IPAA OGIS New York
April 9-10, 2018

Ultra Petroleum Corp. NASDAQ: UPL

Forward Looking Statements and Risk Factors

Forward-Looking Statements and Estimates

This presentation contains "forward-looking statements" within the meaning of the federal securities laws, including statements about our business strategies and plans, plans for future drilling and resource development, prospective levels of capital expenditures and production and operating costs, and estimates of future results. Any statement in this presentation, including any opinions, forecasts, projections or other statements, other than statements of historical fact, are forward-looking statements. Although we believe the expectations reflected in such forward-looking statements are reasonable, we can give no assurance such expectations are correct, and actual results may differ materially from those projected. In addition, this presentation includes information about our proved reserves. The Securities and Exchange Commission ("SEC") permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible oil and gas reserves that meet the SEC's definitions for such terms. This presentation also includes information about oil and gas quantity estimates that are not permitted to be disclosed in SEC filings, including terms or designations such as "estimated ultimate recovery" or "EUR" or "resource" or "resource potential" or other terms bear similar or related descriptions. These types of estimates do not represent and are not intended to represent any category of reserves based on SEC definitions, do not comply with guidelines established by the American Institute of Certified Public Accountants regarding forecasts of oil and gas reserves estimates, are, by their nature, more speculative than estimates of proved, probable and possible reserves disclosed in SEC filings, and, accordingly, are subject to substantially greater uncertainty of being actually realized. Actual volumes or quantities of oil and gas that may be ultimately recovered will likely differ substantially from such estimates. Factors affecting such ultimate recovery include the scope of our actual drilling program, which will be directly affected by the availability of capital, drilling and production costs, commodity prices, availability of drilling services and equipment, lease expirations, transportation constraints, regulatory approvals, field spacing rules, and actual drilling, completion and production results as well as other factors. These estimates may change significantly as the development of properties provides additional data. This presentation also includes estimates of values attributable to the locations on which such oil and gas quantity estimates are based. The estimates of value set forth in this presentation were calculated based on the assumptions and methodologies set forth in this presentation, which differ materially from the assumptions and methodologies oil and gas companies are required to use in calculating PV-10 values of proved reserves disclosed in SEC filings. As a result, the estimates of values included in this presentation do not represent and are not intended to represent the "PV-10" value that would be attributable to such items if such items were calculated based on applicable SEC requirements.

Risk Factors

Certain risks and uncertainties inherent in our operating businesses as well as certain on-going risks related to our operational and financial results are set forth in our filings with the Securities and Exchange Commission ("SEC"), particularly in the section entitled "Risk Factors" included in our most recently-filed Annual Report on Form 10-K, our most recently-filed Quarterly Reports on Form 10-Q, and from time to time in other filings we make with the SEC. Some of the risk and uncertainties related to our business include, but are not limited to, increased competition, the timing and extent of changes in prices for oil and gas, particularly in the areas where we own properties, conduct operations, and market our production, as well as the timing and extent of our success in discovering, developing, producing and estimating oil and gas reserves, including from any horizontal wells we drill in the future, the timing and cost of our future production and development activities, our ability to successfully monetize the properties we are marketing, weather and government regulation, and the availability and cost of oil field services, personnel and equipment.

Investors are encouraged to review and consider the risk factors set forth in our historical and future SEC filings, as well as any set forth in this presentation, in connection with a review and consideration of this presentation. Our SEC filings are available directly from the company – please send any requests to Ultra Petroleum Corp. at 400 North Sam Houston Parkway East, Suite 1200, Houston, Texas 77060 (Attention: Investor Relations). Our SEC filings are also available from the SEC on their website at www.sec.gov or by telephone request at 1-800-SEC-0330.

Presentation Index

Company Overview

Market Snapshot	
NASDAQ Symbol	**UPL**
Market Capitalization, $ million (April 5)	**$738**
Net Debt @ 12/31/17, $ million	**$2,159**
Enterprise Value, $ million (April 5)	**$2,897**

Production & Reserves	
Q417 Production[1], Bcfe	**74.5**
SEC Proved Developed Reserves[2], Bcfe	**2,392**
SEC Proved Developed PV-10%[2], $billion	**$2.2**

Acreage	
Net Acreage – Wyoming:	
Pinedale Vertical Core	27,000
Horizontal Flank, 700 net locations	28,000
Additional Flank Acreage/Jonah	23,000
Net Acreage – Wyoming	**78,000**
Net Acreage – Utah	**8,000**
% Operated	**90%**
% HBP	**91%**

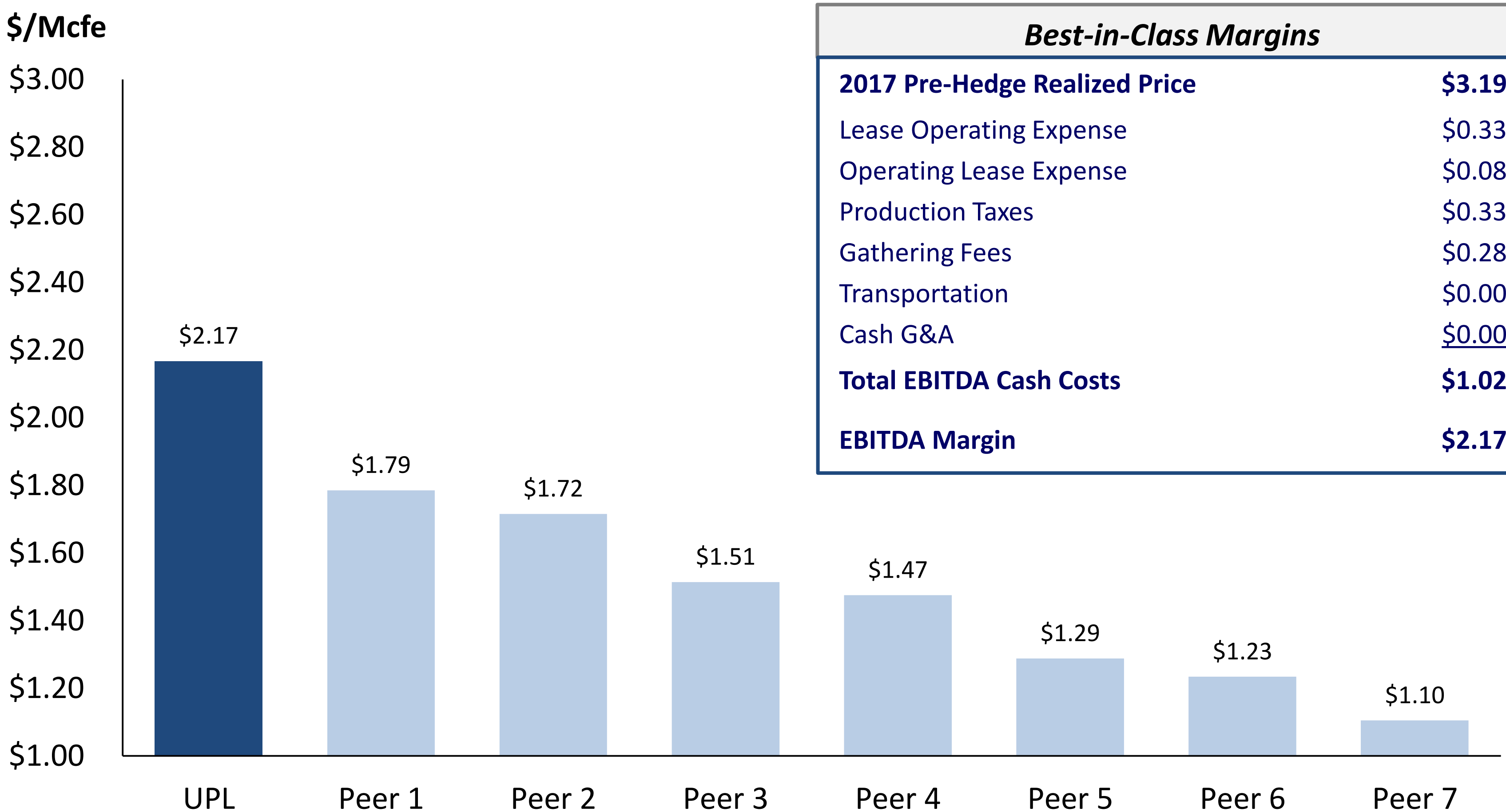
Ultra Petroleum Corp. NASDAQ: UPL

Wyoming Inventory	
Vertical locations, gross	**4,600**
Horizontal locations, gross	**1,600**
Total	**6,200**

[1]Accounts for divestment of 0.3 Bcfe PA production in December.
[2] YE17 Proved reserves includes a limited PUD program of reduced vertical development and a HZ program that has yet to be booked.

Best-in-Class Margins

2017 EBITDA Margin ($/Mcfe)



Best-in-Class Margins	
2017 Pre-Hedge Realized Price	**$3.19**
Lease Operating Expense	$0.33
Operating Lease Expense	$0.08
Production Taxes	$0.33
Gathering Fees	$0.28
Transportation	$0.00
Cash G&A	$0.00
Total EBITDA Cash Costs	**$1.02**
EBITDA Margin	**$2.17**

Note: Peers include AR, COG, ECR, EQT, GPOR, RRC and SWN

Prolific Basin Drives Lowest Breakevens

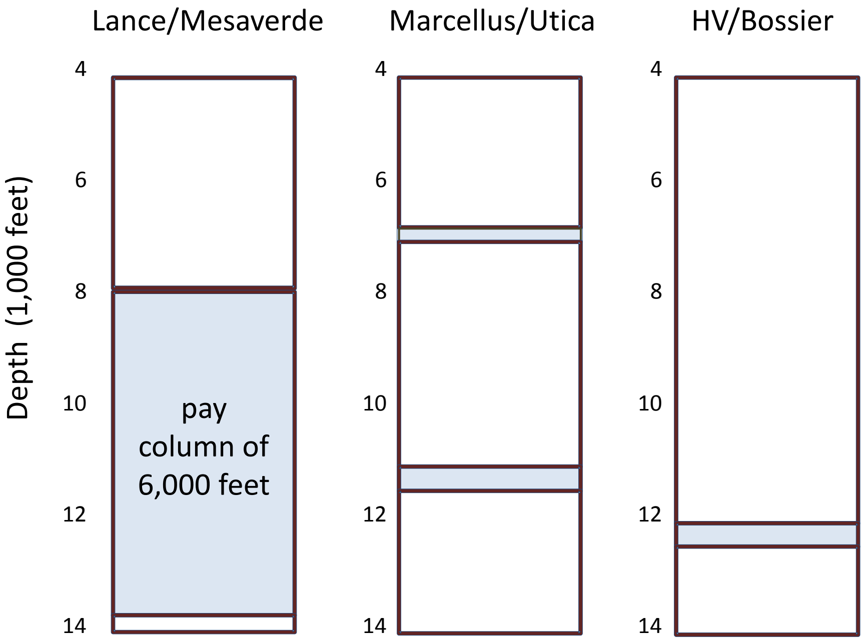
Highly Attractive Geology

- Pinedale field in the Green River Basin is one of the top gas fields in the U.S. with potential recovery of 39 Tcfe
- UPL's premier position is in the prolific Lance and Mesaverde formations – with productive depths ranging from 8,000 – 14,000 feet

Highly Competitive Economics

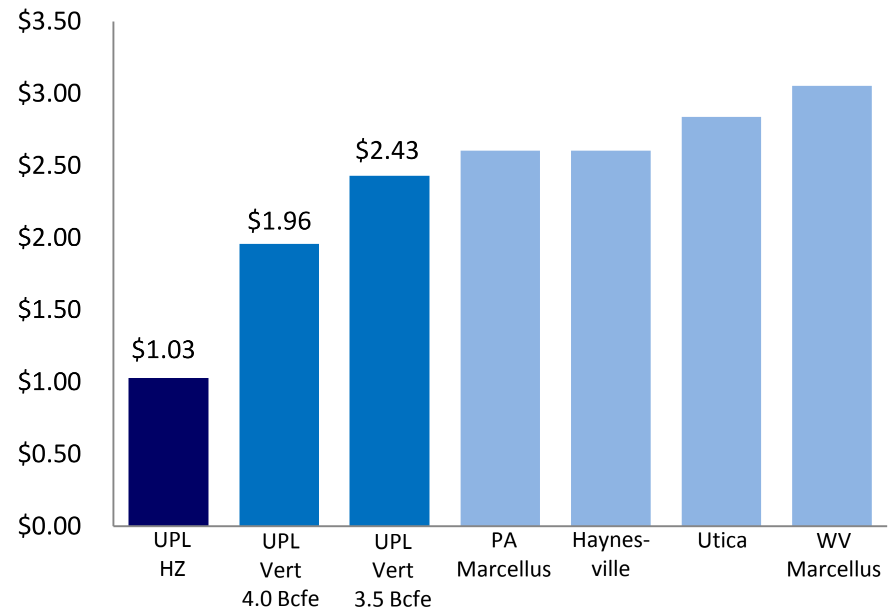
- UPL has a nearly 25-year track record in the basin and is the largest acreage holder in Pinedale
- UPL's contiguous acreage position, execution and relentless focus on operating and capital costs drives the lowest breakevens of the peer group

Schematic Pay Zone Comparison



Source: EIA and Wall Street Research.

Natural Gas Breakevens, $/Mcf



UPL HZ well: IP = 32 MMcfe/d;
EUR = 20 Bcfe; DC&E costs = $9 million

Source: Company data and BMO.

New UPL Strategic Focus and Unique Strengths

Operating and Financial Fundamentals	*Disciplined approach*
	Accelerate horizontal program
	Capital efficient growth
	Free cash flow generation
Capital Efficiency and Discipline	*Balance sheet flexibility*
	Increase hedging program
	Drive shareholder value
Investor Alignment and Messaging	*Improve investor communication*
	Set and meet expectations
	Increase transparency

2018 Capital Plan and Guidance

2018 Plan

- **Capital Efficiency:**
  - Disciplined deployment of capital
  - Relentless pursuit to control costs
  - Reducing rig count from 7 to 4
  - Focused on superior returns: core verticals and high-rate horizontals
- **Cash Flow Visibility:**
  - Increased hedges of gas, oil and basis
  - Grow Wyoming production by 7% – 11%
  - Generate free cash flow
  - Divest Utah assets
- **Accelerate Horizontal Development:**
  - All operated rigs are HZ capable
  - Drill 15-20 HZ wells in 2018 (5x 2017)
  - Increased to 33% of drilling capex
  - Reduced vertical drilling - focused in core

Capital Program = $400 MM

Pinedale Operated Vertical	$240
Pinedale Operated Horizontal	$120
Pinedale Non-Operated Vertical	$30
Corporate Other	$10

2018 Production Guidance

Full Year 2018[2], Bcfe	280 – 290
1st Quarter 2018[2], MMcfe/d	790 – 810
Wyoming annual growth	7% – 11%

2018 Expense Guidance (per Mcfe)

Lease Operating Expense	$0.28-0.32
Facility Lease Expense	0.07-0.09
Production Taxes[1]	0.28-0.30
Gathering Fees, net	0.26-0.28
Transportation Charges	0.00-0.00
DD&A	0.67-0.70
General & Administrative	0.00-0.02
Interest Expense	0.50-0.51
Total	**$2.06-2.22**

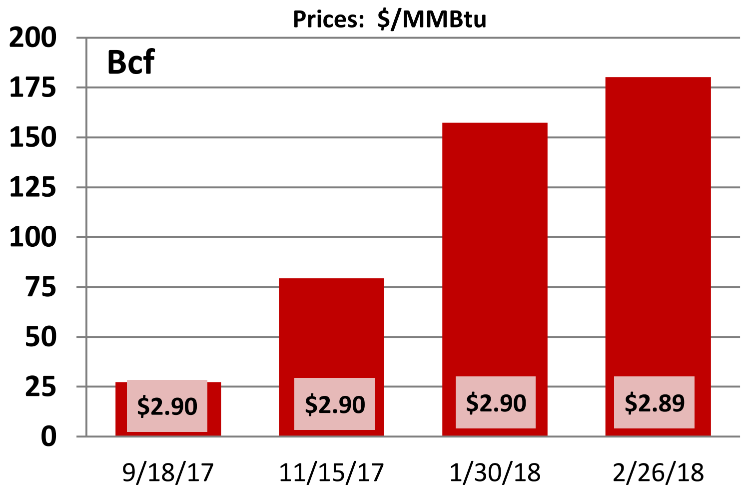
(1) Based on realized prices of $3.00 per Mcf and $60.00 per Bbl
(2) 2018 production guidance includes UT through March 31, 2018

Early 2018 Accomplishments

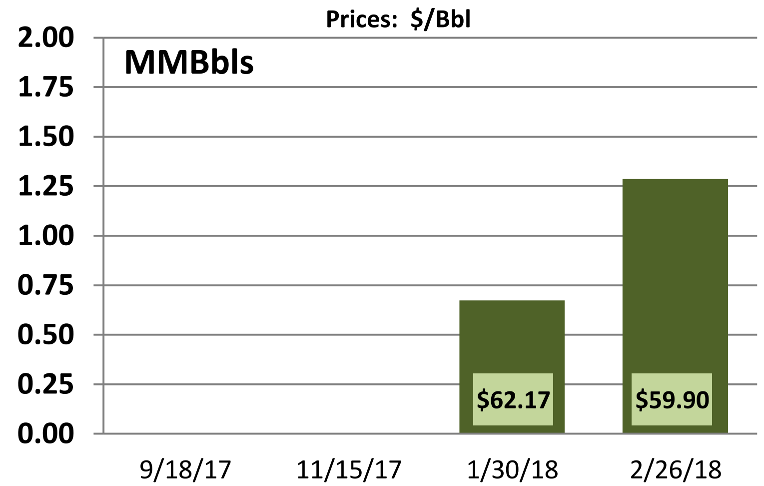
- ***Flowing back Warbonnet 9-23 A-2H, the 2nd 2-mile lateral in the Lower Lance A:*** 54.5 MMcfe/d (873 Bopd, 10% oil)
- ***Drilled and completed the first Mesaverde HZ in Pinedale:*** 1-mile lateral with IP = 17 MMcfe/d (335 Bopd, 12% oil) and validated interval as a horizontal target
- ***Vertical IP's increasing:*** 1Q18 Avg. = 7.5 MMcfe/d
- ***Reducing operated rig fleet from 7 to 4:*** remaining rigs are equipped for HZ development
- ***Increased hedges for 2018 forecasted volumes:*** from 10% in 3Q17 to 65% currently; includes hedges for gas, oil and basis
- ***Marketing Utah assets:*** bids due in March
- ***Successful transition of leadership:*** continuity of operations maintained while strategy shifts to more disciplined approach with focus on capital efficiency

Increased Hedges for 2018 Volumes

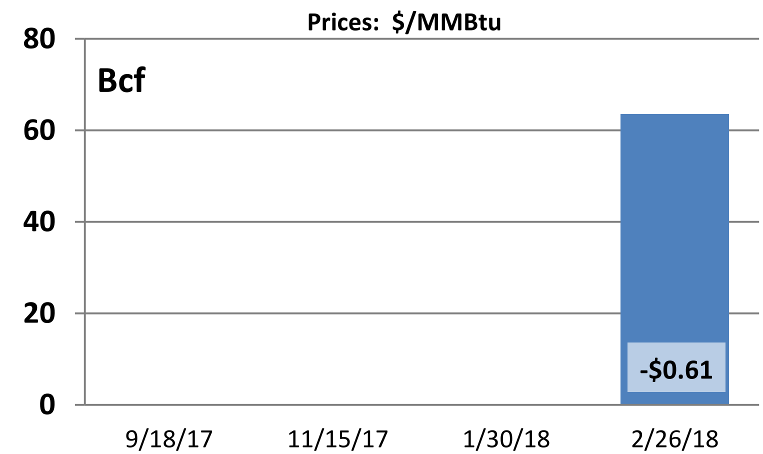
Gas Volumes Hedged for 2018 As Of:



Oil Volumes Hedged for 2018 As Of:



Basis Hedged for 2018 As Of:



Locking-in Price with Basis Hedges

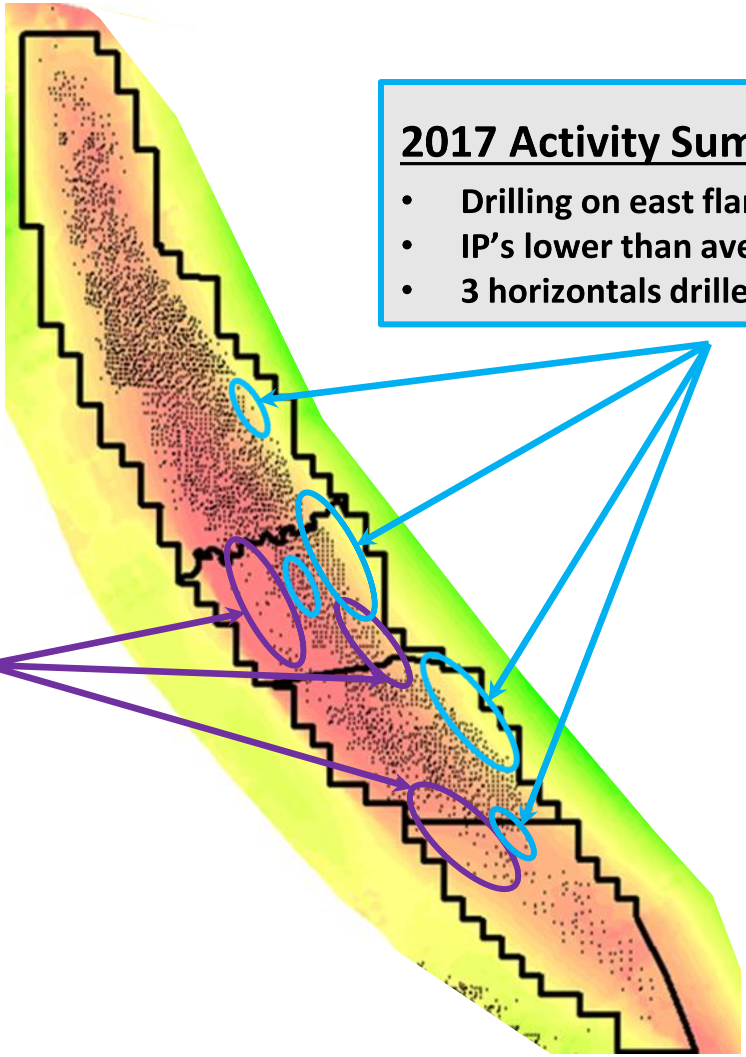
Henry Hub Swap ($/MMBtu)	$2.89
Basis Differential Hedge	-$0.61
Price per MMBtu	$2.28
BTU Factor	1.07
Price per Mcf	$2.44
WTI Swap (no differential)	$59.90
Price per Mcfe[(1)]	**$2.82**

[(1)]Price per Mcfe based on 95% natural gas / 5% condensate mix

2018 Development Program

2018 Program:

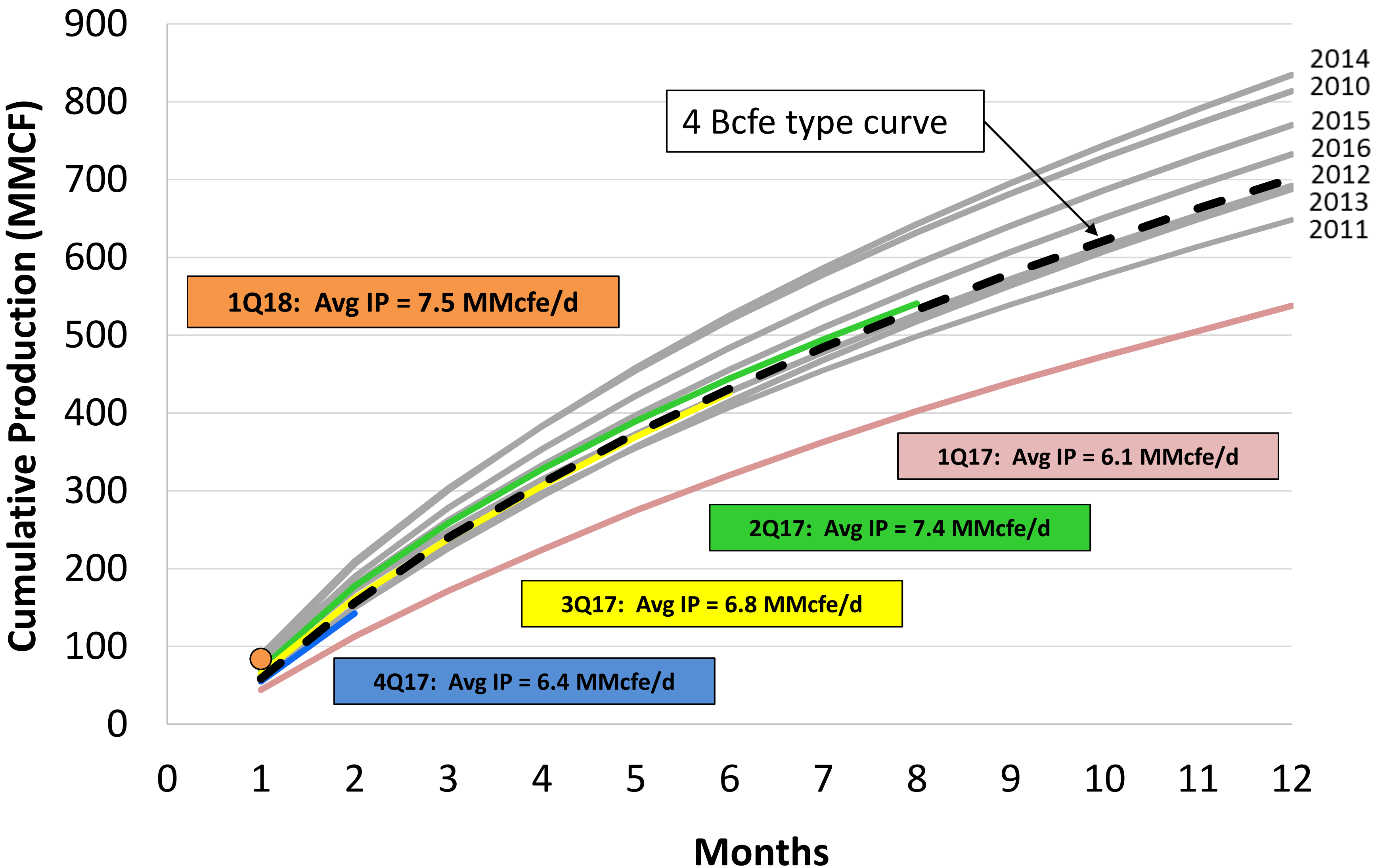
- Disciplined Capital Approach
  - — Grow within cash flow
  - — Reducing operated rigs from 7 to 4
- Vertical development
  - — Focused in core
  - — 1Q18 Avg IP = 7.5 MMcfe/d
- Horizontal development
  - — 1/3rd of DC&E capex for horizontals
  - — 15-20 horizontal wells in 2018
  - — Planning for 36 HZ wells in 2019



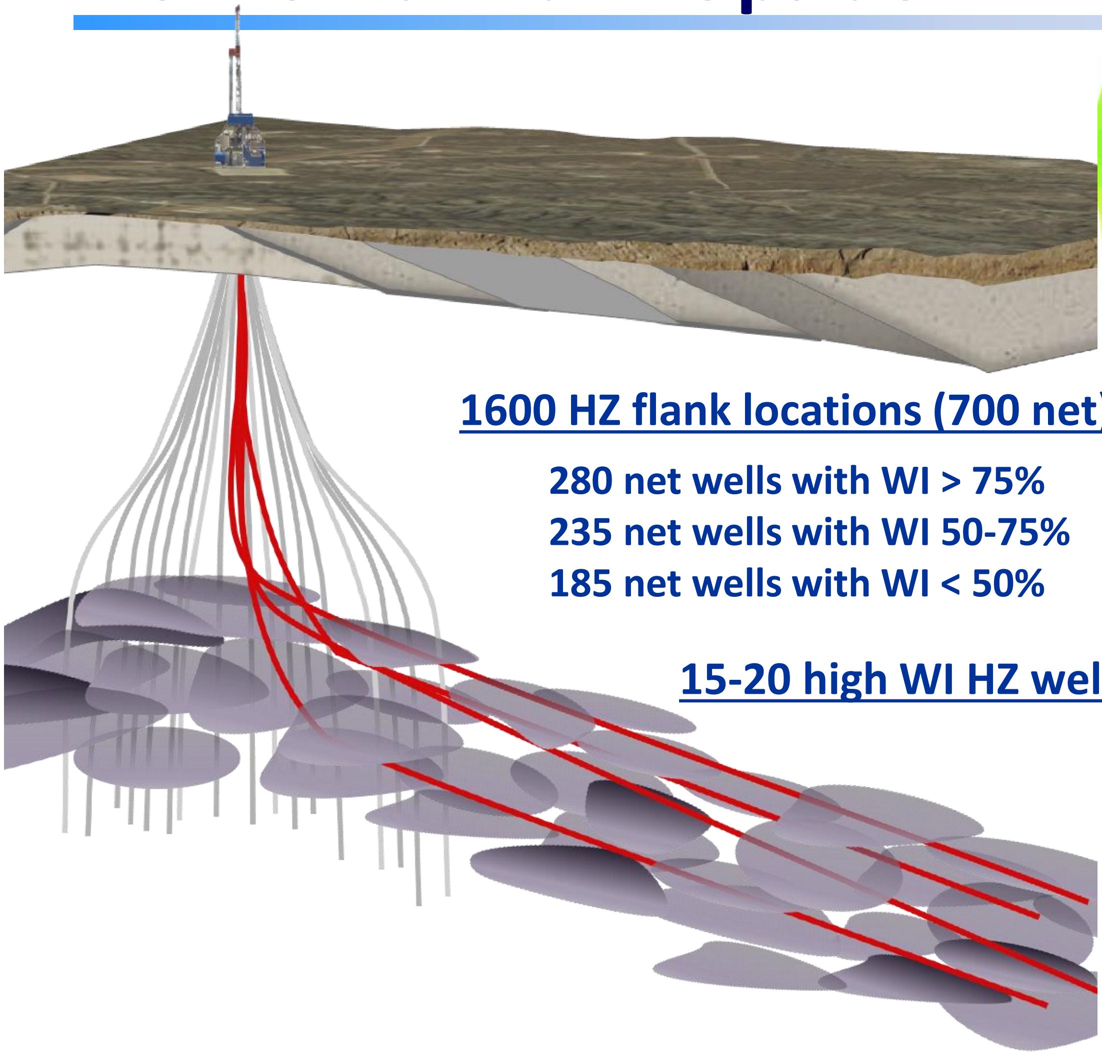
2017 Activity Summary:

- Drilling on east flank
- IP's lower than average
- 3 horizontals drilled

Vertical Well Performance



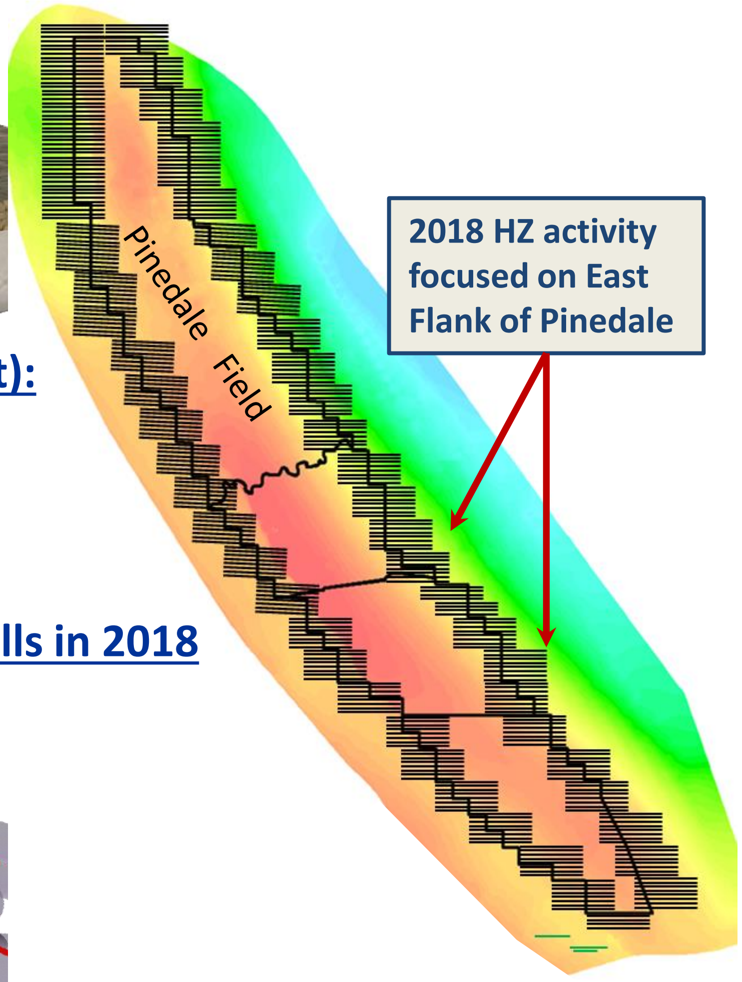
Horizontal Flank Upside



<u>1600 HZ flank locations (700 net):</u>

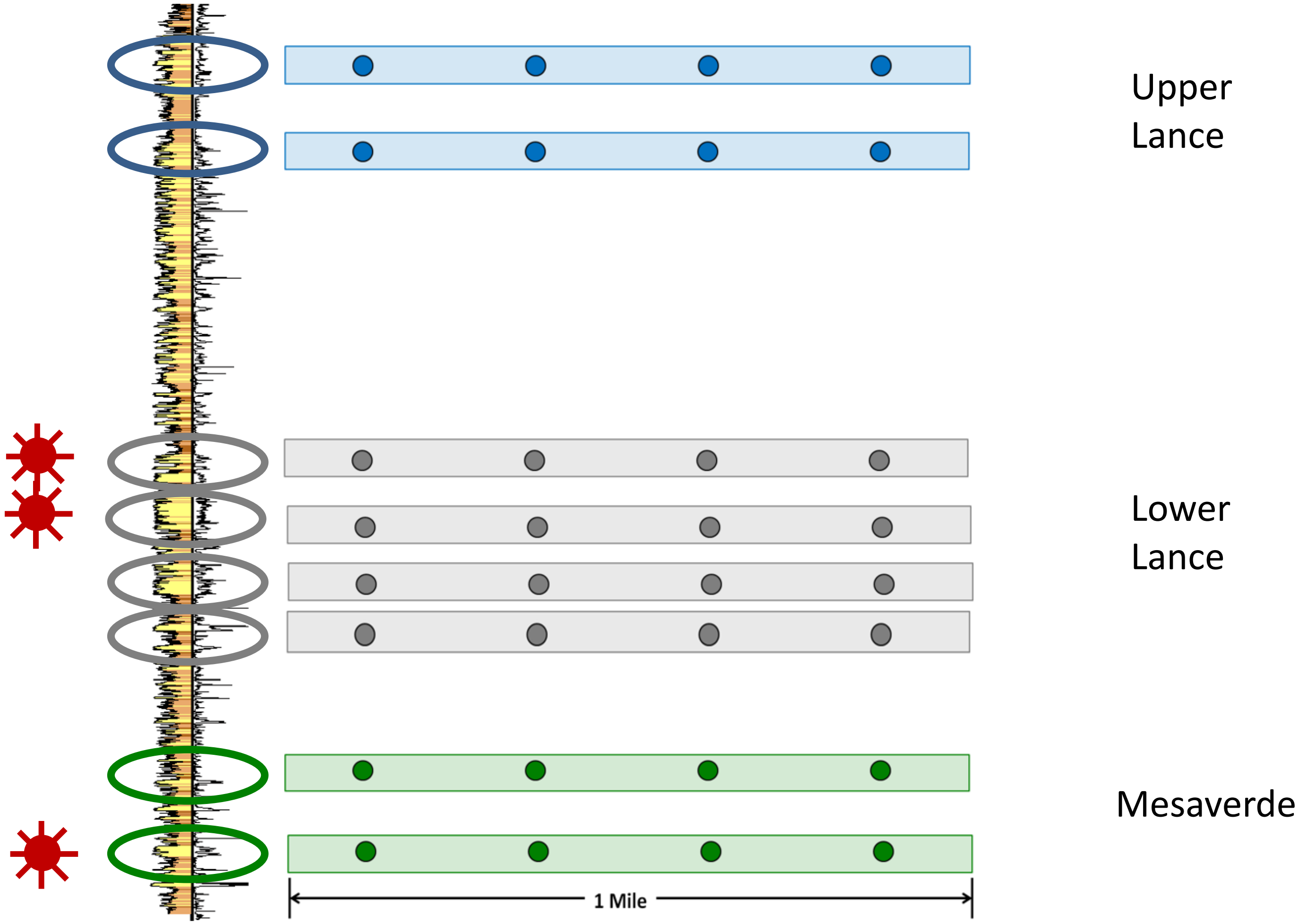
280 net wells with WI > 75%
235 net wells with WI 50-75%
185 net wells with WI < 50%

<u>15-20 high WI HZ wells in 2018</u>



Significant Stacked Pay Horizontal Potential

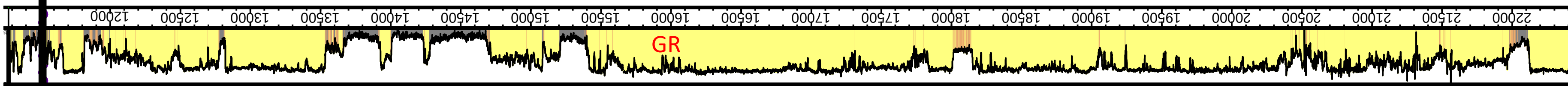
50 pads x 8 targets/pad x 4 locations/target = 1,600 potential locations (700 net)



Warbonnet 9-23 A-1H and Warbonnet 9-23 A-2H

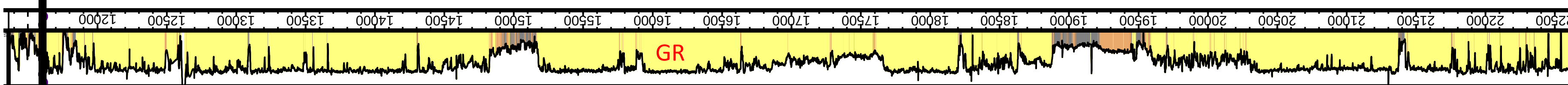
Start of Lateral

WB 9-23 A-1H
Lateral Length: 10,300’, 49 frac stages, 11.6MM lbs proppant



WB 9-23 A-2H
Lateral Length: 11,000’, 49 frac stages, 12.4MM lbs proppant

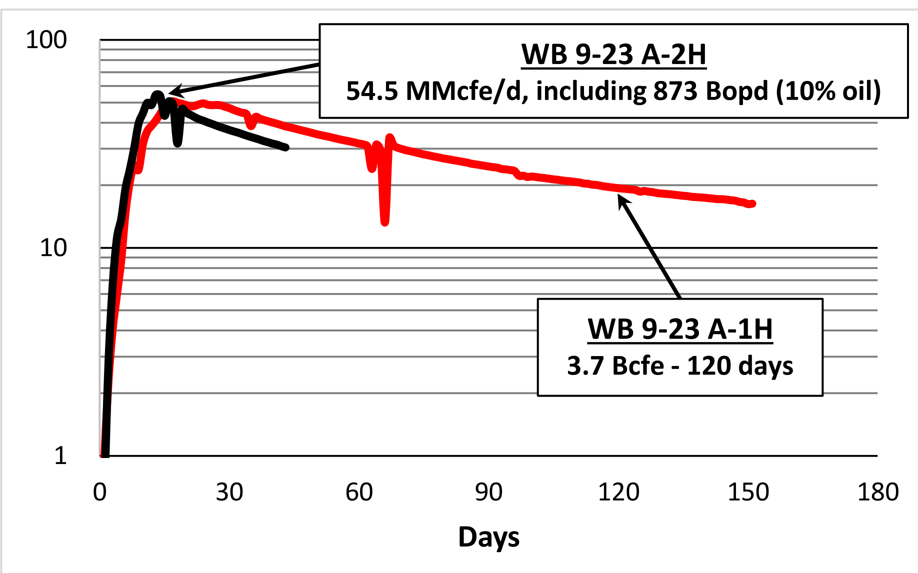
TD 22,483’



Lower Lance A Sands

TD 22,690’

Production Rate, MMcfe/d



Improved Performance: A-1H vs. A-2H

	WB 9-23 A-1H	WB 9-23 A-2H
Lateral length	10,300’	11,000’
Spud to rig release	32.5 days	25.1 days
Rig release to sales	20.9 days	14.4 days
DC&E costs	$10 MM	$9 MM
IP (30-day)	36 MMcfe/d	37 MMcfe/d

Horizontal Program Potential

Horizontal Well Assumptions

- EUR = 20 Bcfe (2.0 Bcfe / 1000')
- IP (24-hr) = 30.4 MMcfd / 32.2 MMcfed
- IP (30-day) = 25 MMcfd/ 26.7 MMcfed
- Oil Yield = 11 Bbls/MMcf
- DC&E Costs = $9 MM (Warbonnet 9-23 A-2H)
- LOE = $3,000/well/month

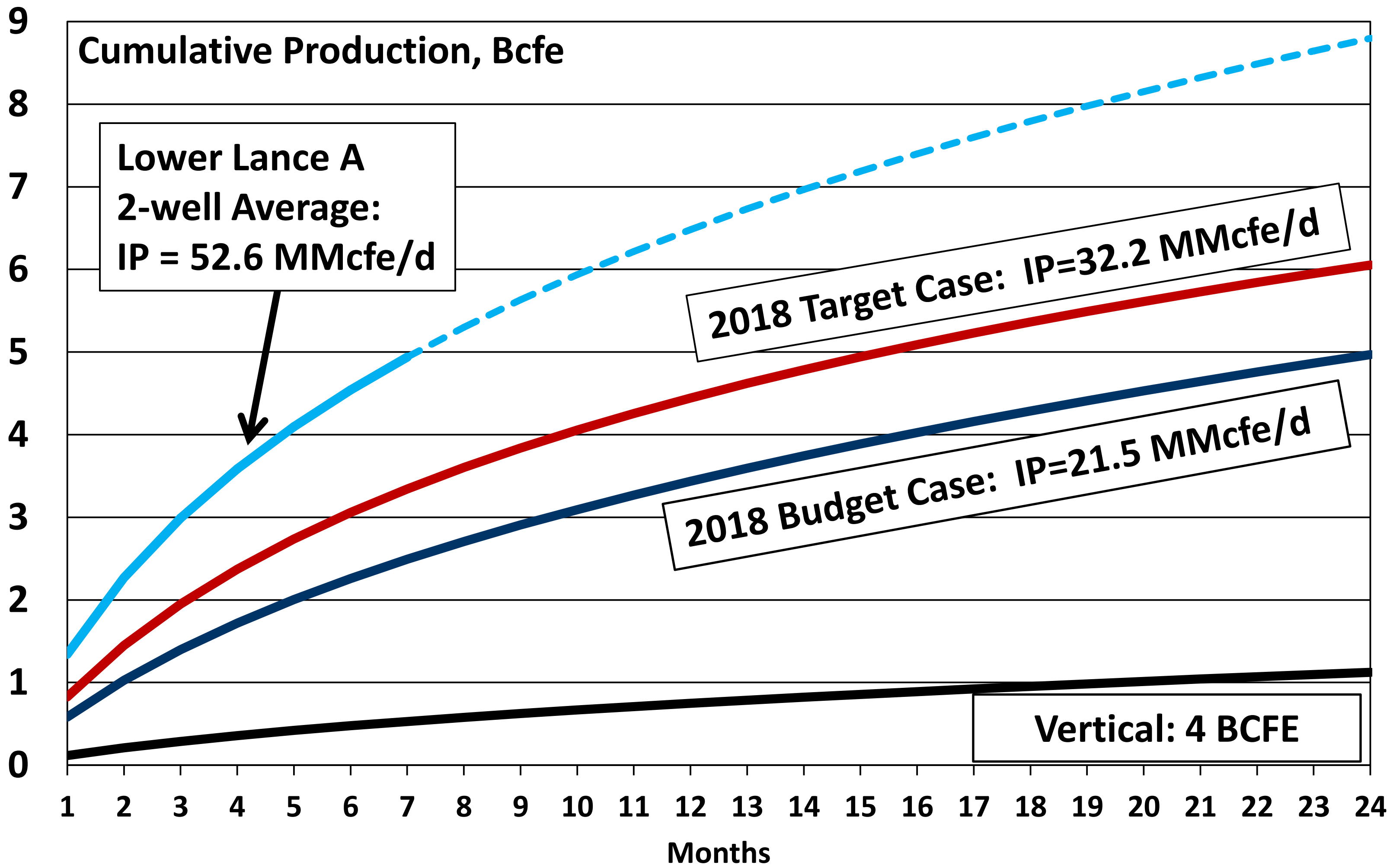
Resulting Economics[1]

- IRR > 100%
- NPV10 = $14.3MM
- Discounted Payout = 12 months
- Breakeven Price = $1.03/Mcf
- F&D = $0.56 per Mcfe
- Recycle Ratio = 4.4x

Potential Resource Metrics	
EUR / 1000' lateral	1.2 – 3.0 Bcfe/1000'
EUR/well (2-mile lateral)	12 – 30 Bcfe
Oil Yield, Bbls/MMcf (% oil volume) (% oil revenue)	10 – 30 Bbls/MMcf (6-15%) (17-37%)
Gross Location Count	1,600
Gross Resource[2], Tcfe	19 – 48 Tcfe
Net W.I. Location Count	700
Net Resource, Tcfe	7 – 17 Tcfe

[1]Economics based on HHUB=$3.00/MMBtu & WTI=$60.00 /Bbl
[2]Additional resource incremental to the 39 Tcfe identified in the core of Pinedale

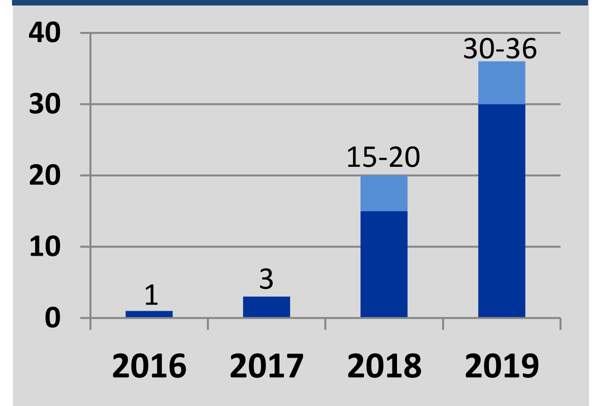
2018 Plan: Horizontal Production Profile



Transition to Horizontal Program

- 2016-2018 timeline of horizontal activity
- Currently planning for 3 HZ rigs in 2019

Ramp Up in HZ wells per year



2016

1st HZ Well Drilled:
- 1-mile lateral on east flank
- Lower Lance B
- IP(24-hr): 3 MMcfe/d
- Total DC&E Cost = $6 MM

Oct – Nov 17

2nd HZ Well Drilled:
- 2-mile lateral on east flank
- Lower Lance A
- IP(24-hr): 51 MMcfe/d
- Produced 3.7 Bcfe in 120 days
- Total DC&E Cost = $10 MM

Dec 17 – Jan 18

3rd HZ Well Drilled:
- 1-mile lateral on east flank
- Deeper Mesaverde
- IP(24-hr): 17 MMcfe/d
- Total DC&E Cost = $13 MM

Jan – Feb 18

4th HZ Well Drilled:
- 2-mile lateral on east flank
- Lower Lance A
- IP(24-hr): 54.5 MMcfe/d
- Total DC&E Cost = $9 MM

Jan – Jun 18

Jan – Jun 18 Activity:
- 6-8 wells to spud in 1H18
- Focus on Lower Lance in Warbonnet Area

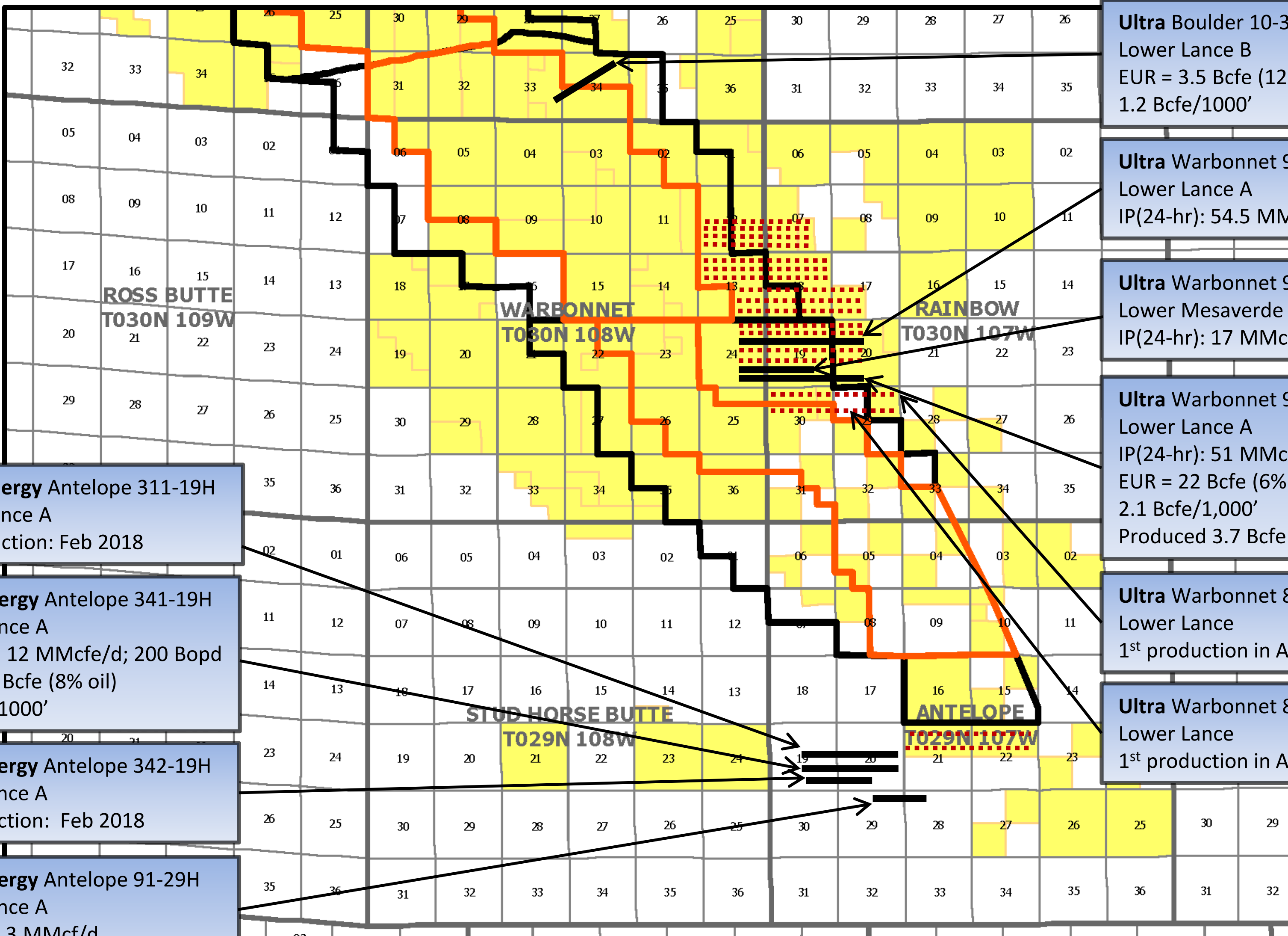
Jul – Dec 18

Jul - Dec 18 Activity:
- 9-12 wells to spud in 2H18
- Expanding activity north and south along east flank

Drilled 4 horizontal wells on East Flank

Accelerate to Full Field Development

Horizontal Activity Summary



Ultra Boulder 10-33 B-1H
Lower Lance B
EUR = 3.5 Bcfe (12% oil)
1.2 Bcfe/1000’

Ultra Warbonnet 9-23 A-2H
Lower Lance A
IP(24-hr): 54.5 MMcfe/d; 873 Bopd

Ultra Warbonnet 9-23 M-1H
Lower Mesaverde
IP(24-hr): 17 MMcfe/d; 335 Bopd

Ultra Warbonnet 9-23 A-1H
Lower Lance A
IP(24-hr): 51 MMcfe/d; 705 Bopd
EUR = 22 Bcfe (6% oil)
2.1 Bcfe/1,000’
Produced 3.7 Bcfe in 120 days

Ultra Warbonnet 8-25 A-2H
Lower Lance
1st production in April 2018

Ultra Warbonnet 8-25 A-1H
Lower Lance
1st production in April 2018

Jonah Energy Antelope 311-19H
Lower Lance A
1st production: Feb 2018

Jonah Energy Antelope 341-19H
Lower Lance A
IP(24-hr): 12 MMcfe/d; 200 Bopd
EUR = 12 Bcfe (8% oil)
2.2 Bcfe/1000’

Jonah Energy Antelope 342-19H
Lower Lance A
1st production: Feb 2018

Jonah Energy Antelope 91-29H
Lower Lance A
IP(24-hr): 3 MMcf/d
EUR = 11 Bcfe (15% oil)
2.8 Bcfe/1,000’

15-20 Planned HZ Wells in 2018

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Appendix

Natural Gas Export Capacity

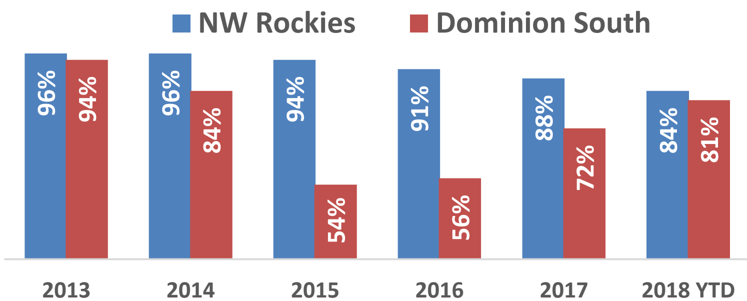
Export Capacity for Pinedale Production

- Large take-away capacity to multiple destinations
- 2 to 3 Bcf/d of excess capacity

Pipeline Capacity Serving the Opal Complex (MMcf/d)

Pipeline	Capacity
Northwest	85
Ruby	1,550
Kern	2,350
Overthrust/REX	1,437
CIG	90
Questar	298
Total Export Capacity	**6,575**

NW Rockies Basis vs. Marcellus as a % of Henry Hub [1]



[1]Source: NYMEX, Bloomberg and Intercontinental Exchange

2018 Full-Year Cash Costs & EBITDA Guidance

Expenses & Cash Costs, $/Mcfe	1Q18[1]	FY18
Lease Operating Expense	0.32 – 0.35	0.28 – 0.32
Facility Lease Expense	0.08 – 0.08	0.07 – 0.09
Production Taxes[2][3]	0.32 – 0.34	0.28 – 0.30
Gathering Fees-gross *Gathering Fees-net[4]*	0.34 – 0.36 *0.26 – 0.28*	0.33 – 0.35 *0.26 – 0.28*
Transportation	0.00 – 0.00	0.00 – 0.00
G&A[5]	0.03 – 0.06	0.00 – 0.02
DD&A	0.67 – 0.70	0.67 – 0.70
Interest	0.50 – 0.51	0.50 – 0.51
Total Expenses Midpoint	$2.33	$2.21

(with Gross Gathering Fees)

Cash Costs Midpoint	$1.06	$0.95

(with Net Gathering Fees)

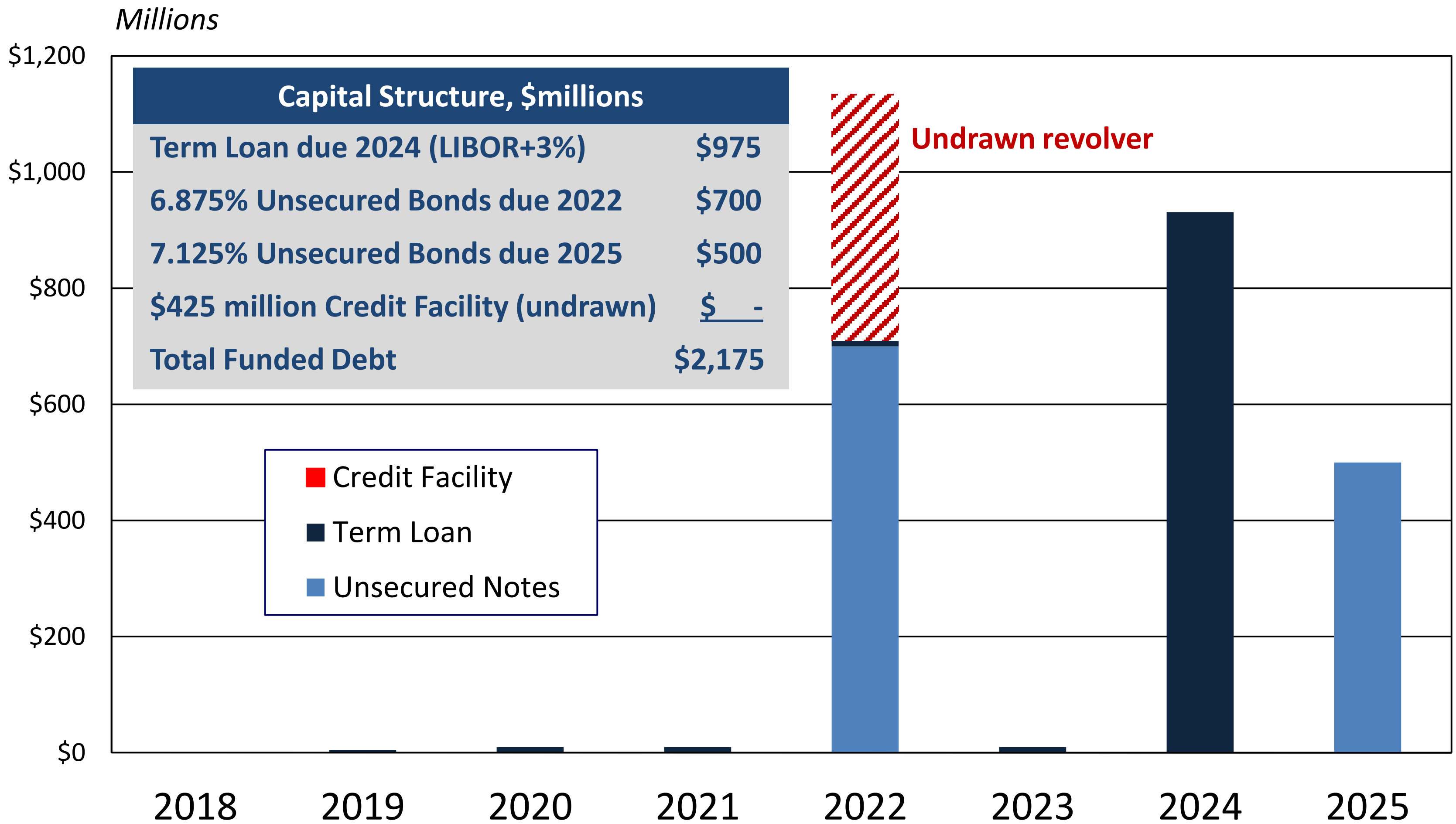
EBITDA Guidance	FY18
Revenue, incl. hedges[6], $/Mcfe	$2.84
Cash Costs, $/Mcfe	($0.95)
EBITDA, $/Mcfe	$1.89
Production Guidance-mid, Bcfe	285
EBITDA, $million (285*$1.89)	$539 million

Notes:

(1) 1Q18 includes Utah assets
(2) 1Q18 Production Taxes @ $3.00 / $60.00
(3) 2Q-4Q18 Prod Taxes @ Feb 20, 2018 strip
(4) Net Gathering Fees include proceeds from liquids processing
(5) Cash G&A for FY18 decreases, 1Q18 is higher due to non-recurring 1Q18 expenses
(6) Full Year Revenue @ Feb 20, 2018 strip with hedges representing 66% of 2018 gas production, 22% of natural gas basis, and 56% of 2018 oil production.

Flexible Balance Sheet

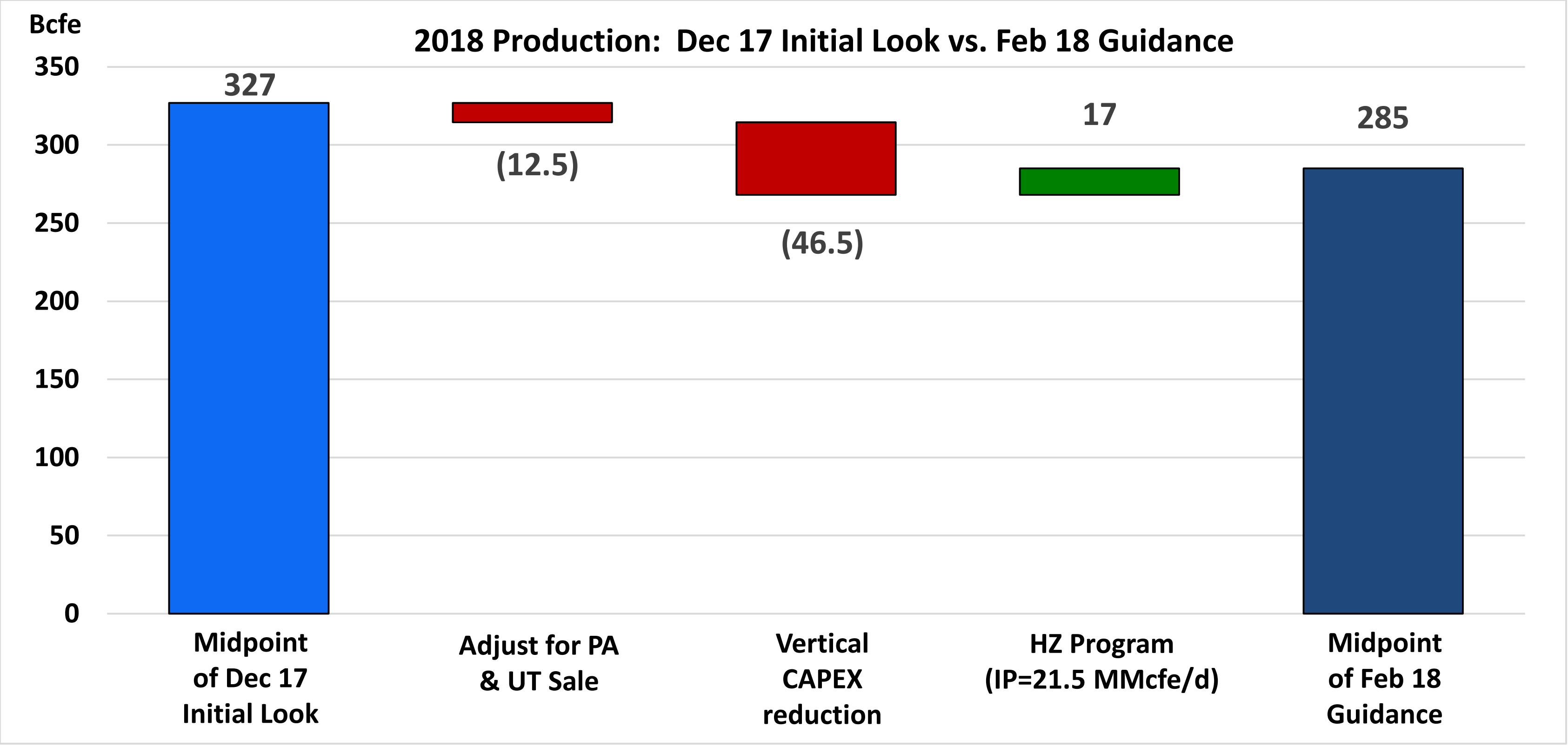
Capital Structure, $millions	
Term Loan due 2024 (LIBOR+3%)	$975
6.875% Unsecured Bonds due 2022	$700
7.125% Unsecured Bonds due 2025	$500
$425 million Credit Facility (undrawn)	$ -
Total Funded Debt	$2,175



*Minimum amounts of term loan due in 2019-2023:
$7.3 million in 2019 and $9.75 million per year in 2020-2023.

2018 Initial Look vs. 2018 Guidance

- Reduced capital budget: balancing production growth with free cash flow generation
- Divesting of PA & UT reduces 2018 volumes: -12.5 BCFE
- Vertical capex cut 50% - Horizontal program of $120 MM is back-end loaded for 2018



YE17 Reserve Reconciliation

Proved Reserves, Bcfe	Proved Developed (PDP + PD)	Proved Undeveloped (PUD)	Total Proved (1P)
Year End 2016	2,510	-	2,510
Adds/Extensions	18	39	57
Sales	(89)	-	(89)
Acquisitions	20	3	23
Production	(277)	-	(277)
Revisions	210	685	895
Year End 2017	2,392	727	3,119

2017 HZ Program adds 3 PD and 4 PUD locations

2017 PA Divestiture

2017 Acquisitions of Incremental WI

Due to SEC guidelines, Pinedale vertical wells converted to PD or booked as PUDs in 2017 included as Revisions

Revisions, Bcfe	Proved Developed (PDP + PD)	Proved Undeveloped (PUD)	Total Proved (1P)
Vertical – Probable to PD	428	-	428
Vertical – Probable to PUD	-	685	685
PD Revisions to YE16 wells	(218)	-	(218)
Total Revisions	210	685	895

In 2017, $518 MM of spent on verticals
Net PD Adds = 428 YE17 Net Rem. +
53 produced in 2017 = 481 Bcfe
F&D = $518 MM / 481 Bcfe = $1.08/Mcfe

Vertical PUD pool rebooked = 685 Bcfe
2 rigs for 3 years
F&D = $607 MM / 685 Bcfe = $0.89/Mcfe

PD Revisions of -218 BCFE includes revisions for price, LOE, performance and NGL processing contract change.

Single Well Economics: Vertical and Horizontal

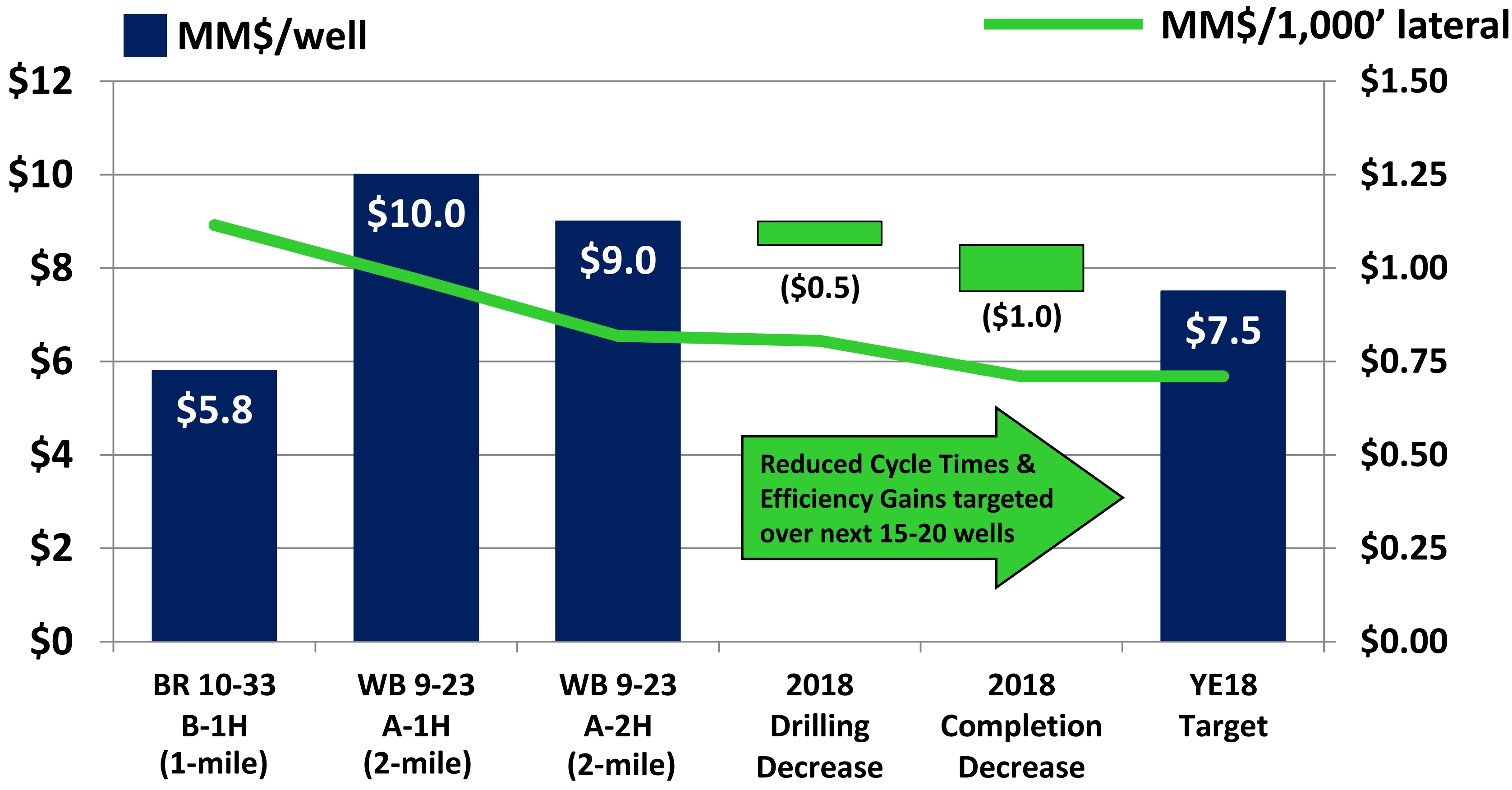
Economic Inputs:
Oil yield = 11 Bbls/MMcf
WTI price = $60/Bbl
LOE = $3,000/well/month
Gas Diff. = HHUB * 0.9
Gath. Fee = $0.28/Mcf
Gath. Fee = $2.50/Bbl
Sev./Adv. Tax = 12%

		Pinedale Vertical			Pinedale Horizontal			
	IP, 30-day MMcfd	**2.9**	**3.8**		**15.0**	**18.9**	**25.0**	**37.3**
	EUR, Bcfe	**3**	**4**		**12**	**15**	**20**	**30**
	DC&E, MM$	**$2.9**	**$2.9**		**$9.0**	**$9.0**	**$9.0**	**$9.0**
IRR Sensitivity to HHUB Price	**$2.00**	2%	10%		12%	23%	47%	139%
	$2.50	8%	19%		21%	38%	80%	>200%
	$3.00	14%	28%		32%	59%	126%	>200%
	$3.50	21%	40%		47%	86%	189%	>200%
	$4.00	29%	54%		65%	121%	>200%	>200%

Well Costs Update – Lower Lance Horizontals

Latest 2-mile lateral in Lower Lance = $9.0 MM

2018 Budget Case = $9 MM/well *YE18 Target Case: $7.5 MM/well*



UPL Horizontal Well Data

Well Name	Status	Interval	Lateral Length	EUR, Bcfe (% oil) [Bcfe/1000’]	Notes
Boulder 10-33 B-1H	1st production Aug 2016	Lower Lance B	5,200‘	3.5 Bcfe (12% oil) *1.2 Bcfe/1000’	100% drilled in zone; possible completion issue in toe Set test Plug: 70% of production from 40% of lateral *(3.5 Bcfe*70%) / (5,200’*40%) = *1.2 Bcfe/1000’ Condensate Yield = 22 Bbls/MMcf Total DC&E Costs = $5.8 MM
Warbonnet 9-23 A-1H	1st production Nov 1, 2017	Lower Lance A	10,300‘	22 Bcfe (6% oil) 2.1 Bcfe/1000’	IP (24-hr) = 51 MMcfe/d IP 30 = 36 MMcfe/d Produced 3.7 Bcfe in 1st 120 days Condensate Yield = 11 Bbls/MMcf 49 frac stages; 11.6 MM # proppant Total DC&E costs = $10MM
Warbonnet 9-23 M-1H	1st production Jan 16, 2018	Lower Mesaverde	5,500‘	TBD (12% oil)	IP (24-hr) = 17 MMcfe/d IP 30 = 8 MMcfe/d Condensate Yield = 22 Bbls/MMcf 20 frac stages; 3.9 MM # proppant Total DC&E costs = $13 MM Stacked lateral is 2,500’ below WB 9-23-A-1H
Warbonnet 9-23 A-2H	1st production Feb 16, 2018	Lower Lance A	11,000‘	TBD (10% oil)	IP (24-hr) = 54.5 MMcfe/d (873 Bopd) IP 30 = 37 MMcfe/d Condensate Yield = 18 Bbls/MMcf 49 frac stages; 12.4 MM # proppant Total DC&E costs = $9MM 2nd well in section testing same zone
Warbonnet 8-25 A-1H	1st Production in April 2018	Lower Lance A	10,000’	TBD	2-mile lateral to test Lower Lance A
Warbonnet 8-25 A-2H	1st Production in April 2018	Lower Lance A	10,000’	TBD	2-mile lateral to test Lower Lance A

Horizontal Well Data (Other Operators)

Well Name	Operator	Status	Interval	Lateral Length	EUR, Bcfe (% oil) [Bcfe/1000']	Notes
Antelope 91-29H	Jonah Energy	1st production Jan 2014	Lower Lance A	3,800'	10.8 Bcfe (15% oil) 2.8 Bcfe/1000'	Low IP: 3 MMcf/d Low decline rate Long cleanup of 11-months before max rate Condensate Yield = 30 Bbls/MMcf (Cum Yield = 35.3)
Antelope 85-29H	Jonah Energy	1st production June 2015	Lower Lance B	7,230'	2.4 Bcfe (15% oil) 0.3 BCFE/1000'	Lateral drilled mostly out of target zone Low IP: 2.5 MMcf/d Condensate Yield = 30 Bbls/MMcf (Cum Yield = 33.7)
Antelope 341-19H	Jonah Energy	1st production Feb 2017	Lower Lance A	5,460'	12.1 Bcfe (8% oil) 2.2 BCFE/1000'	IP (24-hr) = 11 MMcf/d & 200 Bop/d Produced 1.7 Bcfe in 200 days 3rd test of Jonah Field East Flank Condensate Yield = 15 Bbls/MMcf (Cum Yield = 16.6)
Antelope 342-19H	Jonah Energy	1st production Feb 2018	Lower Lance A	4,400'		1,150' South of Antelope 341-19H
Antelope 311-19H	Jonah Energy	1st production Feb 2018	Lower Lance A	7,500'		1,300' North of Antelope 341-19H

Pinedale Vertical Well Economics

Parameter	Value
EUR, Bcfe	4.0
IP30, MMcf/d	3.8
Average Condensate Yield, Bbls/MMcf	11
Decline Curve Parameters	B-factor = 1.6 Initial Decline = 98%
BTU Uplift	1.065
Pricing Differentials	HHUB * 0.90 WTI * 1.00
Gathering Expense	Gas: $0.28/Mcf Oil: $2.50/Bbl
Total Lease Operating Expense[1]	$3,000/well/month
Production Taxes	Severance =6.04% Ad Valorem = 6.00%
NRI/WI	0.80
Drill, Complete & Equip Capital	$2.9 MM (10-acre) $2.6 MM (5-acre)

[1]Total Lease Operating Expense includes all operating expenses for future wells incurred at the asset level. It does not include corporate-level costs such as G&A, facility leases or interest.

IRR Sensitivity: DC&E Costs & EUR

DC&E Capital / Well

EUR [Bcfe]	$2.6MM	$2.9MM
3.0	19%	14%
3.5	27%	21%
4.0	37%	28%
4.5	47%	37%

Based on $3.00 HHUB & 11 Bbl/MMcf condensate

IRR Sensitivity: Gas Price & Yield

HHUB Gas Price

Condensate Yield [Bbls/MMcf]	$2.50	$3.00	$3.50
7.0	15%	24%	34%
11.0	19%	28%	40%
15.0	23%	34%	46%
19.0	28%	40%	53%

Based on $2.9 MM well costs and EUR=4 Bcfe

Economics run at $60.00/Bbl WTI for gas price sensitivities

Well Costs Update - Vertical

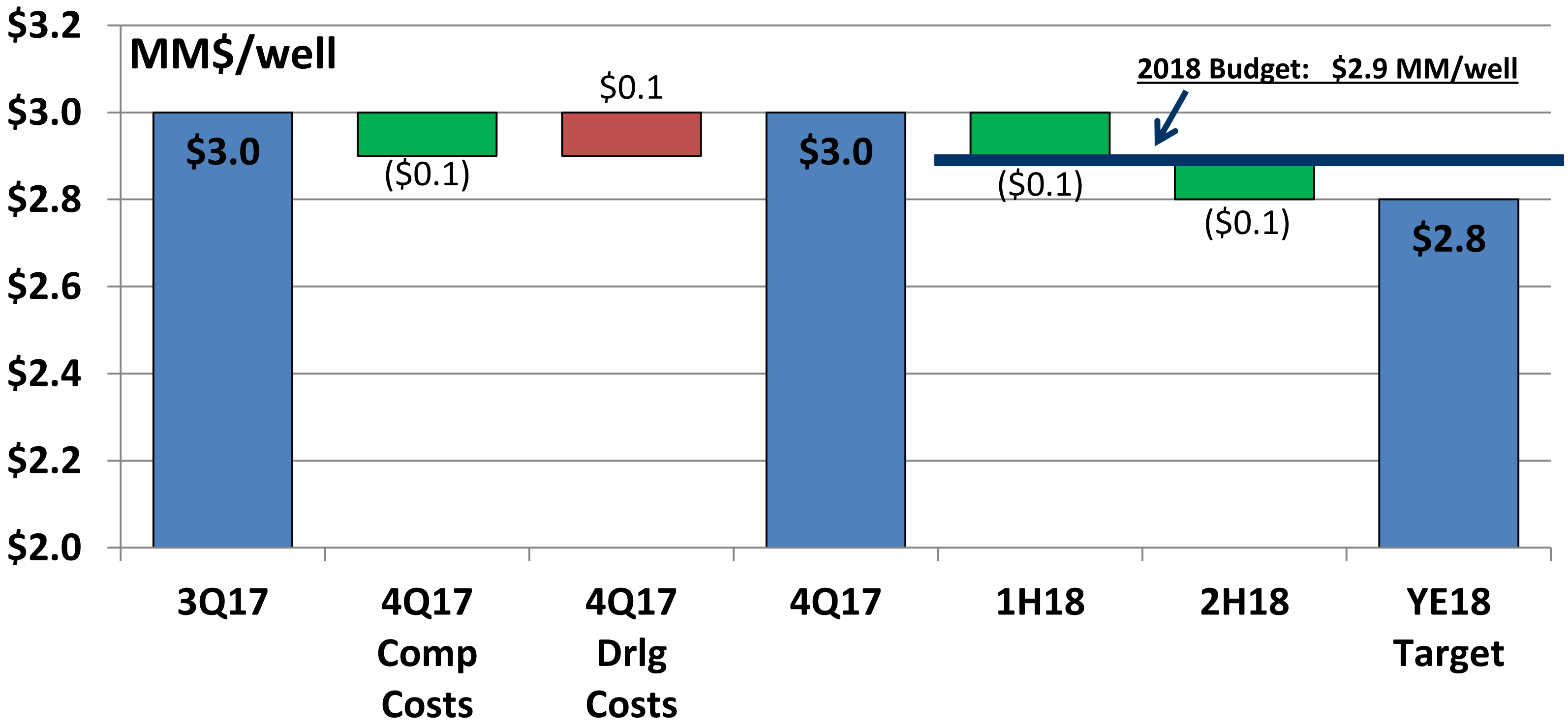
4Q17: Stated goal to reduce by $0.2 MM/well with completion cost reduction - achieved half of that goal by YE17

4Q17: Isolated drilling events: 2 sidetracks and hole instability on limited wells - 4Q17 avg. up by $0.1 MM/well

2018: On track to decrease completions costs by another $0.1MM in 1H18; Additional $0.1 MM possible in 2H18

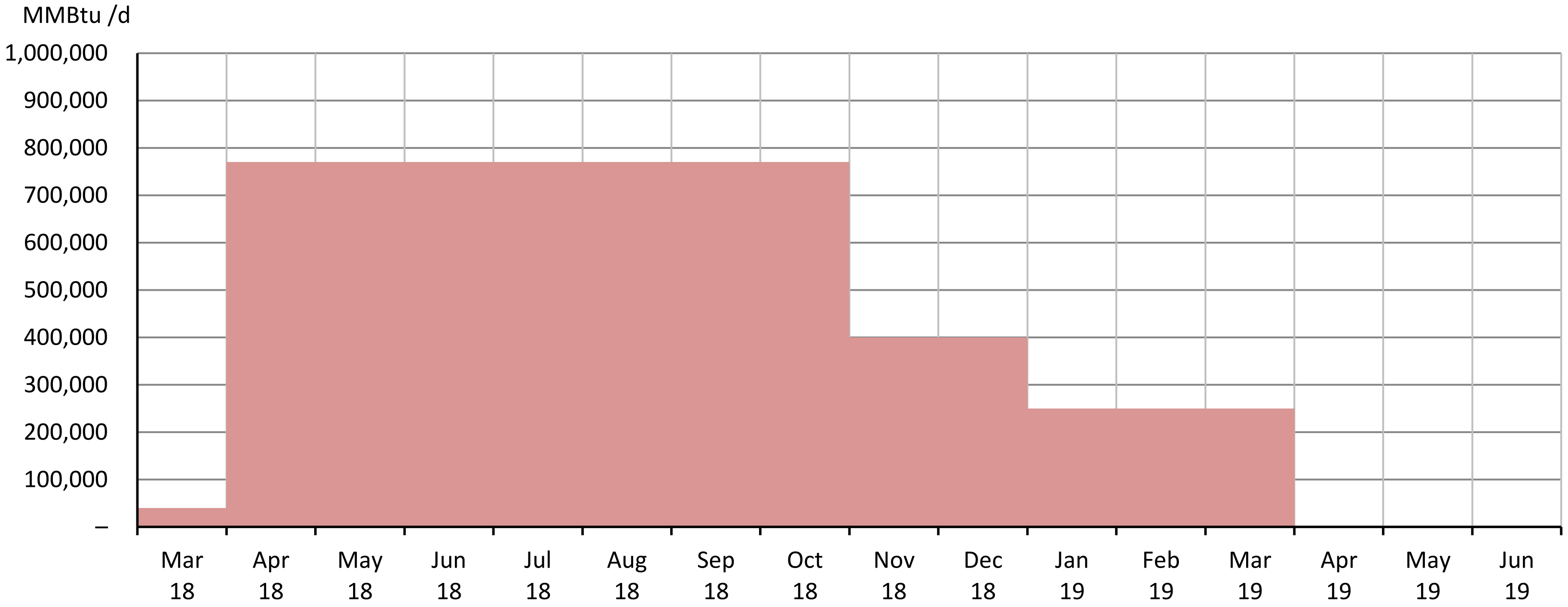
2018: Reversal of 4Q17 drilling cost events offset by projected steel cost increases due to tariffs

2018 Budget Case = $2.9 MM/well ***2018 Target Case = $2.8 MM/well***



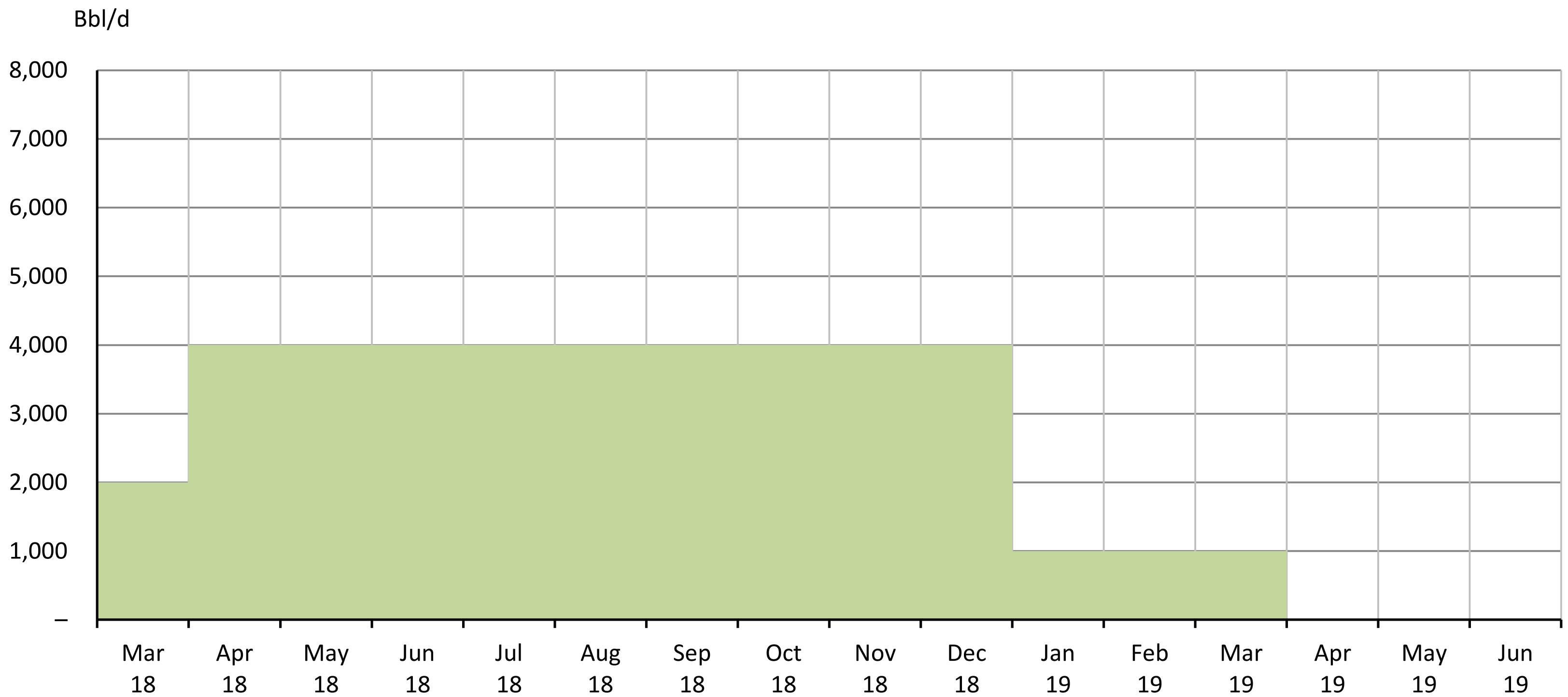
Hedge Positions: NYMEX Gas

MMbtu/d	Period	Type	$/MMBtu
40,000	Mar18	NYMEX costless collar	$3.23 / $3.54
770,000	Apr18 to Oct18	NYMEX Swaps	$2.88
200,000	Nov18 to Dec18	NYMEX Swaps	$2.85
200,000	Nov18 to Mar19	NYMEX Swaps	$2.91
50,000	Jan19 to Mar19	NYMEX Swaps	$2.98



Hedge Positions: NYMEX Oil

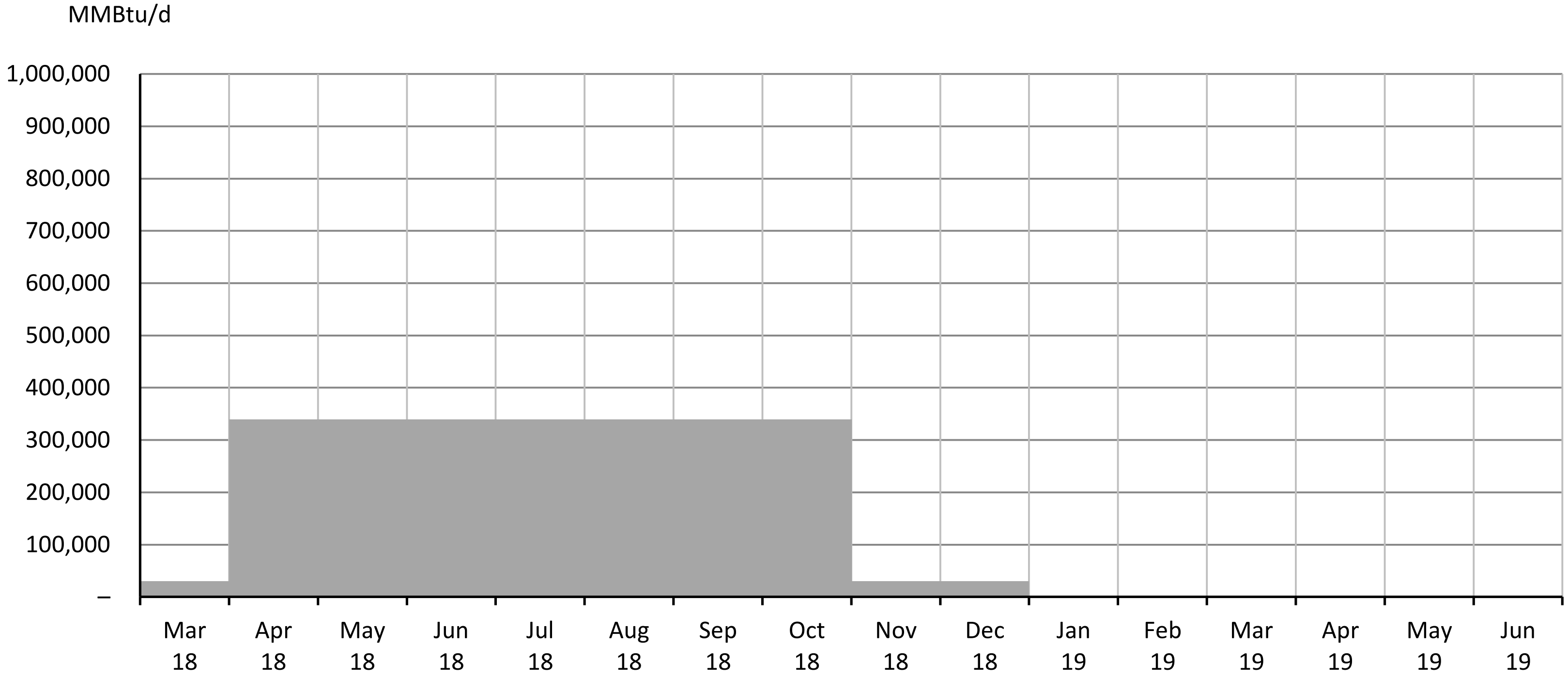
Bbls/d	Period	Type	$/Bbl
2,000	Mar18 to Dec18	NYMEX Swaps	$62.17
2,000	Apr18 to Dec18	NYMEX Swaps	$57.43
1,000	Jan19 to Mar19	NYMEX Swaps	$58.30



As of February 26, 2018

Hedge Positions: ROX Basis Differentials

MMbtu/d	Period	Type	$/MMBtu
30,000	Mar18 to Dec18	ROX basis swaps (financial)	($0.580)
140,000	Apr18 to Oct18	ROX basis swaps (financial)	($0.624)
170,000	Apr18 to Oct18	ROX basis swaps (physical)	($0.614)



As of February 26, 2018