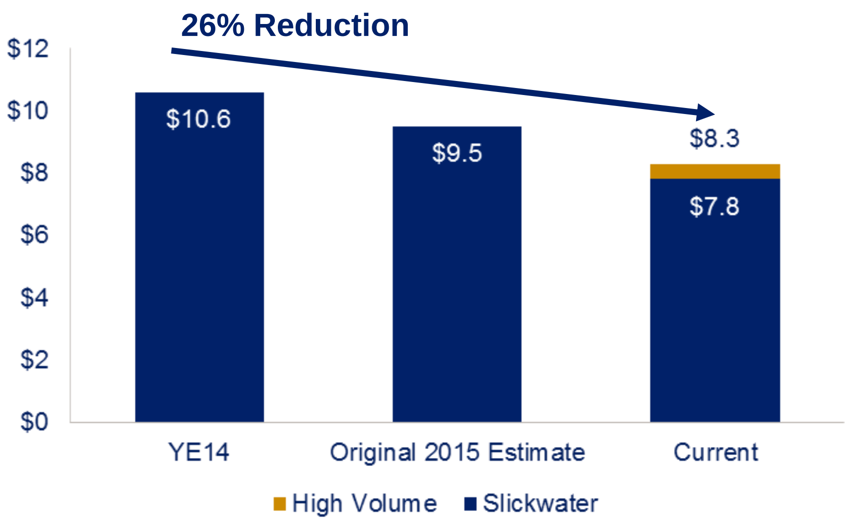


- Exceeded 2Q15 range of 47- 49Mboepd with 50.3Mboepd
- 2Q15 CapEx of $170MM and YTD of $442MM
  - Spending in line with plan

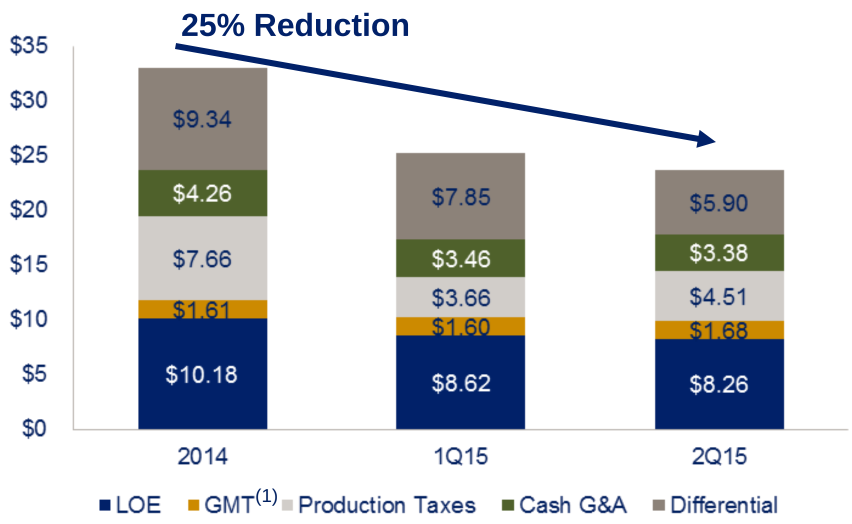
- Increase FY15 range from 46 - 49Mboepd to 49-50Mboepd
- Current CapEx plan anticipates $670MM versus $705MM board approved budget

Cost Structure Improving Cash Flow

Well Costs ($MM)



Cash Operating Costs ($/Boe)



- 50% efficiency / 50% service cost
- Improving drilling days (spud to rig release) from ~24 days in 2014 to ~16 days
- Completion efficiency improved 40% QoQ

- LOE reduced by 19%
  - New guidance for 2015: $8.35-$9.00 per Boe
- Cash G&A reduced by 21%
- Differentials improved by 37%

1) Excluding bulk and non-cash items

2015 Performance Provides Foundation for 2016 Plan

Drivers

Free Cash Flow Positive

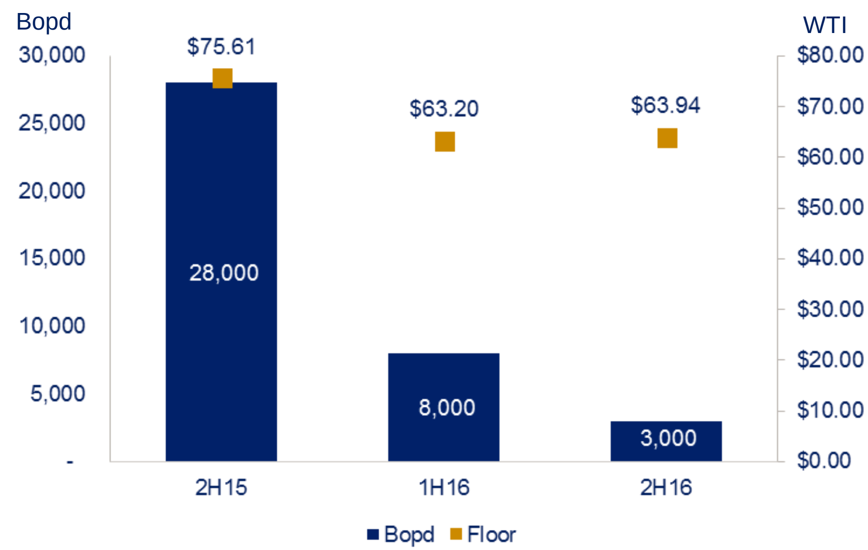
- FCF + in 2Q15 by $36MM
- Projected FCF+ for 2H15 & in 2016
  - Adjusted EBITDA less CapEx & Cash Interest
  - Excluding 2016 infrastructure; ~$120-130MM
- Flat to moderate production growth in 2016 @$50 WTI

Managing balance sheet and preserving liquidity

- Borrowing base of $1.7BN ($1.525BN elected commitments)
- $155MM drawn & $14MM of cash as of 6/30/15
- $463MM equity raise in March 2015
- No near-term debt maturities
- Opportunities for asset monetization

Protecting against downside with hedge program

Strong Hedge Position Protects Against Downside



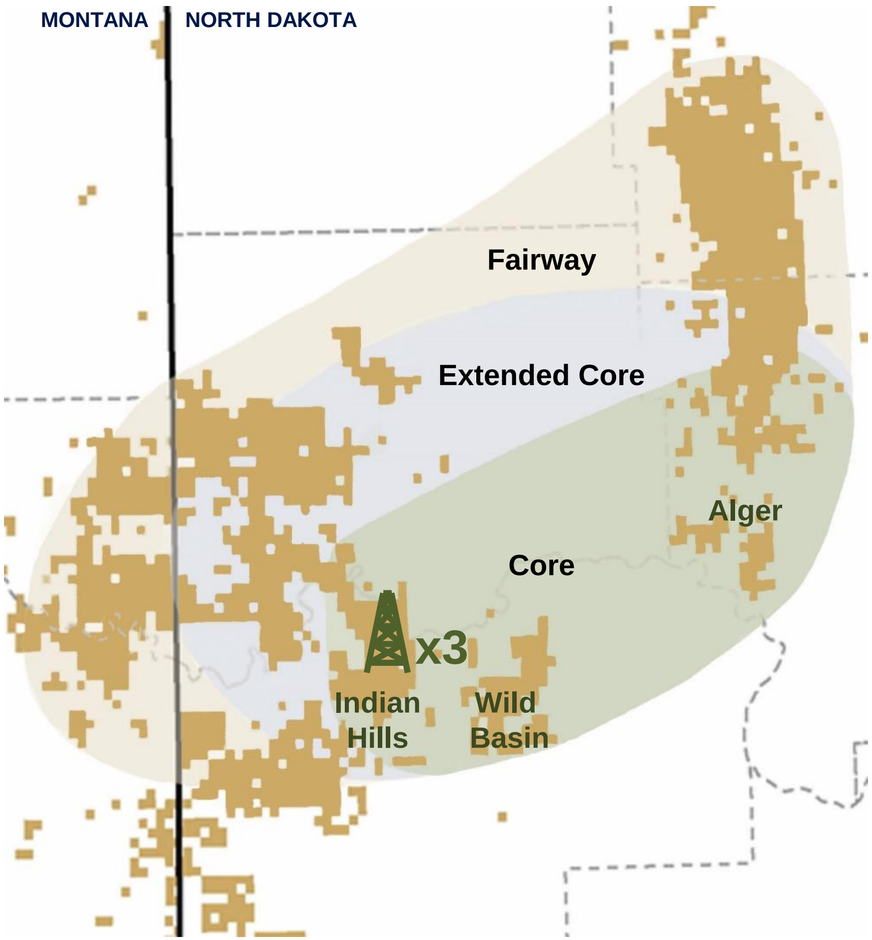
2015 Plan

- Currently planning on total CapEx of $670MM in 2015
  - Board approved budget of $705MM
- Continue to expect to complete 79 gross (63.3 net) and 2.6 net non-op wells in 2015

- Strong liquidity position
- Free cash flow positive
- Lower costs & higher production

Robust Inventory in the Heart of the Williston Basin

Inventory in the Heart of the Play



Depth of Inventory Across Play

Spacing	Wells per DSU	DSUs	Remaining Gross Op Locations[1]	Base EUR (Mboe)[2]
Core	~15	72	825	675
Extended Core	~10	117	917	600
Fairway	~7	216	1,304	450
Total		**405**	**3,046**	

Core	- Highest recoveries - Best infrastructure access - Optimal development plan established
Extended Core	High recovery, Middle Bakken and TFS1 only
Fairway	Shallowest part of the basin, resource can be recovered through Middle Bakken wells

Depth of Inventory in Core

72 operated DSUs across:

- Indian Hills – 31 DSUs
- Wild Basin – 23 DSUs
- Alger – 18 DSUs

825 remaining locations

- 701 wells targeting Bakken and TFS1
- 124 locations are in lower benches of TFS

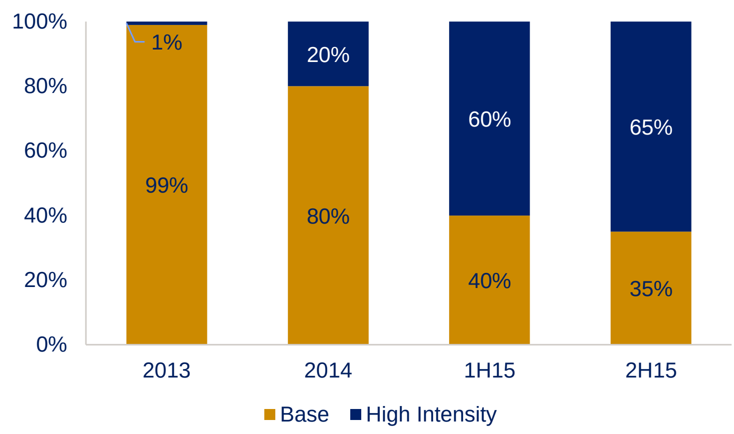
Current pace of completions: 79 gross operated/year

- Bakken and TFS1 represent over 8 years of remaining inventory

1) As of 12/31/14
2) EUR based on base Bakken completion design

2015 High Intensity Program Focused in the Core

Increasing Mix of High Intensity Wells



Design of High Intensity Completions in Core

Design	Slickwater	High Volume Proppant
Stages	36	50
Proppant type	100% ceramic	100% sand
Proppant volume	4.0MM lbs	9.0MM lbs
Technique	Plug & Perf	Plug & Perf
Lift	High capacity	High capacity
Fluids pumped	220k barrels	150k barrels
Current well cost	$7.8MM	$8.3MM

Note: Base well cost in core $7.0MM

Completions Mix in 2Q15

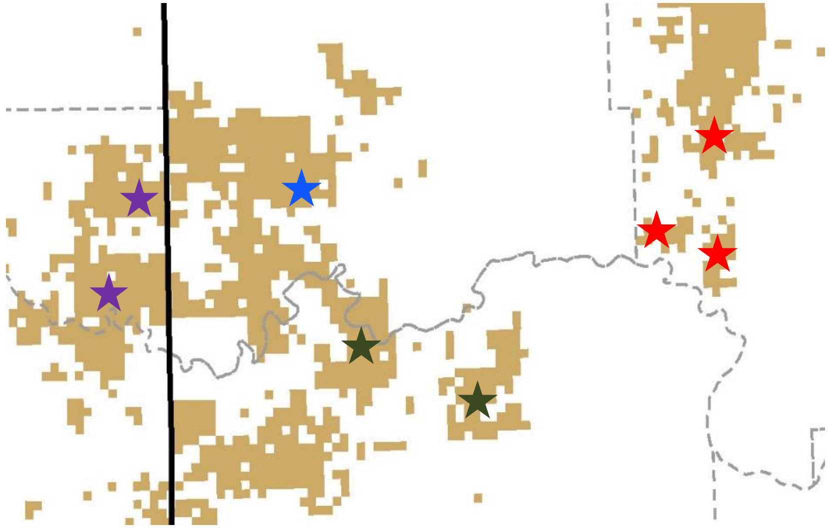
Area	Base	High Intensity	Total
Indian Hills	2	9	11
Alger	4	3	7
Montana	1	0	1
North Cottonwood	2	0	2
Total	**9**	**12**	**21**

Core areas

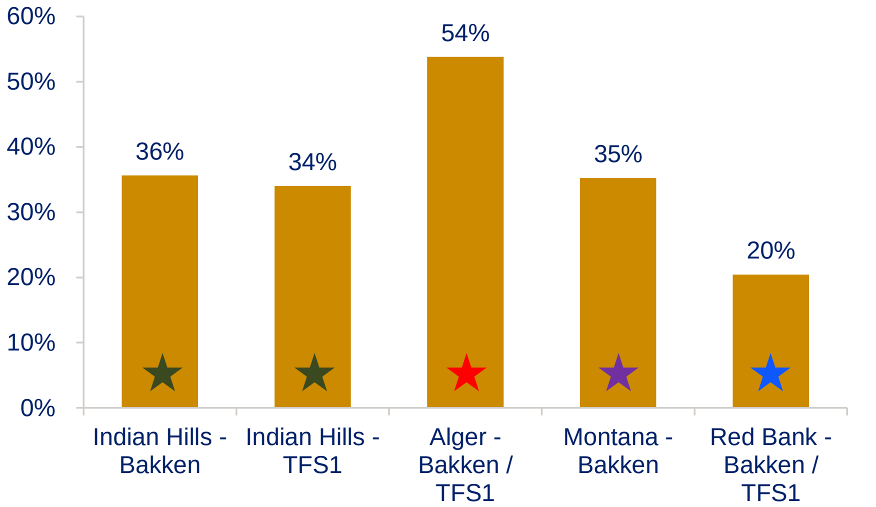
- 86% completed in the core in 2Q15
- 100% planned in core 2H15

High Intensity Application Across Basin

High Intensity Completions



Type Curve Outperformance[1]

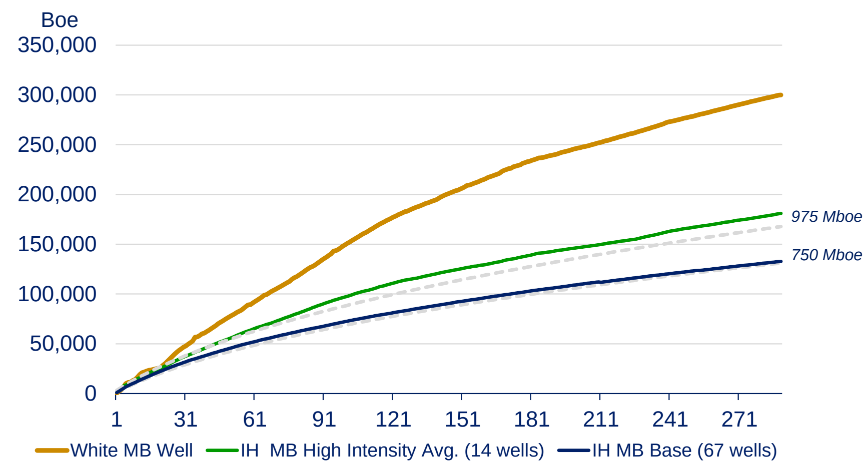


- Seeing 20% – 55%+ uplift in early production
- Potential EUR uplift of 10% – 30% improves returns
- Significant uplift in NPV if EUR is up 10% - 30%, given lower well costs

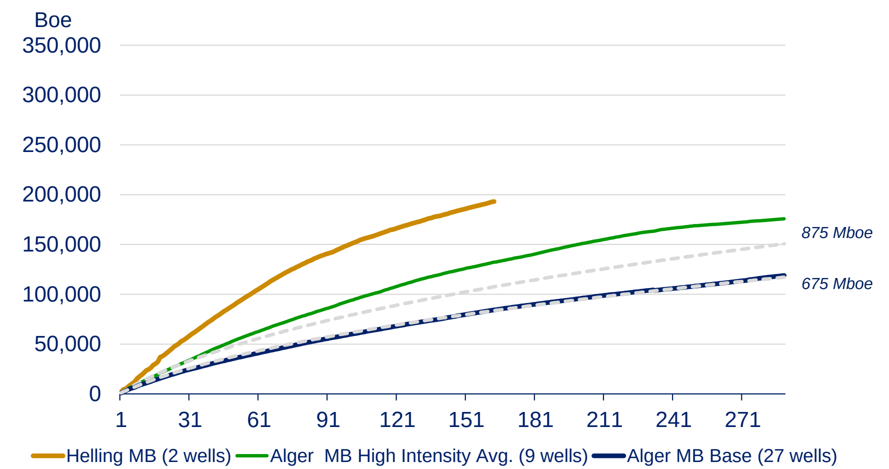
1) Actual results for producing days compared against offsetting base wells

High Intensity Completions Yield Impressive Production Uplift

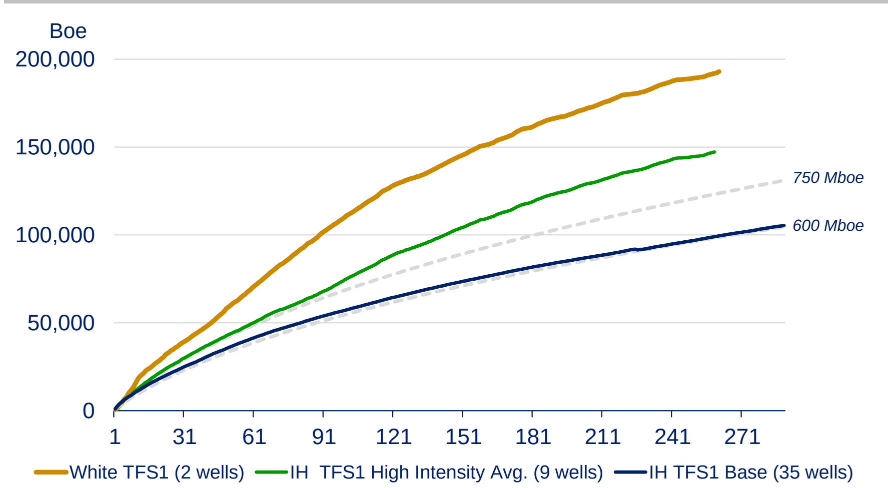
Indian Hills Performance (Bakken)



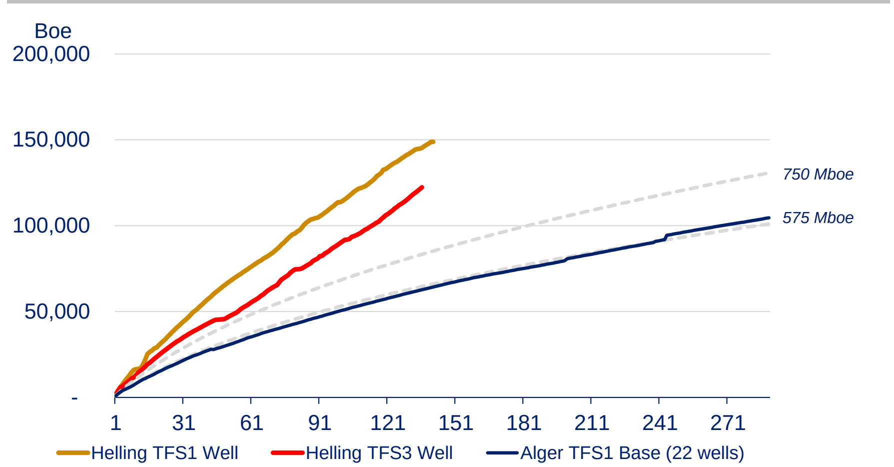
Alger Performance (Bakken)



Indian Hills Performance (TFS1)

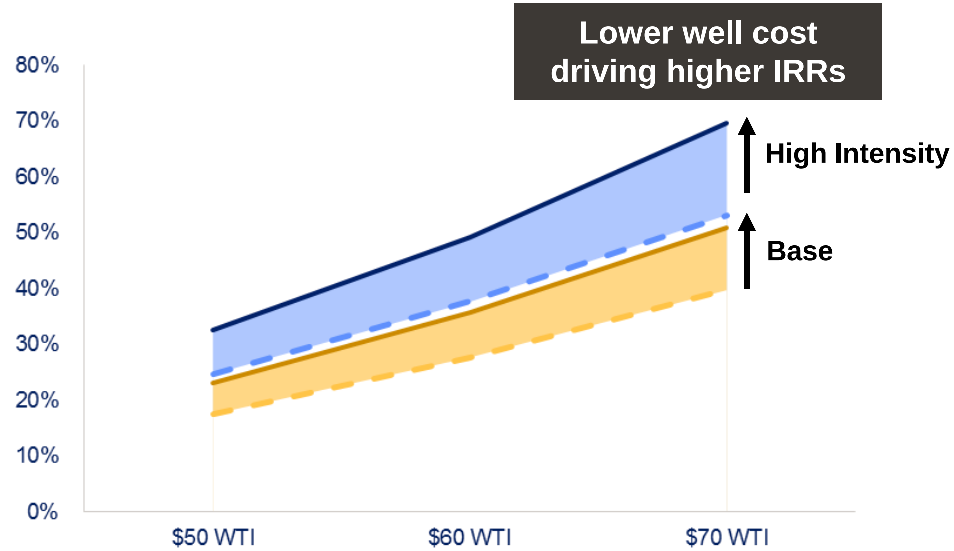


Alger Performance (TFS1&3)

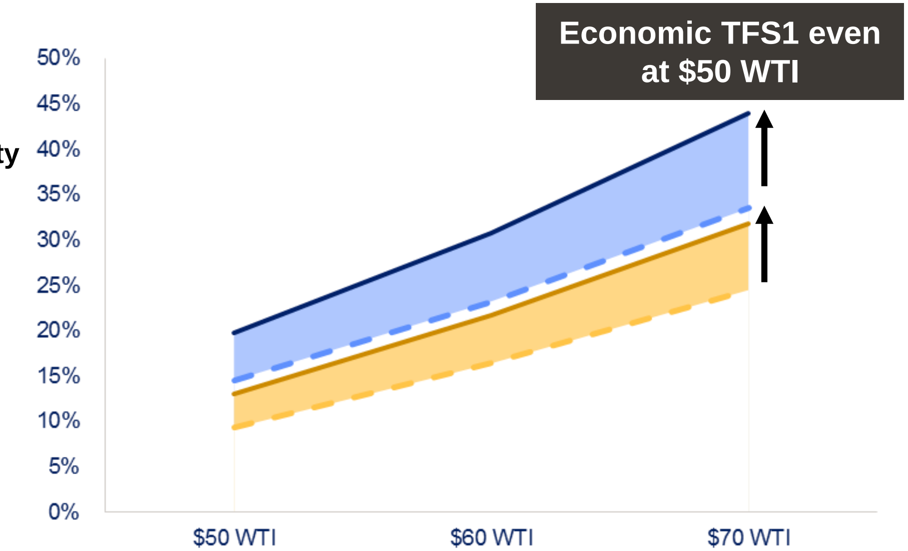


Improving Core Economics with Higher Recoveries and Lower Costs[1]

Average Bakken Returns in the Core



Average TFS1 Returns in the Core



High Intensity Completion Economics

- High-end: $8.0MM well cost - current
- Low-end: $9.0MM well cost - May 15

Base Completion Economics

- High-end: $7.0MM well cost - current
- Low-end: $7.8MM well cost - May 15

1) 10% oil differential, $4.00/mcf realized gas price, 10% production taxes. Type curve parameters: Qi=varies, b=1.6, initial decline 82%, terminal decline 6%

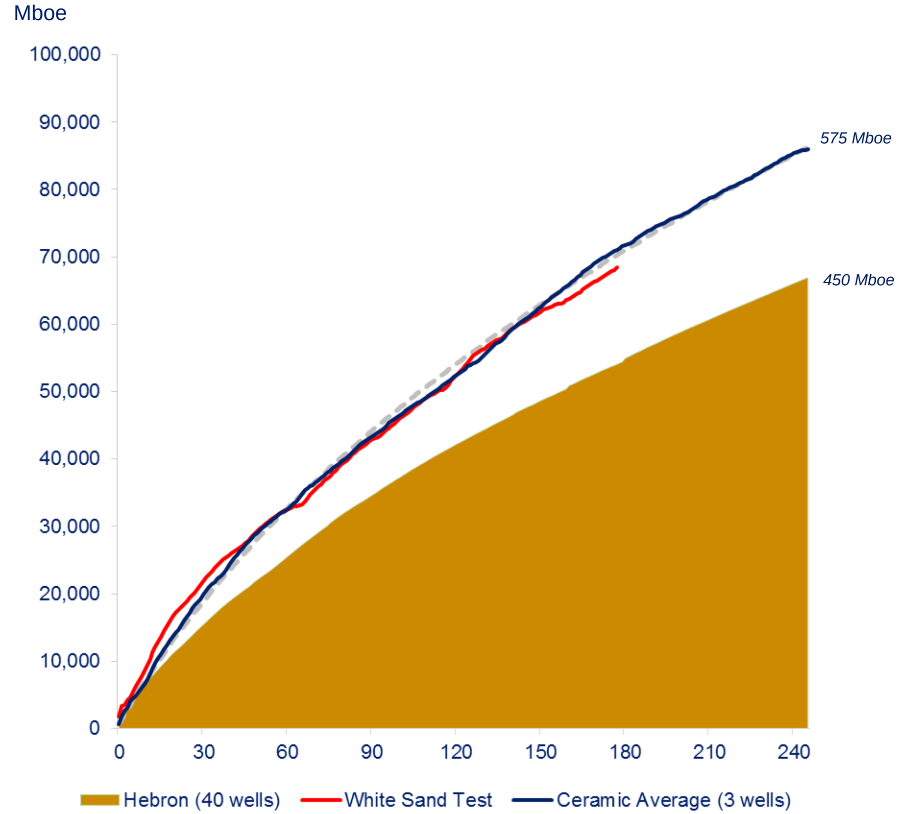
Testing 100% Sand in Slickwater Completions

Increasing High Intensity Returns with Lower Costs

- 100% sand slickwater completions continue to perform outside the core - similar to ceramic offsets
- Saving of ~$500k / well with 100% sand
- Additional sand slickwater tests planned in North Dakota in 2H15
    - Continue to monitor for EUR degradation

Montana IRR @ $60WTI		
Well cost	$7.0MM	$7.5MM
IRR	24%	20%

Montana Well Performance: Sand vs Ceramic



(1) Assumes $60/bbl WTI with 10% differential, $4/mcf gas, Montana production taxes, and 80% NRI. Bakken type curve parameters: Qi=563, b=1.6, initial decline 76%, terminal decline 6%, GOR 900

Oasis Midstream Services ("OMS")

OMS Asset Highlights

Saltwater gathering lines (over 300 miles)

- Increased volume flowing through gathering lines from 40% at YE14 to 65% in 2Q15

Saltwater disposal (SWD) wells (26)

- Increased volume disposed in company wells from 60% at YE14 to 70% in 2Q15

Freshwater distribution lines

Value of OMS to Oasis and other operators

- Lowers LOE
- Increases operational efficiency
- Removes trucks from road and minimizes impact from weather

Annualized YTD EBITDA of $56.2MM[1]

Wild Basin Project

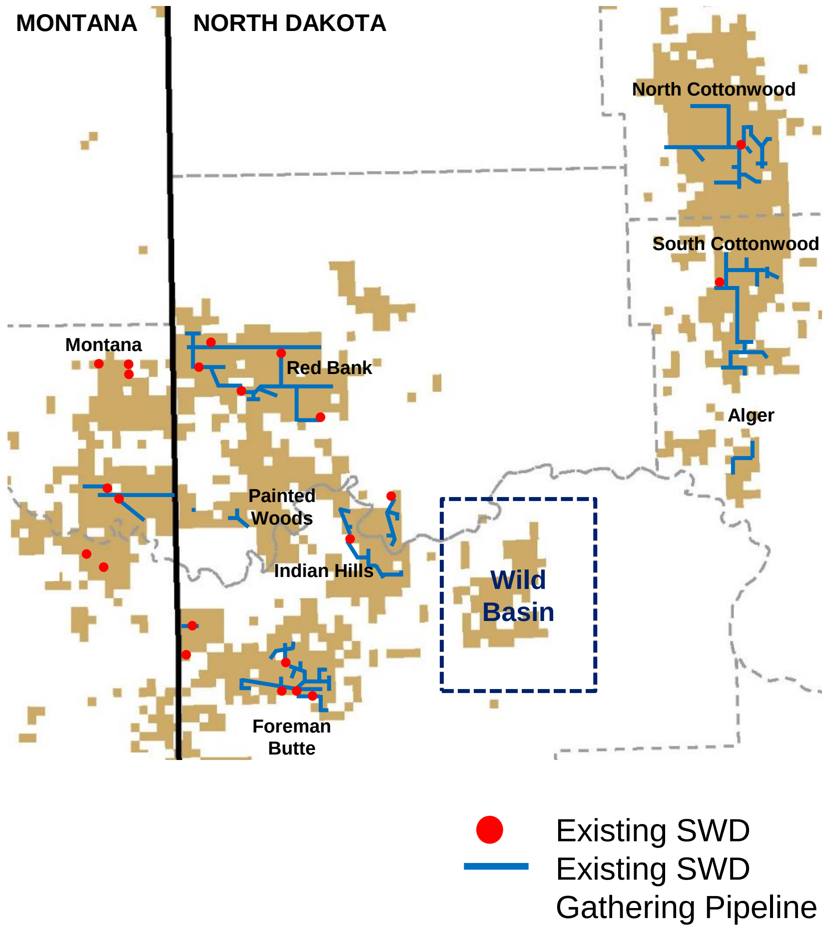
Planned assets in Wild Basin – Controlling a strategic asset

- Natural gas gathering & processing
- Oil gathering, stabilization, and storage
- SWD gathering and wells

Planned Wild Basin Infrastructure CapEx

- 2016 - 2017: $140–150MM total

Saltwater Gathering & Disposal Infrastructure



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

Oil and Gas Infrastructure Development[1]

Infrastructure Highlights

Crude oil gathering (3rd party system)

- Realized $5.90/bbl differential in 2Q15
- Provides marketing flexibility to access to 4 pipeline and 10 different rail connection points
- ~79% gross operated oil production flowing through pipeline systems

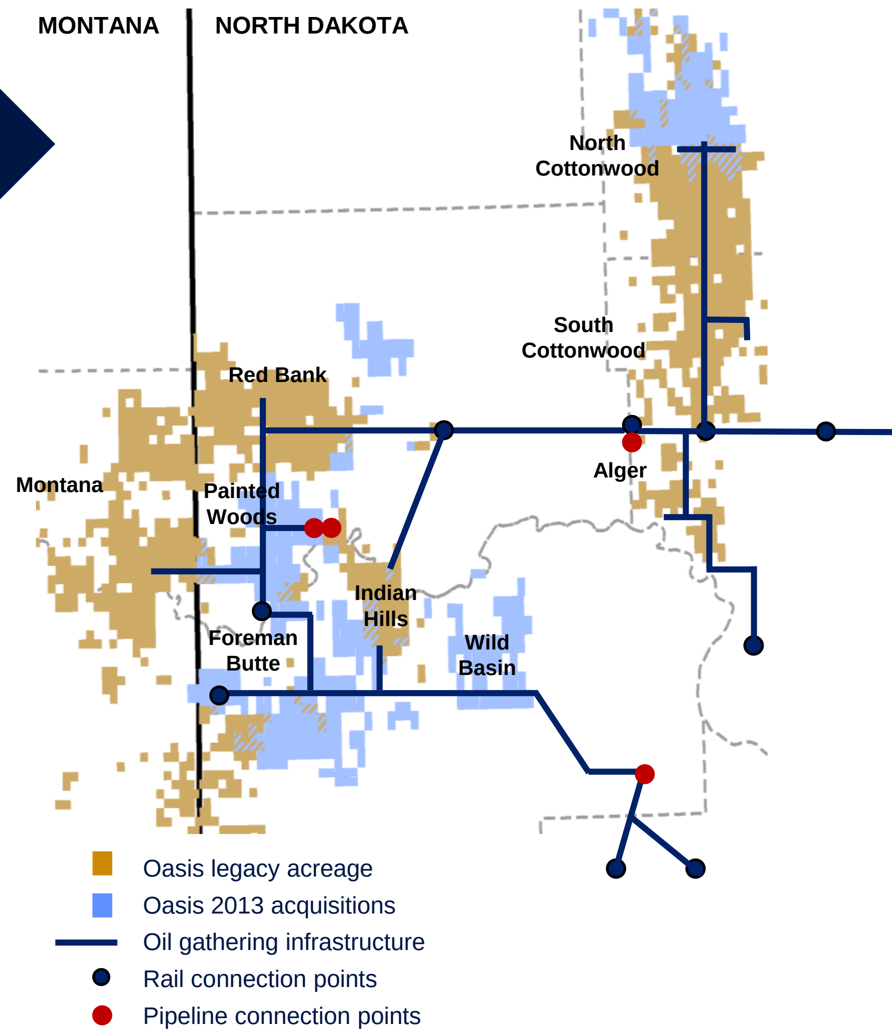
Gas and liquids gathering (3rd party systems)

- Average realization of $2.40/mcf in YTD
- ~97% of wells connected to gathering system
- 89% gas capture for 2Q15 vs. state goal of 77%

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

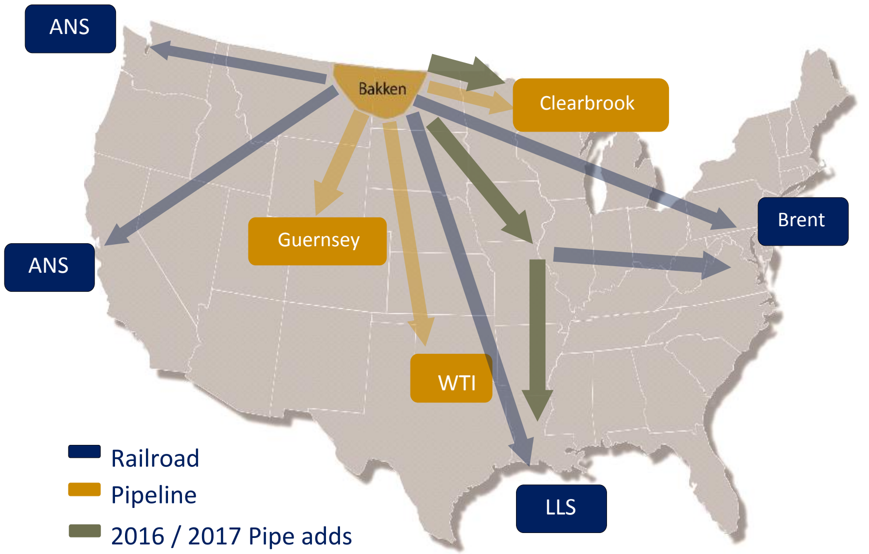
Crude Oil Gathering Infrastructure



1) As of 6/30/15

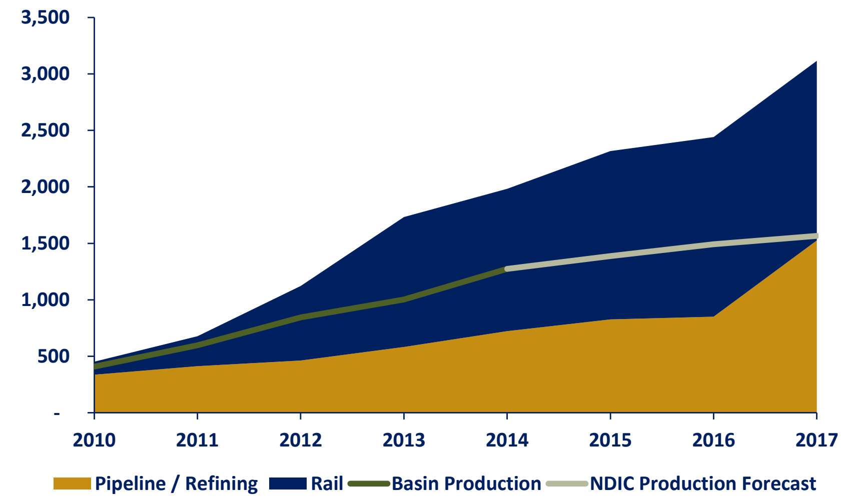
Expanding Takeaway Capacity out of Williston Basin

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 in 2016/2017 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]



(MBopd)	Current Capacity YE2014	Additions 2015	Additions 2016	Additions 2017
Pipeline / Local refining	723	104	24	675
Rail	1,260	230	100	-
Additions in Year		334	124	675
Total Takeaway:	**1,983**	**2,317**	**2,441**	**3,116**
Current Production:[2]	**1,282**			

1) Per North Dakota Pipeline Authority as of August 2015
2) Per NDIC – North Dakota as of May 2015 | Montana & S. Dakota production held flat from April

Investment Highlights

OASIS PETROLEUM

- Oil focused, pure play in the Williston Basin
- Large, concentrated acreage position with highly economic inventory
- Capital discipline strengthens balance sheet & provides operational flexibility
- Proven management team and great people growing long-term shareholder value


OASIS

Balance Sheet

Strong Balance Sheet (6/30/15) and Liquidity

- Liquidity of $1.4 BN
- Current borrowing base of $1.7BN
  - Elected commitments of $1.525BN
- Debt Ratings improving (Moody's / S&P)

	YE13	Current
Corp.	B2/BB-	B1/BB-
Notes	B3/B	B2/B+

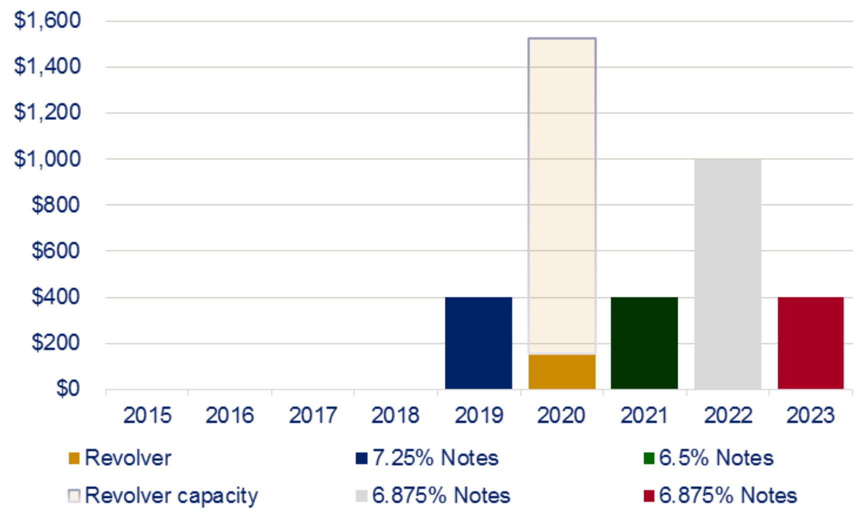
- Primary covenant in borrowing base
  - Minimum interest coverage of 2.5x EBITDAX to cash interest expense
  - LTM ending June 30, 2015 interest coverage of 5.7x
  - No debt to EBITDAX covenant
- $463MM equity offering in March 2015

Capitalization as of 6/30/15 ($MM)[1]

	As Reported
Cash and marketable securities	$14
Current elected commitments	1,525
Borrowing / LCs	(160)
Total Liquidity	**$1,379**

Debt	Face Value
Revolver	$155
7.25% Senior Notes due 2019	400
6.5% Senior Notes due 2021	400
6.875% Senior Notes due 2023	400
6.875% Senior Notes due 2022	1,000
Total long-term debt	**$2,355**

No Near-Term Debt Maturities ($MM)

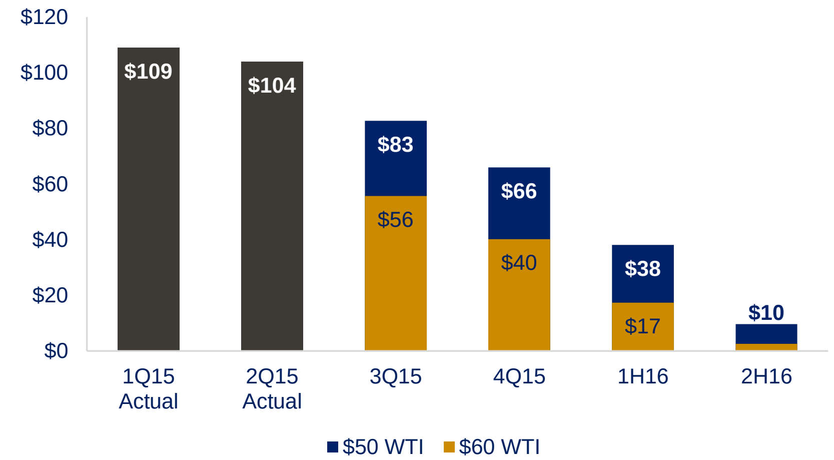


Risk Management[1]

Hedge Position (Oil Only) – Contract Period

Type	Weighted Average Price Floor	Weighted Average Price Ceiling	Bopd
2H15			
Swaps	$73.35	$73.35	23,000
Two Way	$86.00	$103.42	5,000
Total	**$75.61**	**$78.72**	**28,000**
1H16			
Swaps / Total	**$63.20**	**$63.20**	**8,000**
2H16			
Swaps / Total	**$63.94**	**$63.94**	**3,000**

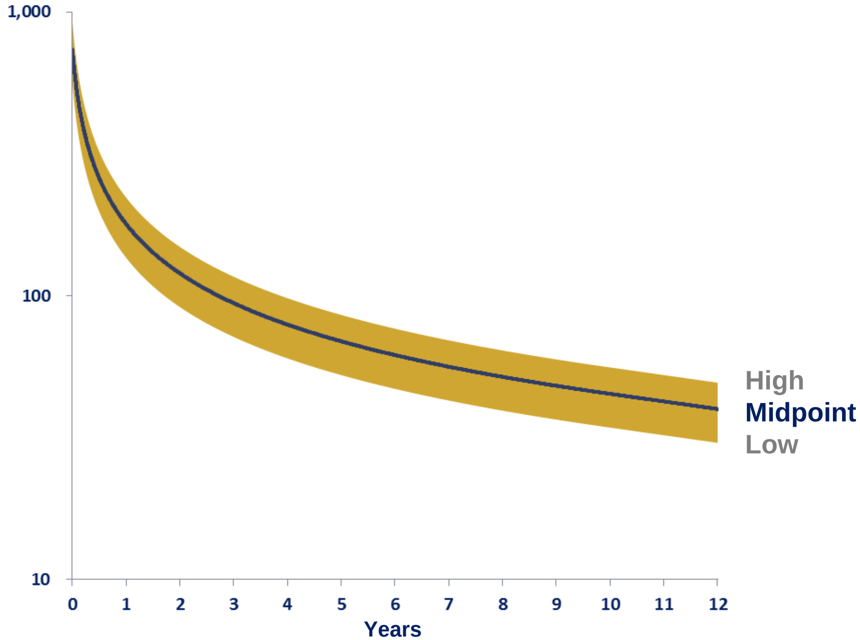
Expected Settlements at Various Prices ($MM)



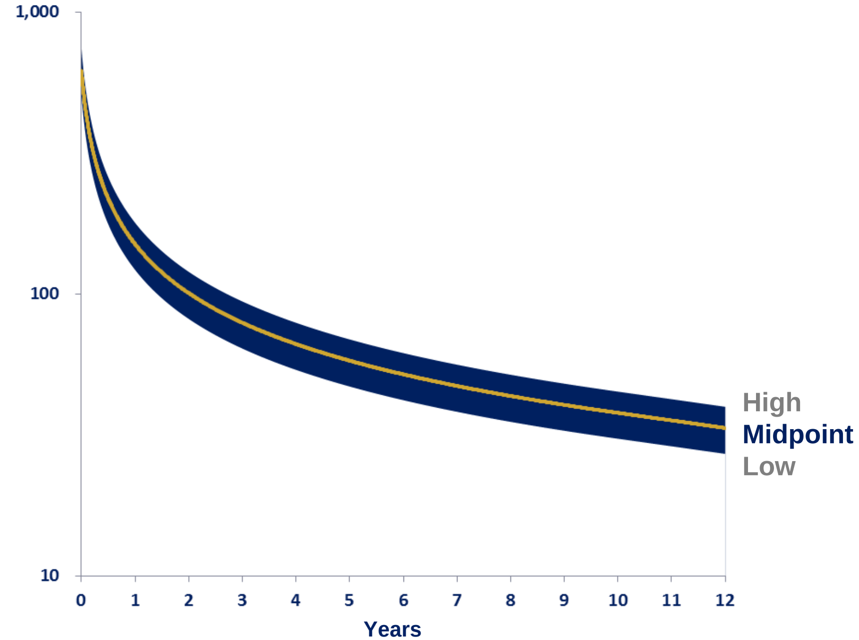
1) As of 8/4/15
2) Hedges are settled and booked the month following the contract period. 2Q15 actual includes contracts from Mar, April, May.

Type Curves in Williston Basin[1]

Middle Bakken Type Curve (MBoe)



TFS Type Curve (MBoe)

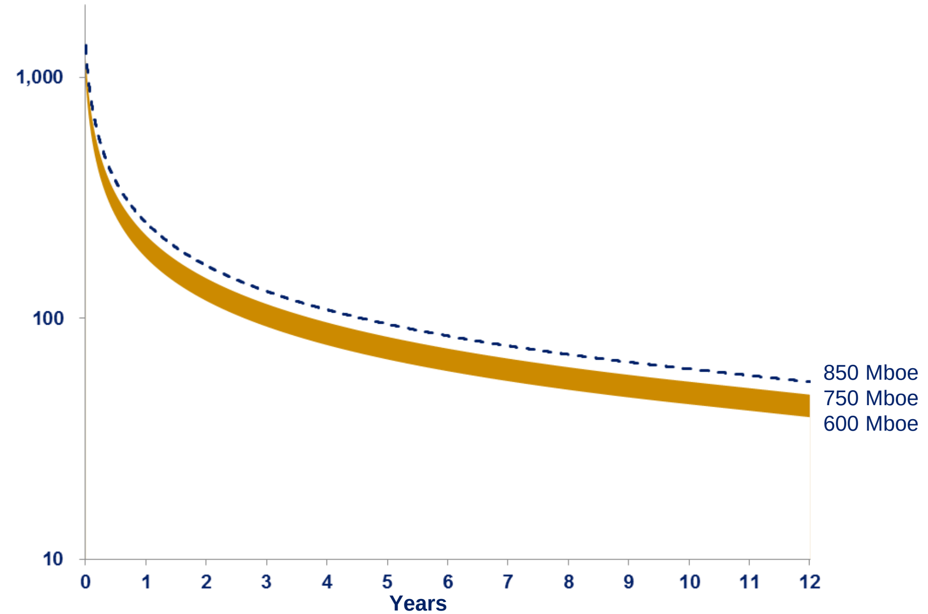


Middle Bakken Type Curve			Metrics	TFS Type Curve		
Low End	Midpoint	High End		Low End	Midpoint	High End
450	**600**	**750**	**Gross Reserves (MBoe)**	**400**	**500**	**600**
536	704	873	IP – 7 day average (Boepd)	480	592	704
415	545	675	1st 60 days - average (Boepd)	371	458	545
359	471	584	2nd 30 days - average (Boepd)	321	396	471
			Cumulative (Mboe)			
14	19	23	30 day	13	16	19
25	33	41	60 day	22	27	33
55	72	89	180 day	49	60	72
85	111	138	365 day	76	93	111

1) Type curve parameters: Qi=varies, b=1.6, initial decline 76%, terminal decline 6%

Core Area Type Curves[1]

Core Area Type Curves (MBoe)



	Low End - Base	High End - Base	Illustrative High Intensity
Gross Reserves (MBoe)	**600**	**750**	**850**
IP – 7 day midpoint (Boepd)	907	1,125	1,271
1st 60 days -average (Boepd)	639	792	895
2nd 30 days - average (Boepd)	524	650	734
Cumulative (Mboe)			
30 day	23	28	32
60 day	38	48	54
180 day	79	98	111
365 day	119	148	167

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

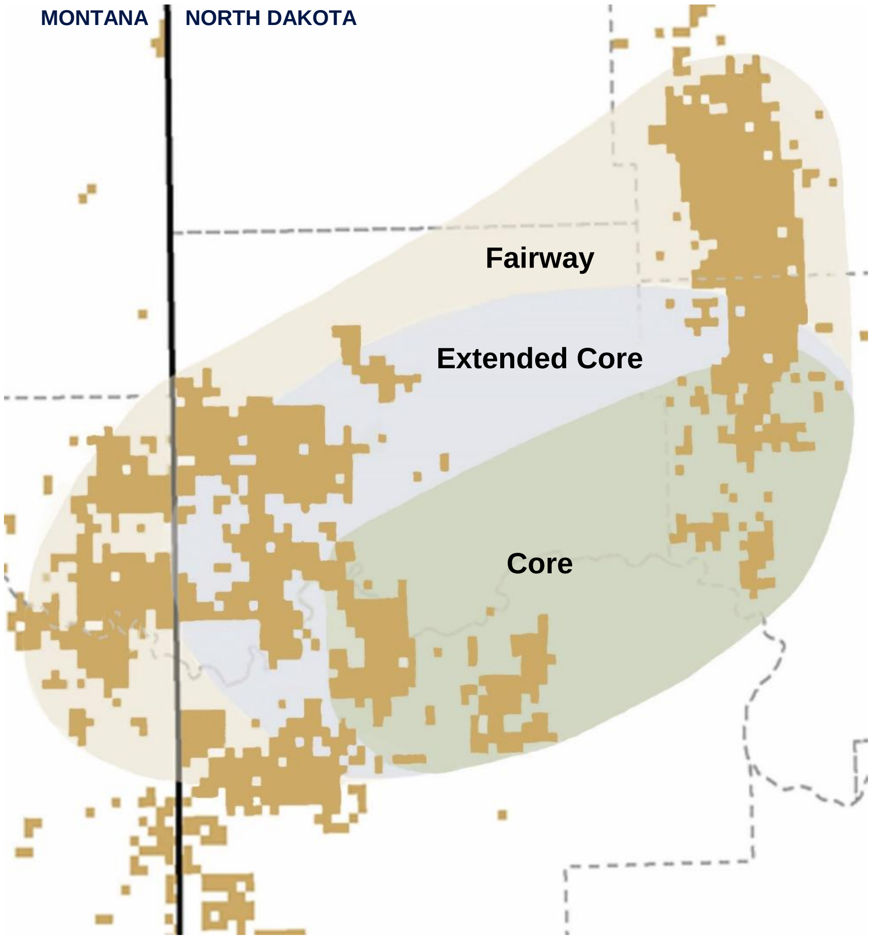
Williston Basin Remaining Inventory[1,2]

Locations & DSU Counts

Area	Wells per DSU	DSUs	Gross Locations	% of Total
Core	~15	72	825	27%
Extended Core	~10	117	917	30%
Fairway	~7	216	1,304	43%
Total		**405**	**3,046**	**100%**

Remaining Operated Locations	Gross Locations	Net Locations
PUD wells		
Core	206	122
Extended Core	178	132
Fairway	53	42
Total PUD	**437**	**296**
Non-Proven wells		
Core	619	345
Extended Core	739	524
Fairway	1,251	904
Total Non-Proven	**2,609**	**1,772**
Total operated wells		
Core	825	467
Extended Core	917	656
Fairway	1,304	946
Total operated	**3,046**	**2,069**

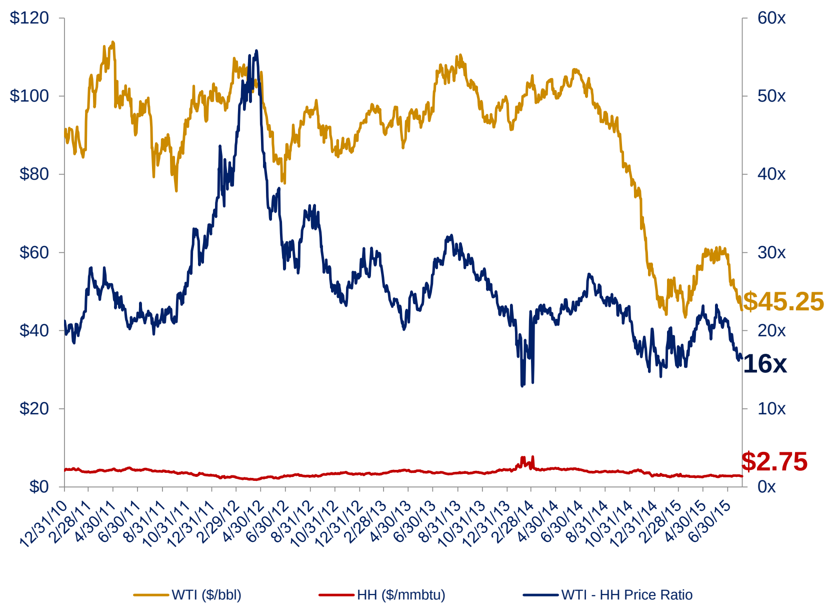
Wells per DSU across Position



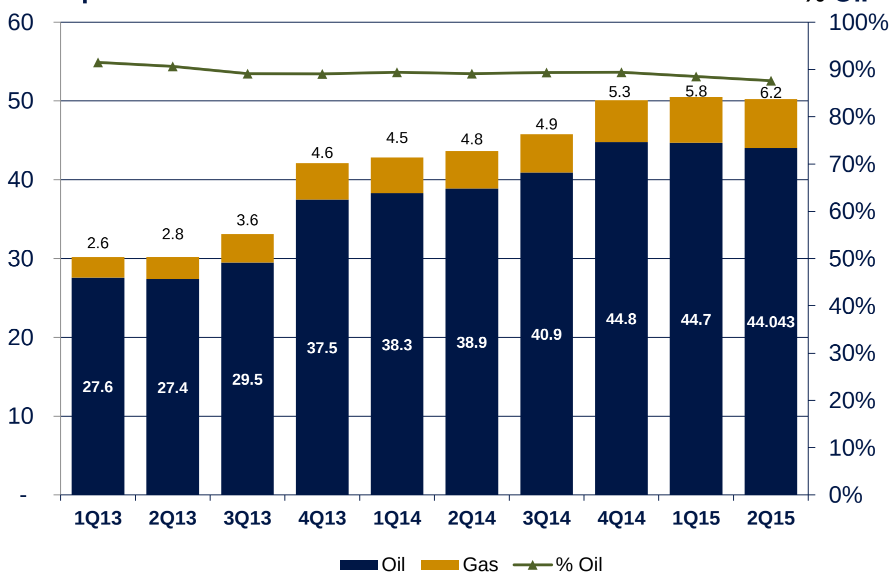
1) As of 12/31/14 not including non-op properties. Inventory assumes a range of wells per DSU from 7 to 18 wells and is dependent upon area.
2) Core inventory includes 116 TFS2 wells and 8 TFS3 wells located in Indian Hills and Alger.

Oil Weighted Production

WTI – Henry Hub Price Disparity ($/bbl to $/Mmbtu)[1]



Oasis Oil and Gas Production (per MBoepd)



1) As of 8/4/15

Key Metrics

Key metrics	West Williston	East Nesson	Total Williston
Net acreage (000s)[1]	358	148	506
Estimated net PDP - MMBoe[1]	101.9	44.4	146.3
Estimated net PUD - MMBoe[1]	95.9	29.8	125.7
Estimated net proved reserves - MMBoe[1]	**197.8**	**74.3**	**272.1**
Percent developed[1]	51.5%	59.8%	53.8%
Operated rigs running[2]	4	0	3
Bakken / TFS operated wells waiting on completion[2]			93
2Q15 production (Mboe/d)			50.3

Bakken/TFS well counts	2015 Budget	YTD Actual	Producing @ 2Q15
Gross operated	79	44	695
Net operated	63.3	37.7	542.5
Working interest in operated wells	*80%*	*86%*	*78%*
Net non-operated	2.6	2.1	24.3
Total net wells	**65.9**	**39.8**	**566.8**

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

1) As of 12/31/14
2) As of 6/30/15

Financial and Operational Results / Guidance

	Actual											Guidance[1]	
Select Operating Metrics	**FY 10**	**FY11**	**FY12**	**FY13**	**1Q 14**	**2Q 14**	**3Q 14**	**4Q 14**	**FY14**	**1Q 15**	**2Q 15**	**3Q 15**	**FY15**
Production (MBoepd)	5.2	10.7	22.5	33.9	42.9	43.7	45.9	50.1	45.7	50.4	50.3	48.0 - 50.0	49.0 - 50.0
Production (MBopd)	4.9	10.2	20.6	30.5	38.3	38.9	41.0	44.8	40.8	44.7	44.0		
% Oil	94%	95%	92%	90%	89%	89%	89%	89%	89%	89%	88%		
WTI ($/Bbl)	$80.19	$94.55	$93.39	$98.05	$98.63	$103.02	$97.18	$72.53	$92.07	$48.58	$57.93		
Realized oil prices ($/Bbl)	$69.60	$86.18	$85.22	$92.34	$89.66	$94.48	$87.17	$62.79	$82.73	$40.73	$52.04		
Differential to WTI	13%	9%	9%	6%	9%	8%	10%	13%	10%	16%	10%		
Realized natural gas prices ($/Mcf)	$6.52	$8.02	$6.52	$6.78	$9.24	$7.56	$5.97	$4.89	$6.81	$3.23	$1.63		
LOE ($/Boe)	$7.43	$8.36	$6.68	$7.65	$10.37	$10.21	$10.51	$9.69	$10.18	$8.62	$8.26		$8.35 - $9.00
Cash marketing, transportation & gathering ($/Boe)	$0.24	$0.34	$1.04	$1.52	$1.53	$1.76	$1.67	$1.48	$1.61	$1.60	$1.68		$1.50 - $1.80
G&A ($/Boe)	$10.39	$7.52	$6.95	$6.09	$6.10	$5.22	$5.67	$5.23	$5.54	$5.14	$4.70		
Production Taxes (% of oil & gas revenue)	10.7%	10.2%	9.4%	9.3%	9.6%	9.7%	10.0%	9.8%	9.8%	9.6%	9.6%		9.0% - 10.0%
DD&A Costs ($/Boe)	$19.91	$19.16	$25.14	$24.81	$23.66	$24.48	$25.35	$25.32	$24.74	$26.10	$26.07		
Select Financial Metrics ($ MM)													
Oil Revenue	$124.7	$321.7	$642.0	$1,028.1	$309.2	$334.6	$328.5	$258.9	$1,231.2	$163.8	$208.6		
Gas Revenue	4.2	8.8	27.0	50.5	22.6	19.6	16.2	14.4	72.8	10.0	5.5		
Bulk Purchase of Oil Revenue	-	-	1.5	5.8	-	-	-	-	-	-	-		
OWS and OMS Revenue	-	-	16.2	57.6	17.7	18.2	24.0	26.4	86.2	6.5	16.0		
Total Revenue	**$128.9**	**$330.4**	**$686.7**	**$1,142.0**	**$349.5**	**$372.4**	**$368.7**	**$299.7**	**$1,390.2**	**$180.4**	**$230.0**		
LOE	14.1	32.7	54.9	94.6	40.0	40.6	44.4	44.7	169.6	39.1	37.8		
Cash marketing, gathering & transportation [2]	0.5	1.4	8.6	18.8	5.2	7.0	7.0	9.5	29.1	7.3	7.6		
Production Taxes	13.8	33.9	63.0	100.5	31.8	34.5	34.6	26.8	127.6	16.6	20.6		
Exploration Costs & Rig Termination	0.3	1.7	3.2	2.3	0.4	0.5	1.1	1.1	3.1	1.9	3.9		
Bulk purchase of oil cost and non-cash valuation adjustment [2]	-	-	0.7	7.2	(0.7)	0.1	0.3	0.6	0.2	0.0	0.0		
OWS and OMS expenses	-	-	11.8	30.7	10.9	8.8	14.9	15.6	50.3	2.0	7.4		
G&A	19.7	29.4	57.2	75.3	23.5	20.8	23.9	24.1	92.3	23.3	21.5		$95 - $100
Adjusted EBITDA [3]	**$82.2**	**$234.5**	**$512.3**	**$821.9**	**$239.8**	**$254.7**	**$238.8**	**$219.5**	**$952.8**	**$208.9**	**$245.4**		
DD&A costs	37.8	75.0	206.7	307.1	91.3	97.3	107.0	116.8	412.3	118.5	119.2		
Interest expense	1.4	29.6	70.1	107.2	40.2	39.0	39.4	39.8	158.4	38.8	37.4		
E&P CapEx [4]	345.6	637.3	1,111.7	916.7	297.1	326.9	419.6	462.3	1,505.9	261.3	145.6		
Non E&P CapEx	6.8	28.7	36.9	26.2	10.4	24.9	18.0	13.4	66.7	9.8	24.8		
Total CapEx [1,4]	$352.4	$666.0	$1,148.6	$942.9	$307.5	$351.8	$437.6	$475.7	$1,572.6	$271.1	$170.4		$670.0
Select Non-Cash Expense Items ($ MM)													
Impairment of oil and gas properties	$12.0	$3.6	$3.6	$1.2	$0.8	$0.0	$1.4	$45.0	$47.2	$5.3	$19.5		
Amortization of restricted stock [5]	1.2	3.7	10.3	12.0	4.5	5.2	6.1	5.5	21.3	7.6	6.1		$27 - $29
Amortization of restricted stock ($/boe) [5]	$0.65	$0.93	$1.26	$0.97	$1.17	$1.30	$1.44	$1.20	$1.28	$1.68	$1.32		

1) Guidance was updated in 8/4/15 press release.
2) 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."
3) Non GAAP Adjusted EBITDA Reconciliation can be found on the Oasis website at www.oasispetroleum.com.
4) Excludes capital for acquisitions in 2013 of $1,563MM. OMS capital included in E&P CapEx.
5) Non-Cash Amortization of Restricted Stock is included in G&A.

Oasis Petroleum Inc.	
Exchange / Ticker	NYSE / OAS
Shares Outstanding (as of 8/4/15)	139.2 MM
Share Price (close on 8/4/15)	$8.58 per share
Approximate Equity Market Capitalization	$1.2 BN

External Support	
Independent Financial/Tax Auditor	PricewaterhouseCoopers
Legal Advisors	DLA Piper LLP / Vinson & Elkins, LLP
Reserves Engineers	DeGolyer and MacNaughton