Options:

1. Participate
   a. JOA covering all section
   b. Wolfcamp AFE Approval
2. Sell Interest
   a. $5000.00/acre for whole section
   b. all rights all depths
3. Force Pooling
4. Spiral/MTDR J.V.
   a. Buys interest @ $5000.00
   b. Sets precedent for other like situations

NMOCC Case No. 15363
Hearing: SEP 6, 2016
Jalapeno EX 3

MATADOR PRODUCTION COMPANY

ONE LINCOLN CENTRE • 5400 LBJ FREEWAY • SUITE 1500 • DALLAS, TEXAS 75240

Phone (972) 371-5200 • Fax (972) 371-5201

ESTIMATE OF COSTS AND AUTHORIZATION FOR EXPENDITURE

DATE:	May 9, 2016	AFE NO.:	300017-014-01
WELL NAME:	Airstrip State Com 31-18S-35E RN 201H	FIELD:	Wolfcamp
LOCATION:		MD/TVD:	15700'/10780'
COUNTY/STATE:	Lea	LATERAL LENGTH:	4,300
MRC WI:			
GEOLOGIC TARGET:	Wolfcamp A		
REMARKS:	Drill and complete a horizontal Wolfcamp A well with 21 stages. Install AL, build TB, and construct PL to gas connect.		

INTANGIBLE COSTS	DRILLING COSTS	COMPLETION COSTS	PRODUCTION COSTS	FACILITY COSTS	TOTAL COSTS
Land / Legal / Regulatory	$ 95,000	$	$ -	$ -	$ 95,000
Location, Surveys & Damages	111,500	17,500	5,000	-	134,000
Drilling	707,000				707,000
Cementing & Float Equip	205,000				205,000
Logging / Formation Evaluation	-	3,850	-		3,850
Mud Logging	32,500				32,500
Mud Circulation System	34,720				34,720
Mud & Chemicals	120,000	24,000			144,000
Mud / Wastewater Disposal	155,000	-			155,000
Freight / Transportation	18,000	16,500		-	34,500
Rig Supervision / Engineering	95,200	52,300	2,400	30,000	179,900
Drill Bits	97,000				97,000
Fuel & Power	70,000	-		-	70,000
Water	42,500	530,000			572,500
Drlg & Completion Overhead	14,000	7,500			21,500
Plugging & Abandonment	-				-
Directional Drilling, Surveys	185,000				185,000
Completion Unit, Swab, CTU	-	60,000	12,000		72,000
Perforating, Wireline, Slickline	-	66,000	-		66,000
High Pressure Pump Truck	-	33,000	10,500	-	43,500
Stimulation	-	945,000			945,000
Stimulation Flowback & Disp	-	45,500	6,000		51,500
Insurance	27,000				27,000
Labor	124,000	15,500	6,000	-	145,500
Rental - Surface Equipment	101,200	112,020	450	6,000	219,670
Rental - Downhole Equipment	45,000	38,000			83,000
Rental - Living Quarters	60,875	26,950	150	1,000	88,975
Contingency	234,050	199,362	2,600	3,700	439,712
TOTAL INTANGIBLES >	2,574,545	2,192,982	45,100	40,700	4,853,327
TANGIBLE COSTS	**DRILLING COSTS**	**COMPLETION COSTS**	**PRODUCTION COSTS**	**FACILITY COSTS**	**TOTAL COSTS**
Surface Casing	$ 54,725	$	$	$	$ 54,725
Intermediate Casing	122,100				122,100
Drilling Liner	293,400				293,400
Production Casing	229,875				229,875
Production Liner	-				-
Tubing	-		52,500		52,500
Wellhead	60,000		40,000		100,000
Packers, Liner Hangers	-	36,000	-		36,000
Tanks	-		-	120,000	120,000
Production Vessels	-		50,000	45,000	95,000
Flow Lines	-		40,000	-	40,000
Rod string	-		-		-
Artificial Lift Equipment	-		53,000		53,000
Compressor	-		-	-	-
Installation Costs	-		30,000	90,000	120,000
Surface Pumps	-		5,000	-	5,000
Non-controllable Surface	-		-	120,000	120,000
Non-controllable Downhole	-		-		-
Downhole Pumps	-		-		-
Measurement & Meter Installation	-		20,000	19,000	39,000
Gas Conditioning / Dehydration			-	-	-
Interconnecting Facility Piping			-	-	-
Gathering / Bulk Lines			-	40,000	40,000
Valves, Dumps, Controllers			-	-	-
Tank / Facility Containment			-	40,000	40,000
Flare Stack			-	20,000	20,000
Electrical / Grounding			7,500	10,000	17,500
Communications / SCADA			-	-	-
Instrumentation / Safety			10,000	25,000	35,000
TOTAL TANGIBLES >	760,100	36,000	308,000	529,000	1,633,100
TOTAL COSTS >	3,334,645	2,228,982	353,100	569,700	6,486,427

PREPARED BY MATADOR PRODUCTION COMPANY:

Drilling Engineer: Patrick Walsh
Completions Engineer: Mac Bell
Production Engineer: Kenneth Dodson

Team Lead - WTX/NM J.T.G.
TG

NMOCC Case No. 15363
Hearing: SEP 6, 2016

Jalapeno EX 4

MATADOR PRODUCTION COMPANY

ONE LINCOLN CENTRE • 5400 LBJ FREEWAY • SUITE 1500 • DALLAS, TEXAS 75240
Phone (972) 371-5200 • Fax (972) 371-5201

ESTIMATE OF COSTS AND AUTHORIZATION FOR EXPENDITURE

DATE:	May 9, 2016	AFE NO.:	300017-014-01
WELL NAME:	Airstrip State Com 31-18S-35E RN 201H	FIELD:	Wolfcamp
LOCATION:		MD/TVD:	15700'/10780'
COUNTY/STATE:	Lea	LATERAL LENGTH:	4,300
MRC WI:			
GEOLOGIC TARGET:	Wolfcamp A		
REMARKS:	Drill and complete a horizontal Wolfcamp A well with 21 stages. Install AL, build TB, and construct PL to gas connect.		

INTANGIBLE COSTS	DRILLING COSTS	COMPLETION COSTS	PRODUCTION COSTS	FACILITY COSTS	TOTAL COSTS
Land / Legal / Regulatory	$ 95,000	$	$ -	$ -	$ 95,000
Location, Surveys & Damages	111,500	17,500	5,000	-	134,000
Drilling	707,000				707,000
Cementing & Float Equip	205,000				205,000
Logging / Formation Evaluation	-	3,850	-		3,850
Mud Logging	32,500				32,500
Mud Circulation System	34,720				34,720
Mud & Chemicals	120,000	24,000			144,000
Mud / Wastewater Disposal	155,000	-			155,000
Freight / Transportation	18,000	16,500		-	34,500
Rig Supervision / Engineering	95,200	52,300	2,400	30,000	179,900
Drill Bits	97,000				97,000
Fuel & Power	70,000	-		-	70,000
Water	42,500	530,000			572,500
Drlg & Completion Overhead	14,000	7,500			21,500
Plugging & Abandonment	-				-
Directional Drilling, Surveys	185,000				185,000
Completion Unit, Swab, CTU	-	60,000	12,000		72,000
Perforating, Wireline, Slickline	-	66,000	-		66,000
High Pressure Pump Truck	-	33,000	10,500	-	43,500
Stimulation	-	945,000			945,000
Stimulation Flowback & Disp	-	45,500	6,000		51,500
Insurance	27,000				27,000
Labor	124,000	15,500	6,000	-	145,500
Rental - Surface Equipment	101,200	112,020	450	6,000	219,670
Rental - Downhole Equipment	45,000	38,000			83,000
Rental - Living Quarters	60,875	26,950	150	1,000	88,975
Contingency	234,050	199,362	2,600	3,700	439,712
TOTAL INTANGIBLES >	2,574,545	2,192,982	45,100	40,700	4,853,327

TANGIBLE COSTS	DRILLING COSTS	COMPLETION COSTS	PRODUCTION COSTS	FACILITY COSTS	TOTAL COSTS
Surface Casing	$ 54,725	$	$	$	$ 54,725
Intermediate Casing	122,100				122,100
Drilling Liner	293,400				293,400
Production Casing	229,875				229,875
Production Liner	-				-
Tubing	-		52,500		52,500
Wellhead	60,000		40,000		100,000
Packers, Liner Hangers	-	36,000	-		36,000
Tanks	-		-	120,000	120,000
Production Vessels	-		50,000	45,000	95,000
Flow Lines	-		40,000	-	40,000
Rod string	-		-		-
Artificial Lift Equipment	-		53,000		53,000
Compressor	-		-	-	-
Installation Costs	-		30,000	90,000	120,000
Surface Pumps	-		5,000	-	5,000
Non-controllable Surface	-		-	120,000	120,000
Non-controllable Downhole	-		-		-
Downhole Pumps	-		-		-
Measurement & Meter Installation	-		20,000	19,000	39,000
Gas Conditioning / Dehydration			-	-	-
Interconnecting Facility Piping			-	-	-
Gathering / Bulk Lines			-	40,000	40,000
Valves, Dumps, Controllers			-	-	-
Tank / Facility Containment			-	40,000	40,000
Flare Stack			-	20,000	20,000
Electrical / Grounding			7,500	10,000	17,500
Communications / SCADA			-	-	-
Instrumentation / Safety			10,000	25,000	35,000
TOTAL TANGIBLES >	760,100	36,000	308,000	529,000	1,633,100
TOTAL COSTS >	3,334,645	2,228,982	353,100	569,700	6,486,427

PREPARED BY MATADOR PRODUCTION COMPANY:

Drilling Engineer: Patrick Walsh Team Lead - WTX/NM J.T.G.
TG
Completions Engineer: Matt Bell

MATADOR PRODUCTION COMPANY

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ESTIMATE OF COSTS AND AUTHORIZATION FOR EXPENDITURE

DATE:	May 9, 2016	AFE NO.:	300017-014-01
WELL NAME:	Airstrip State Com 31-18S-35E RN 201H	FIELD:	Wolfcamp
LOCATION:		MD/TVD:	15700'/10780'
COUNTY/STATE:	Lea	LATERAL LENGTH:	4,300
MRC WI:			
GEOLOGIC TARGET:	Wolfcamp A		
REMARKS:	Drill and complete a horizontal Wolfcamp A well with 21 stages. Install AL, build TB, and construct PL to gas connect.		

INTANGIBLE COSTS	DRILLING COSTS	COMPLETION COSTS	PRODUCTION COSTS	FACILITY COSTS	TOTAL COSTS
Land / Legal / Regulatory	$ 95,000	$	$ -	$ -	$ 95,000
Location, Surveys & Damages	111,500	17,500	5,000	-	134,000
Drilling	707,000				707,000
Cementing & Float Equip	205,000				205,000
Logging / Formation Evaluation	-	3,850	-		3,850
Mud Logging	32,500				32,500
Mud Circulation System	34,720				34,720
Mud & Chemicals	120,000	24,000			144,000
Mud / Wastewater Disposal	155,000	-			155,000
Freight / Transportation	18,000	16,500		-	34,500
Rig Supervision / Engineering	95,200	52,300	2,400	30,000	179,900
Drill Bits	97,000				97,000
Fuel & Power	70,000	-		-	70,000
Water	42,500	530,000			572,500
Drlg & Completion Overhead	14,000	7,500			21,500
Plugging & Abandonment	-				-
Directional Drilling, Surveys	185,000				185,000
Completion Unit, Swab, CTU	-	60,000	12,000		72,000
Perforating, Wireline, Slickline	-	66,000	-		66,000
High Pressure Pump Truck	-	33,000	10,500	-	43,500
Stimulation	-	945,000			945,000
Stimulation Flowback & Disp	-	45,500	6,000		51,500
Insurance	27,000				27,000
Labor	124,000	15,500	6,000	-	145,500
Rental - Surface Equipment	101,200	112,020	450	6,000	219,670
Rental - Downhole Equipment	45,000	38,000			83,000
Rental - Living Quarters	60,875	26,950	150	1,000	88,975
Contingency	234,050	199,362	2,600	3,700	439,712
TOTAL INTANGIBLES >	2,574,545	2,192,982	45,100	40,700	4,853,327

TANGIBLE COSTS	DRILLING COSTS	COMPLETION COSTS	PRODUCTION COSTS	FACILITY COSTS	TOTAL COSTS
Surface Casing	$ 54,725	$	$	$	$ 54,725
Intermediate Casing	122,100				122,100
Drilling Liner	293,400				293,400
Production Casing	229,875				229,875
Production Liner	-				-
Tubing	-		52,500		52,500
Wellhead	60,000		40,000		100,000
Packers, Liner Hangers	-	36,000	-		36,000
Tanks	-		-	120,000	120,000
Production Vessels	-		50,000	45,000	95,000
Flow Lines	-		40,000	-	40,000
Rod string	-		-		-
Artificial Lift Equipment	-		53,000		53,000
Compressor	-		-	-	-
Installation Costs	-		30,000	90,000	120,000
Surface Pumps	-		5,000	-	5,000
Non-controllable Surface	-		-	120,000	120,000
Non-controllable Downhole	-				-
Downhole Pumps	-		-		-
Measurement & Meter Installation	-		20,000	19,000	39,000
Gas Conditioning / Dehydration			-	-	-
Interconnecting Facility Piping			-	-	-
Gathering / Bulk Lines			-	40,000	40,000
Valves, Dumps, Controllers			-	-	-
Tank / Facility Containment			-	40,000	40,000
Flare Stack			-	20,000	20,000
Electrical / Grounding			7,500	10,000	17,500
Communications / SCADA			-	-	-
Instrumentation / Safety			10,000	25,000	35,000
TOTAL TANGIBLES >	760,100	36,000	308,000	529,000	1,633,100
TOTAL COSTS >	3,334,645	2,228,982	353,100	569,700	6,486,427

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ESTIMATE OF COSTS AND AUTHORIZATION FOR EXPENDITURE

DATE:	May 9, 2016	AFE NO.:	300017-014-01
WELL NAME:	Airstrip State Com 31-18S-35E RN 201H	FIELD:	Wolfcamp
LOCATION:		MD/TVD:	15700'/10780'
COUNTY/STATE:	Lea	LATERAL LENGTH:	4,300
MRC WI:			
GEOLOGIC TARGET:	Wolfcamp A		
REMARKS:	Drill and complete a horizontal Wolfcamp A well with 21 stages. Install AL, build TB, and construct PL to gas connect.		

INTANGIBLE COSTS	DRILLING COSTS	COMPLETION COSTS	PRODUCTION COSTS	FACILITY COSTS	TOTAL COSTS
Land / Legal / Regulatory	$ 95,000	$	$ -	$ -	$ 95,000
Location, Surveys & Damages	111,500	17,500	5,000	-	134,000
Drilling	707,000				707,000
Cementing & Float Equip	205,000				205,000
Logging / Formation Evaluation	-	3,850	-		3,850
Mud Logging	32,500				32,500
Mud Circulation System	34,720				34,720
Mud & Chemicals	120,000	24,000			144,000
Mud / Wastewater Disposal	155,000	-			155,000
Freight / Transportation	18,000	16,500		-	34,500
Rig Supervision / Engineering	95,200	52,300	2,400	30,000	179,900
Drill Bits	97,000				97,000
Fuel & Power	70,000	-		-	70,000
Water	42,500	530,000			572,500
Drlg & Completion Overhead	14,000	7,500			21,500
Plugging & Abandonment	-				-
Directional Drilling, Surveys	185,000				185,000
Completion Unit, Swab, CTU	-	60,000	12,000		72,000
Perforating, Wireline, Slickline	-	66,000	-		66,000
High Pressure Pump Truck	-	33,000	10,500	-	43,500
Stimulation	-	945,000			945,000
Stimulation Flowback & Disp	-	45,500	6,000		51,500
Insurance	27,000				27,000
Labor	124,000	15,500	6,000	-	145,500
Rental - Surface Equipment	101,200	112,020	450	6,000	219,670
Rental - Downhole Equipment	45,000	38,000			83,000
Rental - Living Quarters	60,875	26,950	150	1,000	88,975
Contingency	234,050	199,362	2,600	3,700	439,712
TOTAL INTANGIBLES >	2,574,545	2,192,982	45,100	40,700	4,853,327

TANGIBLE COSTS	DRILLING COSTS	COMPLETION COSTS	PRODUCTION COSTS	FACILITY COSTS	TOTAL COSTS
Surface Casing	$ 54,725	$	$	$	$ 54,725
Intermediate Casing	122,100				122,100
Drilling Liner	293,400				293,400
Production Casing	229,875				229,875
Production Liner	-				-
Tubing	-		52,500		52,500
Wellhead	60,000		40,000		100,000
Packers, Liner Hangers	-	36,000	-		36,000
Tanks	-		-	120,000	120,000
Production Vessels	-		50,000	45,000	95,000
Flow Lines	-		40,000	-	40,000
Rod string	-		-		-
Artificial Lift Equipment	-		53,000		53,000
Compressor	-		-	-	-
Installation Costs	-		30,000	90,000	120,000
Surface Pumps	-		5,000	-	5,000
Non-controllable Surface	-		-	120,000	120,000
Non-controllable Downhole	-		-		-
Downhole Pumps	-		-		-
Measurement & Meter Installation	-		20,000	19,000	39,000
Gas Conditioning / Dehydration			-	-	-
Interconnecting Facility Piping			-	-	-
Gathering / Bulk Lines			-	40,000	40,000
Valves, Dumps, Controllers			-	-	-
Tank / Facility Containment			-	40,000	40,000
Flare Stack			-	20,000	20,000
Electrical / Grounding			7,500	10,000	17,500
Communications / SCADA			-	-	-
Instrumentation / Safety			10,000	25,000	35,000
TOTAL TANGIBLES >	760,100	36,000	308,000	529,000	1,633,100
TOTAL COSTS >	3,334,645	2,228,982	353,100	569,700	6,486,427

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ESTIMATE OF COSTS AND AUTHORIZATION FOR EXPENDITURE

DATE:	May 9, 2016	AFE NO.:	300017-014-01
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COUNTY/STATE:	Lea	LATERAL LENGTH:	4,300
MRC WI:			
GEOLOGIC TARGET:	Wolfcamp A		
REMARKS:	Drill and complete a horizontal Wolfcamp A well with 21 stages. Install AL, build TB, and construct PL to gas connect.		

INTANGIBLE COSTS	DRILLING COSTS	COMPLETION COSTS	PRODUCTION COSTS	FACILITY COSTS	TOTAL COSTS
Land / Legal / Regulatory	$ 95,000	$	$ -	$ -	$ 95,000
Location, Surveys & Damages	111,500	17,500	5,000	-	134,000
Drilling	707,000				707,000
Cementing & Float Equip	205,000				205,000
Logging / Formation Evaluation	-	3,850	-		3,850
Mud Logging	32,500				32,500
Mud Circulation System	34,720				34,720
Mud & Chemicals	120,000	24,000			144,000
Mud / Wastewater Disposal	155,000	-			155,000
Freight / Transportation	18,000	16,500		-	34,500
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Water	42,500	530,000			572,500
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Plugging & Abandonment	-				-
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Stimulation	-	945,000			945,000
Stimulation Flowback & Disp	-	45,500	6,000		51,500
Insurance	27,000				27,000
Labor	124,000	15,500	6,000	-	145,500
Rental - Surface Equipment	101,200	112,020	450	6,000	219,670
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TANGIBLE COSTS	DRILLING COSTS	COMPLETION COSTS	PRODUCTION COSTS	FACILITY COSTS	TOTAL COSTS
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Production Liner	-				-
Tubing	-		52,500		52,500
Wellhead	60,000		40,000		100,000
Packers, Liner Hangers	-	36,000	-		36,000
Tanks	-		-	120,000	120,000
Production Vessels	-		50,000	45,000	95,000
Flow Lines	-		40,000	-	40,000
Rod string	-		-		-
Artificial Lift Equipment	-		53,000		53,000
Compressor	-		-	-	-
Installation Costs	-		30,000	90,000	120,000
Surface Pumps	-		5,000	-	5,000
Non-controllable Surface	-		-	120,000	120,000
Non-controllable Downhole	-		-		-
Downhole Pumps	-		-		-
Measurement & Meter Installation	-		20,000	19,000	39,000
Gas Conditioning / Dehydration			-	-	-
Interconnecting Facility Piping			-	-	-
Gathering / Bulk Lines			-	40,000	40,000
Valves, Dumps, Controllers			-	-	-
Tank / Facility Containment			-	40,000	40,000
Flare Stack			-	20,000	20,000
Electrical / Grounding			7,500	10,000	17,500
Communications / SCADA			-	-	-
Instrumentation / Safety			10,000	25,000	35,000
TOTAL TANGIBLES >	760,100	36,000	308,000	529,000	1,633,100
TOTAL COSTS >	3,334,645	2,228,982	353,100	569,700	6,486,427

PREPARED BY MATADOR PRODUCTION COMPANY:

Drilling Engineer: Patrick Walsh Team Lead - WTX/NM J.T.G.

Completions Engineer: Matt Bell TG

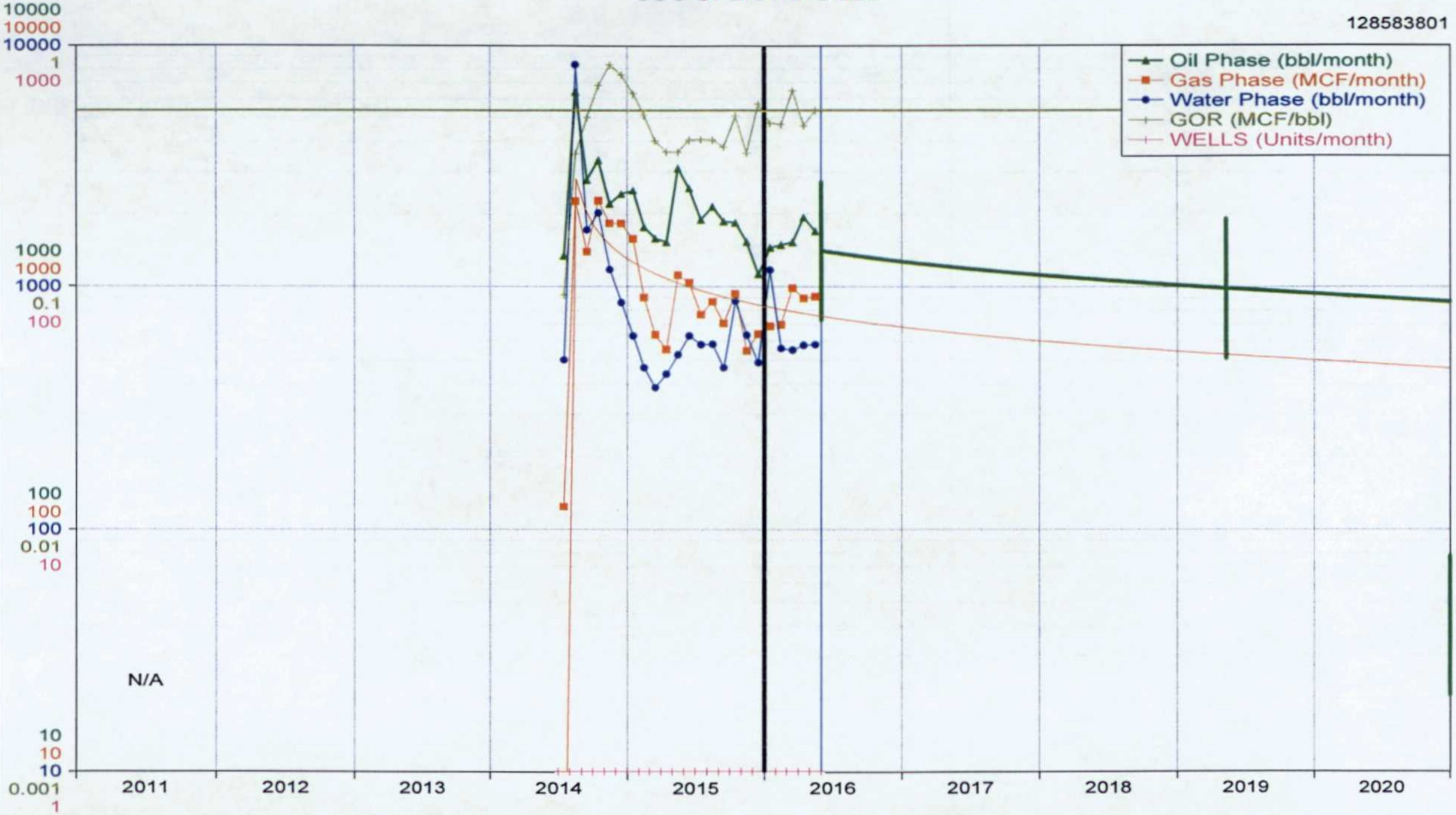
MALLO 5 FEDERAL 4H
LEA ONE SPRING
LEA (NM) COUNTY, NM
CIMAREX ENERGY COMPANY

Gas Phase	
#1 Segment Information	
Type:	
n%:	0.000
De%:	0.000
Qi:	0.000
Qe:	0.000
Limit:	
Prior Cum.:	
Ultimate:	

Oil Phase	
#1 Segment Information	
Type:	Hyperbolic
n%:	138.202
De%:	11.813
Qi:	594.940
Qe:	421.060
Limit:	12/10/2019 Date
Prior Cum.:	66.753
Ultimate:	147.882

NMOCC Case No. 15363
Hearing: SEP 6, 2016
Jalapeno EX 5

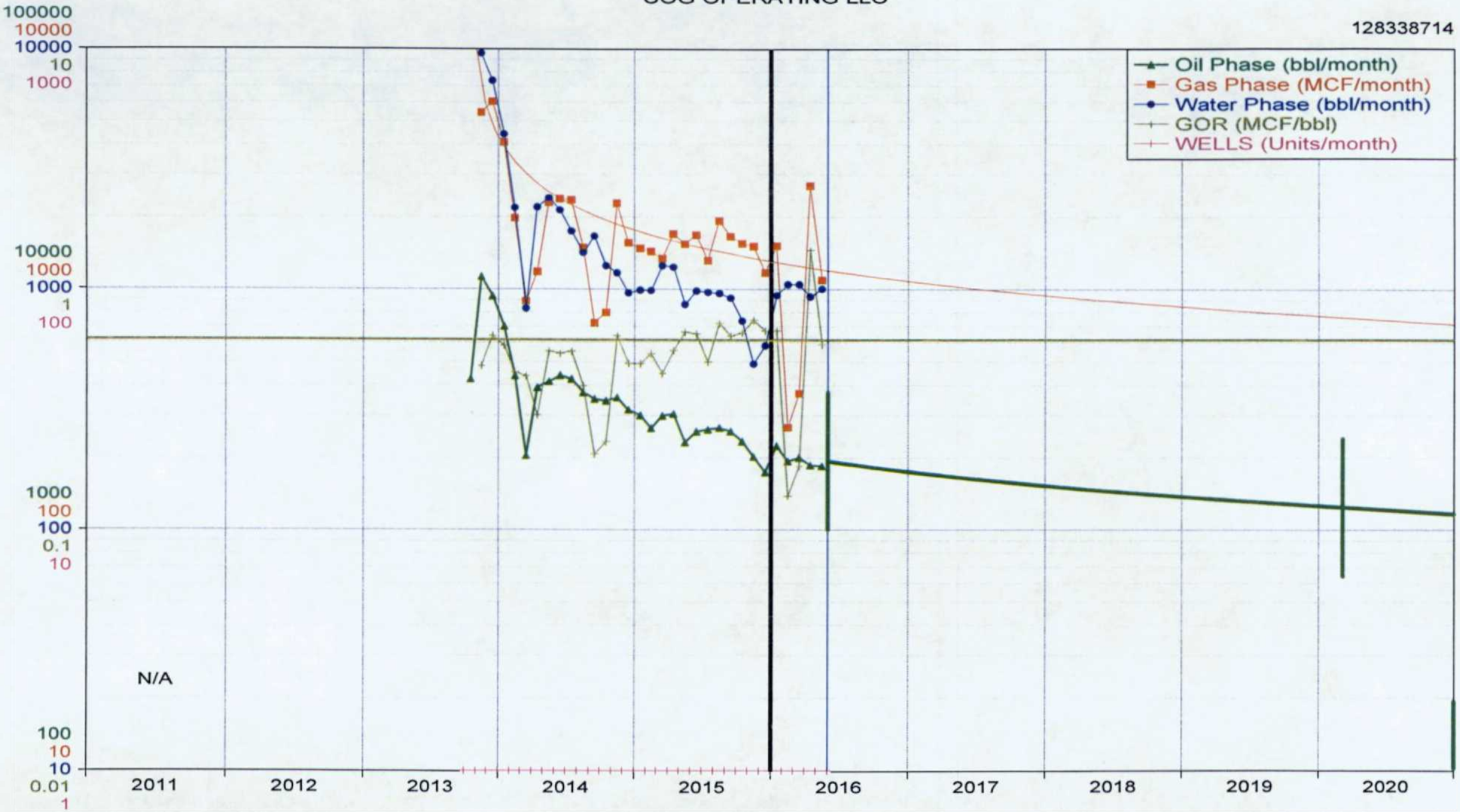
ALBATR STATE COM 2H
AIRSTR BONE SPRING
LEA (NM) COUNTY, NM
COG OPERATING LLC



Gas Phase	
#1 Segment Information	
Type:	
n%:	0.000
De%:	0.000
Qi:	0.000
Qe:	0.000
Limit:	
Prior Cum.:	
Ultimate:	

Oil Phase	
#1 Segment Information	
Type:	Hyperbolic
n%:	267.784
De%:	18.332
Qi:	1414.240
Qe:	990.169
Limit:	05/11/2019 Date
Prior Cum.:	50.152
Ultimate:	237.255

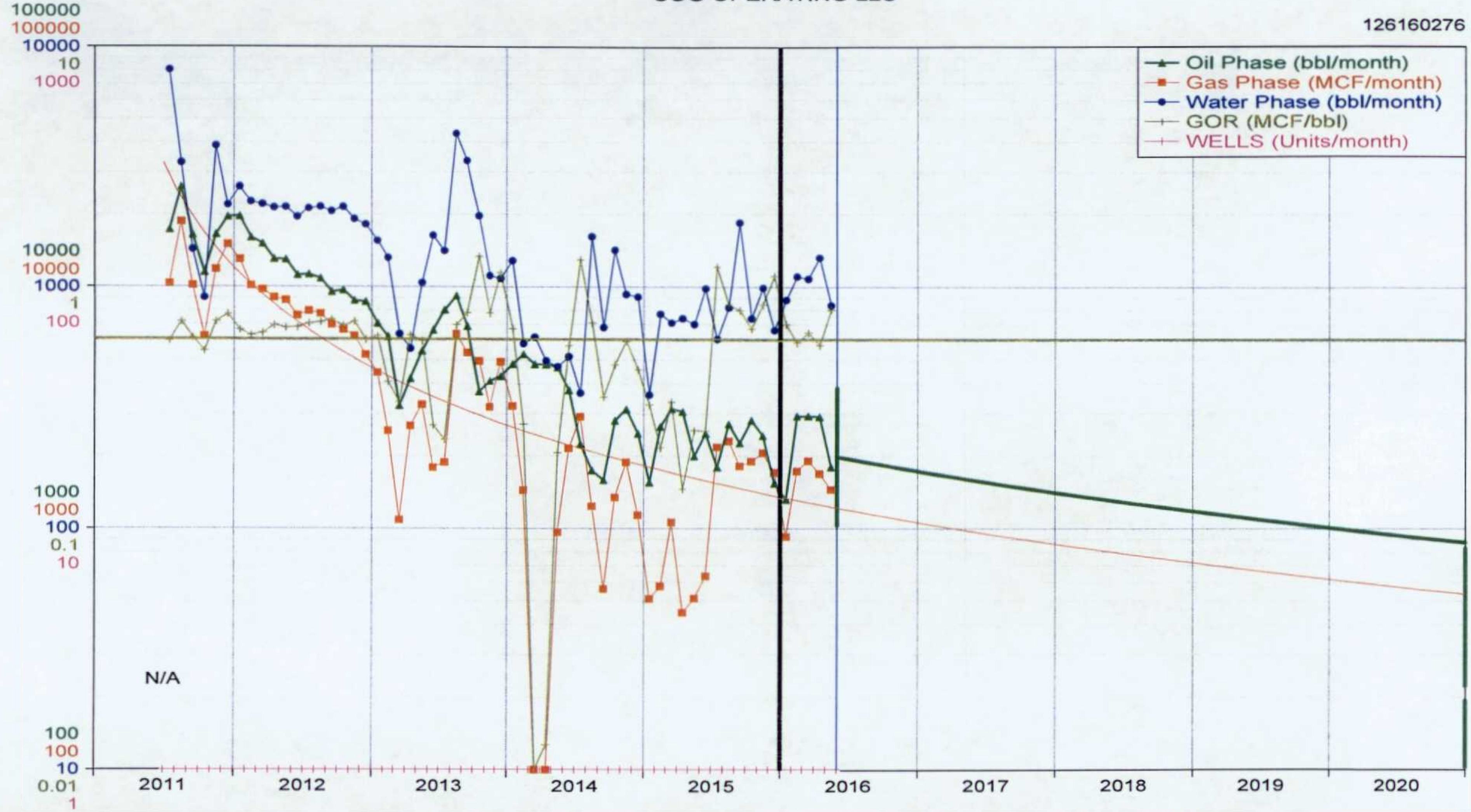
KING C[illegible]RA 2 STATE 2H
SCHAR[illegible] BONE SPRING
LEA (NM) COUNTY, NM
COG OPERATING LLC



Gas Phase	
#1 Segment Information	
Type:	
n%:	0.000
De%:	0.000
Qi:	0.000
Qe:	0.000
Limit:	
Prior Cum.:	
Ultimate:	

Oil Phase	
#1 Segment Information	
Type:	Hyperbolic
n%:	200.951
De%:	17.310
Qi:	1940.374
Qe:	1245.320
Limit:	03/06/2020 Date
Prior Cum.:	113.072
Ultimate:	365.023

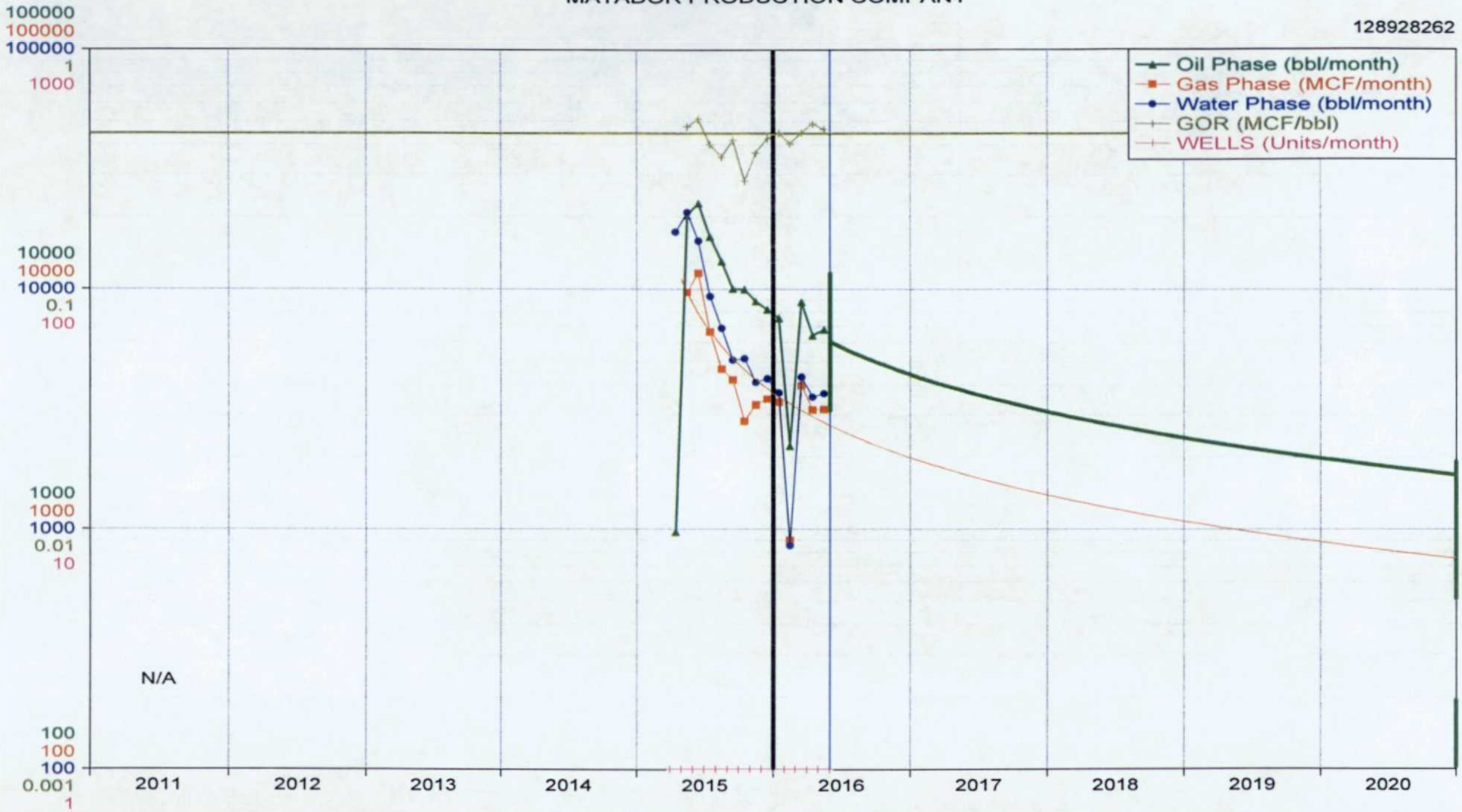
AIRCO A 12 STATE 2H
SCHAR BONE SPRING
LEA (NM) COUNTY, NM
COG OPERATING LLC



Gas Phase	
#1 Segment Information	
Type:	
n%:	0.000
De%:	0.000
Qi:	0.000
Qe:	0.000
Limit:	
Prior Cum.:	
Ultimate:	

Oil Phase	
#1 Segment Information	
Type:	Hyperbolic
n%:	75.343
De%:	21.904
Qi:	1990.374
Qe:	430.216
Limit:	01/28/2028 Date
Prior Cum.:	406.622
Ultimate:	590.867

CIMARRON 1[illegible] 34 RN STATE 134H
QUAIL RIDGE BONE SPRING
LEA (NM) COUNTY, NM
MATADOR PRODUCTION COMPANY



Gas Phase
#1 Segment Information

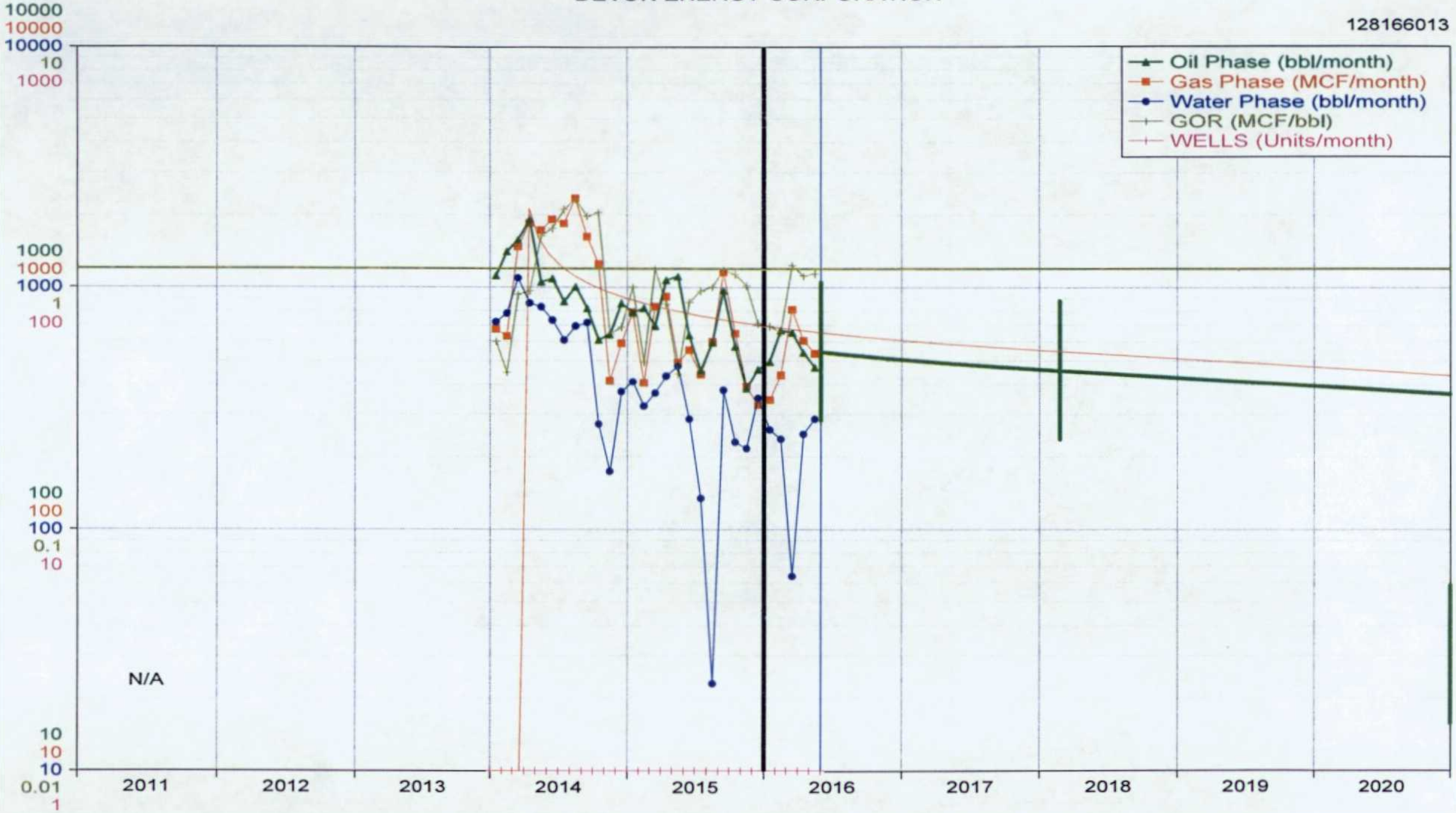
Type:	
n%:	0.000
De%:	0.000
Qi:	0.000
Qe:	0.000
Limit:	
Prior Cum.:	
Ultimate:	

Oil Phase
#1 Segment Information

Type:	Hyperbolic
n%:	115.971
De%:	47.065
Qi:	6053.571
Qe:	990.646
Limit:	02/13/2026 Date
Prior Cum.:	142.875
Ultimate:	524.674

BUTTER CU[illegible]35 STATE COM 1H
AIRSTR[illegible]BONE SPRING
LEA (NM) COUNTY, NM
DEVON ENERGY CORPORATION

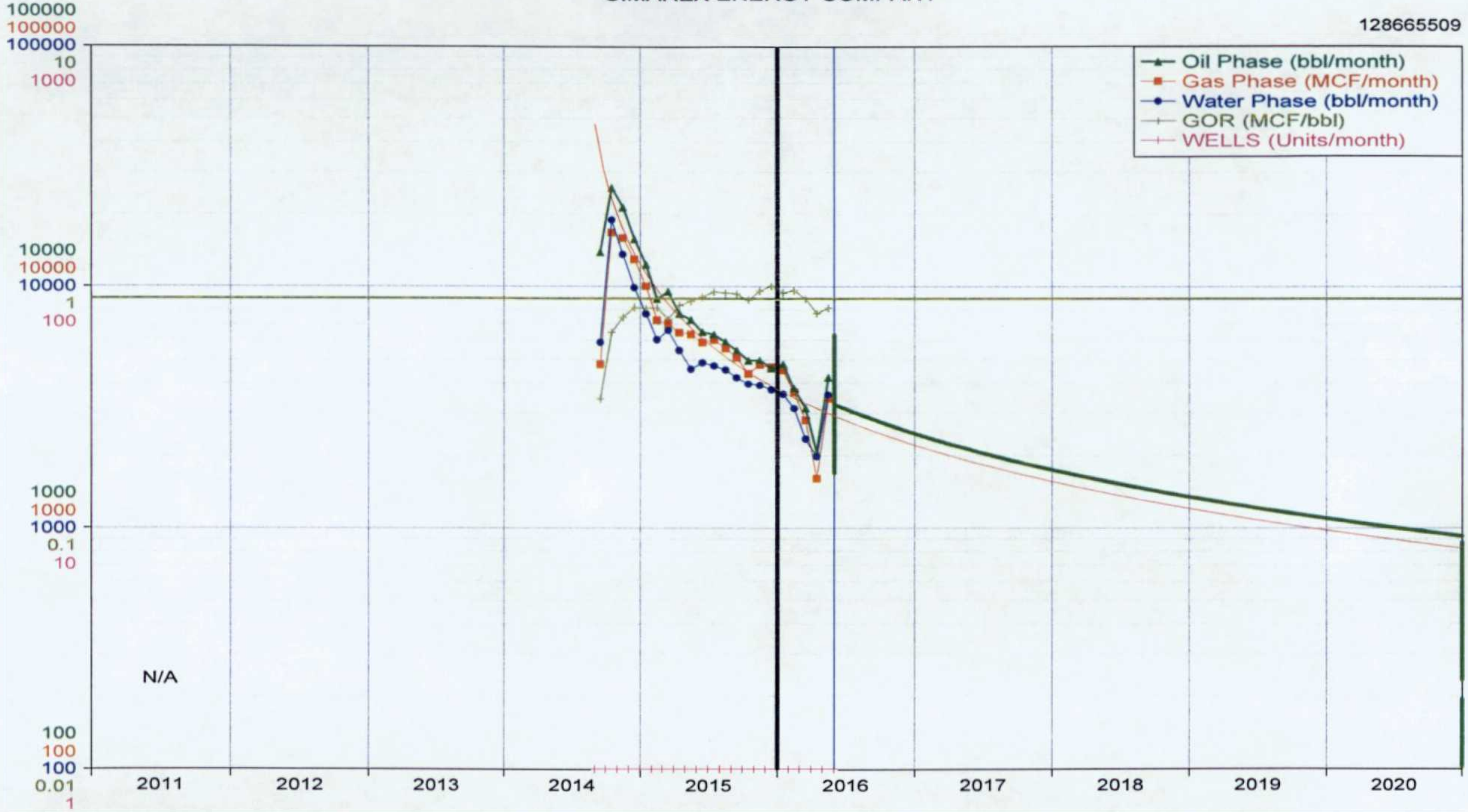
128166013



Gas Phase	
#1 Segment Information	
Type:	
n%:	0.000
De%:	0.000
Qi:	0.000
Qe:	0.000
Limit:	
Prior Cum.:	
Ultimate:	

Oil Phase	
#1 Segment Information	
Type:	Hyperbolic
n%:	327.376
De%:	13.074
Qi:	546.160
Qe:	456.619
Limit:	02/24/2018 Date
Prior Cum.:	24.433
Ultimate:	100.363

CORDONIZ FEDERAL COM 4H
QUAIL RIDGE NE SPRING, SOUTH
LEA (NM) COUNTY, NM
CIMAREX ENERGY COMPANY

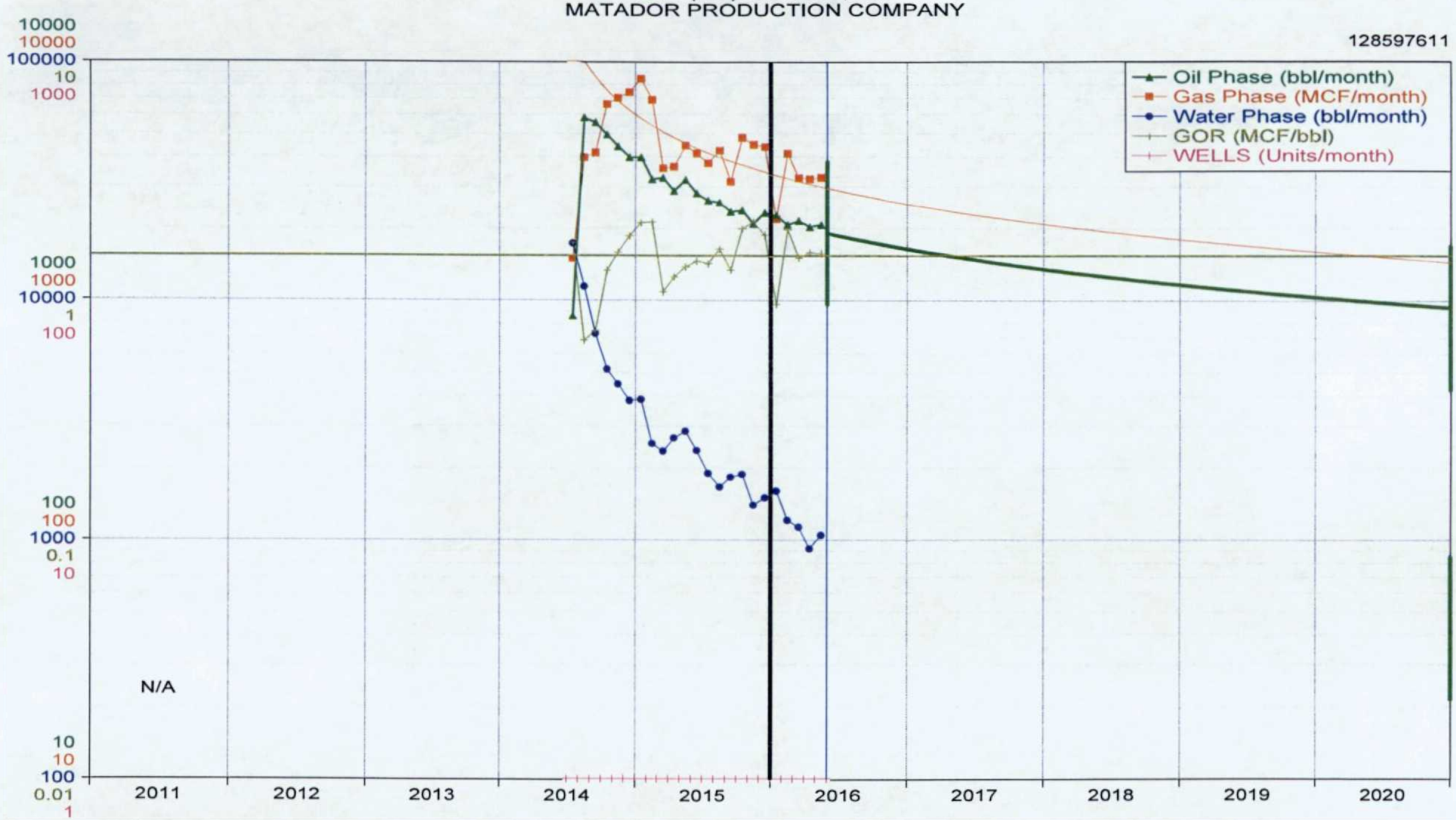


Gas Phase	
#1 Segment Information	
Type:	
n%:	0.000
De%:	0.000
Qi:	0.000
Qe:	0.000
Limit:	
Prior Cum.:	
Ultimate:	

Oil Phase	
#1 Segment Information	
Type:	Hyperbolic
n%:	98.004
De%:	42.004
Qi:	3276.019
Qe:	450.614
Limit:	08/19/2027 Date
Prior Cum.:	179.554
Ultimate:	383.967

PICK[illegible]D STATE 2H
E-K[illegible]OLFCAMP
LEA (NM) COUNTY, NM
MATADOR PRODUCTION COMPANY

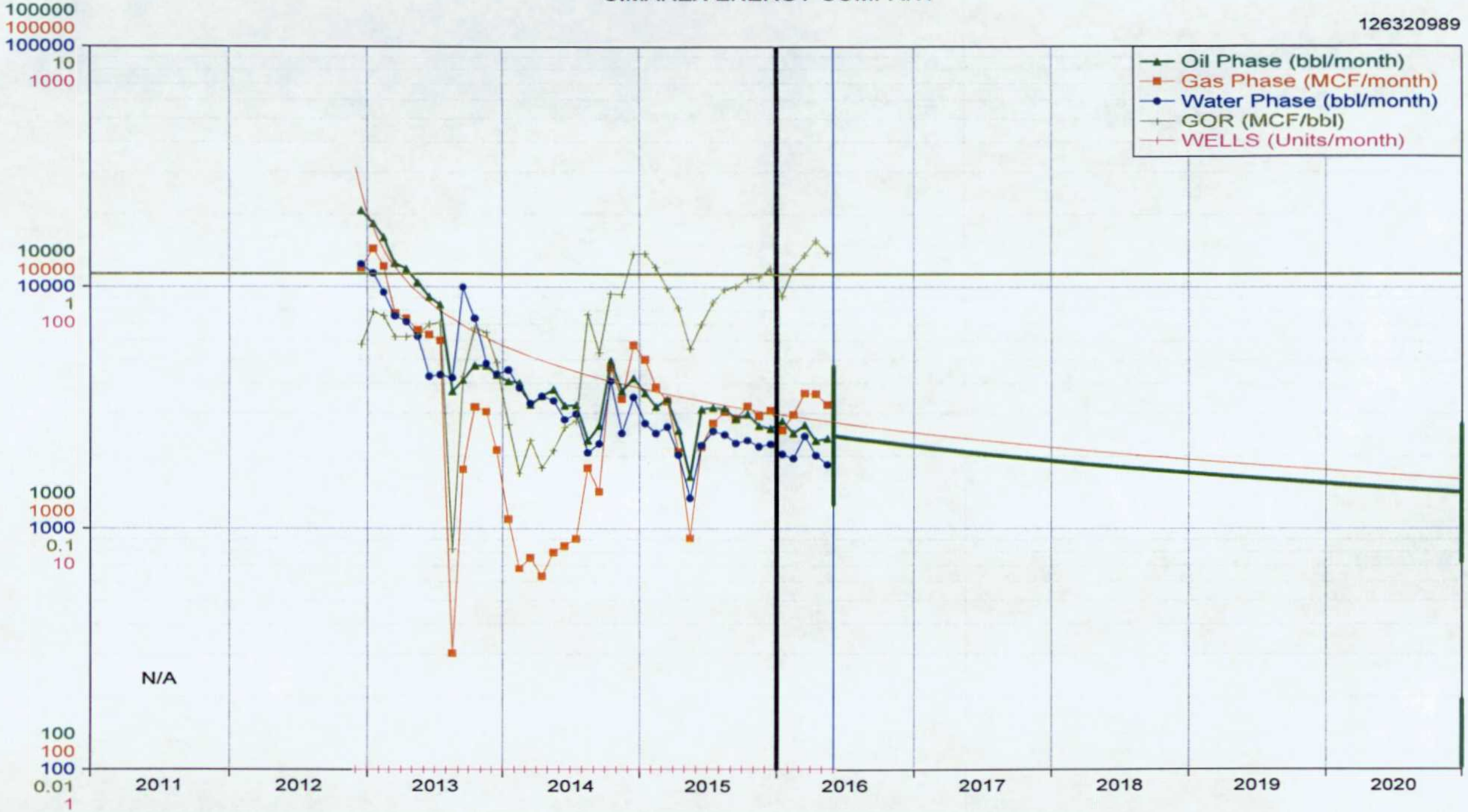
128597611



Gas Phase	
#1 Segment Information	
Type:	
n%:	0.000
De%:	0.000
Qi:	0.000
Qe:	0.000
Limit:	
Prior Cum.:	
Ultimate:	

Oil Phase	
#1 Segment Information	
Type:	Hyperbolic
n%:	163.282
De%:	25.558
Qi:	1917.660
Qe:	848.569
Limit:	03/12/2022 Date
Prior Cum.:	70.037
Ultimate:	277.266

CHAPARRAL FEDERAL COM 3H
QUAIL RIDGE NE SPRING, SOUTH
LEA (NM) COUNTY, NM
CIMAREX ENERGY COMPANY



Gas Phase	
#1 Segment Information	
Type:	
n%:	0.000
De%:	0.000
Qi:	0.000
Qe:	0.000
Limit:	
Prior Cum.:	
Ultimate:	

Oil Phase	
#1 Segment Information	
Type:	Hyperbolic
n%:	153.207
De%:	16.632
Qi:	2435.050
Qe:	1400.644
Limit:	03/13/2021 Date
Prior Cum.:	220.378
Ultimate:	529.200

Case 1		**Case 2**		**Case 3**	
100% Working Interest 75% Net Revenue Interest		70% Working Interest 52.5% Net Revenue Interest		50% Working Interest 37.5% Net Revenue Interest	
Gross Oil	639,696 bbl	Gross Oil	639,696 bbl	Gross Oil	639,696 bbl
Gross Gas	372,272 MCF	Gross Gas	372,272 MCF	Gross Gas	372,272 MCF
BOEQ	701,741 BOEQ	BOEQ	701,741 BOEQ	BOEQ	701,741 BOEQ
Net Well Cost	$6,000,000	Net Well Cost (Incl. Cost Rec = $1,800,000)	$6,000,000	Net Well Cost (Incl. Cost Rec = $3,000,000)	$6,000,000
Net Cash Flow	$17,448,395	Net Cash Flow	$12,213,877	Net Cash Flow	$8,724,198
		Cost Recovery	$1,800,000	Cost Recovery	$3,000,000
		Penalty (Max 200%) (191% Actual)	$3,434,519	Penalty (Max 200%) (191% Actual)	$5,724,197
Net to Matador	$17,448,395		$17,448,395		$17,448,395
Rate of Return	38.1 %	Rate of Return	38.1 %	Rate of Return	38.1 %
Revenue to Other Working Interest If They are Non-Consent			$0.00		$0.00

Case 4		**Case 5**		**Case 6**	
100% Working Interest 75% Net Revenue Interest		70% Working Interest 52.5% Net Revenue Interest		50% Working Interest 37.5% Net Revenue Interest	
Gross Oil	402,815 bbl	Gross Oil	402,815 bbl	Gross Oil	402,815 bbl
Gross Gas	231,416 MCF	Gross Gas	231,416 MCF	Gross Gas	231,416 MCF
BOEQ	441,384 BOEQ	BOEQ	441,384 BOEQ	BOEQ	441,384 BOEQ
Net Well Cost	$6,000,000	Net Well Cost (Incl. Cost Rec = $1,800,000)	$6,000,000	Net Well Cost (Incl. Cost Rec = $3,000,000)	$6,000,000
Net Cash Flow	$10,003,162	Net Cash Flow	$7,002,213	Net Cash Flow	$5,001,581
		Cost Recovery	$1,800,000	Cost Recovery	$3,000,000
		Penalty (Max 200%) (67% Actual)	$1,200,949	Penalty (Max 200%) (67% Actual)	$2,001,581
Matador Total	$10,003,162		$10,003,162		$10,003,162
Rate of Return	12.6 %	Rate of Return	12.6 %	Rate of Return	12.6 %
Revenue to Other Working Interest If They are Non-Consent			$0.00		$0.00

NMOCC Case No. 15363
Hearing: SEP 6, 2016

Jalapeno EX 6

Case 1

100% Working Interest
75% Net Revenue Interest

Gross Oil	639,696 bbl
Gross Gas	372,272 MCF
BOEQ	701,741 BOEQ
Net Well Cost	$6,000,000
Net Cash Flow	$17,448,395
Net to Matador	$17,448,395
Rate of Return	38.1 %

Revenue to Other Working Interest
If They are Non-Consent

Case 2

70% Working Interest
52.5% Net Revenue Interest

Gross Oil	639,696 bbl
Gross Gas	372,272 MCF
BOEQ	701,741 BOEQ
Net Well Cost (Incl. Cost Rec = $1,800,000)	$6,000,000
Net Cash Flow	$12,213,877
Cost Recovery	$1,800,000
Penalty (Max 200%) (191% Actual)	$3,434,519
Matador Total	$17,448,395
Rate of Return	38.1 %
Revenue to Other Working Interest If They are Non-Consent	$0.00

Case 3

50% Working Interest
37.5% Net Revenue Interest

Gross Oil	639,696 bbl
Gross Gas	372,272 MCF
BOEQ	701,741 BOEQ
Net Well Cost (Incl. Cost Rec = $3,000,000)	$6,000,000
Net Cash Flow	$8,724,198
Cost Recovery	$3,000,000
Penalty (Max 200%) (191% Actual)	$5,724,197
Matador Total	$17,448,395
Rate of Return	38.1 %
Revenue to Other Working Interest If They are Non-Consent	$0.00

Case 4

100% Working Interest
75% Net Revenue Interest

Gross Oil	402,815 bbl
Gross Gas	231,416 MCF
BOEQ	441,384 BOEQ
Net Well Cost	$6,000,000
Net Cash Flow	$10,003,162
Matador Total	$10,003,162
Rate of Return	12.6 %

Revenue to Other Working Interest
If They are Non-Consent

Case 5

70% Working Interest
52.5% Net Revenue Interest

Gross Oil	402,815 bbl
Gross Gas	231,416 MCF
BOEQ	441,384 BOEQ
Net Well Cost (Incl. Cost Rec = $1,800,000)	$6,000,000
Net Cash Flow	$7,002,213
Cost Recovery	$1,800,000
Penalty (Max 200%) (67% Actual)	$1,200,949
Matador Total	$10,003,162
Rate of Return	12.6 %
Revenue to Other Working Interest If They are Non-Consent	$0.00

Case 6

50% Working Interest
37.5% Net Revenue Interest

Gross Oil	402,815 bbl
Gross Gas	231,416 MCF
BOEQ	441,384 BOEQ
Net Well Cost (Incl. Cost Rec = $3,000,000)	$6,000,000
Net Cash Flow	$5,001,581
Cost Recovery	$3,000,000
Penalty (Max 200%) (67% Actual)	$2,001,581
Matador Total	$10,003,162
Rate of Return	12.6 %
Revenue to Other Working Interest If They are Non-Consent	$0.00

What does having a 100% Cost & 200% Non-Consent Risk Penalty Mean?

- The Airstrip would have to produce enough BOE to make <u>$19,500,000</u>... in addition to the cost of operating the well (9% chance this happen).
- Matador could make a profit of $13,000,000 without having the mineral owners who could not afford to participate see any value from their minerals.
- The OCC has set up a situation where the average well that costs $6.5 mm will make a profit of $2,600,000 (at $50 oil). Yet, an overwhelming majority will never meet the 200% (or the 133%) non-consent risk penalty threshold.

- **91% chance that the non-consenting party will have their minerals taken**

NMOCC Case No. 15363
Hearing: SEP 6, 2016
Jalapeno EX 7

RISK BASED ON MATADOR'S ANALYSIS

Probability of Success

One cannot have a greater probability of success than 100%, nor a greater risk than 100%. Matador's analysis ignores this fact. But using Matador's figures otherwise:

STOGNER METHOD

Pg = .25 x .66 = .165

Pr = .50 x .66 = .33

Po = .75 x <u>.66</u> = <u>.495</u>

2.000 99 chance of success. So deduct this from an automatically imposed 200% and one gets a risk penalty of 101%. But, Stogner's method puts the burden in the wrong place by assuming an automatic 200% risk and reduction from that.

CORRECT METHOD

Pg = .25 x .333 = .08325

Pr = .50 x .333 = .1665

Po = .75 x <u>.333</u> = <u>.2475</u>

1.000 .497525 Chance of Success and thus a 50.275 chance of failure. So the risk penalty should be 50.275

NMOCC Case No. 15363
Hearing: SEP 6, 2016
Jalapeno EX 8 rev.

TOTAL RISK ASSUMING $6.5MM COST AND ASSUMING PAYOUT AT 200,000 BOE

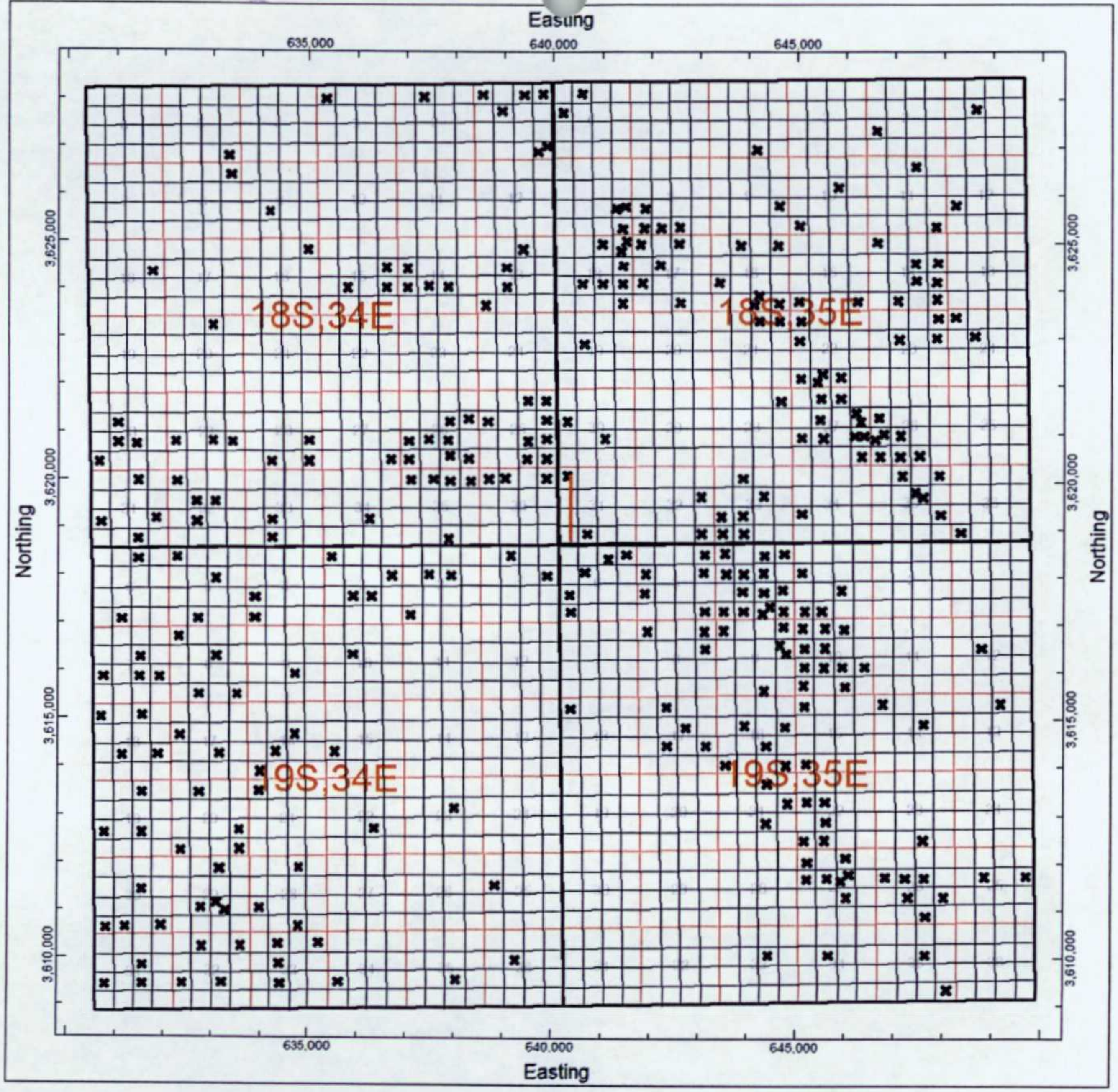
- Geologic=0
- Operational=1%
- Reservoir=29%

TOTAL=30%

ANY RISK PENALTY OVER 30% IS AN IMPAIRMENT OF OUR CORRELATIVE RIGHTS

NMOCC Case No. 15363
Hearing: SEP 6, 2016

Jalapeno EX 8



Wells that penetrate the Wolfcamp formation

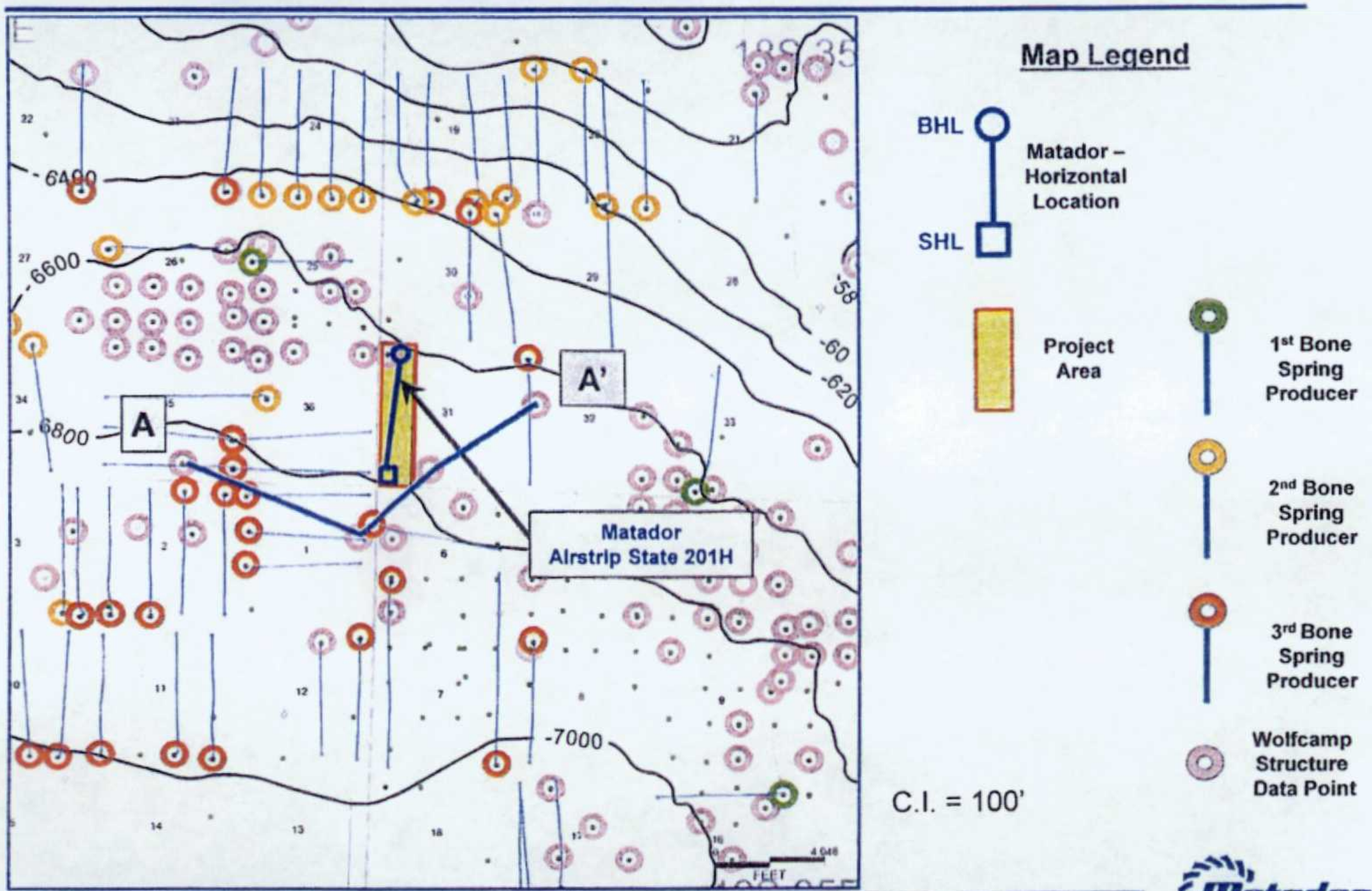
PROPOSED AIRSTRIP WELL IN RED

NMOCC Case No. 15363
Hearing: SEP 6, 2016

Jalapeno EX 9

Airstrip; Wolfcamp Pool (Pool Code 970)
Structure Map (Top Wolfcamp Subsea)

Matador
Exhibit 12

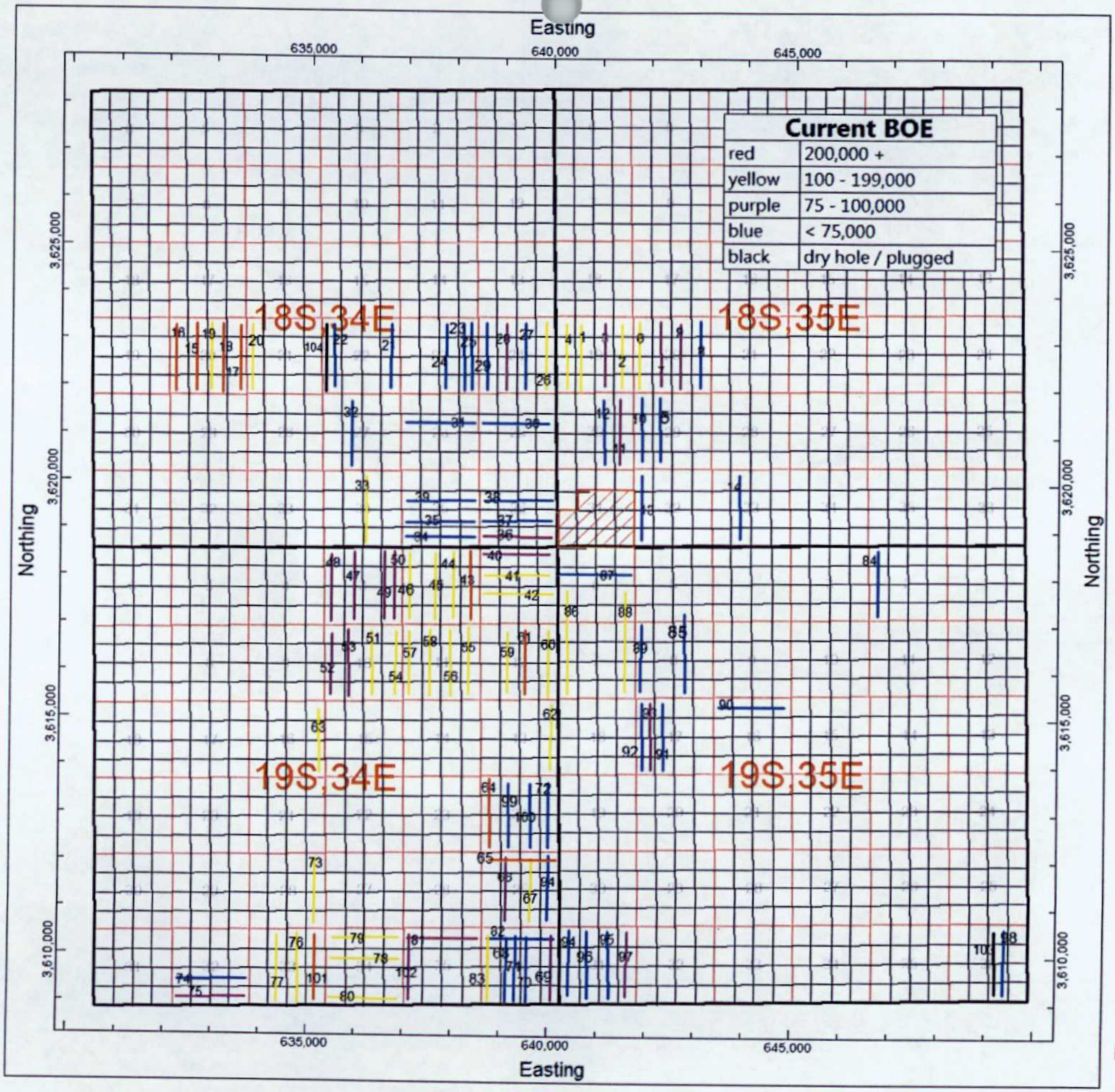


Airstrip State Com 31-18S-35E #201H

Matador

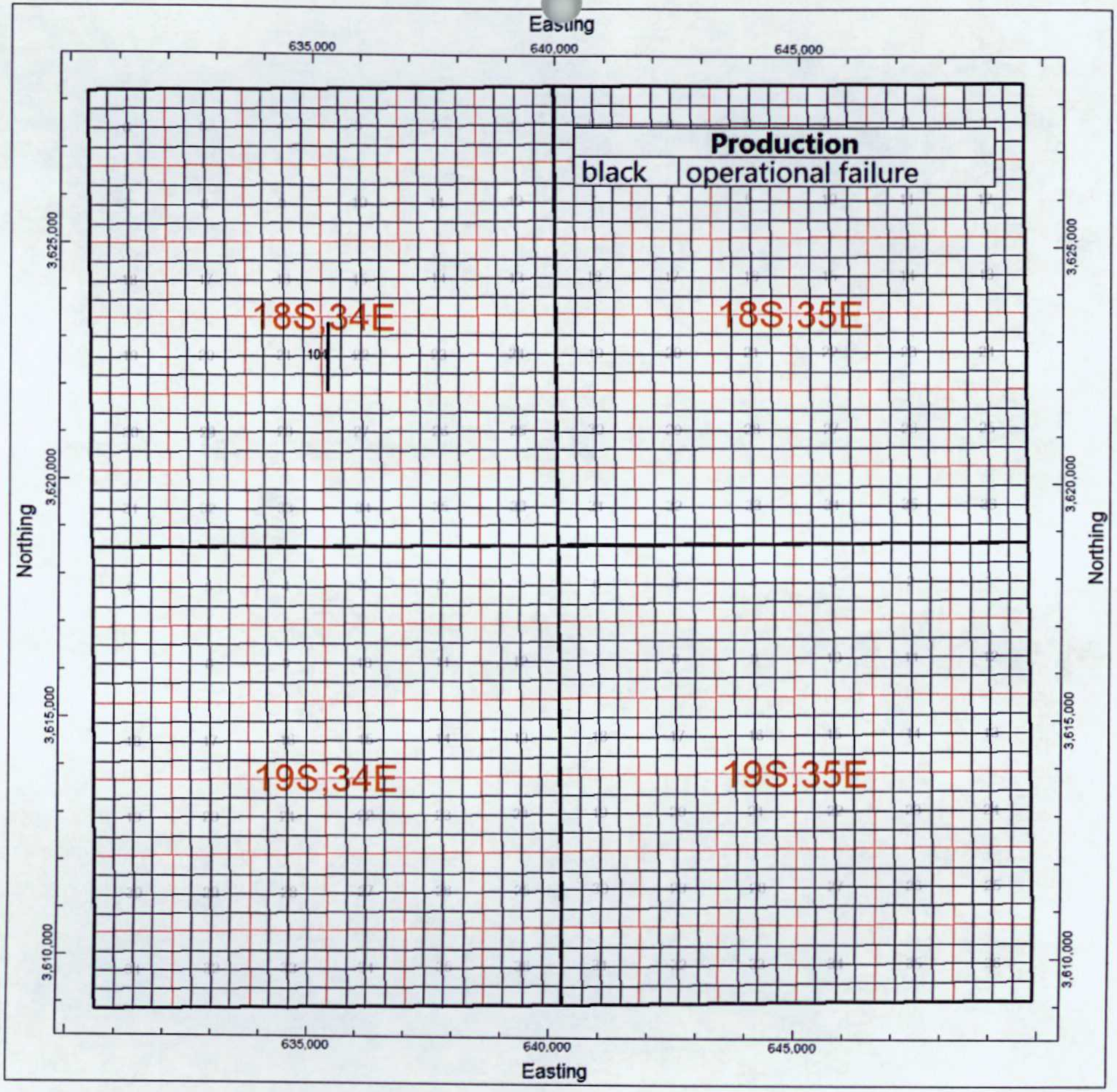
NMOCC Case No. 15363
Hearing: SEP 6, 2016

Jalapeno EX 10



NMOCC Case No. 15363
Hearing: SEP 6, 2016

Jalapeno EX 11

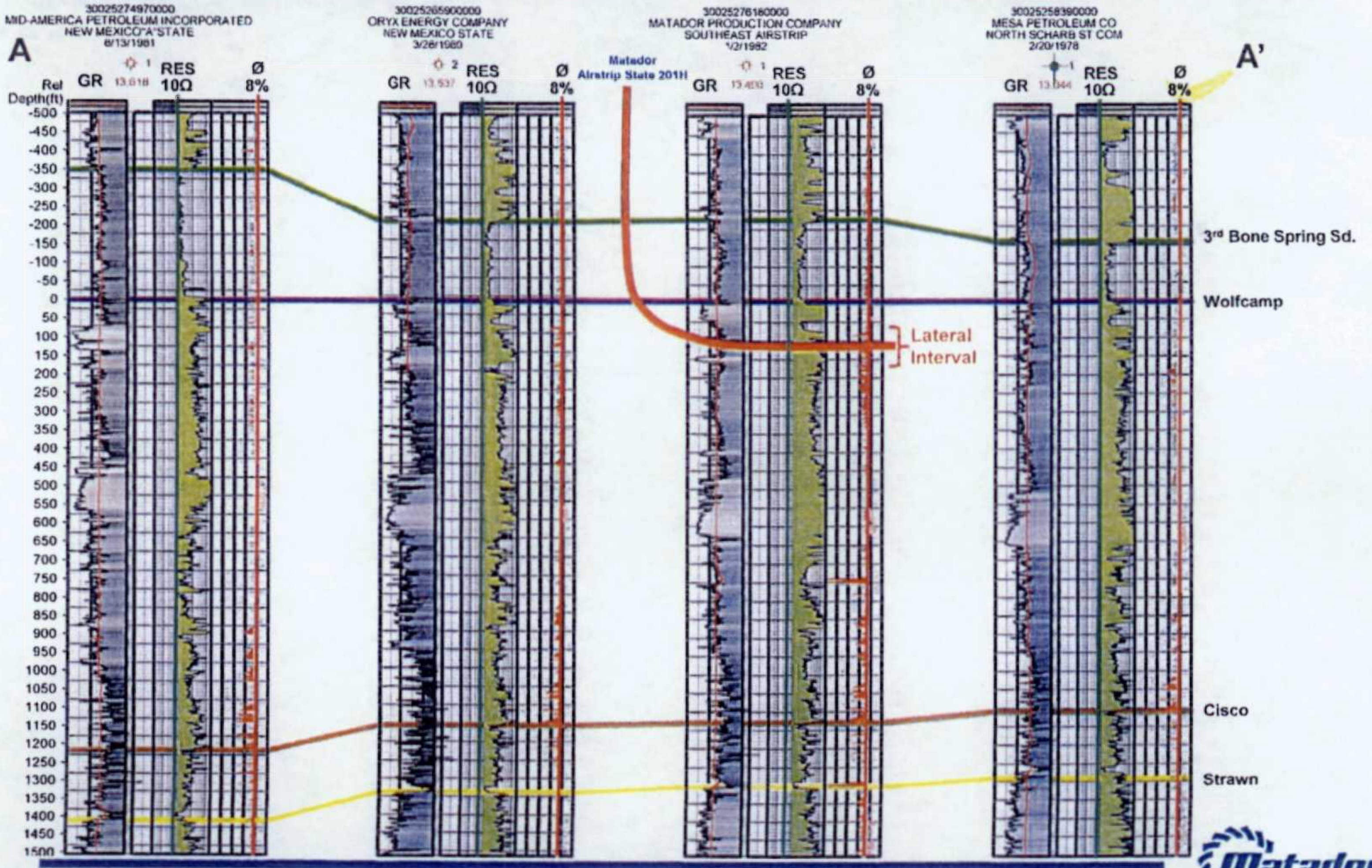


NMOCC Case No. 15363
Hearing: SEP 6, 2016

Jalapeno EX 12

Matador
Exhibit 13

Airstrip; Wolfcamp Pool (Pool Code 970)
Stratigraphic Cross Section A - A'



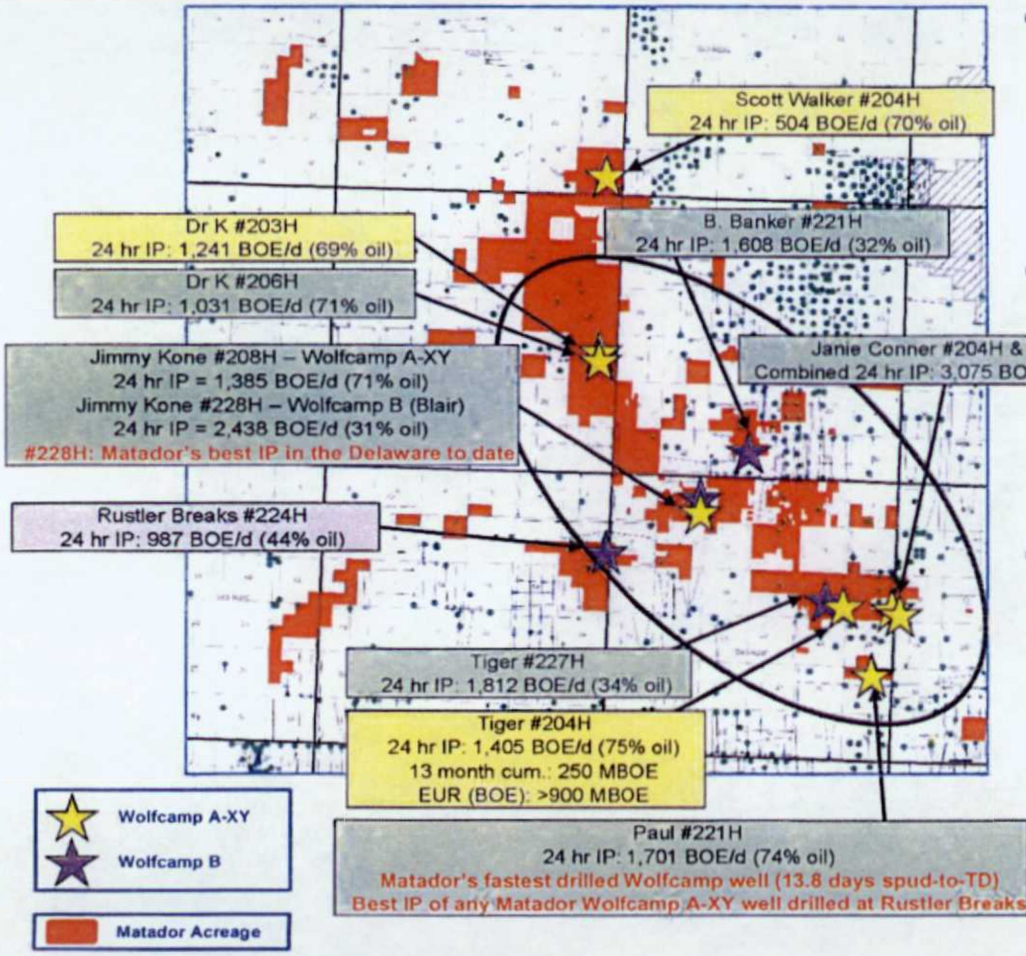
Airstrip State Com 31-18S-35E #201H

Matador

NMOCC Case No. 15363
Hearing: SEP 6, 2016

Jalapeno EX 13

Rustler Breaks -- Focus on Wolfcamp Development in 2016



Note: All acreage at June 30, 2016. Some tracts not shown on map.
(1) Flowing casing pressure

- **First Half of 2016 Accomplishments**
  - *Achieved YE2016 drilling time targets for both Wolfcamp A-XY and Wolfcamp B on recent wells*
  - *Well costs near or below YE2016 targets*
  - *Successfully tested third Wolfcamp B bench (Blair)*
  - *Completed 3D seismic shoot across prospect area*
- **2016 Plans**
  - *Focus on Wolfcamp development*
    - *19 gross (15.8 net) wells planned for 2016*
    - *17 gross (14.5 net) wells on production*
      - *8 Wolfcamp A-XY & 9 Wolfcamp B*
  - *Complete 60 MMcf/d cryogenic processing plant and gathering system to support operations*
- **Recent 24-Hour Initial Potential Test Results**

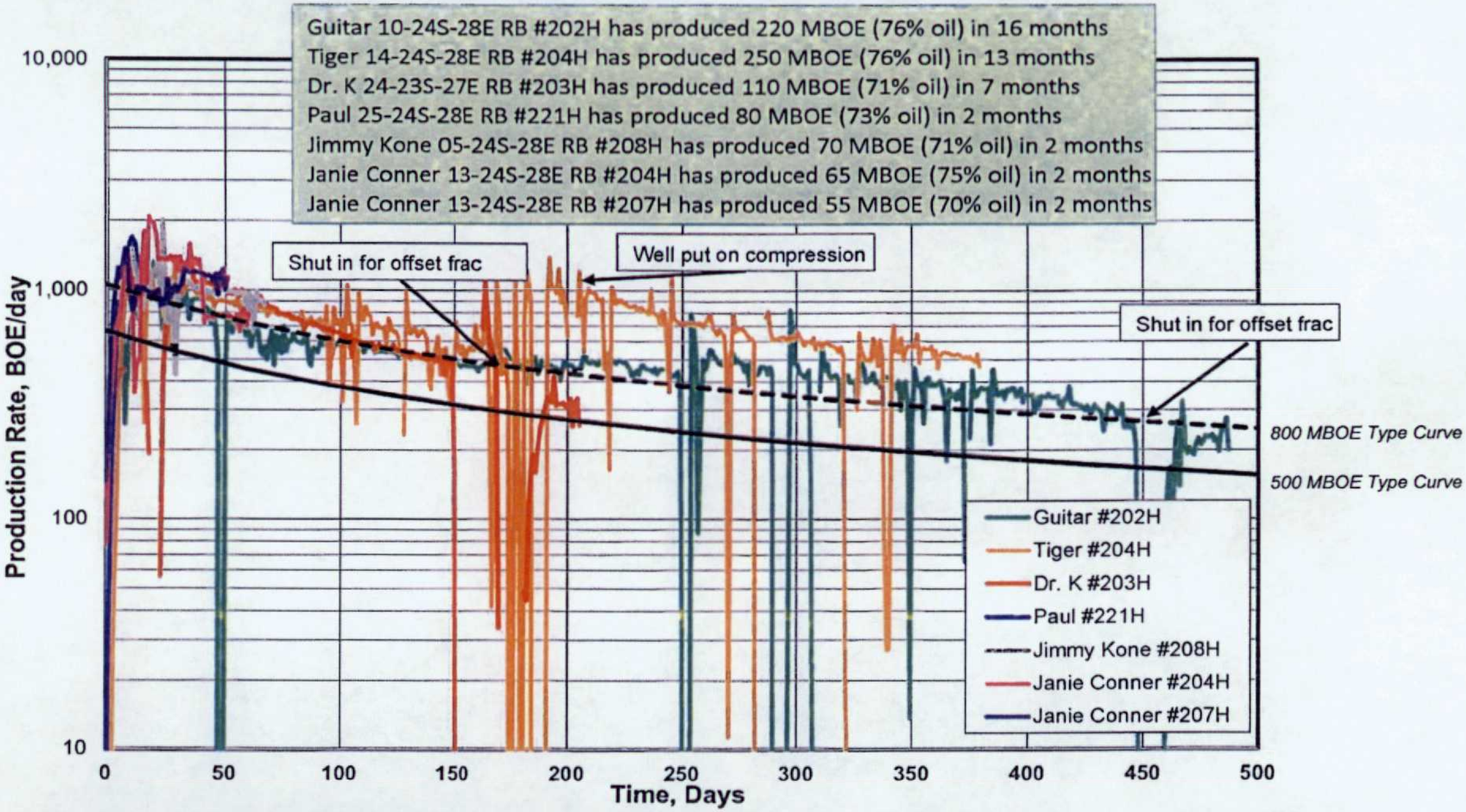
Well	Oil Eq. (BOE/d)	Oil (Bbl/d)	Natural Gas (MMcf/d)	% Oil	P_f[1] (psi)	Choke (inches)
Paul 25-24S-28E RB #221H (Wolfcamp A-XY)	1,701	1,253	2.7	74%	2,425	34/64ths
Janie Conner 13-24S-28E RB #204H (Wolfcamp A-XY)	1,550	1,146	2.4	74%	2,380	34/64ths
Janie Conner 13-24S-28E RB #207H (Wolfcamp A-XY)	1,525	1,094	2.6	72%	2,130	34/64ths
Jimmy Kone 05-24S-28E RB #208H (Wolfcamp A-XY)	1,385	982	2.4	71%	2,100	34/64ths
Dr. K 24-23S-27E RB #206H (Wolfcamp A-XY)	1,031	732	1.8	71%	1,500	34/64ths
B. Banker 33-23S-28E RB #221H (Wolfcamp B-Middle)	1,608	515	6.6	32%	2,700	36/64ths
Jimmy Kone 05-24S-28E RB #228H (Wolfcamp B-Blair)	2,438	751	10.1	31%	2,975	36/64ths
Tiger 14-24S-28E RB #227H (Wolfcamp B-Blair)	1,812	623	7.1	34%	2,770	36/64ths

Matador

NMOCC Case No. 15363
Hearing: SEP 6, 2016

Jalapeno EX 14

Rustler Breaks Wolfcamp A-XY Wells Performing Above Expectations



Note: Production from selected Wolfcamp A-XY wells in Rustler Breaks prospect area as of July 2016

Matador

NMOCC Case No. 15363
Hearing: SEP 6, 2016

Jalapeno EX 15

ESTIMATED ULTIMATE RECOVERIES IN BOE FOR RECENT MATADOR WOLFCAMP WELLS

Expected production	# wells	percentage	cumulative percentage
Greater than 400,000 boe	5	71%	71% cum
200,000 boe to 399,999 boe	2	29%	100% cum
100,000 boe to 199,999 boe	0	0%	0% cum
Wells with expected production less than 100,000 bbls.	0	0%	
Totals	7		

*There are 7 additional New Mexico Matador Wolfcamp wells of which we are aware. We lacked the data to derive EURs for these wells. However, their reported BOE IPs averaged 350 BOE more per day than those wells represented above for which we did have the data. Thus, the 7 additional wells appear to be superior to those represented above.

NMOCC Case No. 15363
Hearing: SEP 6, 2016

Jalapeno EX 16

District I
1625 N. French Dr., Hobbs, NM 88240
Phone:(575) 393-6161 Fax:(575) 393-0720
District II
811 S. First St., Artesia, NM 88210
Phone:(575) 748-1283 Fax:(575) 748-9720
District III
1000 Rio Brazos Rd., Aztec, NM 87410
Phone:(505) 334-6178 Fax:(505) 334-6170
District IV
1220 S. St Francis Dr., Santa Fe, NM 87505
Phone:(505) 476-3470 Fax:(505) 476-3462

State of New Mexico
Energy, Minerals and Natural Resources
Oil Conservation Division
1220 S. St Francis Dr.
Santa Fe, NM 87505

Form C-101
August 1, 2011

Permit 225357

APPLICATION FOR PERMIT TO DRILL, RE-ENTER, DEEPEN, PLUGBACK, OR ADD A ZONE

1. Operator Name and Address MATADOR PRODUCTION COMPANY One Lincoln Centre Dallas, TX 75240		2. OGRID Number 228937 3. API Number 30-025-43395
4. Property Code 314818	5. Property Name AIRSTRIP 31 18 35 RN STATE COM	6. Well No. 201H

7. Surface Location

UL - Lot	Section	Township	Range	Lot Idn	Feet From	N/S Line	Feet From	E/W Line	County
M	31	18S	35E		150	S	660	W	Lea

8. Proposed Bottom Hole Location

UL - Lot	Section	Township	Range	Lot Idn	Feet From	N/S Line	Feet From	E/W Line	County
D	31	18S	35E	D	330	N	710	W	Lea

9. Pool Information

AIRSTRIP;WOLFCAMP	970

Additional Well Information

11. Work Type New Well	12. Well Type OIL	13. Cable/Rotary	14. Lease Type State	15. Ground Level Elevation 3945
16. Multiple N	17. Proposed Depth 15378	18. Formation Wolfcamp	19. Contractor	20. Spud Date 1/1/2017
Depth to Ground water		Distance from nearest fresh water well		Distance to nearest surface water

☒ **We will be using a closed-loop system in lieu of lined pits**

21. Proposed Casing and Cement Program

Type	Hole Size	Casing Size	Casing Weight/ft	Setting Depth	Sacks of Cement	Estimated TOC
Surf	17.5	13.375	54.5	1950	1640	0
Int1	12.25	9.625	40	6000	1831	0
Int2	8.75	7	29	10974	612	5000
Prod	6.125	4.5	13.5	15378	567	9500

Casing/Cement Program: Additional Comments

22. Proposed Blowout Prevention Program

Type	Working Pressure	Test Pressure	Manufacturer
Annular	5000	3000	CAMERON
Double Ram	10000	5000	CAMERON
Pipe	10000	5000	CAMERON

			OIL CONSERVATION DIVISION		
23. I hereby certify that the information given above is true and complete to the best of my knowledge and belief. **I further certify I have complied with 19.15.14.9 (A) NMAC ☒ and/or 19.15.14.9 (B) NMAC ☒, if applicable.** Signature:					
Printed Name:	Electronically filed by Ava Monroe		Approved By:	Paul Kautz	
Title:	Engineering Tech		Title:	Geologist	
Email Address:	amonroe@matadorresources.com		Approved Date:	8/24/2016	Expiration Date: 8/24/2018
Date:	8/24/2016	Phone: 972-371-5218	Conditions of Approval Attached		

NMOCC Case No. 15363
Hearing: SEP 6, 2016

Jalapeno EX 17

District I
1625 N. French Dr., Hobbs, NM 88240
Phone: (575) 393-6161 Fax: (575) 393-0720
District II
811 S. First St., Artesia, NM 88210
Phone: (575) 748-1283 Fax: (575) 748-9720
District III
1000 Rio Brazos Road, Aztec, NM 87410
Phone: (505) 334-6178 Fax: (505) 334-6170
District IV
1220 S. St. Francis Dr., Sante Fe, NM 87505
Phone: (505) 476-3460 Fax: (505) 476-3462

State of New Mexico
Energy, Minerals & Natural Resources
Department
OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Sante Fe, NM 87505

FORM C-102
Revised August 1, 2011
Submit one copy to appropriate District Office

☐ **AMENDED REPORT**

WELL LOCATION AND ACREAGE DEDICATION PLAT

[1]API Number	[2]Pool Code	[3]Pool Name
	970	Airstrip;Wolfcamp

[4]Property Code	[5]Property Name	[6]Well Number
	AIRSTRIP 31 18S 35E RN STATE COM	#201H
[7]OGRID No.	[8]Operator Name	[9]Elevation
228937	MATADOR PRODUCTION COMPANY	3945'

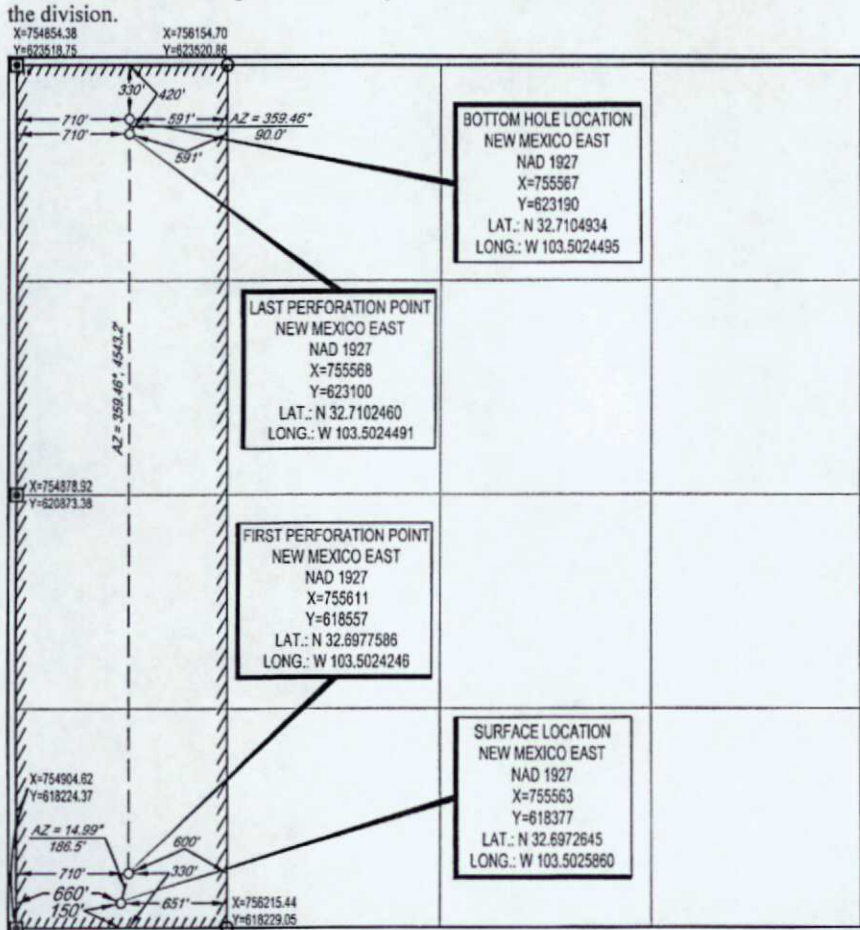
[10]Surface Location

UL or lot no.	Section	Township	Range	Lot Idn	Feet from the	North/South line	Feet from the	East/West line	County
M	31	18-S	35-E	–	150'	SOUTH	660'	WEST	LEA

UL or lot no.	Section	Township	Range	Lot Idn	Feet from the	North/South line	Feet from the	East/West line	County
D	31	18-S	35-E	–	330'	NORTH	710'	WEST	LEA

[12]Dedicated Acres	[13]Joint or Infill	[14]Consolidation Code	[15]Order No.
154.28			

No allowable will be assigned to this completion until all interests have been consolidated or a non-standard unit has been approved by the division.



[17]OPERATOR CERTIFICATION

I hereby certify that the information contained herein is true and complete to the best of my knowledge and belief, and that this organization either owns a working interest or unleased mineral interest in the land including the proposed bottom hole location or has a right to drill this well at this location pursuant to a contract with an owner of such a mineral or working interest, or to a voluntary pooling agreement or a compulsory pooling order heretofore entered by the division.

Sam Pryor 8-23-16
Signature Date

Sam Pryor
Printed Name

spryor@matadorresources.com
E-mail Address

[18]SURVEYOR CERTIFICATION

I hereby certify that the well location shown on this plat was plotted from field notes of actual surveys made by me or under my supervision, and that the same is true to the best of my belief.

04/14/2015
Date of Survey
Signature and Seal of Professional Surveyor

MICHAEL B. BROWN
NEW MEXICO
18329
PROFESSIONAL SURVEYOR

Certificate Number

District I
1625 N. French Dr., Hobbs, NM 88240
Phone:(575) 393-6161 Fax:(575) 393-0720
District II
811 S. First St., Artesia, NM 88210
Phone:(575) 748-1283 Fax:(575) 748-9720
District III
1000 Rio Brazos Rd., Aztec, NM 87410
Phone:(505) 334-6178 Fax:(505) 334-6170
District IV
1220 S. St Francis Dr., Santa Fe, NM 87505
Phone:(505) 476-3470 Fax:(505) 476-3462

State of New Mexico
Energy, Minerals and Natural Resources
Oil Conservation Division
1220 S. St Francis Dr.
Santa Fe, NM 87505

Form APD Comments

Permit 225357

PERMIT COMMENTS

Operator Name and Address:	API Number:
MATADOR PRODUCTION COMPANY [228937] One Lincoln Centre Dallas, TX 75240	30-025-43395 Well: AIRSTRIP 31 18 35 RN STATE COM #201H

Created By	Comment	Comment Date

District I
1625 N. French Dr., Hobbs, NM 88240
Phone:(575) 393-6161 Fax:(575) 393-0720
District II
811 S. First St., Artesia, NM 88210
Phone:(575) 748-1283 Fax:(575) 748-9720
District III
1000 Rio Brazos Rd., Aztec, NM 87410
Phone:(505) 334-6178 Fax:(505) 334-6170
District IV
1220 S. St Francis Dr., Santa Fe, NM 87505
Phone:(505) 476-3470 Fax:(505) 476-3462

State of New Mexico
Energy, Minerals and Natural Resources
Oil Conservation Division
1220 S. St Francis Dr.
Santa Fe, NM 87505

Form APD Conditions

Permit 225357

PERMIT CONDITIONS OF APPROVAL

Operator Name and Address:	API Number:
MATADOR PRODUCTION COMPANY [228937] One Lincoln Centre Dallas, TX 75240	30-025-43395 Well: AIRSTRIP 31 18 35 RN STATE COM #201H

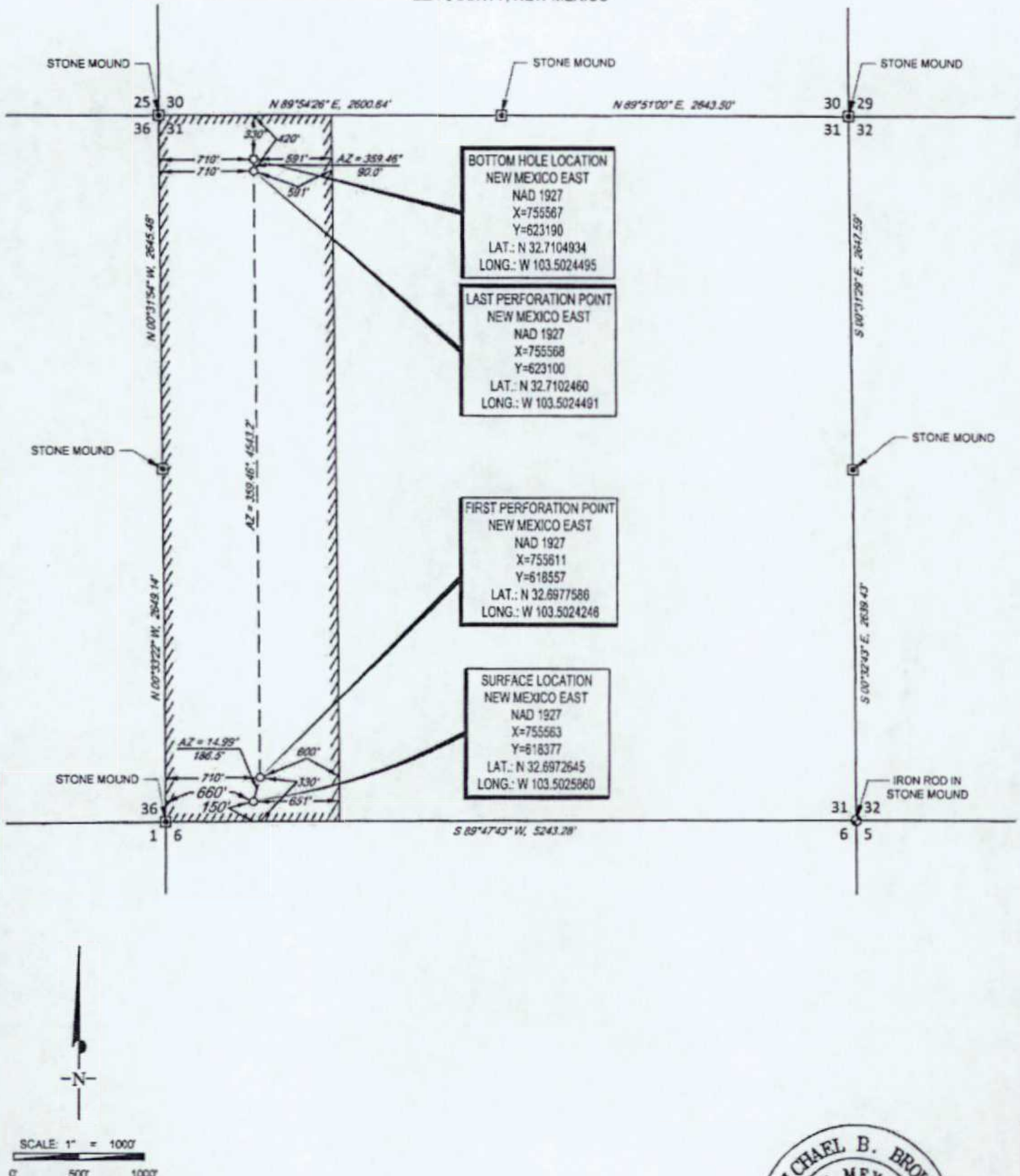
OCD Reviewer	Condition
pkautz	Will require a directional survey with the C-104
pkautz	Once the well is spud, to prevent ground water contamination through whole or partial conduits from the surface, the operator shall drill without interruption through the fresh water zone or zones and shall immediately set in cement the water protection string
pkautz	If using a pit for drilling and completion operations, must have an approved pit from prior to spudding the well.
pkautz	1) SURFACE & INTERMEDIATE1 CASING - Cement must circulate to surface -- 2) INTERMEDIATE2 CASING - Cement must tie back into intermediate1 casing -- 3) PRODUCTION CASING - Cement must tie back into intermediate2 casing --
pkautz	If cement does not circulate to surface, must run temperature survey or other log to determine top of cement
pkautz	Surface casing must be set 25' below top of Rustler Anhydrite in order to seal off protectable water
pkautz	Must notify OCD Hobbs Office if lost circulation is encountered at 575-370-3186
pkautz	Must notify OCD Hobbs Office of any water flows in the Salado Formation at 575-370-3186. Report depth and flow rate
pkautz	1) Must notify OCD Hobbs Office prior to running Stage Tool at 575-370-3186 2) If using Stage Tool on Surface casing, Stage Tool must be set greater than 350' from surface and a minimum of 200 feet above surface shoe. 3) When using a Stage Tool on Intermediate or Production Casing Stage must be a minimum of 50 feet below previous casing shoe.
pkautz	The New! Gas Capture Plan (GCP) notice is posted on the NMOCD website under Announcements. The Plan became effective May 1, 2016. A copy of the GCP form is included with the NOTICE and is also in our FORMS section under Unnumbered Forms. Please review filing dates for all applicable activities currently approved or pending and submit accordingly. Failure to file a GCP may jeopardize the operator's ability to obtain C-129 approval to flare gas after the initial 60-day completion period.

30-025-43395

Matador PRODUCTION COMPANY

OCD – HOBBS
08/24/2016
RECEIVED

SECTION 31, TOWNSHIP 18-S, RANGE 35-E, N.M.P.M.
LEA COUNTY, NEW MEXICO



LEASE NAME & WELL NO.: AIRSTRIP 31 18S 35E RN STATE COM #201H

SECTION 31 TWP 18-S RGE 35-E SURVEY N.M.P.M.
COUNTY LEA STATE NM
DESCRIPTION 150' FSL & 660' FWL

DISTANCE & DIRECTION
FROM INT. OF NM-529 & NM-238 GO WEST ON NM-529 ±4.5 MILES TO A POINT ±250 FEET SOUTH OF THE LOCATION.

MICHAEL B. BROWN
NEW MEXICO
18329
PROFESSIONAL SURVEYOR

Michael Blake Brown, P.S. No. 18329
AUGUST 04, 2015

ALL BEARINGS, DISTANCES, AND COORDINATE VALUES CONTAINED HEREON ARE GRID BASED UPON THE NEW MEXICO STATE PLANE COORDINATE SYSTEM, EAST ZONE OF THE NORTH AMERICAN DATUM 1927, U.S. SURVEY FEET

THIS EASEMENT/SERVITUDE LOCATION SHOWN HEREON HAS BEEN SURVEYED ON THE GROUND UNDER MY SUPERVISION AND PREPARED ACCORDING TO THE EVIDENCE FOUND AT THE TIME OF SURVEY, AND DATA PROVIDED BY MATADOR PRODUCTION COMPANY. THIS CERTIFICATION IS MADE AND LIMITED TO THOSE PERSONS OR ENTITIES SHOWN ON THE FACE OF THIS PLAT AND IS NON-TRANSFERABLE. THIS SURVEY IS CERTIFIED FOR THIS TRANSACTION ONLY.

TOPOGRAPHIC
LOYALTY INNOVATION LEGACY
1400 EVERMAN PARKWAY, Ste. 197 • FT. WORTH, TEXAS 76140
TELEPHONE: (817) 744-7512 • FAX (817) 744-7548
2903 NORTH BIG SPRING • MIDLAND, TEXAS 79705
TELEPHONE: (432) 682-1653 OR (800) 767-1653 • FAX (432) 682-1743
WWW.TOPOGRAPHIC.COM

30-025-43395

District I
1625 N. French Dr., Hobbs, NM 88240
District II
811 S. First St., Artesia, NM 88210
District III
1000 Rio Brazos Road, Aztec, NM 87410
District IV
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources Department

Oil Conservation Division
1220 South St. Francis Dr.
Santa Fe, NM 87505

Submit Original
to Appropriate
District Office

OCD - HOBBS
08/24/2016
RECEIVED

GAS CAPTURE PLAN

Date: 8/23/2016

X Original

Operator & OGRID No.: Matador Production Company (228937)

☐ Amended - Reason for Amendment:____________________

This Gas Capture Plan outlines actions to be taken by the Operator to reduce well/production facility flaring/venting for new completion (new drill, recomplete to new zone, re-frac) activity.

Note: A C-129 must be submitted and approved prior to exceeding 60 days allowed by Rule 19.15.18.12.A

Well(s)/Production Facility – Name of facility

The well(s) that will be located at the production facility are shown in the table below.

Well Name	API	Well Location (ULSTR)	Footages	Expected MCF/D	Flared or Vented	Comments
Airstrip 31 18 35 RN State Com #201H	N/A	M-31-18S-35E	SHL:150'S 660'E BHL:330'N 710'W	~800	Flared	

Gathering System and Pipeline Notification

The well will be connected to a production facility after flowback operations are complete so long as the gas transporter system is in place. The gas produced from the production facility should be connected to Longwood Midstream Delaware, LLC's gathering system located in Lea County, New Mexico. It will require ~1,100' of pipeline to connect the facility to the gathering system. Matador Production Company periodically provides a drilling, completion and estimated first production date for wells that are scheduled to be drilled in the foreseeable future to Longwood Midstream Delaware, LLC. If changes occur that will affect the drilling and completion schedule, Matador Production Company will notify Longwood Midstream Delaware, LLC. Additionally, the gas produced from the well will be processed at a processing plant further downstream in Sec. 32, Twn. 19S, Rng. 37E, Lea County, New Mexico, and, although unanticipated, any issues with downstream facilities could cause flaring at the wellhead. The actual flow of the gas will be based on compression operating parameters and gathering system pressures measured when the well starts producing.

Flowback Strategy

After fracture treatment/completion operations (flowback), the well will be produced to temporary production tanks and the gas will be flared or vented. During flowback, the fluids and sand content will be monitored. If the produced fluids contain minimal sand, then the well will be turned to production facilities. The gas sales should start as soon as the well starts flowing through the production facilities, unless there are operational issues on the midstream system at that time. Based on current information, it is Matador's belief the system will be able to take the gas upon completion of the well.

Safety requirements during cleanout operations may necessitate that sand and non-pipeline quality gas be vented and/or flared rather than sold on a temporary basis.

Alternatives to Reduce Flaring

Below are alternatives considered from a conceptual standpoint, but determined to be impractical, to reduce the amount of gas flared.

- Power Generation – On lease
  - Operating a generator will only utilize a portion of the produced gas and the remainder of gas would still need to be flared.
  - Power generation also requires an agreement with a power company that is willing to purchase the gas. The terms of any such agreement typically require a long term commitment from the operator at certain and steady deliverables. With gas decline rates and the unpredictability of markets, it is impracticable for the operator to agree to a long term commitment because as the wells decline the operator would be burdened with penalties for failure to meet the deliverables.
- Compressed Natural Gas – On lease
  - Compressed Natural Gas is likely to be uneconomic to operate when the gas volume declines.
- NGL Removal – On lease
  - NGL Removal requires a plant and is expensive on such a small scale rendering it uneconomic and still requires residue gas to be flared.

Matador
RESOURCES COMPANY

Investor Presentation

NMOCC Case No. 15363
Hearing: SEP 6, 2016
Jalapeno EX 18

July 2016

NYSE: MTDR

Disclosure Statements

Safe Harbor Statement – This presentation and statements made by representatives of Matador Resources Company ("Matador" or the "Company") during the course of this presentation include "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. "Forward-looking statements" are statements related to future, not past, events. Forward-looking statements are based on current expectations and include any statement that does not directly relate to a current or historical fact. In this context, forward-looking statements often address expected future business and financial performance, and often contain words such as "could," "believe," "would," "anticipate," "intend," "estimate," "expect," "may," "should," "continue," "plan," "predict," "potential," "project," "hypothetical," "forecasted," and similar expressions that are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. Actual results and future events could differ materially from those anticipated in such statements, and such forward-looking statements may not prove to be accurate. These forward-looking statements involve certain risks and uncertainties, including, but not limited to, the following risks related to Matador's financial and operational performance: general economic conditions; Matador's ability to execute its business plan, including whether Matador's drilling program is successful; changes in oil, natural gas and natural gas liquids prices and the demand for oil, natural gas and natural gas liquids; Matador's ability to replace reserves and efficiently develop its current reserves; Matador's costs of operations, delays and other difficulties related to producing oil, natural gas and natural gas liquids; Matador's ability to integrate acquisitions, including the merger with Harvey E. Yates Company; Matador's ability to make other acquisitions on economically acceptable terms; availability of sufficient capital to execute Matador's business plan, including from its future cash flows, increases in Matador's borrowing base and otherwise; weather and environmental conditions; and other important factors which could cause actual results to differ materially from those anticipated or implied in the forward-looking statements. For further discussions of risks and uncertainties, you should refer to Matador's SEC filings, including the "Risk Factors" section of Matador's most recent Annual Report on Form 10-K and any subsequent Quarterly Reports on Form 10-Q. Matador undertakes no obligation and does not intend to update these forward-looking statements to reflect events or circumstances occurring after the date of this presentation, except as required by law, including the securities laws of the United States and the rules and regulations of the SEC. You are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date of this presentation. All forward-looking statements are qualified in their entirety by this cautionary statement.

Cautionary Note – The Securities and Exchange Commission (SEC) permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserves. Potential resources are not proved, probable or possible reserves. The SEC's guidelines prohibit Matador from including such information in filings with the SEC.

Definitions – Proved oil and natural gas reserves are the estimated quantities of oil and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Matador's production and proved reserves are reported in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Where Matador produces liquids-rich natural gas, the economic value of the natural gas liquids associated with the natural gas is included in the estimated wellhead natural gas price on those properties where the natural gas liquids are extracted and sold. Estimated ultimate recovery (EUR) is a measure that by its nature is more speculative than estimates of proved reserves prepared in accordance with SEC definitions and guidelines and is accordingly less certain. Type curves shown in this presentation are used to compare actual well performance to a range of potential production results calculated without regard to economic conditions; actual recoveries may vary from these type curves based on individual well performance and economic conditions.

Matador RESOURCES COMPANY

Company Summary

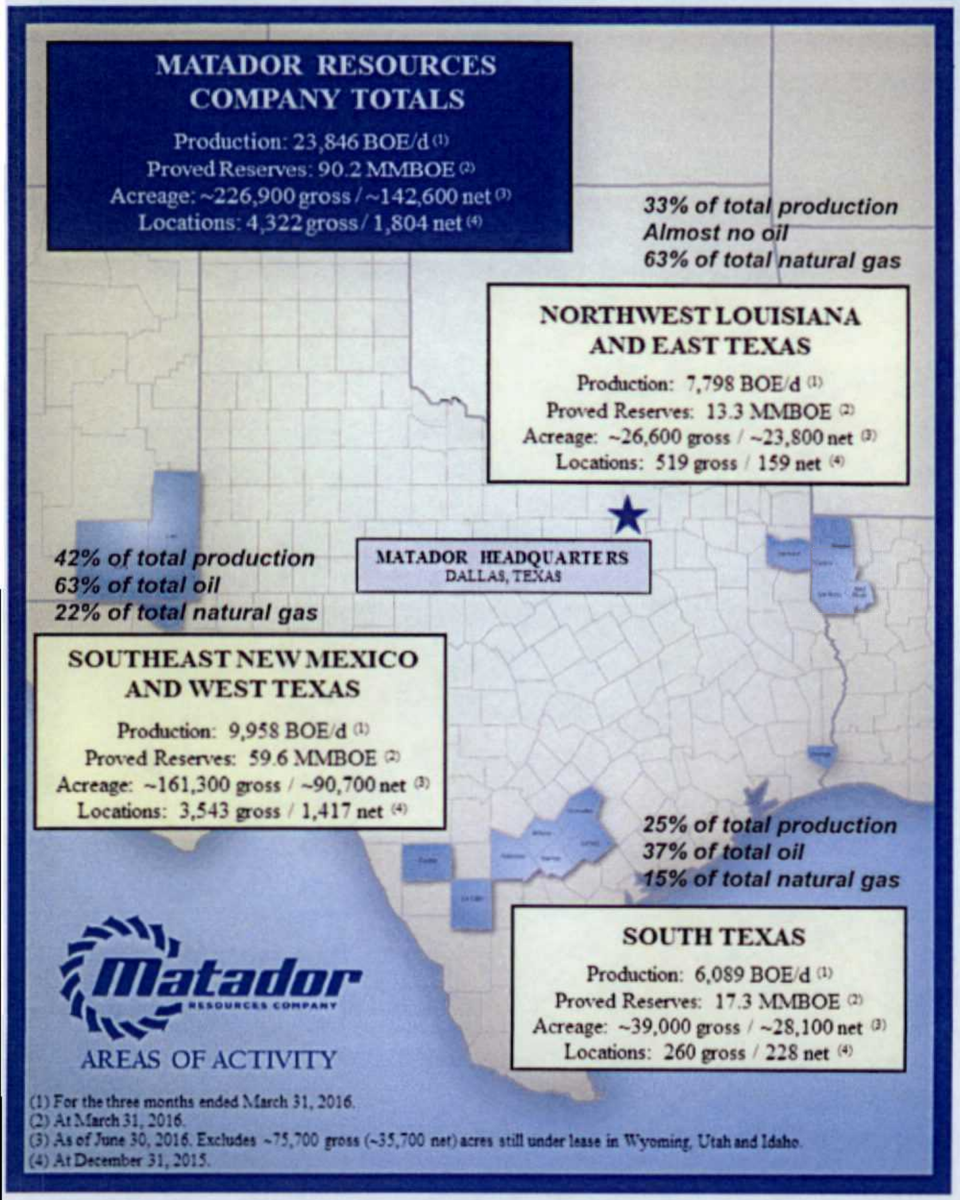
Company Overview

Exchange: Ticker	NYSE: MTDR
Shares Outstanding(1)	93.3 million common shares
Share Price(1)	$22.05/share
Market Capitalization(1)	~$2.1 billion

	Actual 2014 Results	*Actual 2015 Results*	*2016 Guidance*	*% YoY Change*
Capital Spending	$610 million	$482 million(2)	$325 million	- 33%
Total Oil Production	3.3 million Bbl	4.5 million Bbl	4.9 to 5.1 million Bbl	+ 11%
Total Natural Gas Production	15.3 Bcf	27.7 Bcf	26.0 to 28.0 Bcf	- 3%
Total Oil Equivalent Production	5.9 million BOE	9.1 million BOE	9.2 to 9.8 million BOE	+ 4%
Adjusted EBITDA(3)	$263 million	$223 million	$120 to $130 million(4)	- 44%

(1) Market capitalization based on closing share price as of July 15, 2016 and shares outstanding as reported in the Form 10-Q at May 6, 2016.
(2) For operations only. Does not include capital expenditures associated with the HEYCO transaction or two associated joint ventures.
(3) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see Appendix.
(4) Estimated 2016 Adjusted EBITDA is based upon the midpoint of 2016 production guidance range as provided on February 3, 2016 and affirmed on May 3, 2016. Estimated average realized prices for oil and natural gas used in these estimates were $39.75/Bbl (WTI oil price of $43.75/Bbl less $4.00/Bbl of estimated price differentials) and $2.37/Mcf (NYMEX Henry Hub natural gas price assuming regional differentials and uplifts from natural gas processing roughly offset), respectively, for the period April through December 2016.

Matador Resources Company – Operations Overview



Market Capitalization(1)	**~$2.1 billion**	
Avg. Daily Production(2)	**27,300 BOE/d**	
Oil (% total)(2)	13,700 Bbl/d (50%)	
Natural Gas (% total)(2)	81.7 MMcf/d (50%)	
Proved Reserves @ 3/31/2016	**90.2 million BOE**	↑ 14%*
% Proved Developed	37%	
% Oil	56%	
2016E CapEx(3)	**$325 million**	
% Delaware Basin	~97%	
Gross Acreage(4)	**~226,900 acres**	
Net Acreage(4)	**~142,600 acres**	
Engineered Drilling Locations(5)	**4,322 gross / 1,804 net**	↑ 32%*
Delaware Basin	3,543 gross / 1,417 net	↑ 48%*
Eagle Ford	260 gross / 228 net	
Haynesville/Cotton Valley	519 gross / 159 net	

* Note: Represents year-over-year increase as compared to each respective figure.

(1) Market capitalization based on closing share price as of July 15, 2016 and shares outstanding as reported in the Form 10-Q at May 6, 2016.

(2) Average daily production as of early May 2016, as reported in the Company's May 3, 2016 earnings release. Values do not reflect average production rates for the second quarter of 2016.

(3) 2016 estimated capital expenditures, including all anticipated operations, midstream, land and non-operated well expenditures as of May 6, 2016, assuming a 3-rig program in the Delaware Basin in 2016.

(4) As of June 30, 2016. Excludes ~75,700 gross (~35,700 net) acres still under lease in Wyoming, Utah and Idaho.

(5) Identified and engineered locations for potential future drilling, including specified production units and estimated lateral lengths, costs and well spacing using objective criteria for designation. Locations identified as of December 31, 2015, but including no locations at Twin Lakes. Includes all identified locations where Matador has an operated or non-operated working interest.

Matador Has Made Tremendous Progress Since its IPO

	At IPO(1): February 7, 2012	*Today(2)*	*Difference*
Oil Production	414 Bbl/d (6% oil)	13,700 Bbl/d (50% oil)(3)	↑ +33-fold
Proved Reserves	27 MMBOE (4% oil)	90 MMBOE (56% oil)	↑ +3-fold
Proved Oil Reserves	1.1 MMBbl	50.7 MMBbl	↑ +46-fold
Delaware Acreage	~7,500 net acres	~90,700 net acres(4)	↑ +12-fold
Leverage(5)	1.5x(6)	1.5x	↔ Flat
Share Price	$12.00(7)	$22.05(8)	↑ +84%

(1) Unless otherwise noted, at or for the nine months ended September 30, 2011.
(2) Unless otherwise noted, at or for the three months ended March 31, 2016.
(3) As of early May 2016, as reported in the Company's May 3, 2016 earnings release.
(4) As of June 30, 2016.
(5) Calculated as net debt divided by LTM Adjusted EBITDA. Net debt is equal to debt outstanding less available cash. Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see Appendix.
(6) At December 31, 2011.
(7) As of February 7, 2012 at time of IPO.
(8) Closing share price as of July 15, 2016.

Matador's Production Growth History

Average Daily Oil Production
(Bbl/d)

Average Daily Natural Gas Production
(MMcf/d)

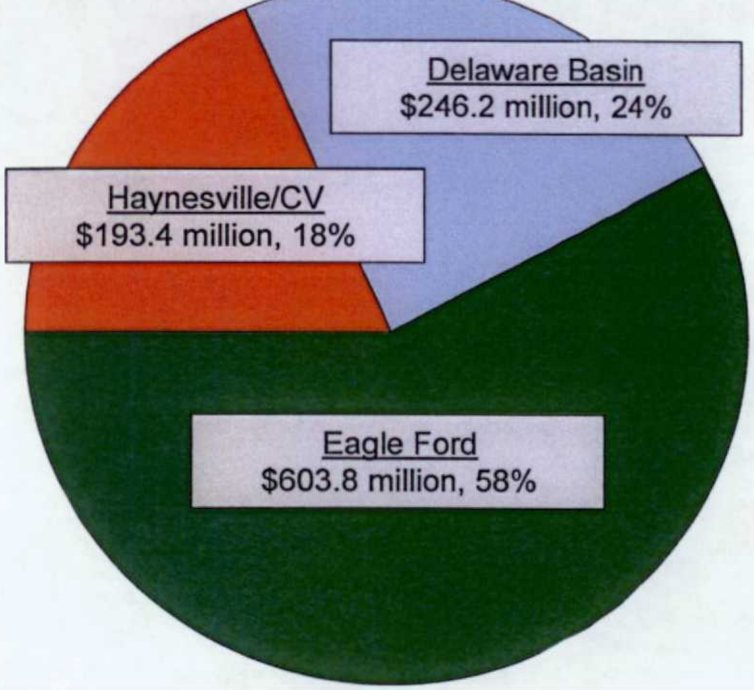
Average Daily Total Production
(MBOE/d)

Oil Production Mix
(% of Average Daily Production)

(1) Production rates for early May 2016, as provided in the Company's May 3, 2016 earnings release. Values do not reflect average production rates for the second quarter of 2016.

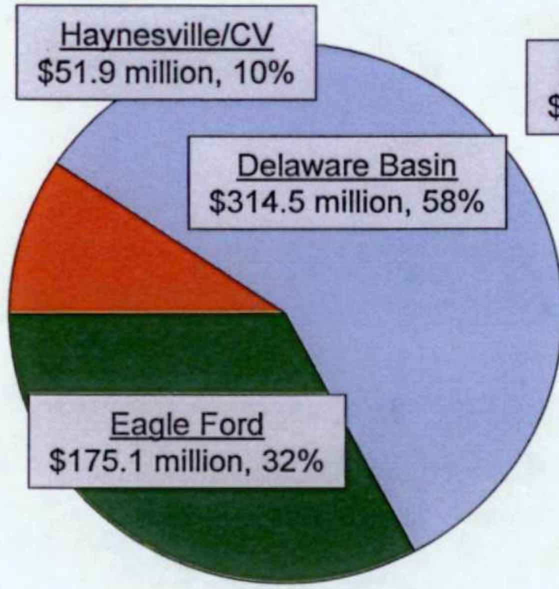
Matador

Matador's Reserves Volumes at an All-Time High at March 31, 2016



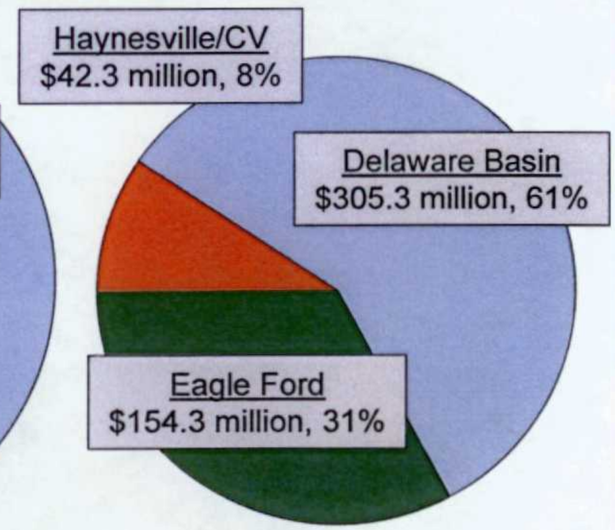
YE 2014

68.7 million BOE
24.2 million Bbl oil (35% oil)
PV-10[(1)]: $1,043.4 million
$91.48 oil / $4.35 gas



YE 2015

85.1 million BOE
45.6 million Bbl oil (54% oil)
PV-10[(1)]: $541.6 million
$46.79 oil / $2.59 gas



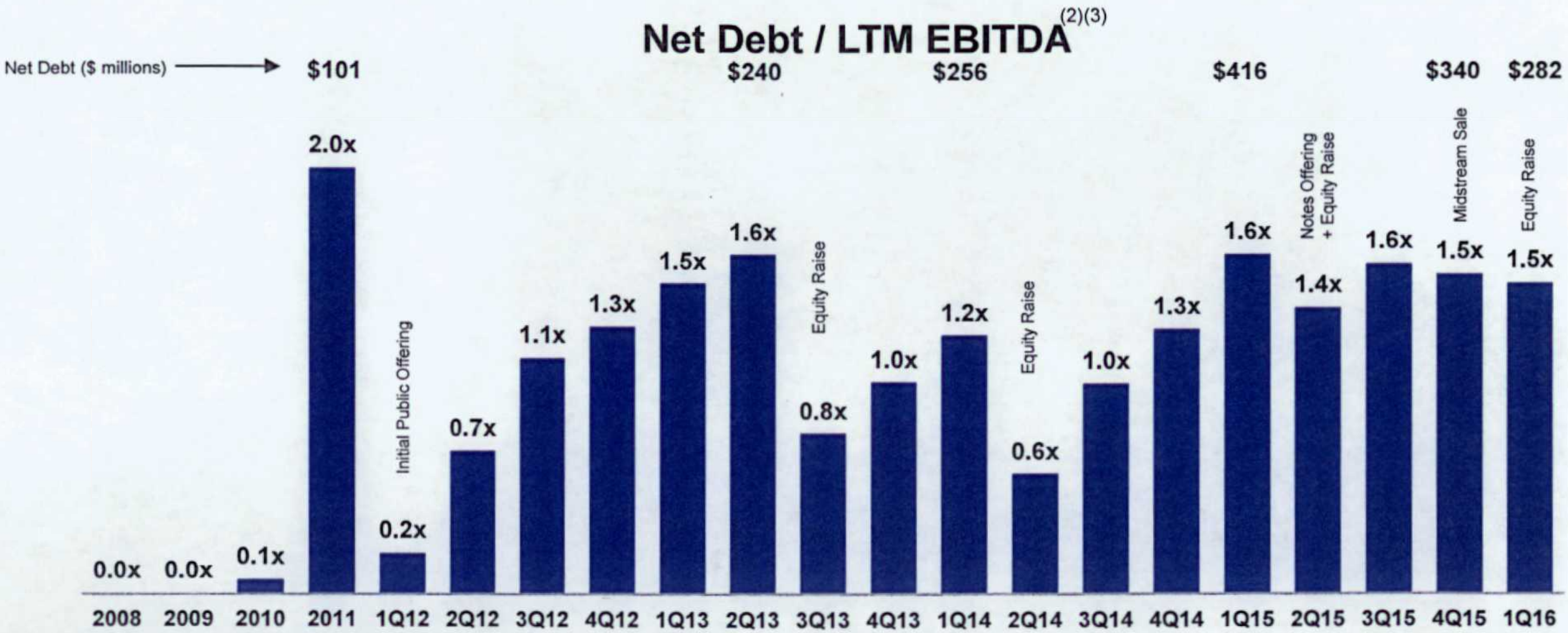
Q1 2016

90.2 million BOE ↑ 6%
50.7 million Bbl oil (56% oil) ↑ 11%
PV-10[(1)]: $501.9 million ↓ 7%
$42.77 oil / $2.40 gas ↓ 8%

Note: Oil and natural gas prices noted are in $/Bbl and $/MMBtu, respectively. Prices reflect the arithmetic average of first-day-of-month oil and natural gas prices for the 12-month periods January 1 to December 31, 2014 and 2015 and April 1, 2015 to March 31, 2016, respectively, as per SEC guidelines for reserves estimation.
(1) PV-10 is a non-GAAP financial measure. For a reconciliation of PV-10 (non-GAAP) to Standardized Measure (GAAP), see Appendix.

Committed to Maintaining Strong Balance Sheet

- Preserved and enhanced liquidity through April 2015 equity and Senior Notes offerings, sale of certain Loving County midstream assets for ~$143 million[1] in October 2015 and March 2016 equity offering
- Substantial liquidity to execute planned drilling program throughout 2016, including proceeds from March 2016 equity offering of ~$142 million and $300 million in undrawn borrowing capacity at July 18, 2016
- Strong financial position with Net Debt/LTM Adjusted EBITDA[2][3] of ~1.5x, well below peer average



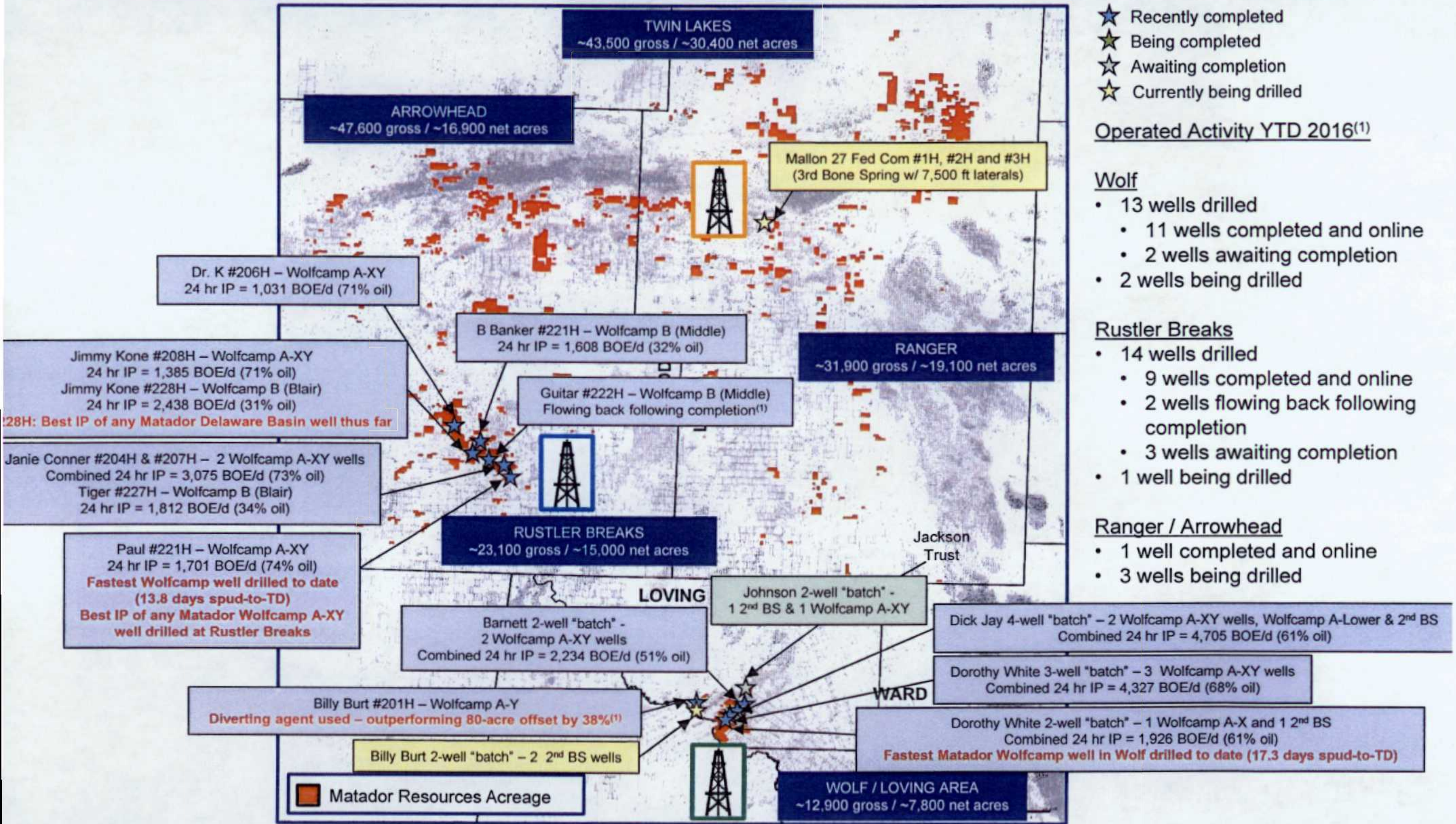
(1) Excluding customary purchase price adjustments.
(2) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see Appendix.
(3) Net Debt is equal to debt outstanding less available cash (including $43 million of restricted cash held in escrow at December 31, 2015).



Delaware Basin

Southeast New Mexico and West Texas

Delaware Basin Acreage Position and Recent Operations and Results



Recently completed
Being completed
Awaiting completion
Currently being drilled

Operated Activity YTD 2016(1)

Wolf
- 13 wells drilled
  - 11 wells completed and online
  - 2 wells awaiting completion
- 2 wells being drilled

Rustler Breaks
- 14 wells drilled
  - 9 wells completed and online
  - 2 wells flowing back following completion
  - 3 wells awaiting completion
- 1 well being drilled

Ranger / Arrowhead
- 1 well completed and online
- 3 wells being drilled

Note: All acreage at June 30, 2016. Some tracts not shown on map.
(1) At July 18, 2016.

Understanding the Opportunities

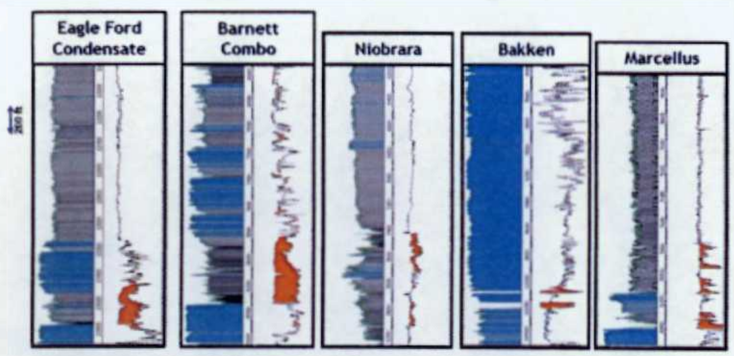
Most current unconventional plays target one or two zones across a trend area.

The Delaware Basin has over a dozen unique targets between the top of the Brushy Canyon and the Woodford.

Objective: To drill and complete better wells for less money

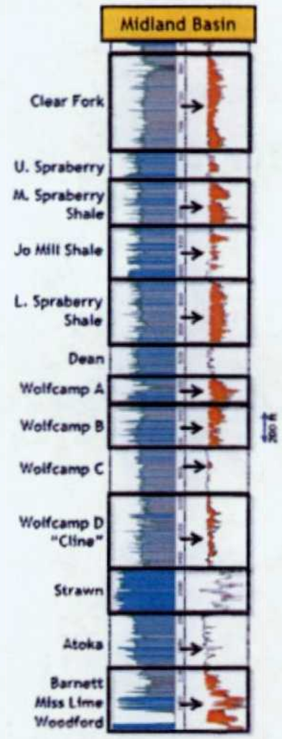
Challenge: To identify the best targets within multiple prospective intervals across a geologically complex basin

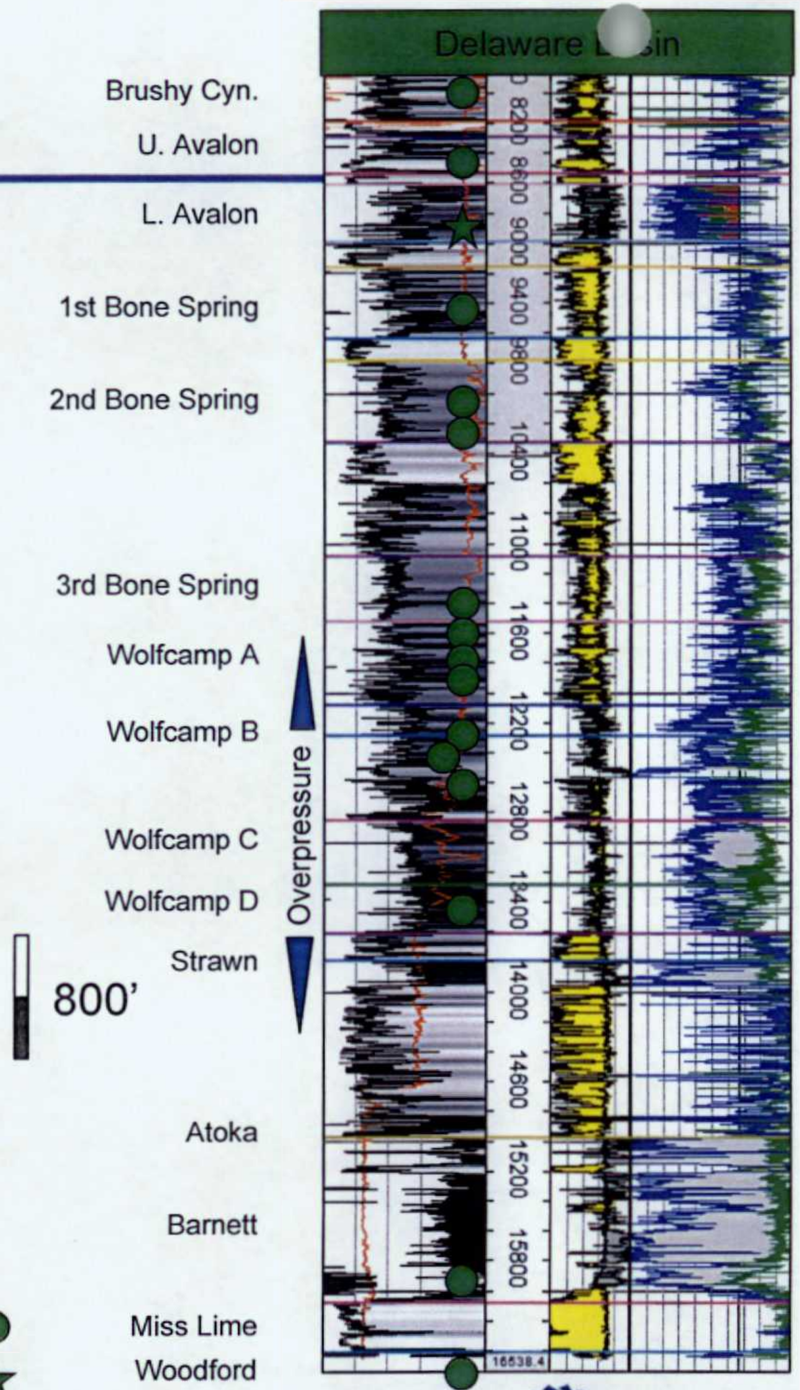
Matador's geoscience staff is committed to bringing the best targets forward!



Source: PXD

All logs plotted at same scale





Tested by MTDR

Tested by others

Matador

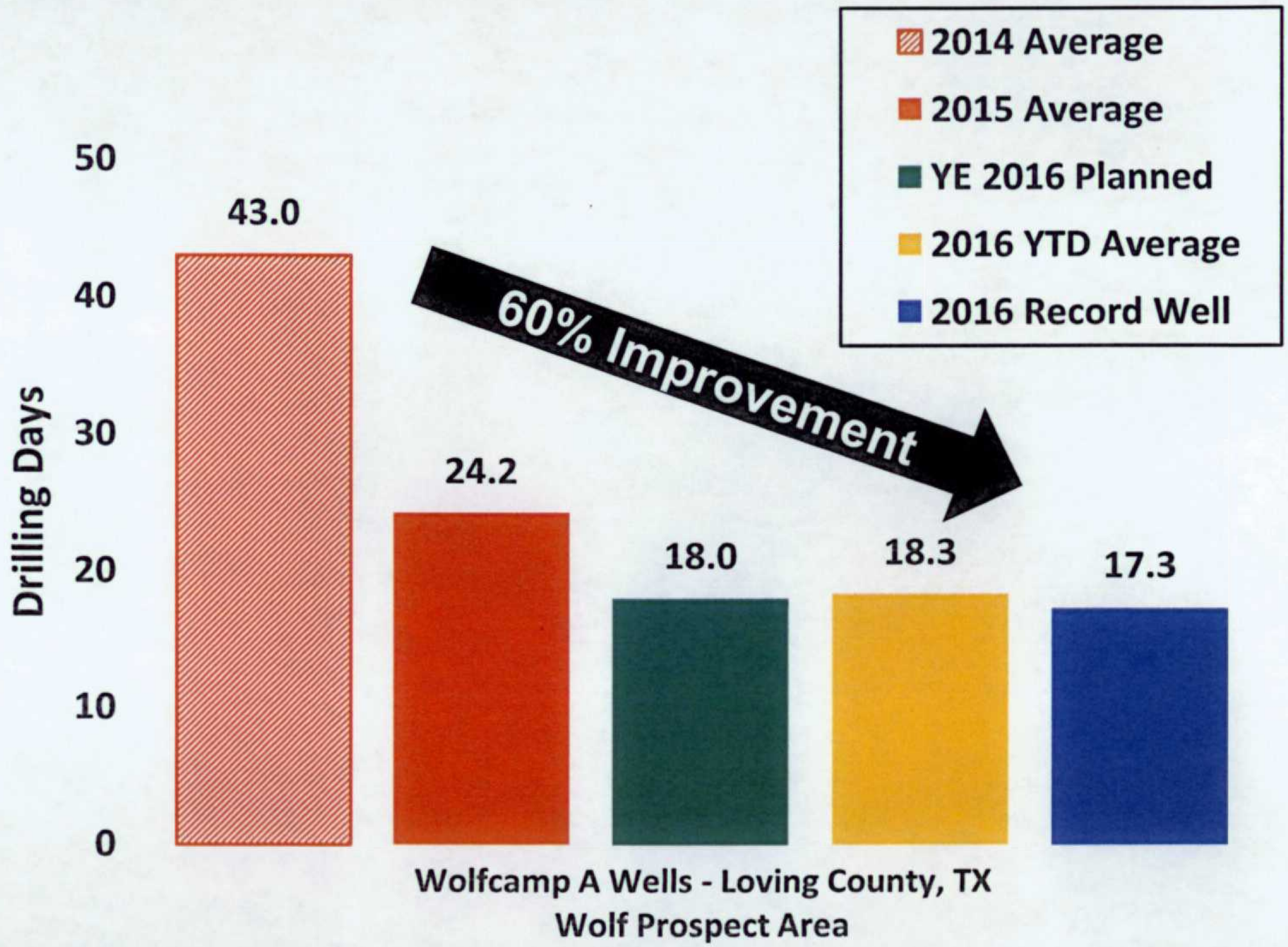
Delaware Basin Inventory Continues to Increase

- Matador has identified up to 3,543 gross (1,417 net) potential locations(1) for future drilling on its Delaware Basin acreage
  - *Only 118 gross (71.1 net) locations are PUD locations at December 31, 2015*
- Matador anticipates operating up to 2,263 gross (1,284 net) of these potential locations(2)
- Inventory does not yet include any locations for Twin Lakes prospect area

	Total Locations Identified(1)(3)		Potential Matador Operated Locations(1)(2)	
Formation	Gross	Net	Gross	Net
Delaware Group	276	100	178	90
Avalon	322	144	233	136
1st Bone Spring	556	177	290	152
2nd Bone Spring	657	243	381	215
3rd Bone Spring	489	203	325	186
Wolfcamp A-XY	280	122	187	111
Lower Wolfcamp A	339	164	256	154
Wolfcamp B	275	123	191	113
Wolfcamp D	349	140	222	126
TOTAL	3,543	1,417	2,263	1,284

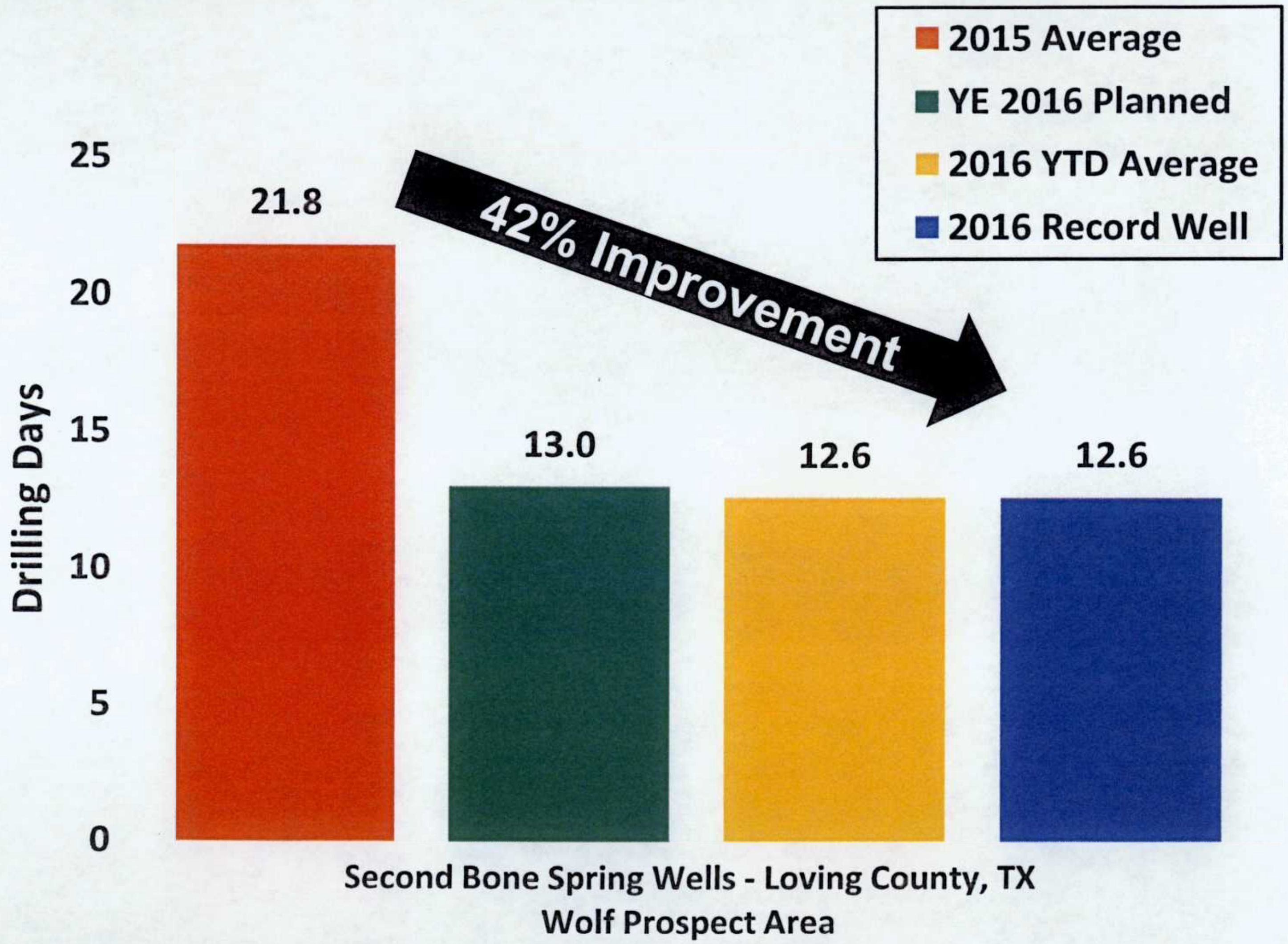
(1) At December 31, 2015.
(2) Includes any identified locations in which Matador's working interest is at least 25%.
(3) Identified and engineered locations for potential future drilling, including specified production units and estimated lateral lengths, costs and well spacing using objective criteria for designation. Locations identified as of December 31, 2015, but including no locations at Twin Lakes. Includes all identified locations where Matador has an operated or non-operated working interest.

Improving Drilling Times – Wolfcamp A Wells, Loving County, TX



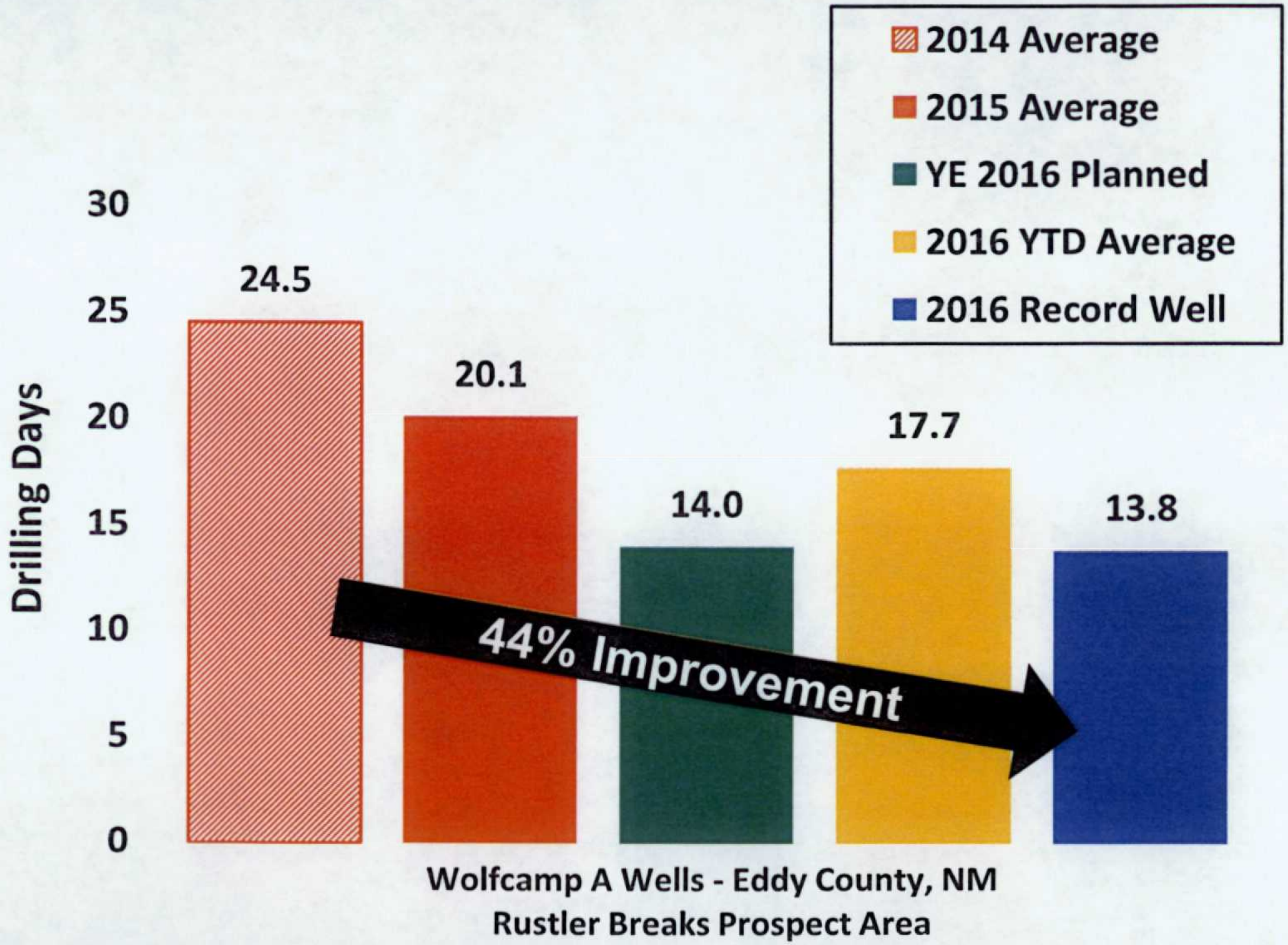
Note: Drilling days are spud to total depth.
Note: Loving County record well – Dorothy White #203H.

Improving Drilling Times – Second Bone Spring Wells, Loving County, TX



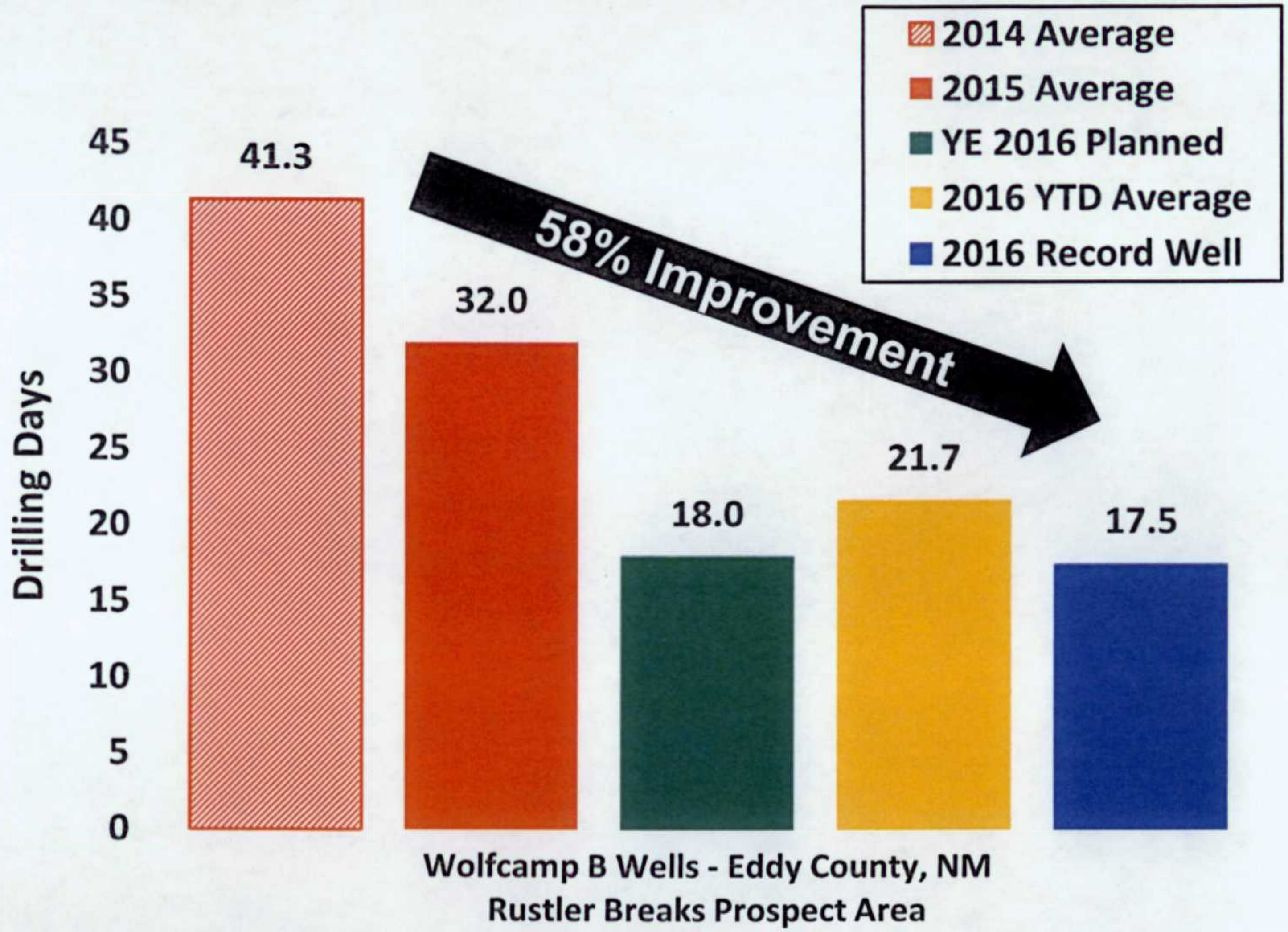
Note: Drilling days are spud to total depth.
Note: Loving County record well – Dorothy White #123H.

Improving Drilling Times – Wolfcamp A Wells, Eddy County, NM



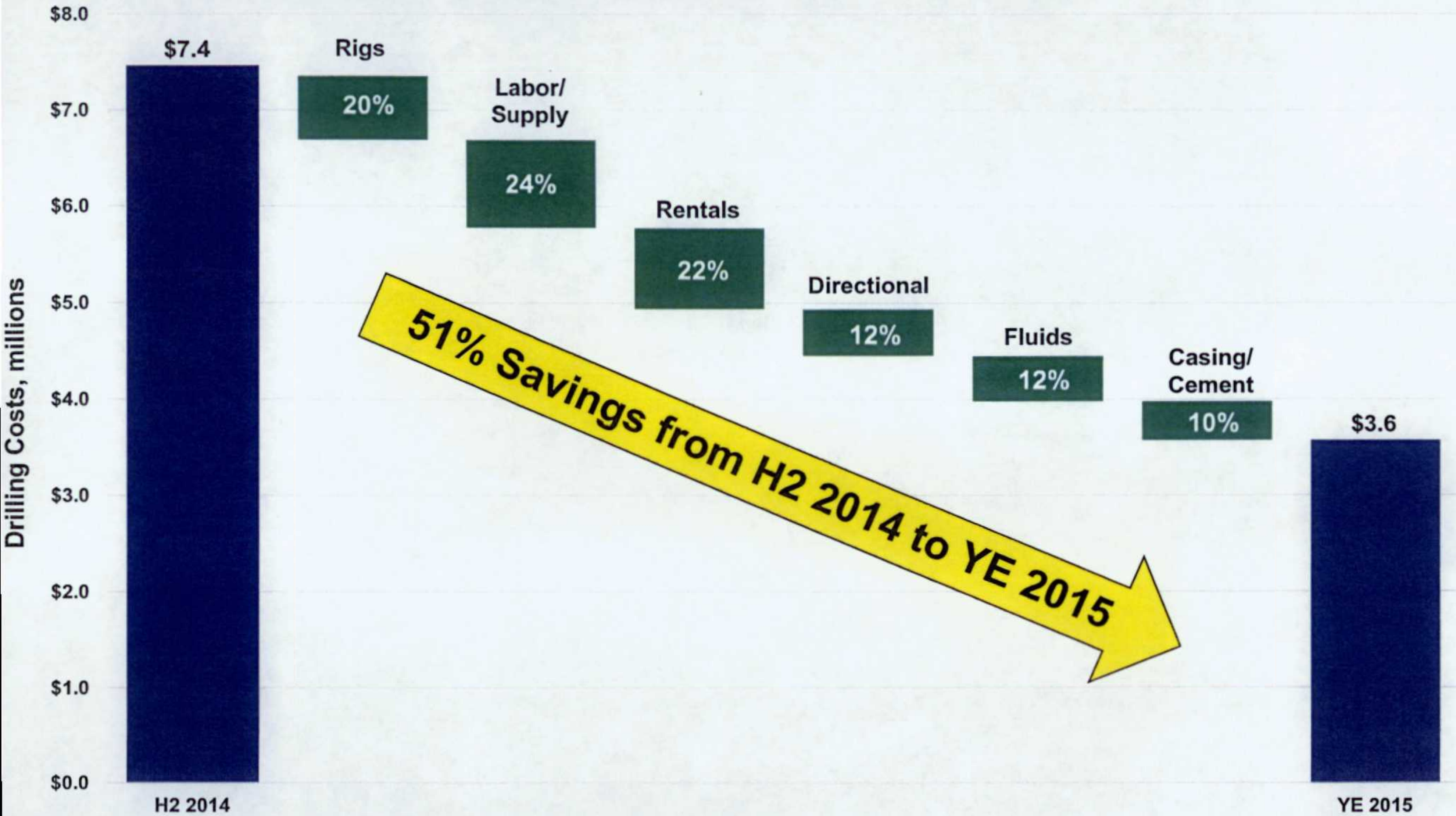
Note: Drilling days are spud to total depth.
Note: Eddy County record well – Paul #221H.
Note: 2015 averages include Scott Walker #204H with time associated with pilot hole, logging and sidetrack removed.

Improving Drilling Times – Wolfcamp B Wells, Eddy County, NM

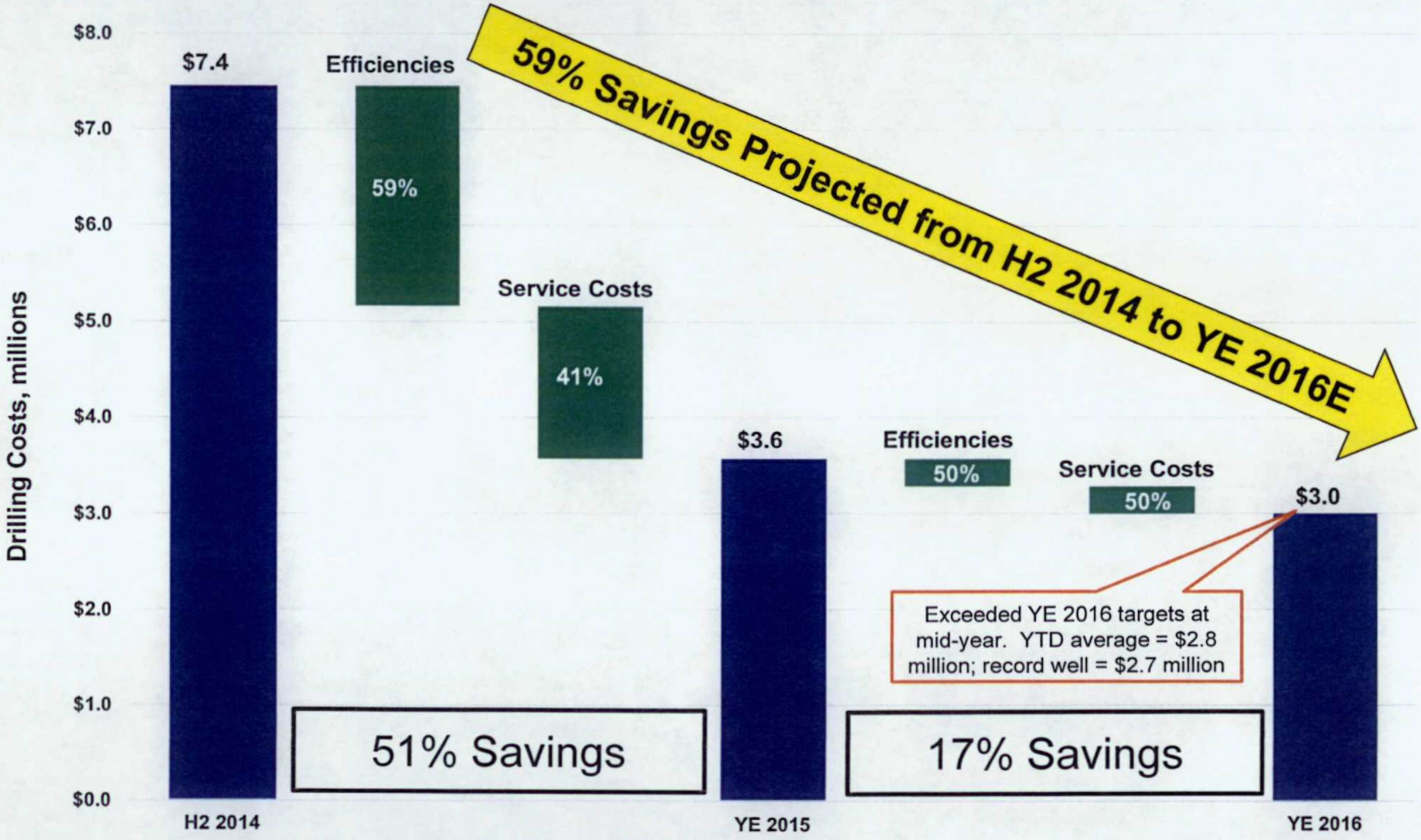


Note: Drilling days are spud to total depth.
Note: Eddy County record well – B Banker #221H.

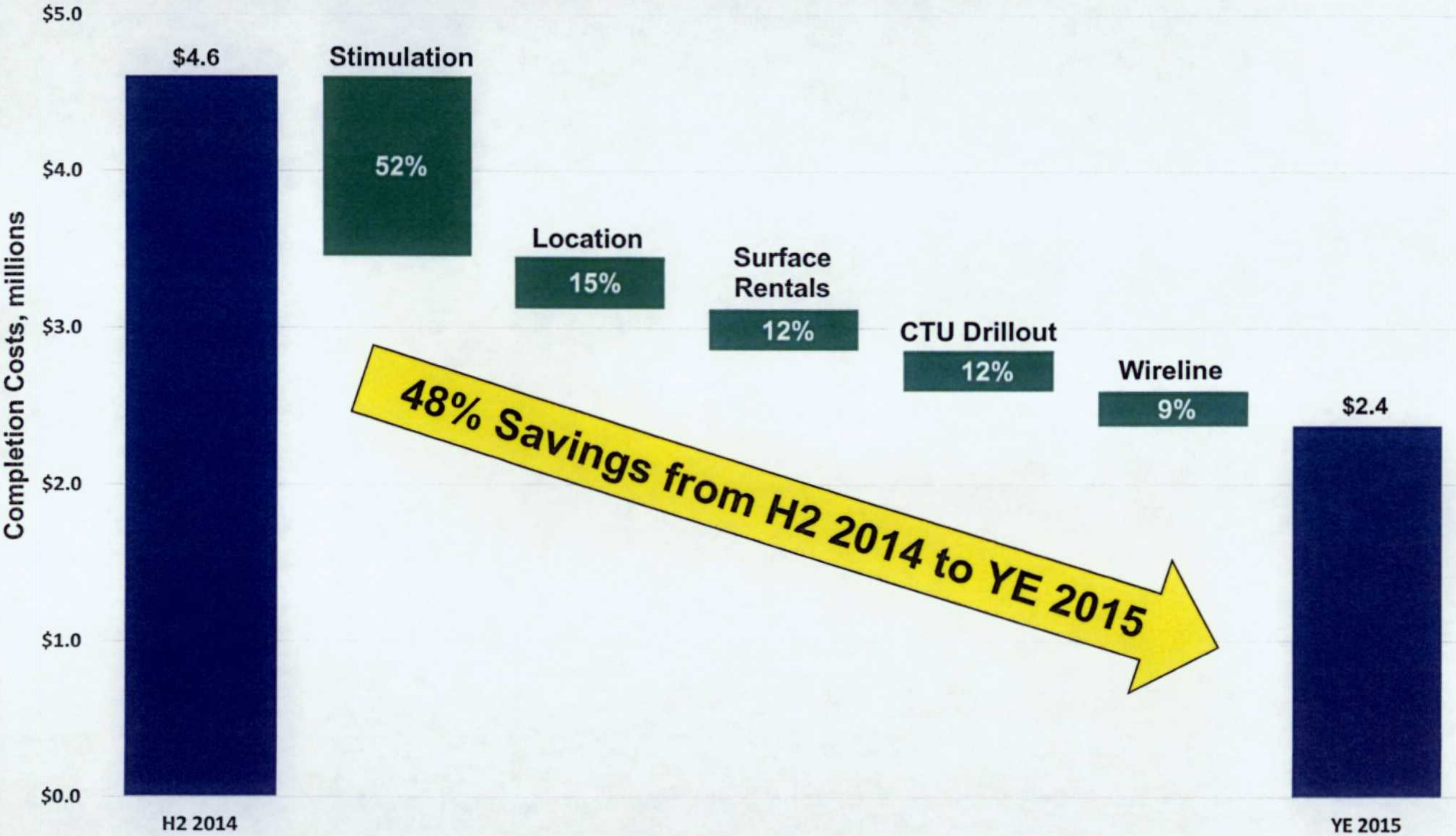
2015 Wolf Area Drilling Cost Improvements



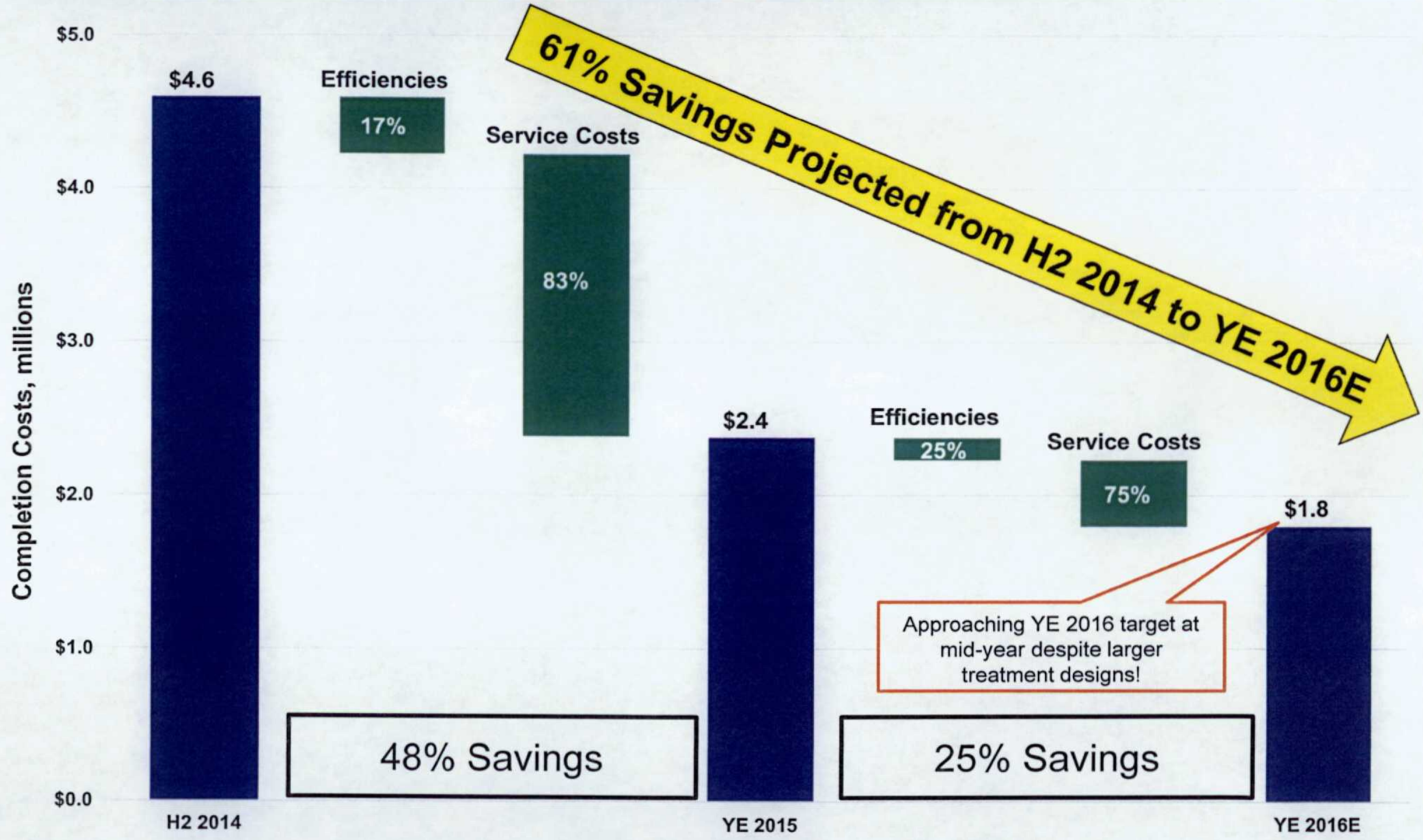
2016 Anticipated Wolf Area Drilling Cost Improvements



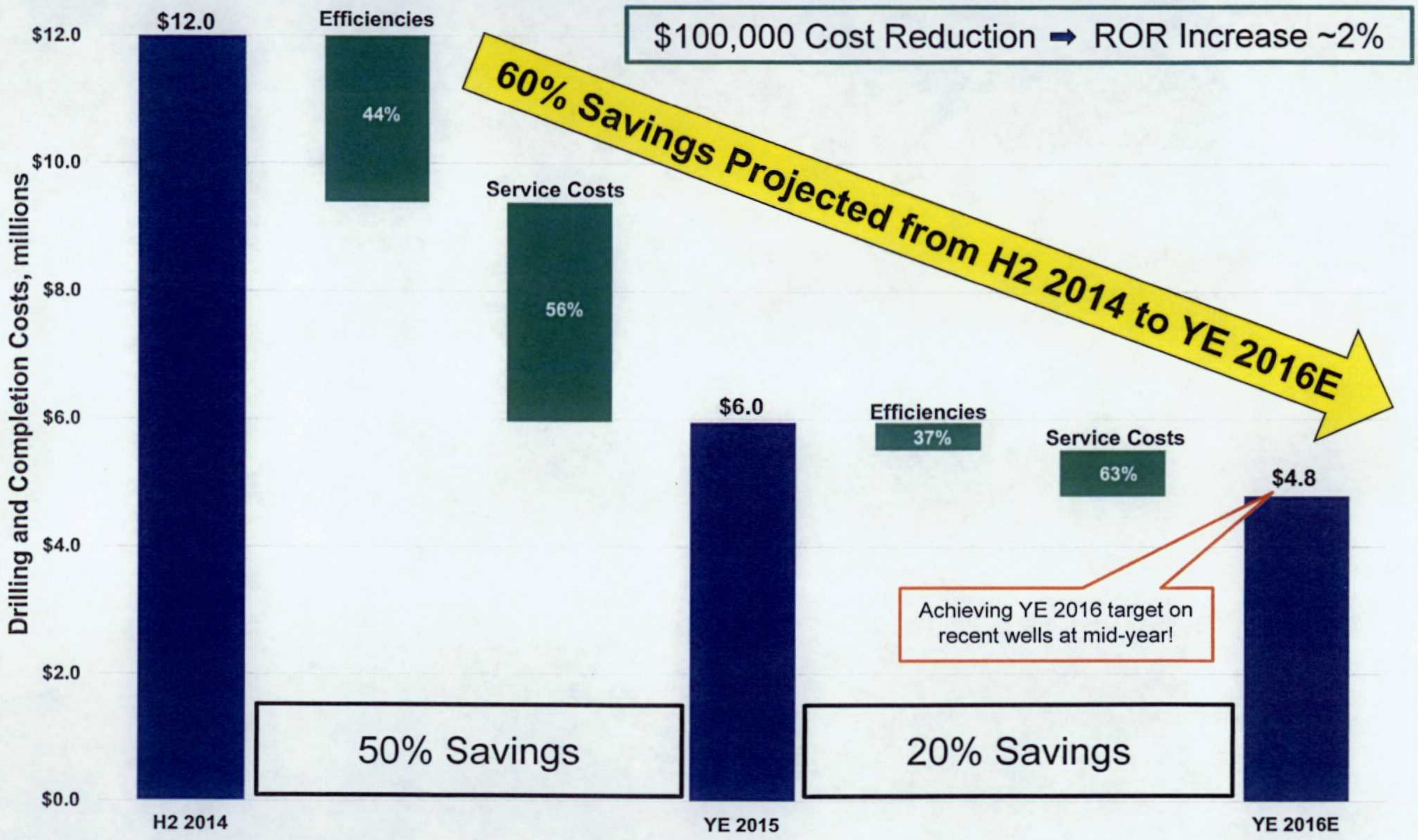
2015 Wolf Area Completion Cost Improvements



2016 Anticipated Wolf Area Completion Cost Improvements

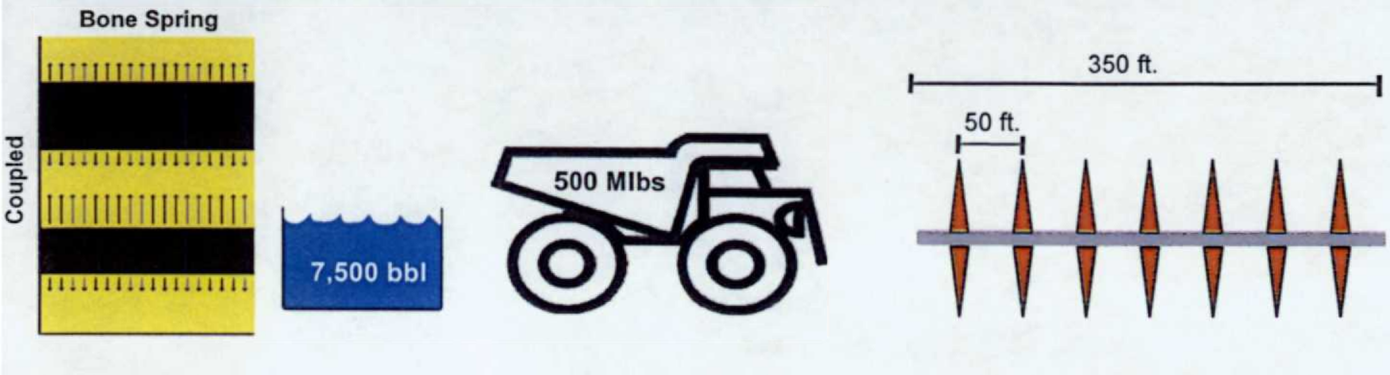


2016 Anticipated Wolf Area Total Drilling and Completion Cost Improvements

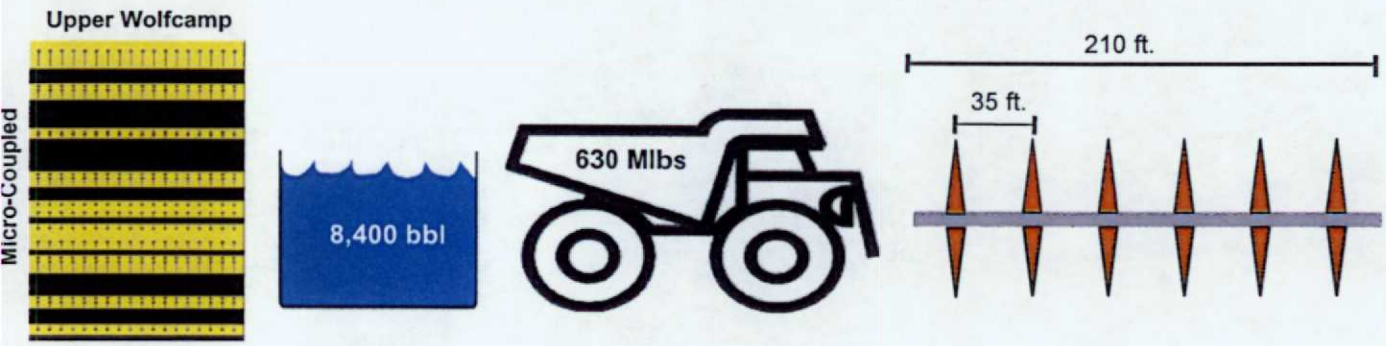


Note: Does not include production and facilities costs.

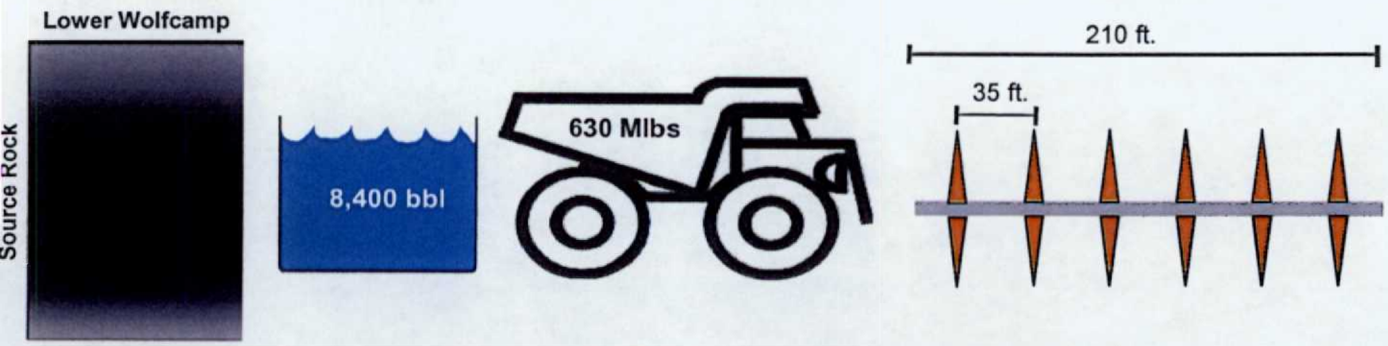
Evolution of Delaware Basin Frac Design – Reservoir Specific



Gen 1	Gen 2	Gen 3
2,000 lbs/ft	1,333 lbs/ft	2,100 lbs/ft
40 Bbl/ft	20 Bbl/ft	40 Bbl/ft
50' cluster spacing	75' cluster spacing	50' cluster Spacing
4 wells	6 wells	2 wells



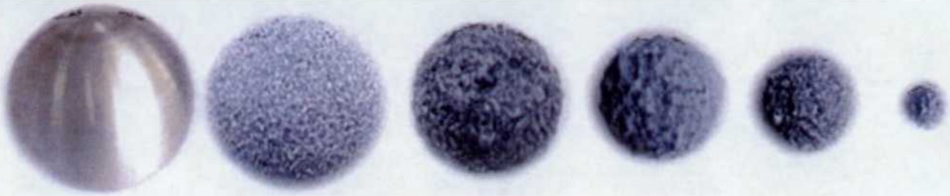
Gen 1	Gen 2	Gen 3
2,000 lbs/ft	2,000 lbs/ft	3,000 lbs/ft
40 Bbl/ft	30 Bbl/ft	40 Bbl/ft
35' cluster spacing	50' cluster spacing	35' cluster Spacing
10 wells	13 wells	12 wells



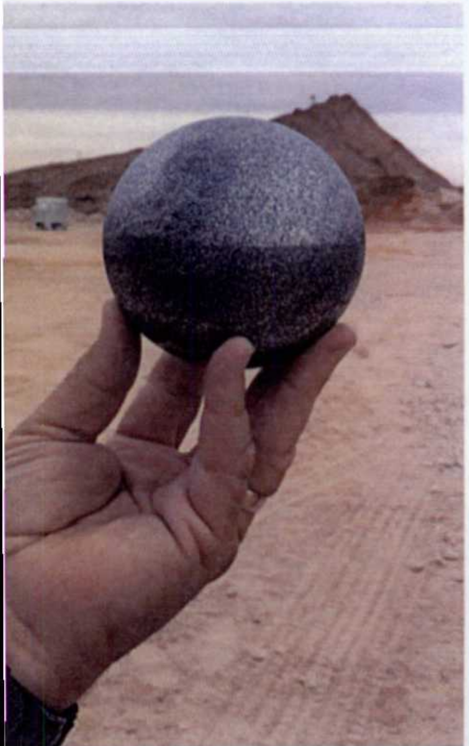
Gen 1	Testing
2,000 lbs/ft	3,000 lbs/ft
40 Bbl/ft	40 Bbl/ft
35' cluster spacing	35' cluster Spacing
1 well	1 well

Dissolvable Technologies

3.625" I.D.



Est. savings of over $45,000 by eliminating coiled tubing unit ("CTU") drillout



- Substitute for conventional ball and seat frac plugs
- Large bore flow-through plug - 3.625" I.D.
- Ball and seat both remain in wellbore, ball dissolves with combination of temperature, chlorides and flowback rate
- Chemically traced frac fluid in various stages of completion
  - Results confirmed contribution from all stages traced
- Elimination of CTU drillout operations
  - Resulted in flowback operations within 24 hours of frac completion
  - Removes mechanical risk of CTU drill out

Note: Savings based on average plug and coiled tubing intervention costs from the fourth quarter of 2015.

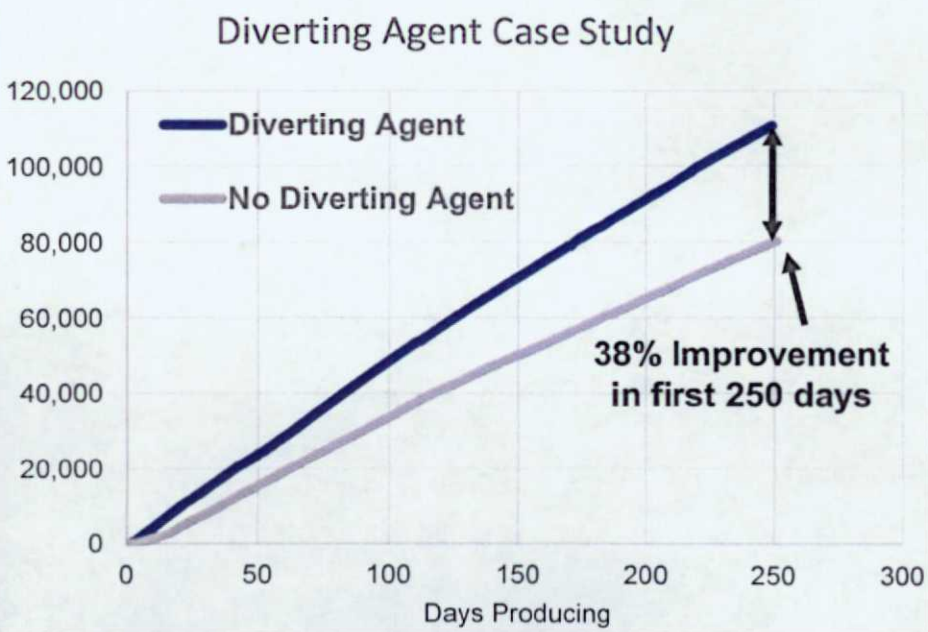
Improving Completion Performance – Diverting Agent Case Study

Initial Case Study Results:

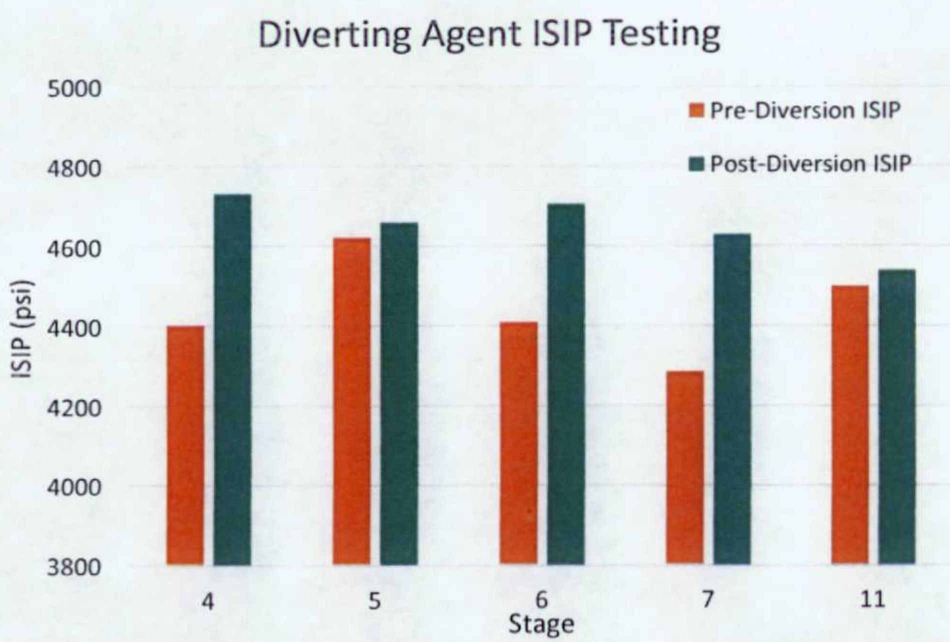
- Tested diverting agent on two offset Wolfcamp wells with near identical frac designs on 80-acre spacing
- Well without diverting agent was completed and producing six months prior to the well with diverting agent
- Well completed with diverting agent has seen a 38% uplift over its predecessor after first 250 days production

Ongoing Studies:

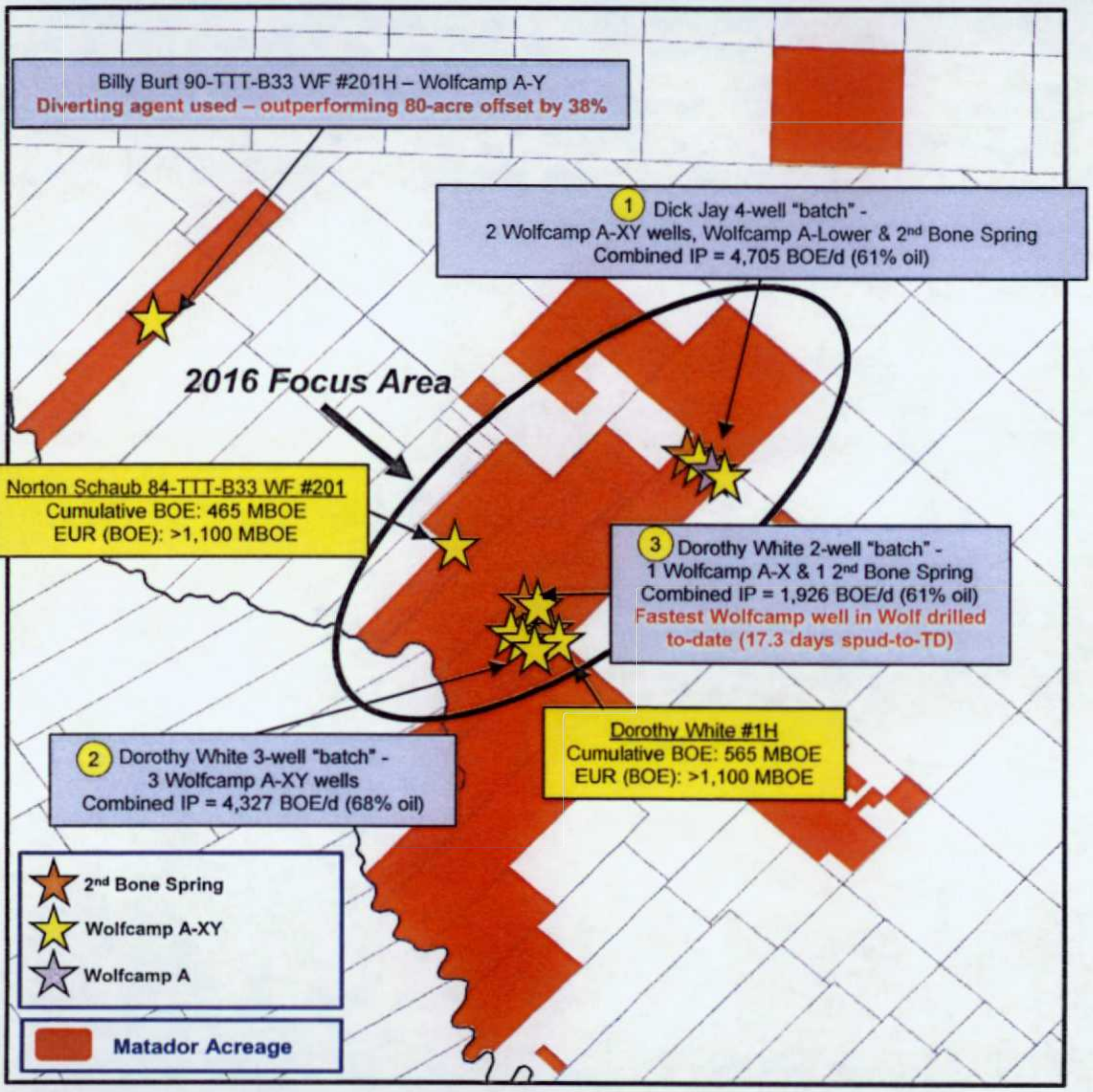
- Pumped diverting agent on five Loving County Wolfcamp wells in 2016
- Fracture treatment diagnostics give indication of newly created fractures, post diversion, in higher stress rock
- Plans are to start using diverting agents in Rustler Breaks Wolfcamp wells



Note: Production normalized to 5,000' lateral length



Wolf Prospect Area – Continued Focus on Wolfcamp Development in 2016



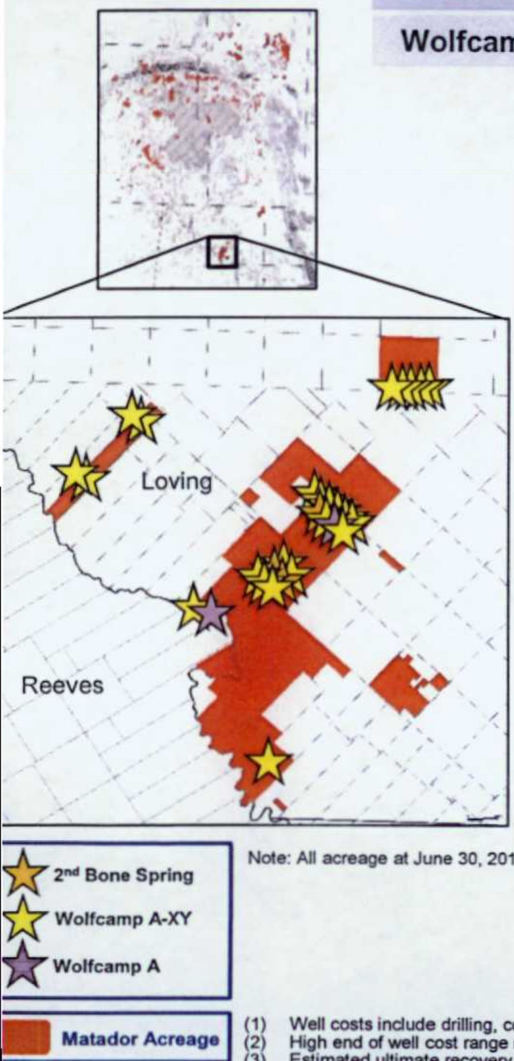
Note: All acreage at June 30, 2016. Some tracts not shown on map.
(1) Flowing casing pressure

- **First Half of 2016 Accomplishments**
  - *Achieved YE2016 drilling time targets for both Wolfcamp and Second Bone Spring on recent wells*
  - *Well costs near or below YE2016 targets*
  - *Generating "repeatable" results*
- **2016 Plans**
  - *Focus on Wolfcamp development and Bone Spring delineation*
    - *19 gross (16.3 net) wells planned for 2016*
    - *17 gross (15.3 net) wells on production*
- **Recent 24-Hour Initial Potential Test Results**

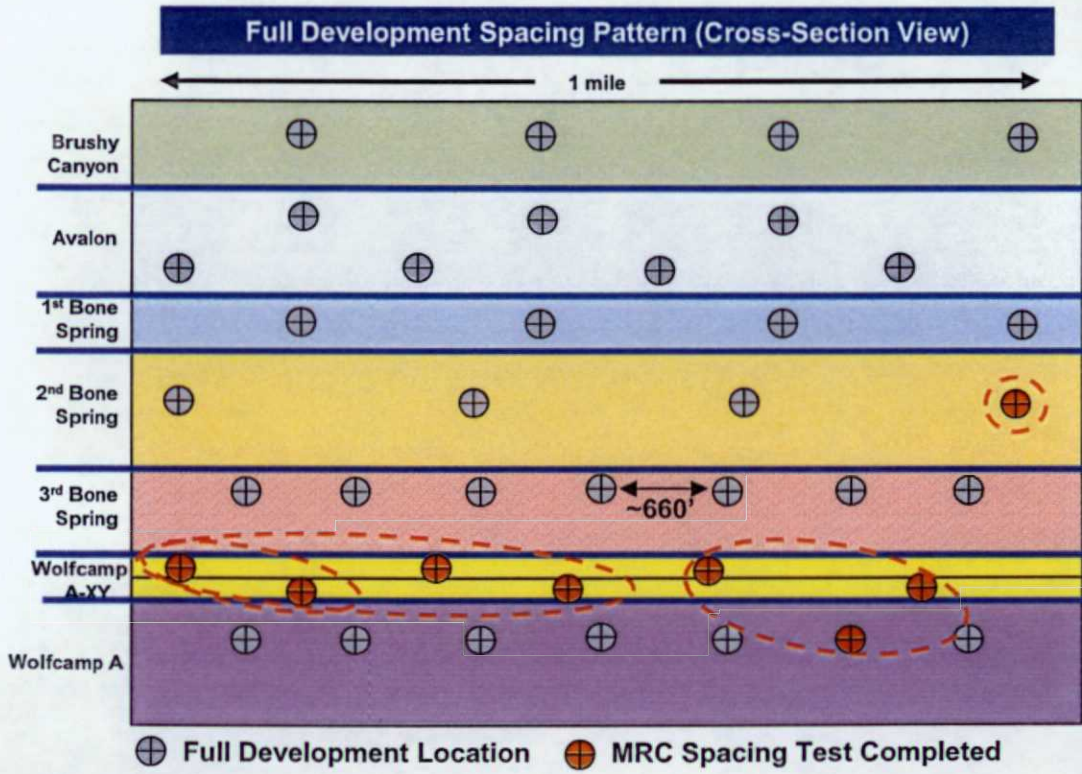
Well	Oil Eq. (BOE/d)	Oil (Bbl/d)	Natural Gas (MMcf/d)	% Oil	P_f[1] (psi)	Choke (inches)
Dick Jay 92-TTT-B01 WF #124H (Second Bone Spring)	1,093	733	2.2	67%	1,410	36/64th
Dick Jay 92-TTT-B01 WF #203H (Wolfcamp A-Y)	1,050	677	2.2	64%	3,000	28/64th
Dick Jay 92-TTT-B01 WF #204H (Wolfcamp A-X)	1,553	906	3.9	58%	2,950	30/64th
Dick Jay 92-TTT-B01 WF #212H (Wolfcamp A-Lower)	1,009	539	2.8	53%	2,475	30/64th
1 **Total**	4,705	2,855	11.1	61%		
Dorothy White 82-TTT-B33 WF #202H (Wolfcamp A-X)	1,416	924	3.0	65%	2,600	32/64th
Dorothy White 82-TTT-B33 WF #204H (Wolfcamp A-X)	1,671	1,165	3.0	70%	2,800	32/64th
Dorothy White 82-TTT-B33 WF #208H (Wolfcamp A-Y)	1,240	851	2.3	69%	2,400	32/64th
2 **Total**	4,327	2,940	8.3	68%		
Dorothy White 82-TTT-B33 WF #123H (Second Bone Spring)	866	526	2.0	61%	1,660	34/64th
Dorothy White 82-TTT-B33 WF #203H (Wolfcamp A-X)	1,060	656	2.4	62%	2,750	28/64th
3 **Total**	1,926	1,182	4.4	61%		
Barnett 90-TTT-B01 WF #203H (Wolfcamp A-X)	994	510	2.9	51%	2,950	30/64th
Barnett 90-TTT-B01 WF #204H (Wolfcamp A-Y)	1,240	632	3.6	51%	3,120	30/64th
4 **Total**	2,234	1,142	6.5	51%		

Wolf Inventory – Multi-Pay Development Potential

Formation	Development Well Costs(1)(2) (millions)	EUR(3) (MBOE)	% Oil
2nd Bone Spring	$4.0 – $5.0	400 – 500	50 – 65%
Wolfcamp A-XY	$5.5 – $6.5	650 – 1,100	65 – 80%



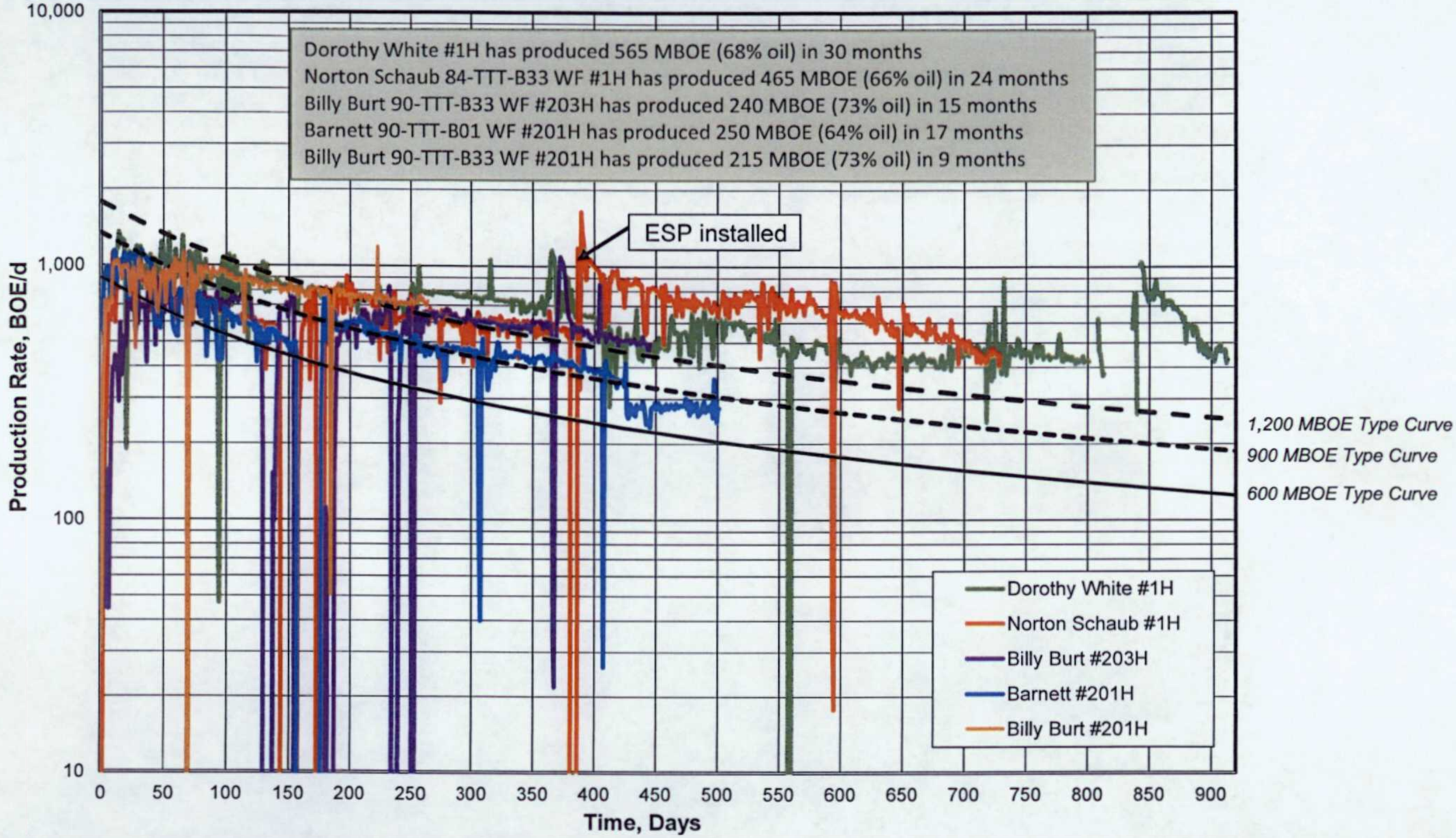
Note: All acreage at June 30, 2016.



Formation	Total Gross Locations(4)	Est. Operated Locations(5)
Brushy Canyon	4	4
Avalon	72	68
1st Bone Spring	Eval. Ongoing	Eval. Ongoing
2nd Bone Spring	70	66
3rd Bone Spring	72	68
Wolfcamp A-XY	51	47
Wolfcamp A	70	66
	339	319

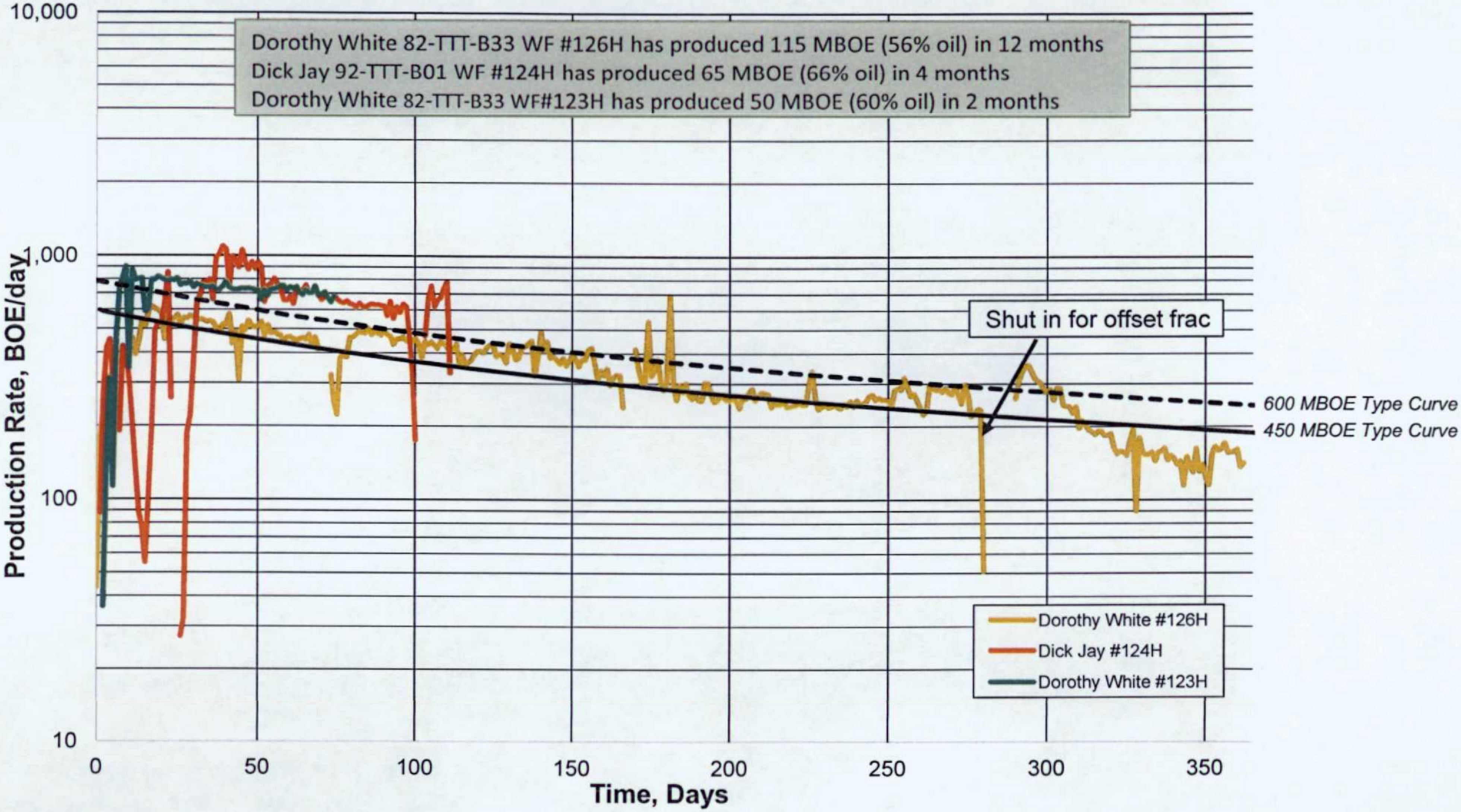
(1) Well costs include drilling, completion, production and facilities costs.
(2) High end of well cost range reflects estimated costs in Q1 2016; lower end of cost range reflects 2016 target.
(3) Estimated ultimate recovery, thousands of barrels of oil equivalent.
(4) Identified and engineered locations for potential future drilling, including specified production units and estimated lateral lengths, costs and well spacing using objective criteria for designation. Locations identified as of December 31, 2015.
(5) Includes any identified locations in which Matador's working interest is at least 25%.

Wolf Area Wolfcamp A-XY Wells Performing Above Expectations



Note: Production from selected Wolfcamp A-XY wells in Wolf prospect area as of July 2016.

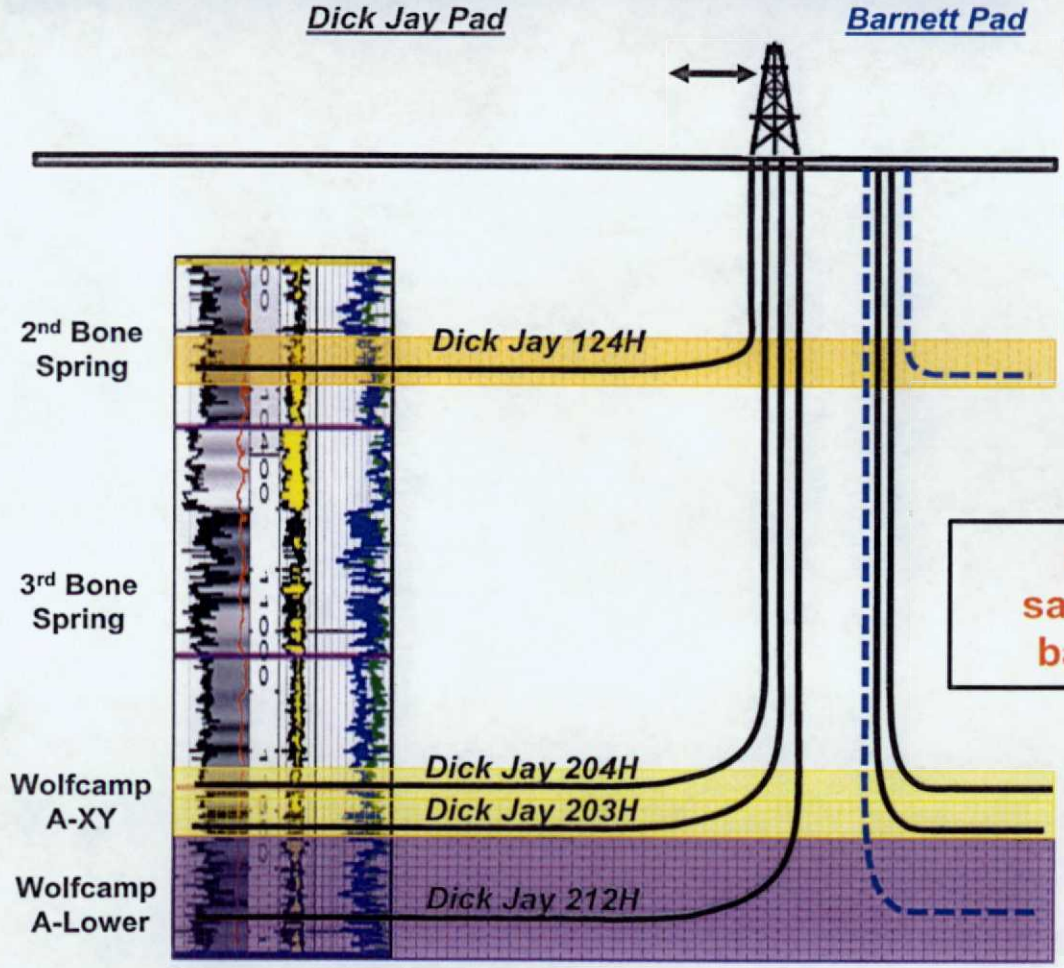
Wolf Second Bone Spring Wells Performing Above Expectations



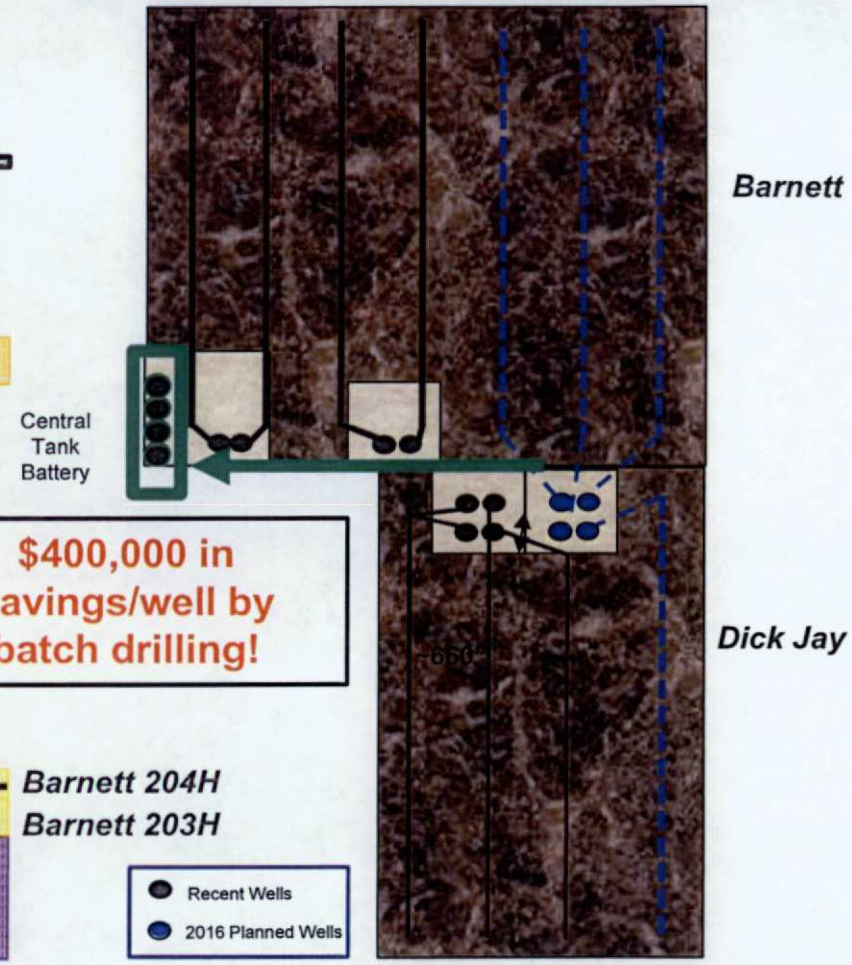
Note: Production as of July 2016.

Drilling Wells in Batch Mode / Central Production Facilities

Dick Jay / Barnett Development (Cross-Section View)



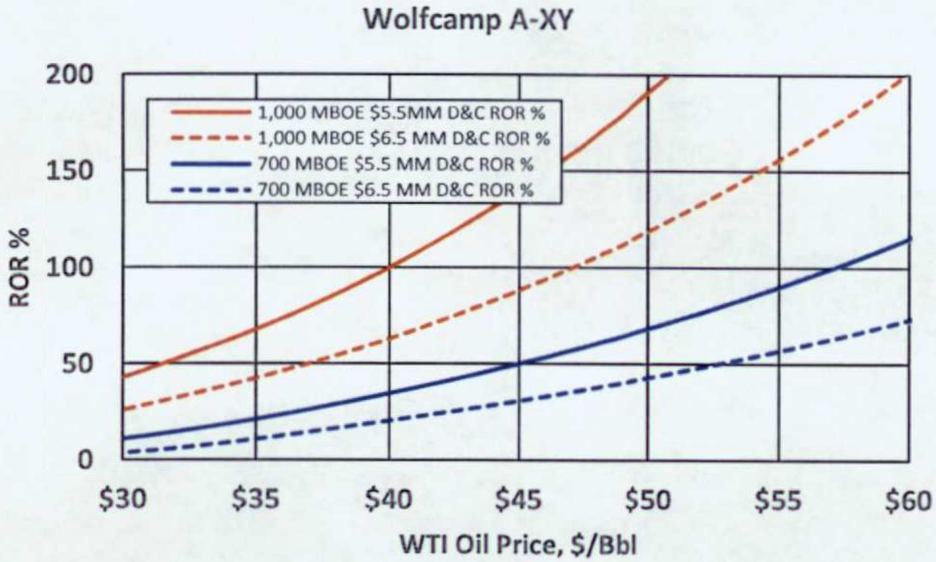
Dick Jay / Barnett Development (Top-Down View)

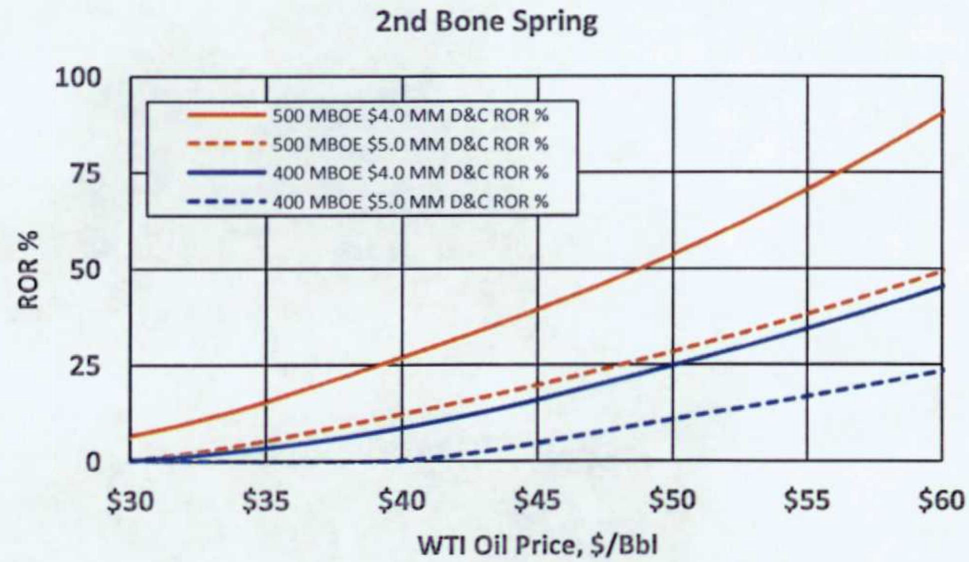


$400,000 in savings/well by batch drilling!

Wolf – Estimated Returns by Formation

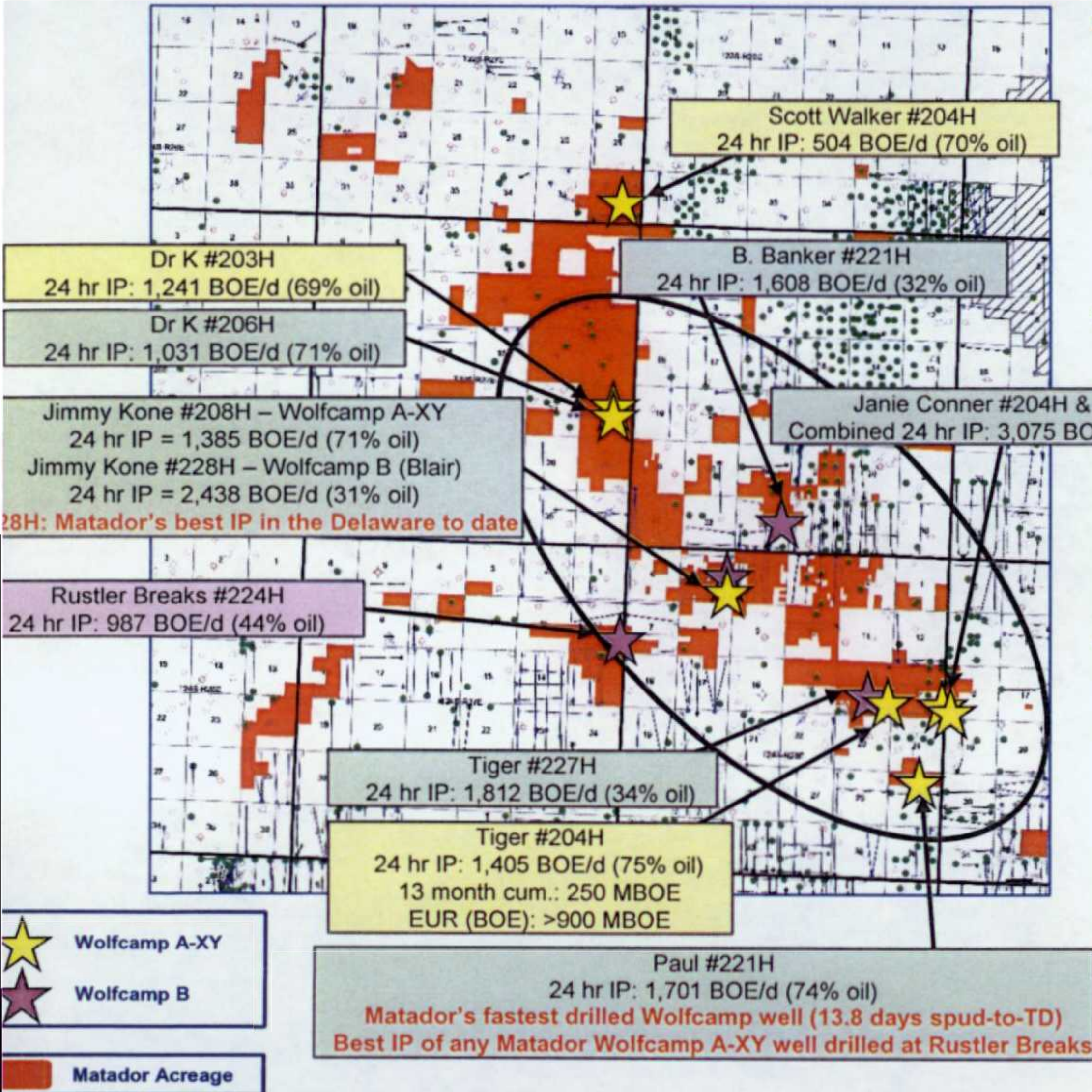
Formation	Development Well Cost[(1)(2)] (millions)	EUR[(3)] (MBOE)	% Oil
2nd Bone Spring	$4.0 - $5.0	400 – 500	50 – 65%
Wolfcamp A-XY	$5.5 - $6.5	650 – 1,100	65 – 80%





Note: Assumes $2.50/Mcf flat natural gas price with -$0.73/Mcf natural gas differential and -$1.75/Bbl oil differential.
(1) Well costs include drilling, completion, production and facilities costs.
(2) High end of well cost range reflects estimated costs in Q1 2016; lower end of cost range reflects 2016 target.
(3) Estimated ultimate recovery, thousands of barrels of oil equivalent.

Rustler Breaks – Focus on Wolfcamp Development in 2016



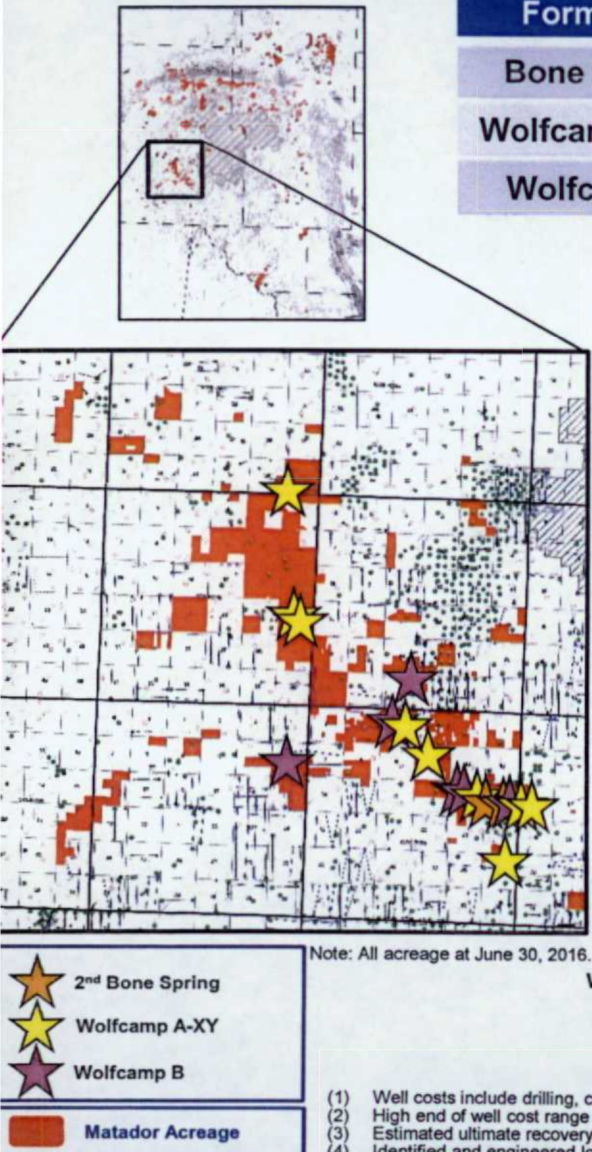
Note: All acreage at June 30, 2016. Some tracts not shown on map.
(1) Flowing casing pressure

- **First Half of 2016 Accomplishments**
  - *Achieved YE2016 drilling time targets for both Wolfcamp A-XY and Wolfcamp B on recent wells*
  - *Well costs near or below YE2016 targets*
  - *Successfully tested third Wolfcamp B bench (Blair)*
  - *Completed 3D seismic shoot across prospect area*
- **2016 Plans**
  - *Focus on Wolfcamp development*
    - *19 gross (15.8 net) wells planned for 2016*
    - *17 gross (14.5 net) wells on production*
      - *8 Wolfcamp A-XY & 9 Wolfcamp B*
  - *Complete 60 MMcf/d cryogenic processing plant and gathering system to support operations*
- **Recent 24-Hour Initial Potential Test Results**

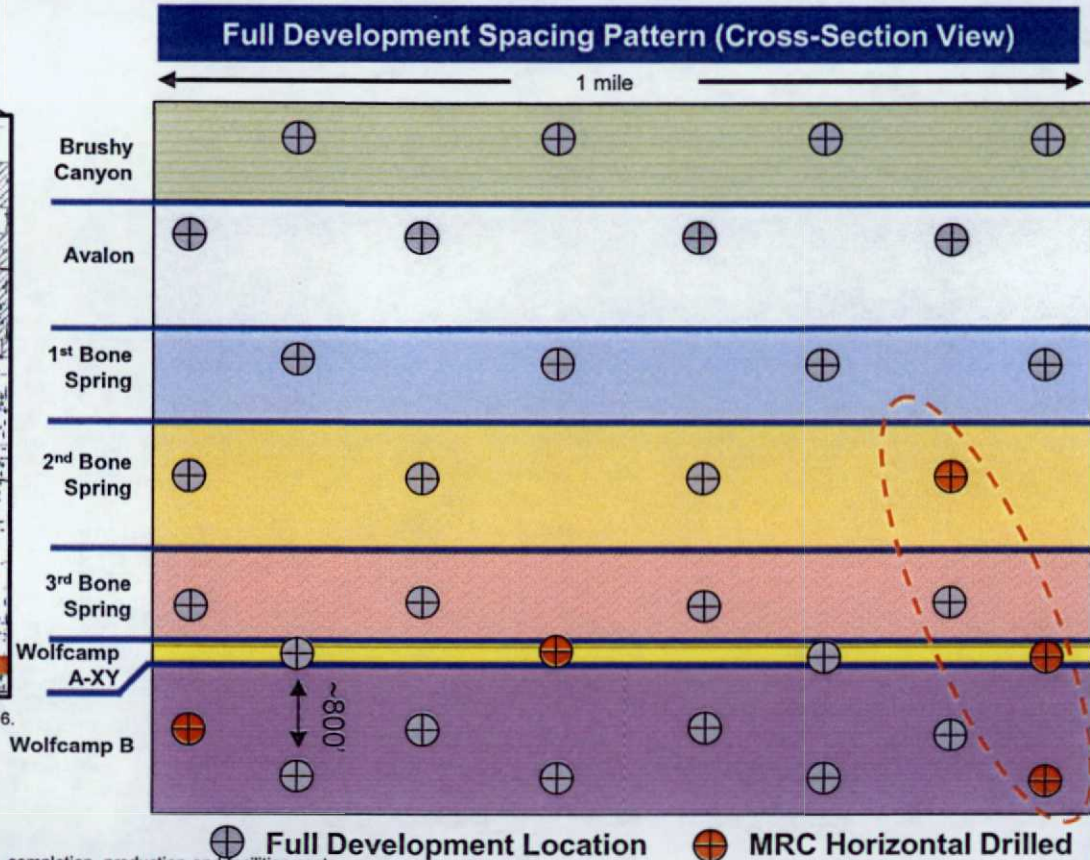
Well	Oil Eq. (BOE/d)	Oil (Bbl/d)	Natural Gas (MMcf/d)	% Oil	P_f [1] (psi)	Choke (inches)
Paul 25-24S-28E RB #221H (Wolfcamp A-XY)	1,701	1,253	2.7	74%	2,425	34/64th
Janie Conner 13-24S-28E RB #204H (Wolfcamp A-XY)	1,550	1,146	2.4	74%	2,380	34/64th
Janie Conner 13-24S-28E RB #207H (Wolfcamp A-XY)	1,525	1,094	2.6	72%	2,130	34/64th
Jimmy Kone 05-24S-28E RB #208H (Wolfcamp A-XY)	1,385	982	2.4	71%	2,100	34/64th
Dr. K 24-23S-27E RB #206H (Wolfcamp A-XY)	1,031	732	1.8	71%	1,500	34/64th
B. Banker 33-23S-28E RB #221H (Wolfcamp B-Middle)	1,608	515	6.6	32%	2,700	36/64th
Jimmy Kone 05-24S-28E RB #228H (Wolfcamp B-Blair)	2,438	751	10.1	31%	2,975	36/64th
Tiger 14-24S-28E RB #227H (Wolfcamp B-Blair)	1,812	623	7.1	34%	2,770	36/64th

Rustler Breaks Inventory – Multi-Pay Development Potential

Formation	Development Well Costs[(1)(2)] (millions)	EUR[(3)] (MBOE)	% Oil
Bone Spring	$3.0 – $4.0	300 – 600	80 – 85%
Wolfcamp A-XY	$5.0 – $6.0	600 – 800	80 – 85%
Wolfcamp B	$5.5 – $6.5	800 – 1,000	40 – 50%



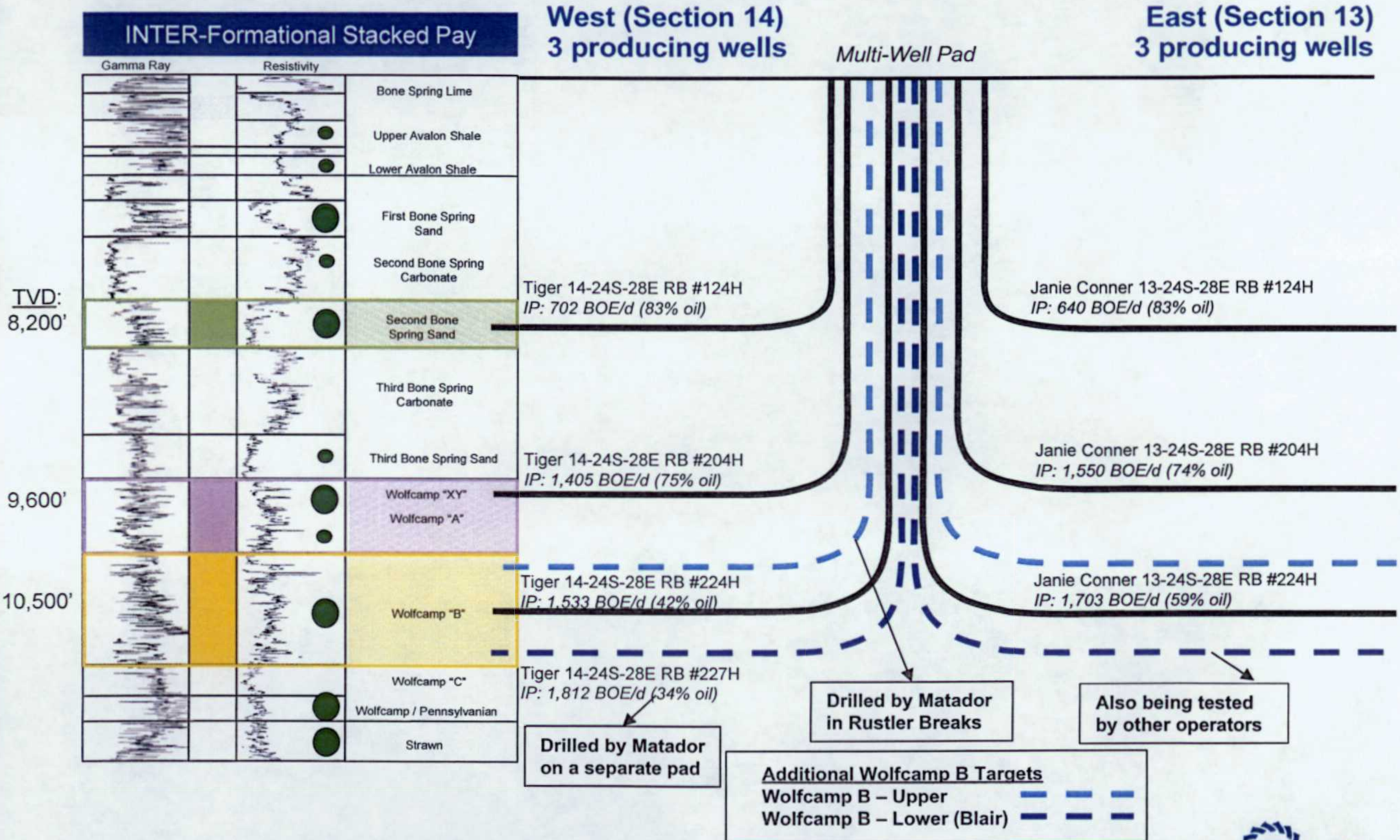
Note: All acreage at June 30, 2016.



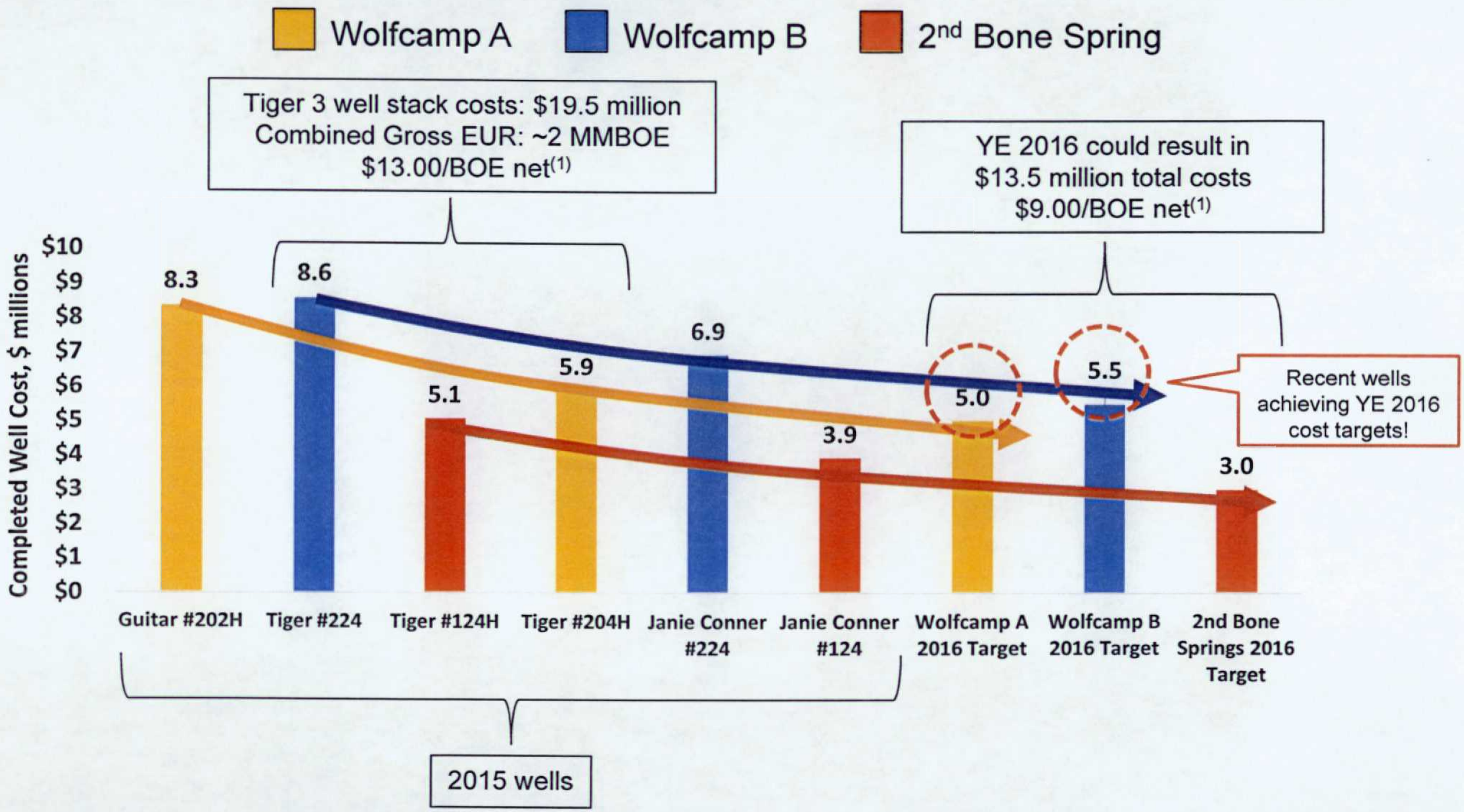
Formation	Total Gross Locations[(4)(5)]	Est. Operated Locations[(5)(6)]
Brushy Canyon	171	115
Avalon	178	123
1st Bone Spring	183	125
2nd Bone Spring	188	127
3rd Bone Spring	173	120
Wolfcamp A-XY	167	114
Wolfcamp B	235	177
	1,637	1,135

(1) Well costs include drilling, completion, production and facilities costs.
(2) High end of well cost range reflects estimated costs in Q1 2016; lower end of cost range reflects 2016 target.
(3) Estimated ultimate recovery, thousands of barrels of oil equivalent.
(4) Identified and engineered locations for potential future drilling, including specified production units and estimated lateral lengths, costs and well spacing using objective criteria for designation. Locations identified as of December 31, 2015.
(5) Includes additional Wolfcamp A lower and Wolfcamp D locations not depicted in chart. As a result, total gross locations and estimated operated locations do not sum.
(6) Includes any identified locations in which Matador's working interest is at least 25%.

Rustler Breaks – 6 Wells Producing From 3 Zones on Multi-Well Pad

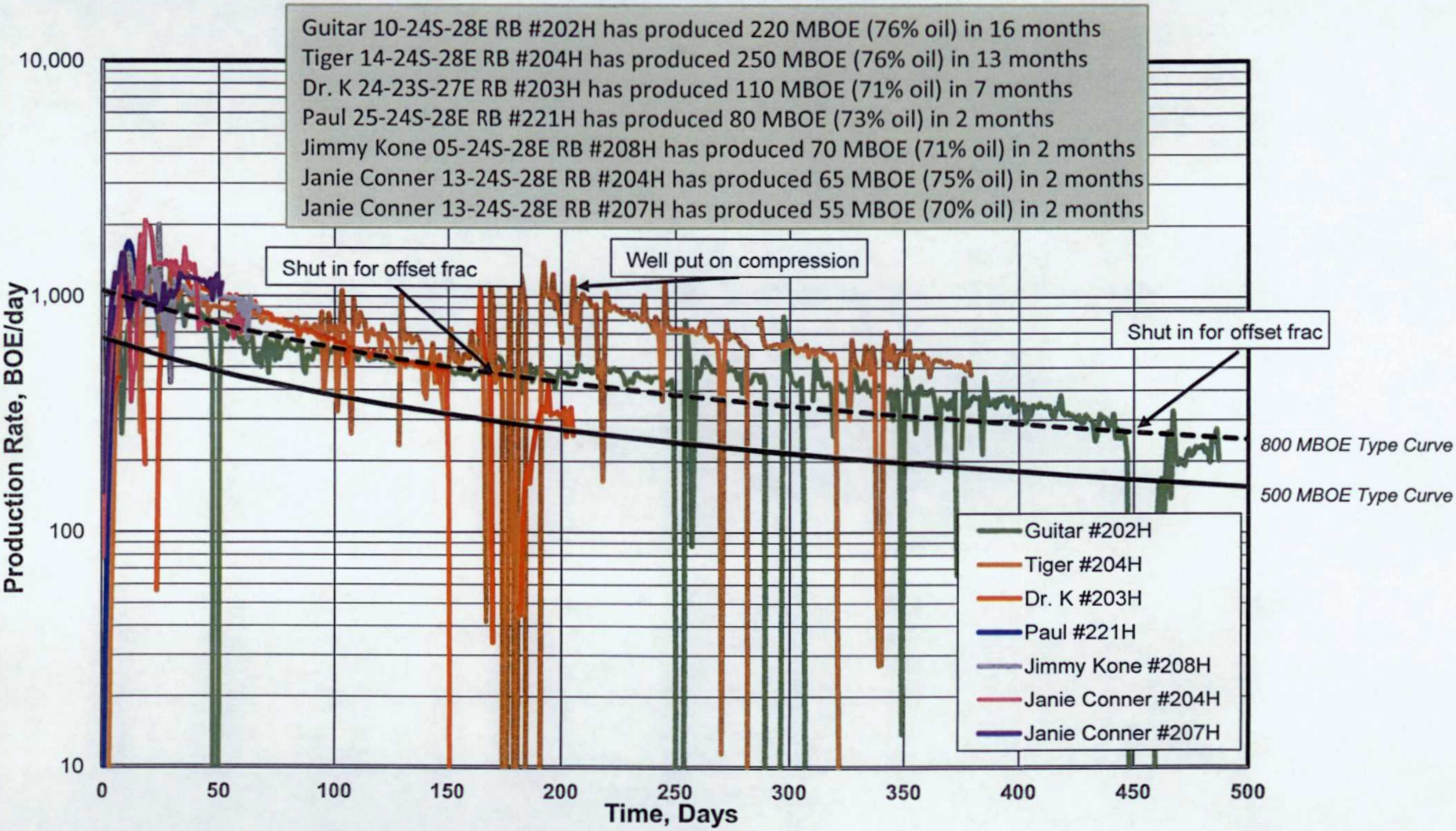


Rustler Breaks Well Cost Achievements



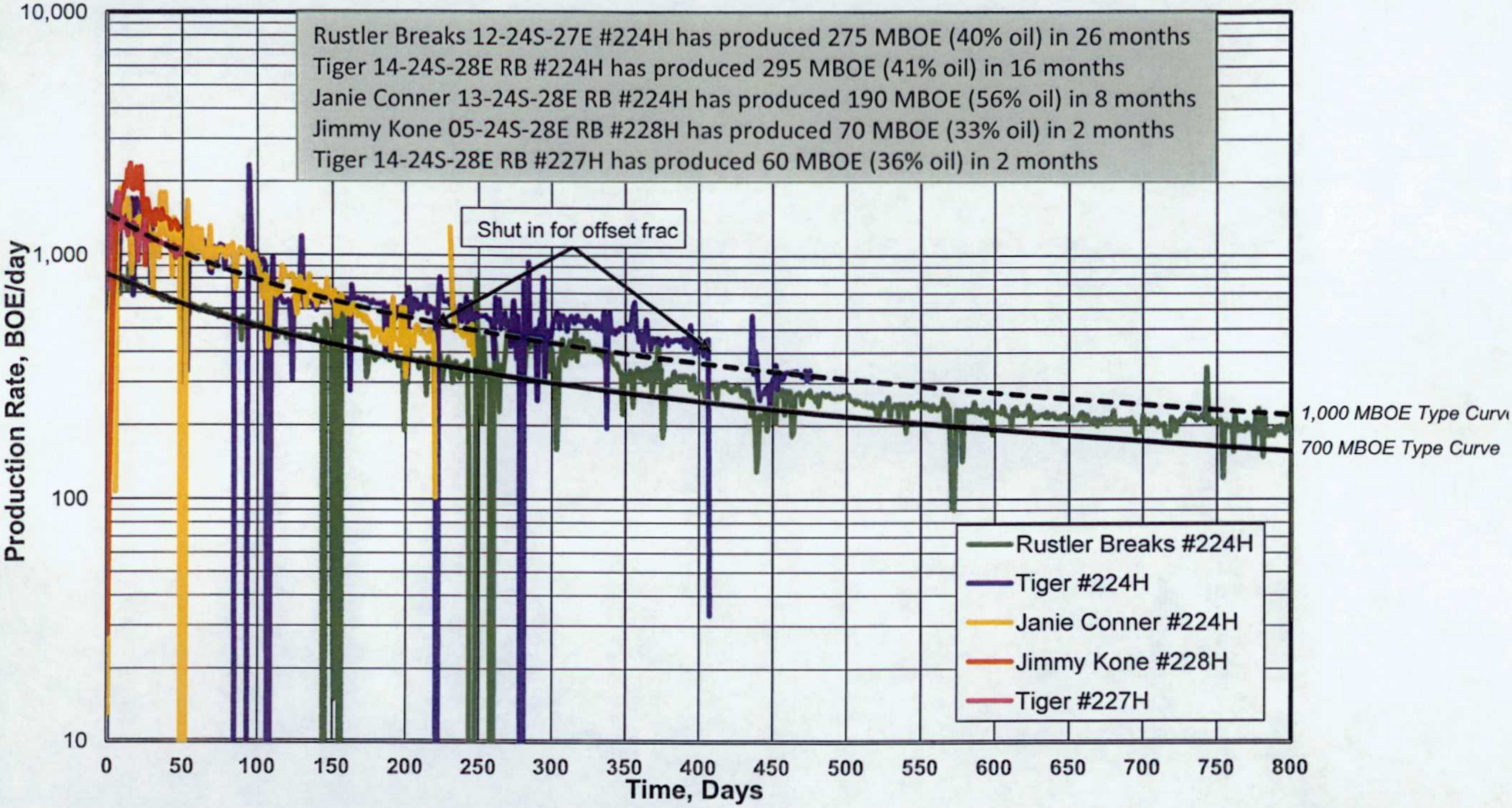
(1) Assumes 75% NRI (net revenue interest) for each well; 2016 well costs are estimates for year-end 2016.

Rustler Breaks Wolfcamp A-XY Wells Performing Above Expectations



Note: Production from selected Wolfcamp A-XY wells in Rustler Breaks prospect area as of July 2016.

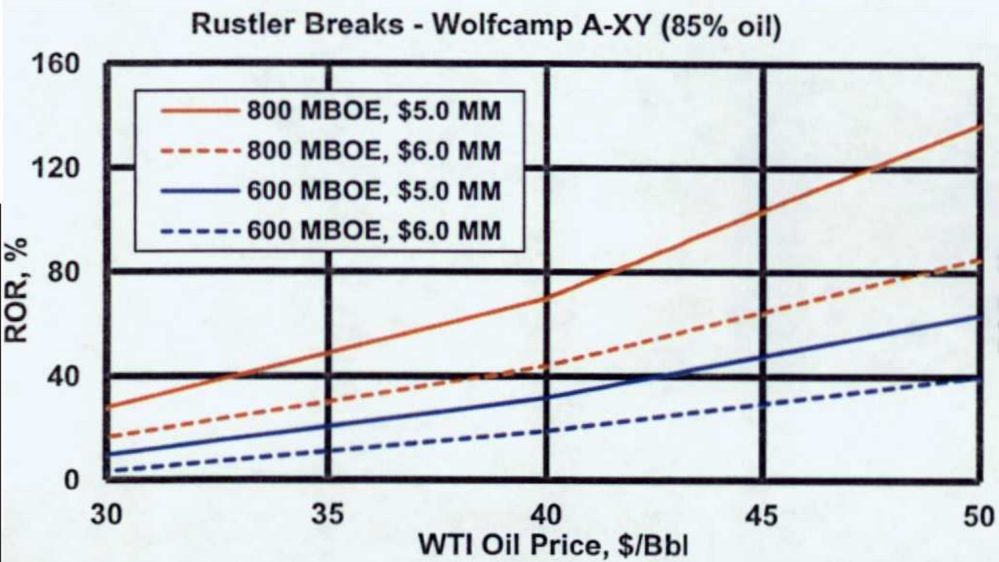
Rustler Breaks Wolfcamp B Wells Performing Above Expectations

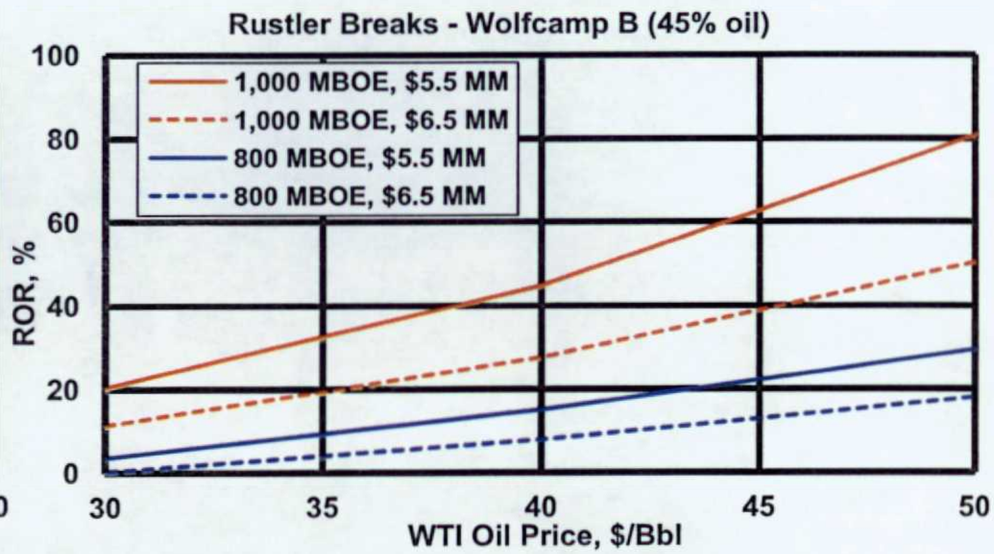


Note: Production from selected Wolfcamp B wells in Rustler Breaks prospect area as of July 2016.

Rustler Breaks – Estimated Returns by Formation

Formation	Development Well Cost(1)(2) (millions)	EUR(3) (MBOE)	% Oil
Wolfcamp A-XY	\$5.0 – \$6.0	600 – 800	80 – 85%
Wolfcamp B	\$5.5 – \$6.5	800 – 1,000	40 – 50%



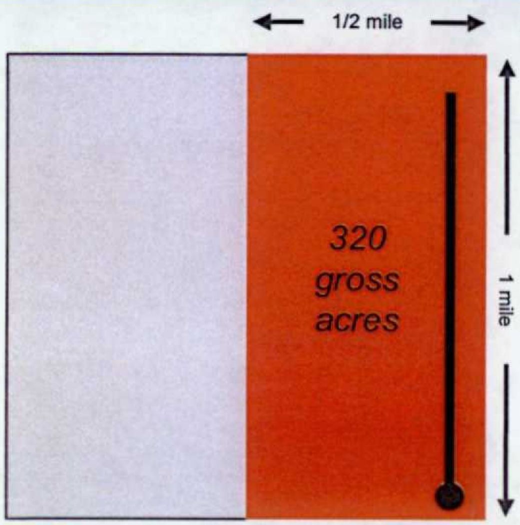


Note: Assumes \$2.50/Mcf flat natural gas price with -\$0.70/Mcf natural gas differential and -\$3.26/Bbl oil differential.
(1) Well costs include drilling, completion, production and facilities costs.
(2) High end of well cost range reflects estimated costs in Q1 2016; lower end of cost range reflects 2016 target.
(3) Estimated ultimate recovery, thousands of barrels of oil equivalent.

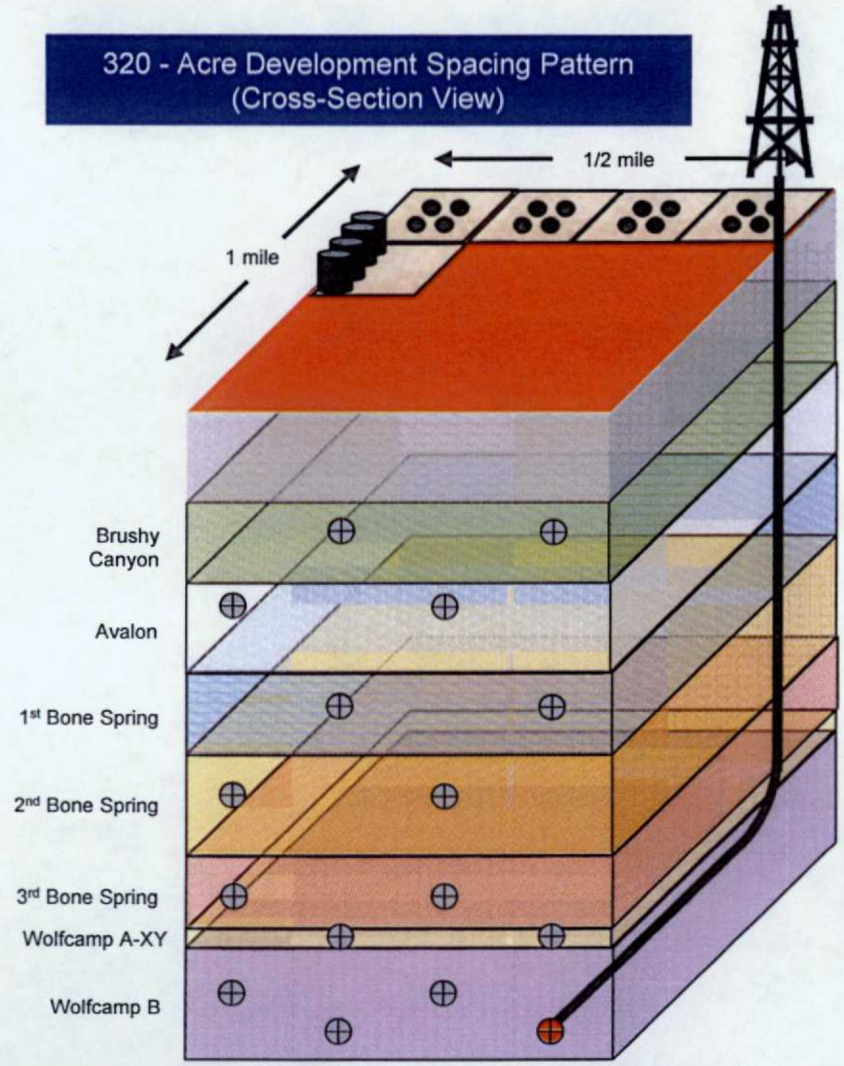
Single Wolfcamp B Well at Rustler Breaks Holds Up To 15 Potential Locations

- *One producing Wolfcamp B well holds 320 surface acres and up to 15 additional potential locations for future development*

320 - Acre Development Spacing Pattern (Aerial View)

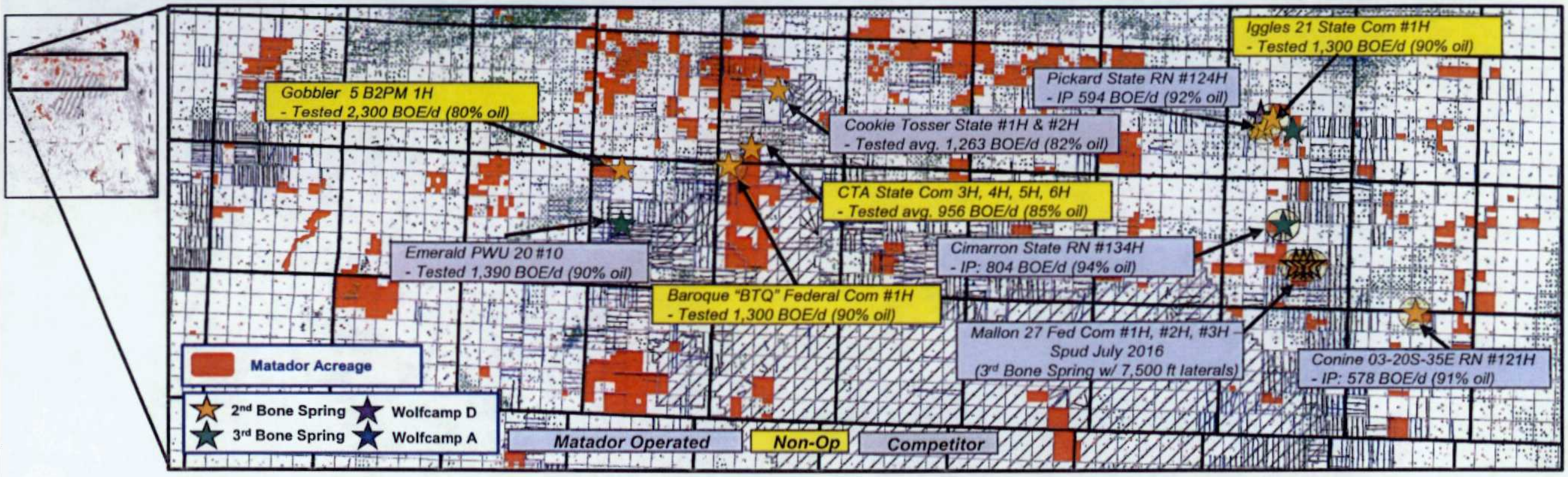


320 - Acre Development Spacing Pattern (Cross-Section View)



Additional Locations Held With Wolfcamp B well
2
2
2
2
2
2
3
15

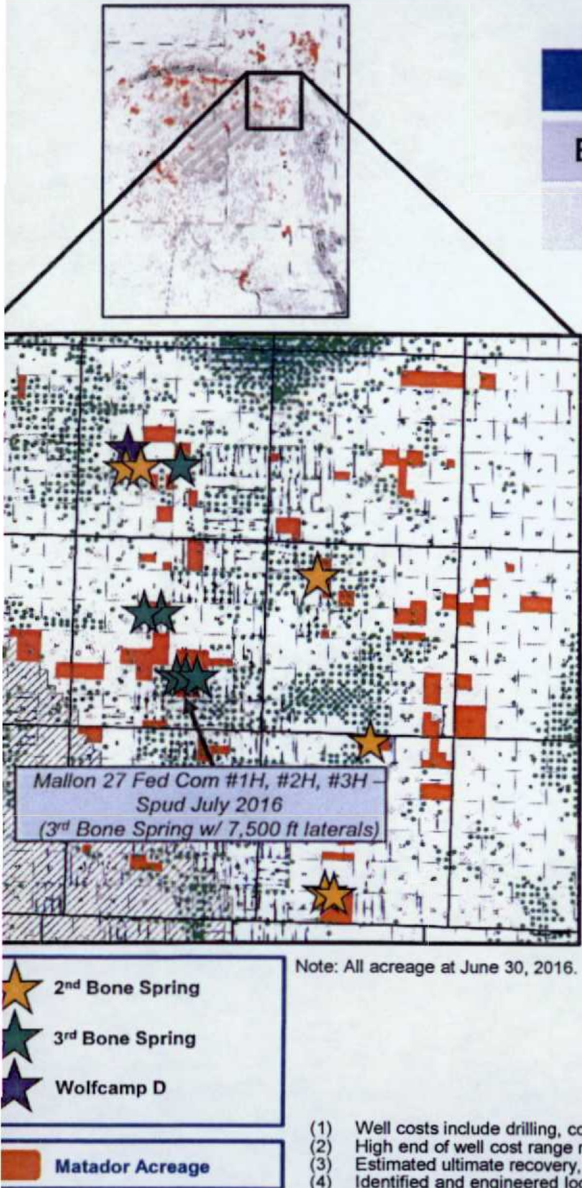
Ranger/Arrowhead – Bone Spring and Wolfcamp Development in 2016



- **2015 Accomplishments**
  - *Merged with HEYCO adding ~60,000 gross and ~20,000 net acres(1)*
  - *12 gross (4.5 net) wells*
  - *Drilled Twin Lakes vertical data well*
  - *Applied for 10 new Federal drilling permits*
- **2016 Plans**
  - *Further delineate and develop Bone Spring*
    - *7 gross (4.9 net) wells with 5 gross (3.9 net) wells on production*
  - *Drill and complete horizontal in Wolfcamp D at Twin Lakes*
  - *Submit 50 to 75 Federal drilling permits for approval and future development (20 submitted to date)(2)*

Note: All acreage at June 30, 2016.
(1) Including additional acreage acquired through subsequent joint ventures with affiliates of HEYCO.
(2) As of July 18, 2016.

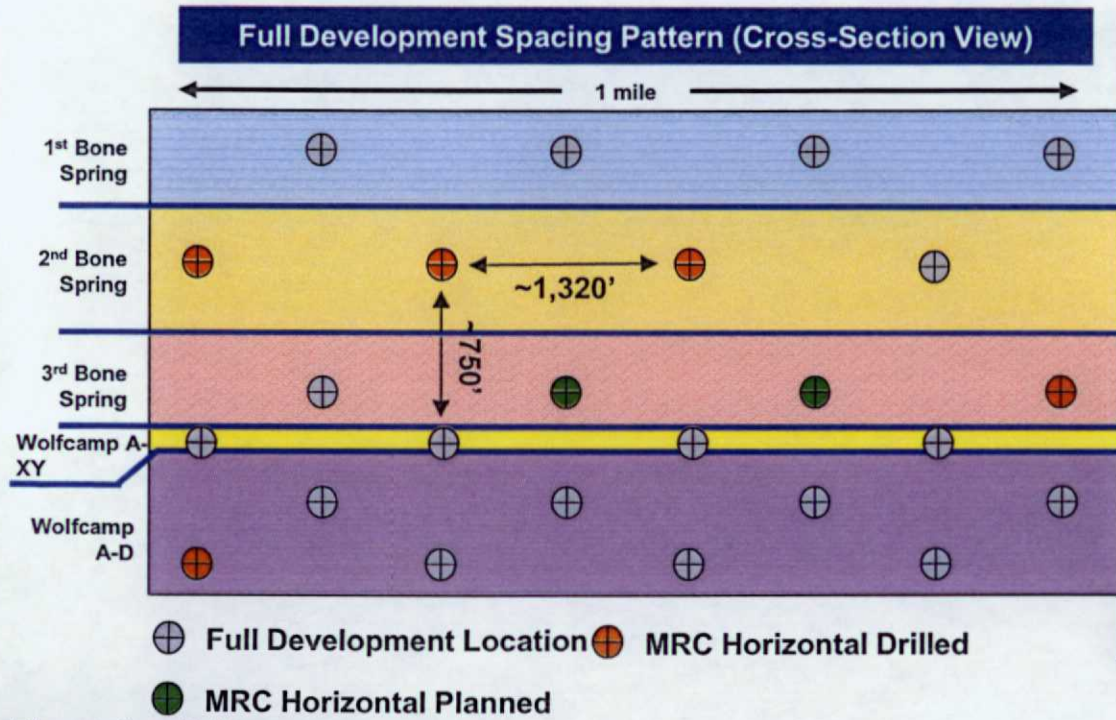
Ranger Inventory – Multi-Well Development Potential



Note: All acreage at June 30, 2016.

Formation	Development Well Costs(1)(2) (millions)	EUR(3) (MBOE)	% Oil
Bone Spring	$4.5 – $6.0	400 – 700	90 – 95%
Wolfcamp	$6.5 – $8.0	200 – 800*	80 – 85%

* Based on Volumetrics and 4-8% Recovery Factor



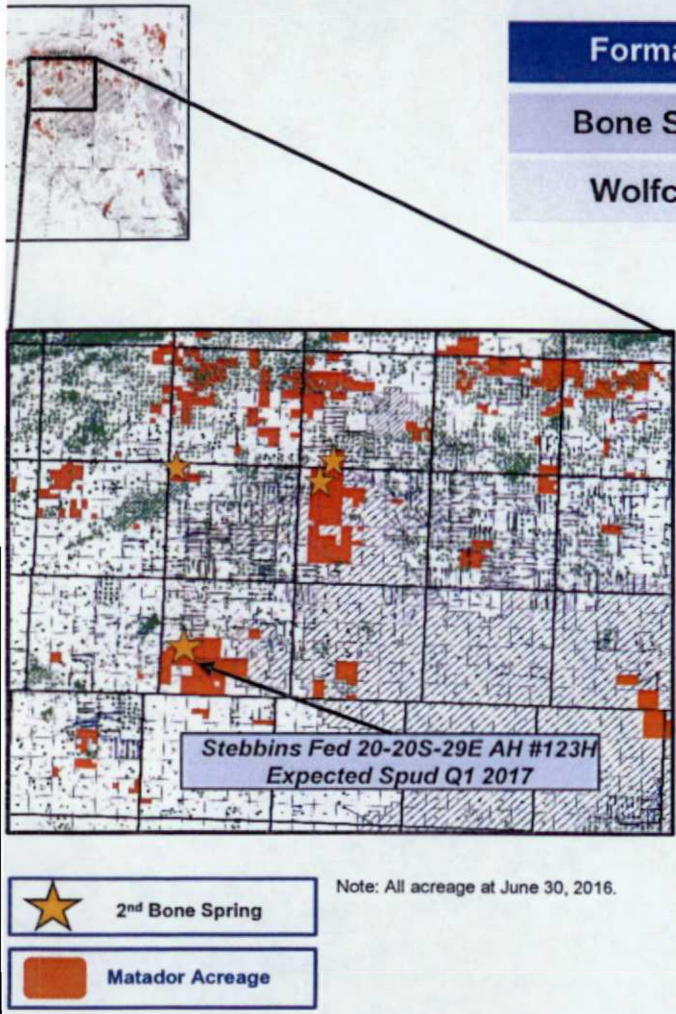
Formation	Total Gross Locations(4)	Est. Operated Locations(5)
1st Bone Spring	155	80
2nd Bone Spring	169	90
3rd Bone Spring	89	43
Wolfcamp A-XY	48	15
Wolfcamp A-D	194	114
	655	342

(1) Well costs include drilling, completion, production and facilities costs.
(2) High end of well cost range reflects estimated costs in Q1 2016; lower end of cost range reflects 2016 target.
(3) Estimated ultimate recovery, thousands of barrels of oil equivalent.
(4) Identified and engineered locations for potential future drilling, including specified production units and estimated lateral lengths, costs and well spacing using objective criteria for designation. Locations identified as of December 31, 2015.
(5) Includes any identified locations in which Matador's working interest is at least 25%.

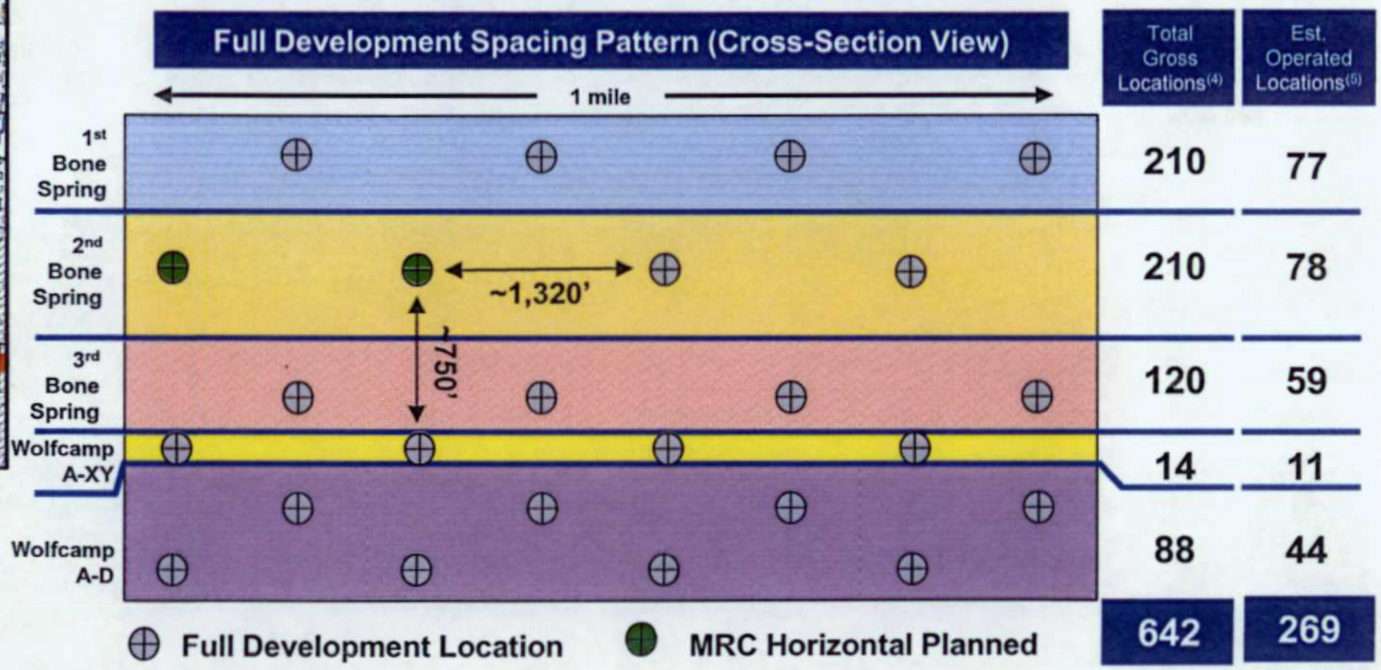
Arrowhead Inventory – Multi-Well Development Potential

Formation	Development Well Costs(1)(2) (millions)	EUR(3) (MBOE)	% Oil
Bone Spring	$4.5 – $6.0	400 – 700	80 – 90%
Wolfcamp	$6.5 – $8.0	200 – 800*	80 – 85%

* Based on Volumetrics and 4-8% Recovery Factor



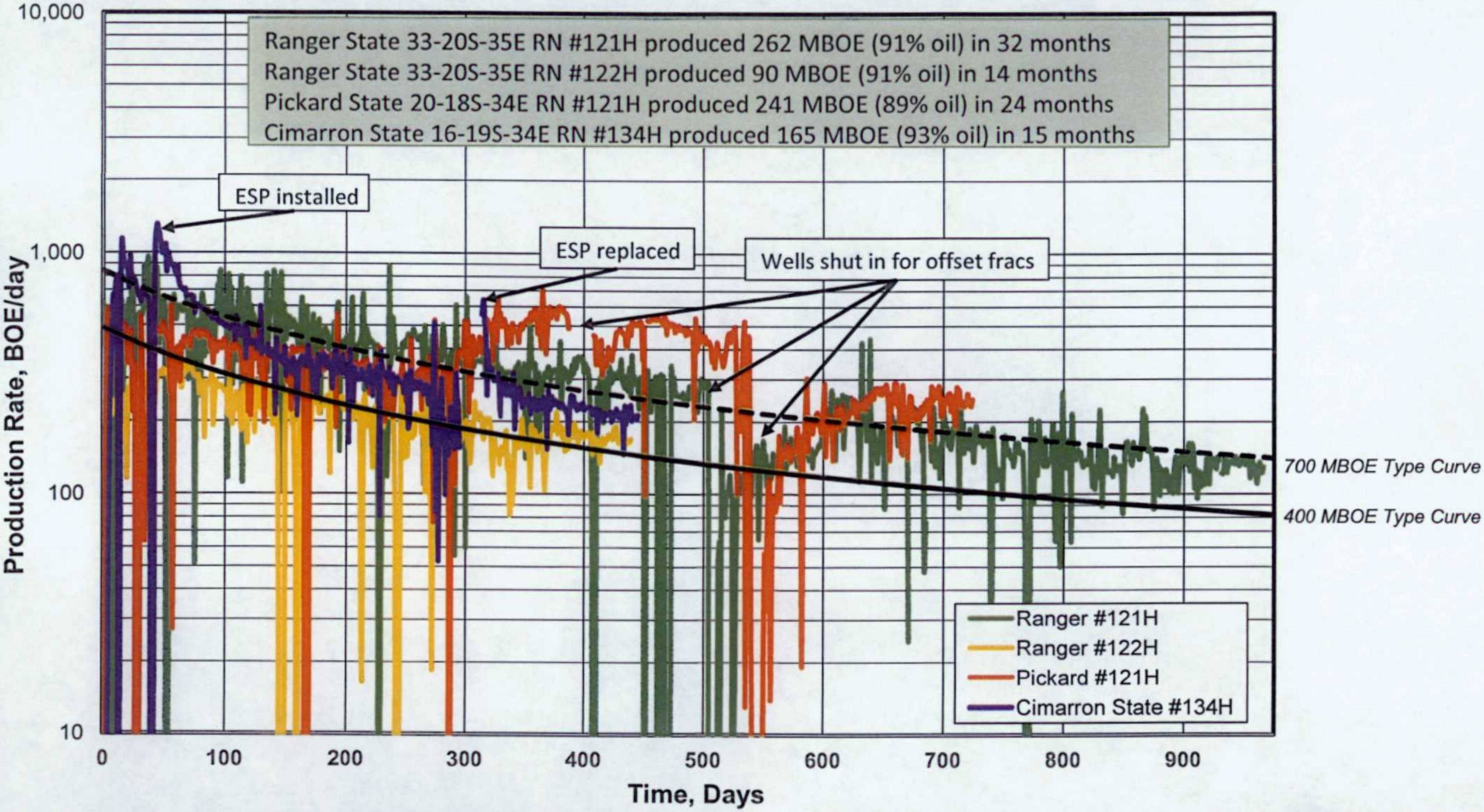
Note: All acreage at June 30, 2016.



(1) Well costs include drilling, completion, production and facilities costs.
(2) High end of well cost range reflects estimated costs in Q1 2016; lower end of cost range reflects 2016 target.
(3) Estimated ultimate recovery, thousands of barrels of oil equivalent.
(4) Gross locations identified as of December, 31, 2015.
(5) Includes any identified locations in which Matador's working interest is at least 25%.

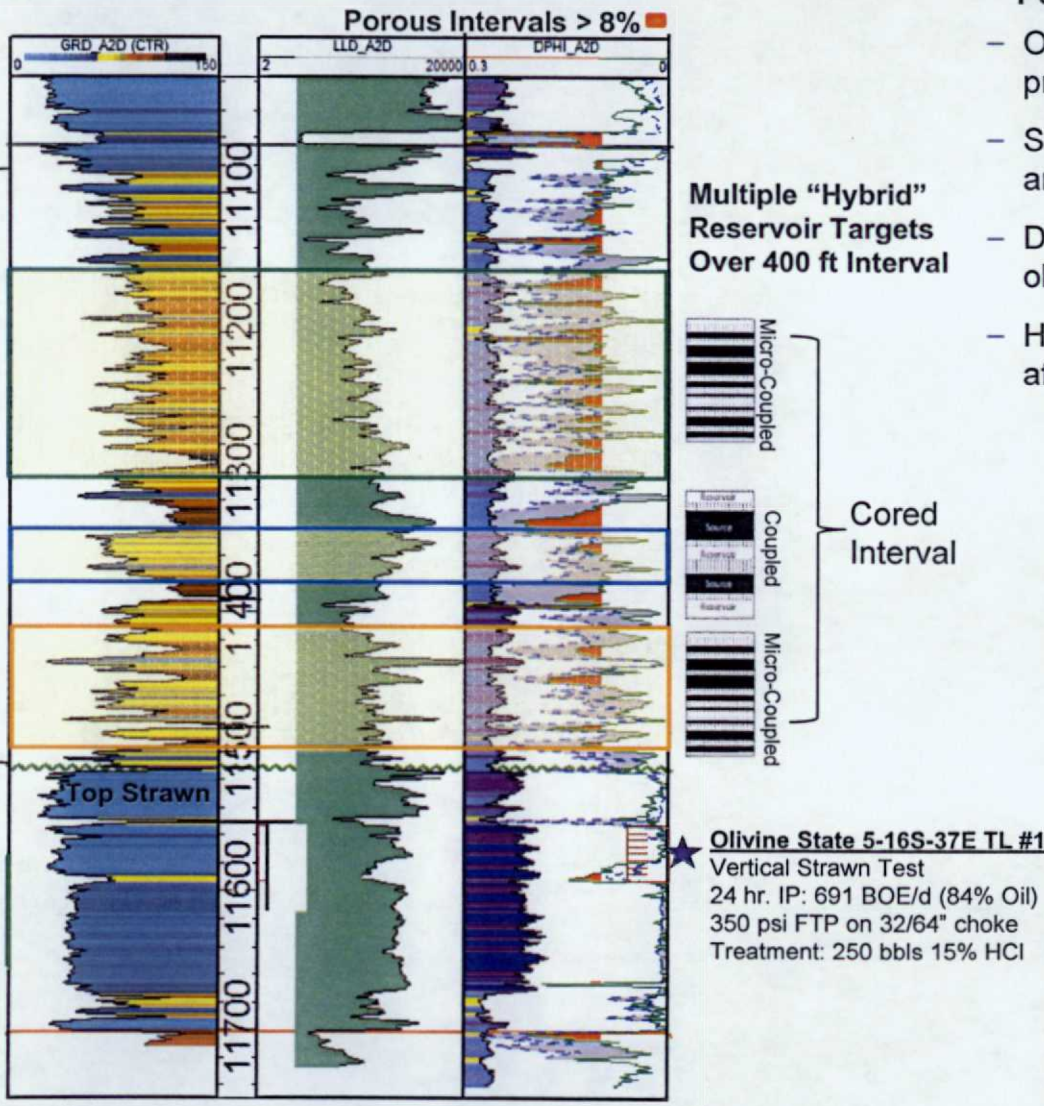
Matador Resources Company

Ranger Area Bone Spring Wells Continued Strong Performance

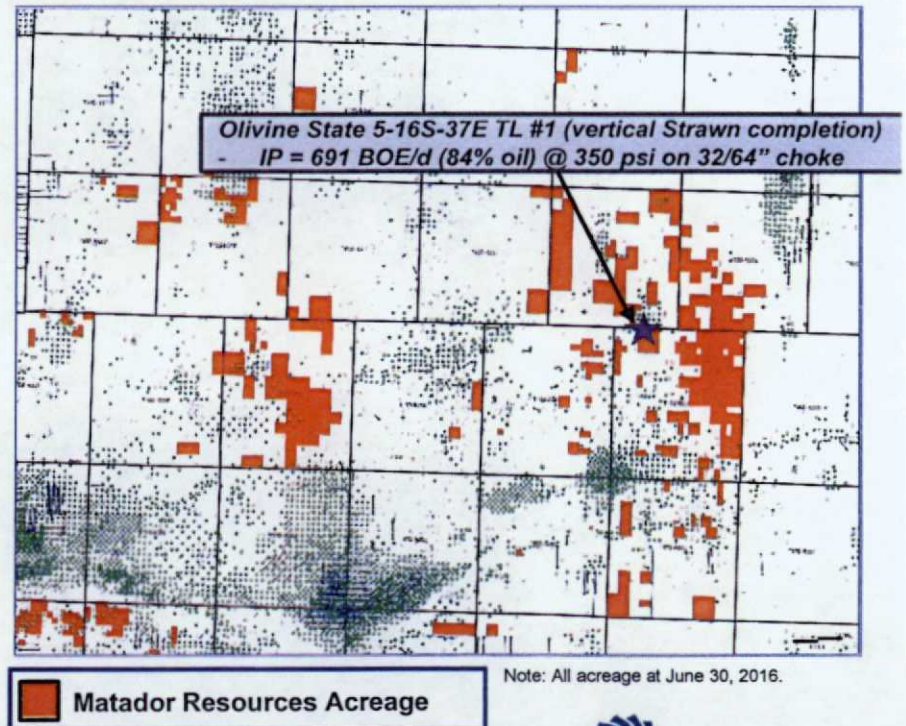


Note: Production from selected Bone Spring wells in Ranger prospect area as of July 2016.

Testing New Oil Shale Play in Twin Lakes Prospect



- **Pennsylvanian-Lower Wolfcamp D Oil Shale**
  - One of the primary source rocks for Twin Lakes prospect area (~43,500 gross and ~30,400 net acres)
  - Super-charged area having produced 1.3 billion Bbl oil and 2.2 trillion cubic feet natural gas
  - Drilled initial data collection well (Olivine State #1) to obtain full set of whole cores and geophysical logs
  - Horizontal well to test Wolfcamp D planned in Q4 2016 after analyzing data for optimal landing target



Note: All acreage at June 30, 2016.



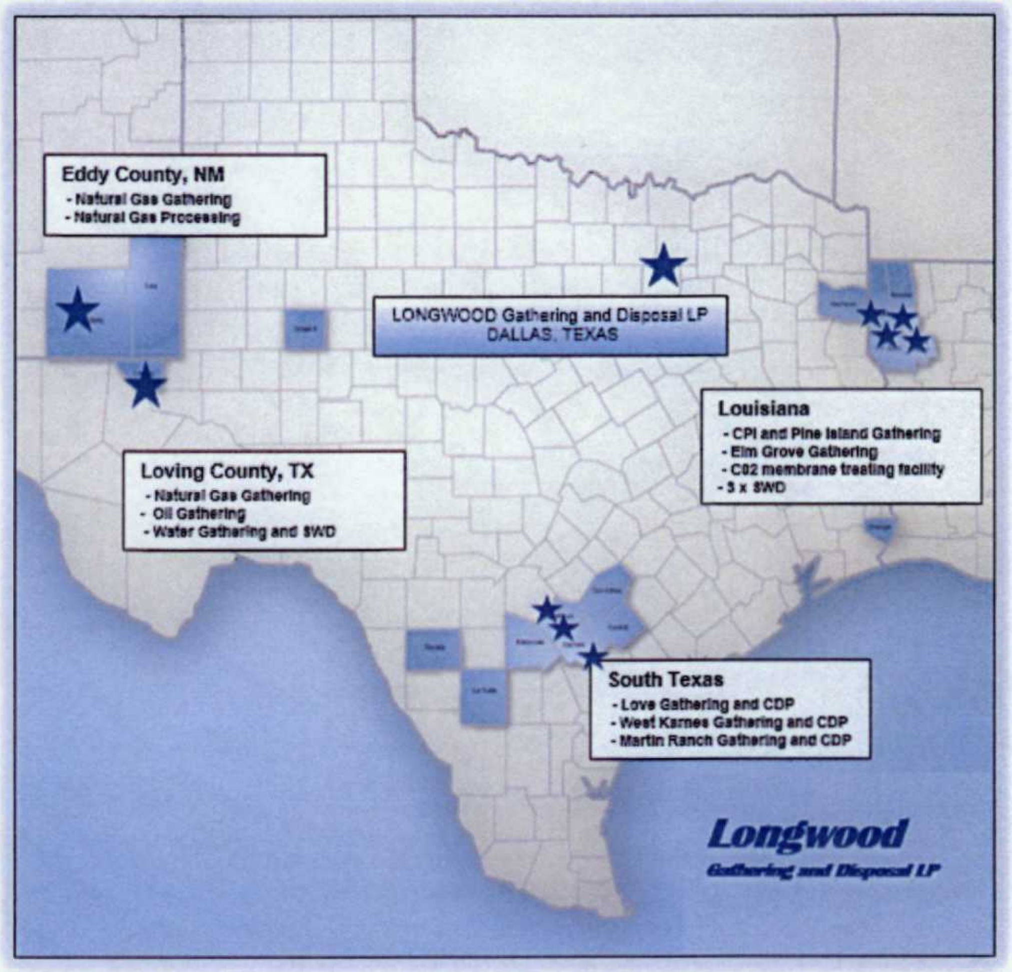
Midstream

Longwood Gathering and Disposal Systems(1) in Delaware Basin

- *Loving County, TX*
  - Gas gathering
  - Water gathering
  - Salt water disposal
  - Oil gathering
  - Cryogenic gas processing plant

Sold to EnLink

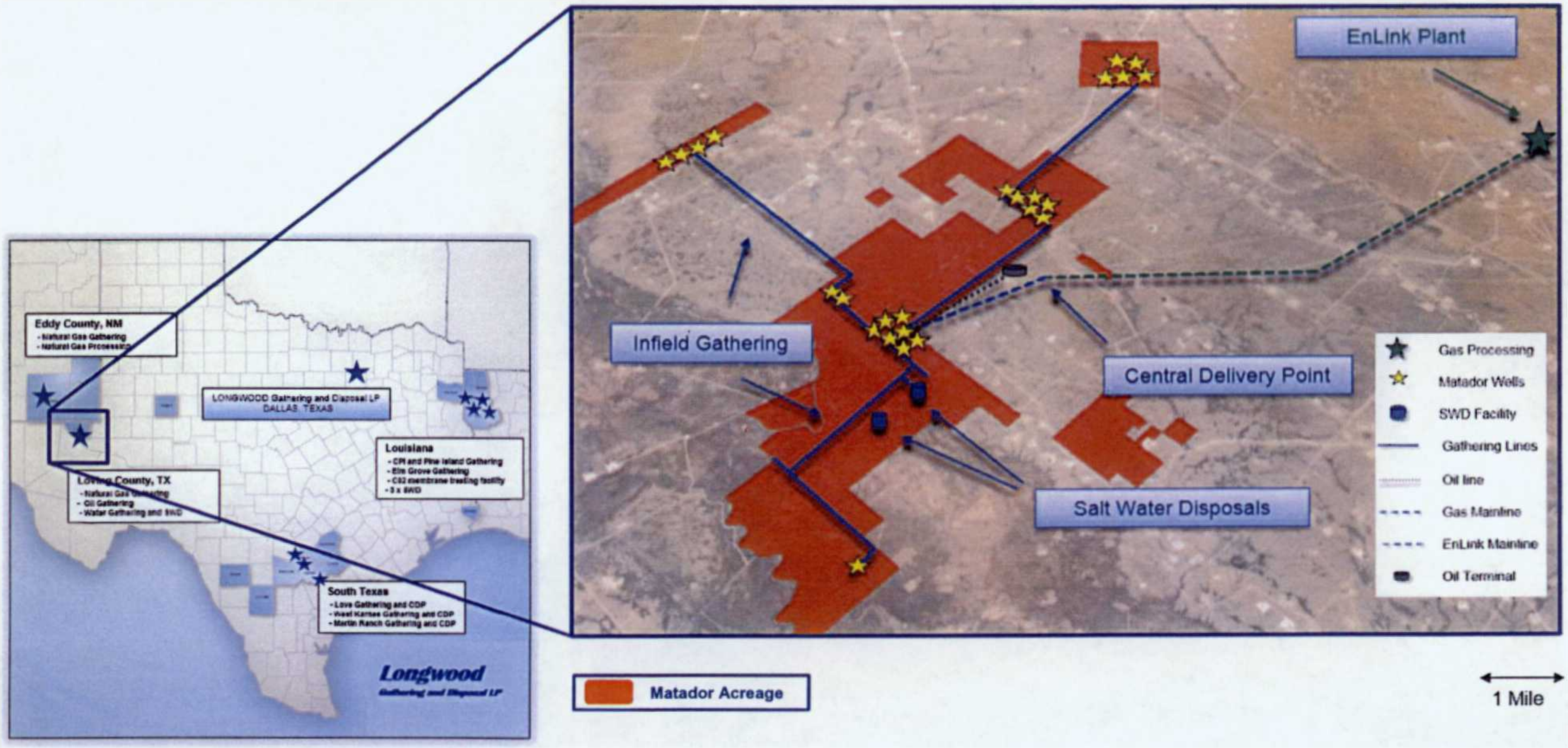
- *Eddy County, NM*
  - Gas gathering and compression
  - Cryogenic gas processing plant
  - Water gathering (pending)
  - Salt water disposal (pending)



(1) Longwood Gathering and Disposal Systems, LP is an indirect wholly owned subsidiary of Matador Resources Company.

Wolf - Loving County, TX – Significant Midstream Footprint

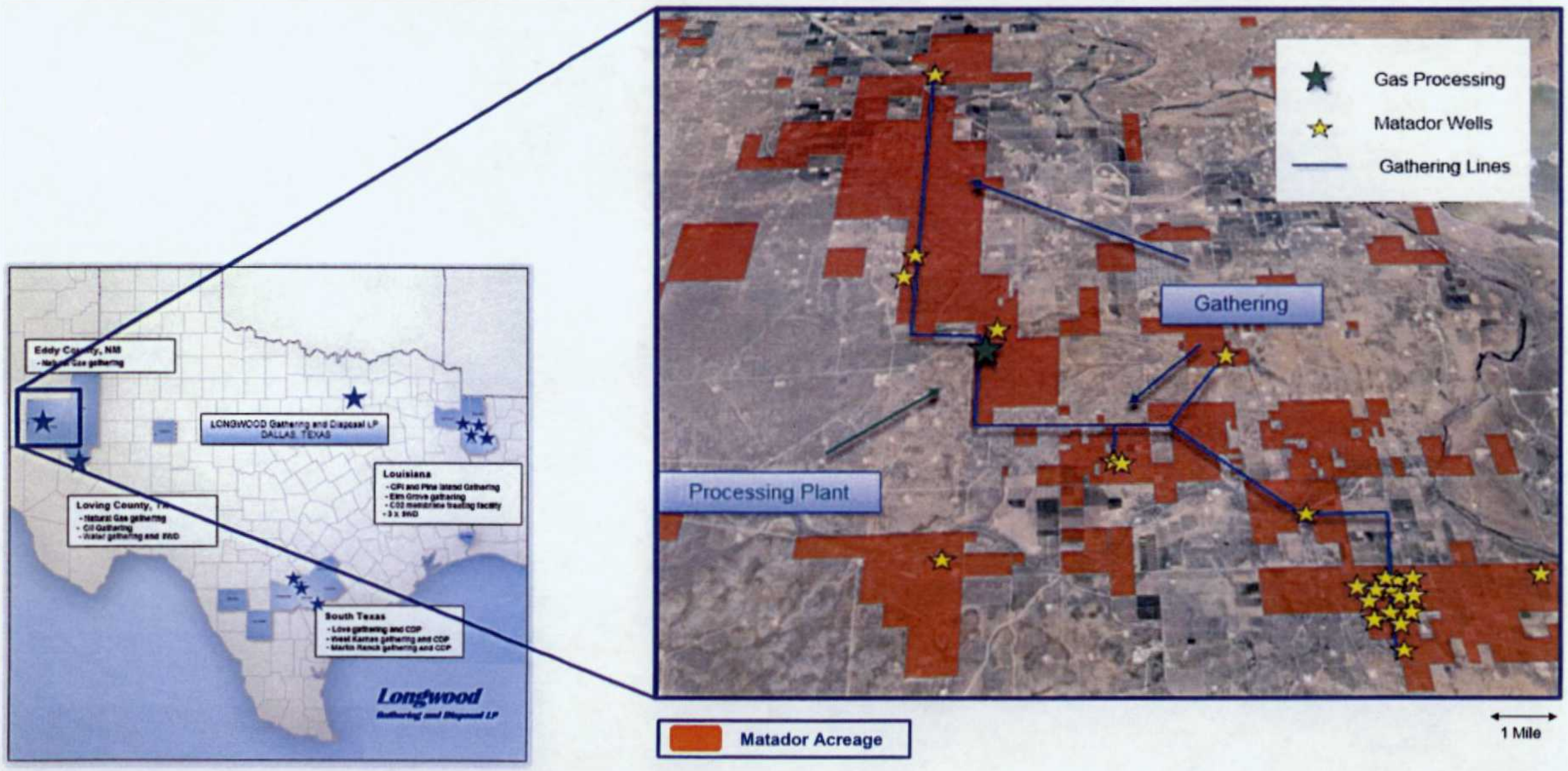
- Gas Gathering
- Water Gathering
- Salt Water Disposal
- Oil Gathering



Note: All acreage at June 30, 2016.

Rustler Breaks - Eddy County, NM – Repeating the Proven Wolf Model

- Natural gas gathering and compression – 12-inch gathering line operational in Q2 2016
- Cryogenic natural gas processing plant – expected to be operational in Q3 2016
- Water gathering (pending)
- Salt water disposal (pending)



Note: All acreage at June 30, 2016.

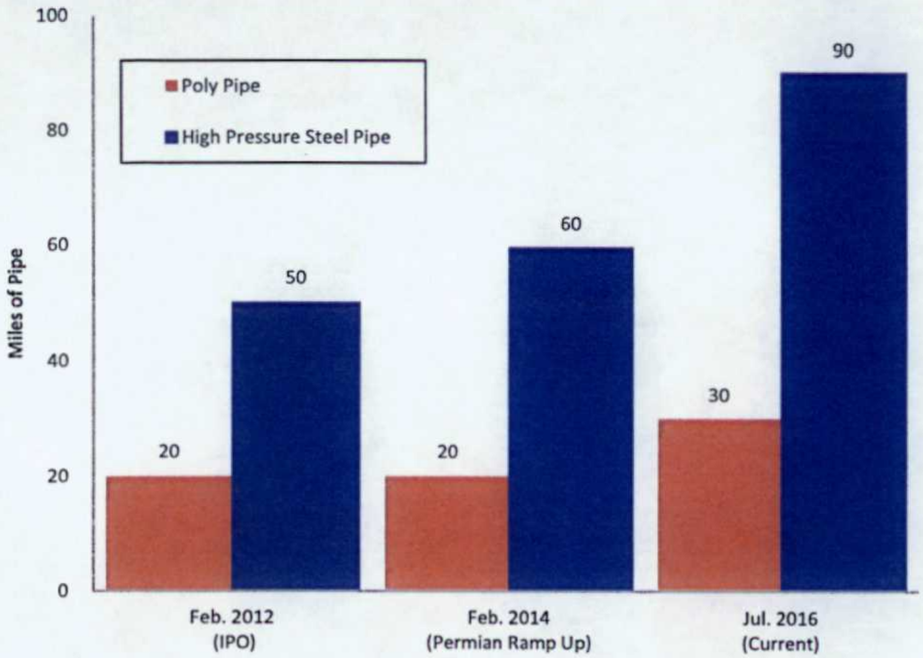
Rustler Breaks Cryogenic Processing Plant

- 60 MMcf per day inlet capacity
- Plant project is ~90% complete
- Critical path - Electrical installation
- Evaluating natural gas liquids (NGL) outlet options

Midstream Business Has Experienced Strong Growth in Recent Years

Longwood Pipeline System

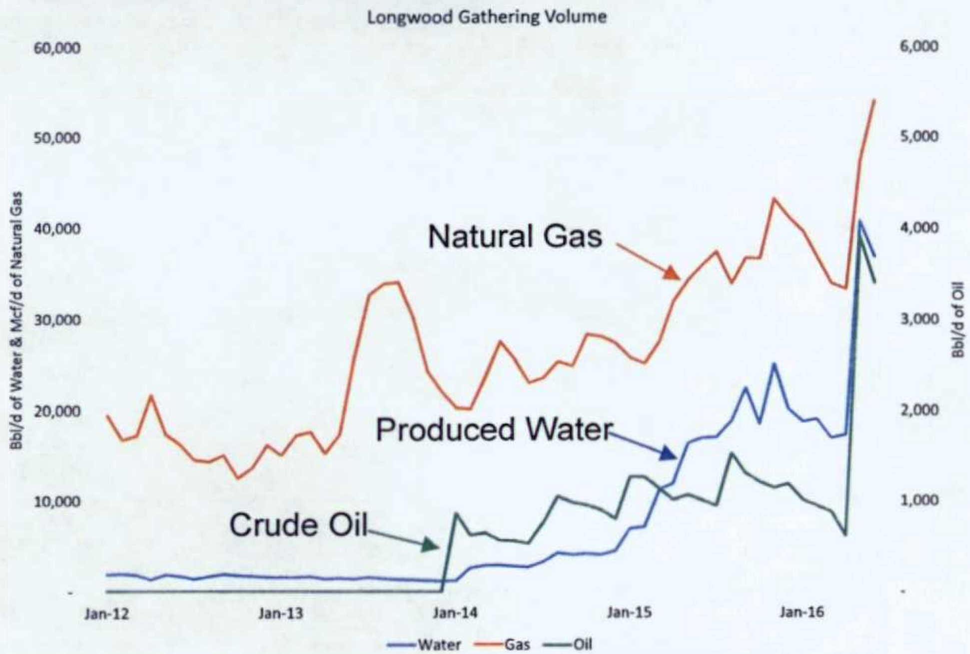
(Miles)



- **Current (July 2016)**
  - ~90 Miles of high pressure steel pipeline
    - Growth primarily attributable to increased Matador activity in the Delaware Basin in West Texas and Southeast New Mexico
    - Primarily for oil and natural gas gathering
  - ~30 Miles of poly pipe
    - Primarily for water gathering

Longwood Gathering Volumes

(Mcf/d of Natural Gas / Bbl/d of Oil/Water)



- **Current (July 2016)**
  - 95.0 MMcf/d of processing capacity constructed expected online by Q3 2016
    - 60.0 MMcf/d expected online in August 2016 in the Rustler Breaks prospect area in Eddy County NM and 35.0 MMcf/d constructed in Wolf prospect area in Loving County, TX (sold to Enlink)
  - 45,000 Bbl/d of salt water disposal capacity in the Wolf prospect area

Matador
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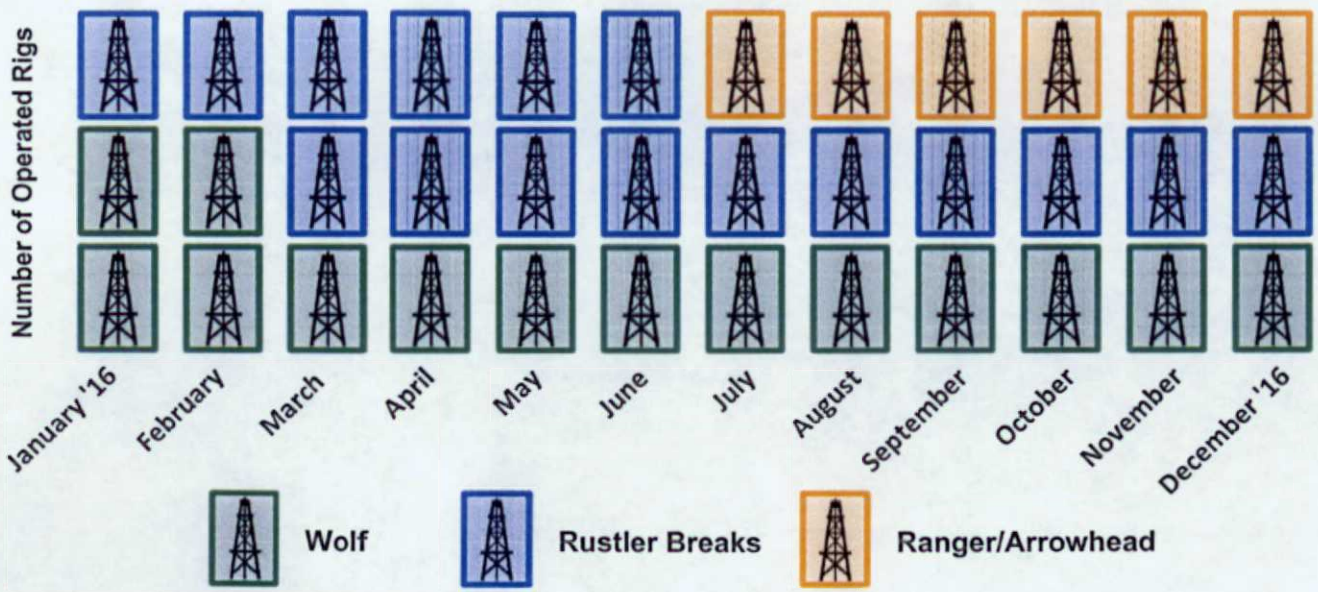
2016 Capital Investment Plan Update

2016 Capital Investment Plan – Summary

- **We will keep the focus on our Delaware Basin assets and opportunities with the intent of creating and preserving long-term shareholder value**
  - *Plan to run 3 rigs throughout 2016*
  - *Continue to improve drilling and completion efficiencies, lower costs, improve well recoveries and returns and upgrade our acreage position*
  - *Continue to invest in Delaware midstream assets, particularly the cryogenic natural gas processing plant and gathering assets we are building in the Rustler Breaks prospect area in Eddy County, NM*

Delaware Basin: 3-Rig Case

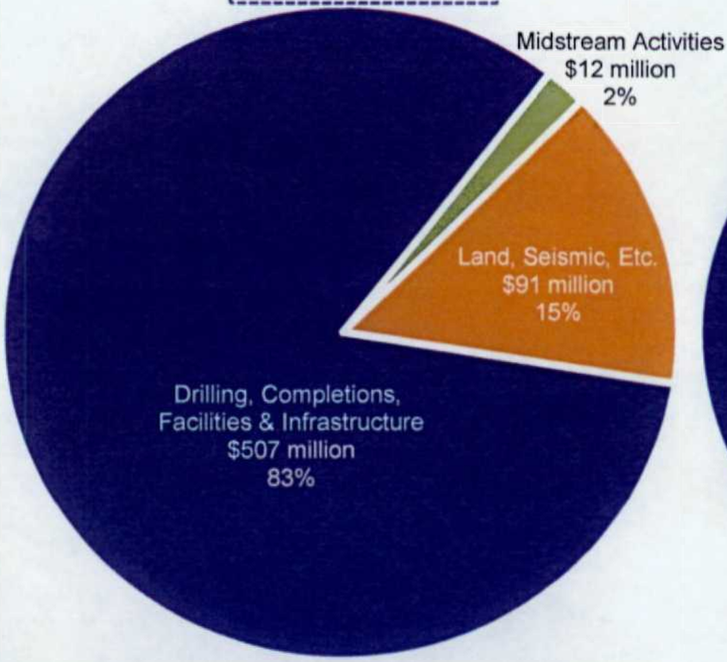


2016 Capital Investment Plan – Summary

- **We estimate our capital budget in 2016 to be approximately $325 million (down 33% from 2015[1])**
  - *We expect to have sufficient liquidity to fund our 2016 capital investments – $118 million in cash and $300 million[2] in undrawn revolving credit facility at July 18, 2016*

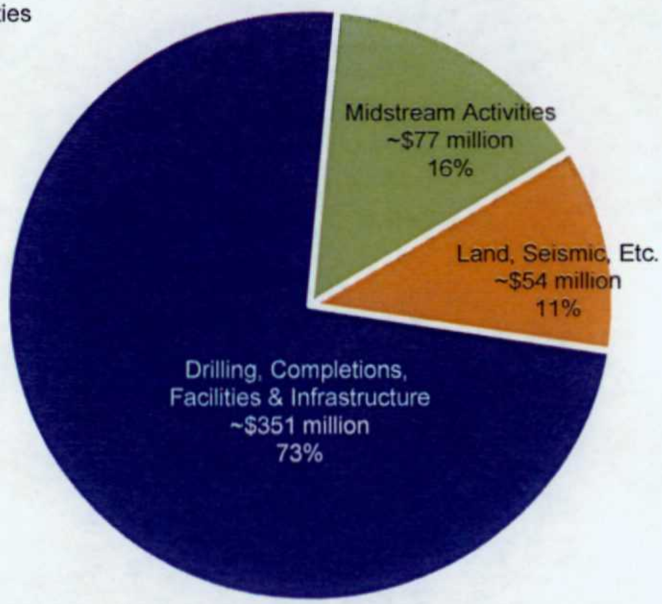
2014 CapEx

$610 million



2015 CapEx

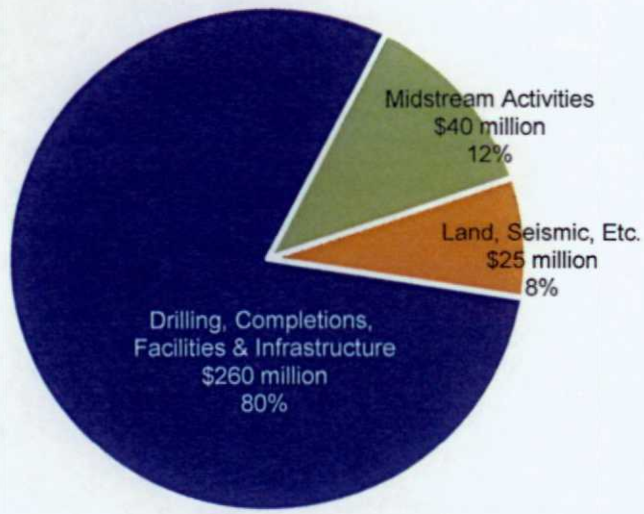
$482 million[1] ↓ 21%



2016E CapEx

3 Delaware Basin rigs throughout 2016

$325 million ↓ 33%



(1) For operations only. Does not include capital expenditures associated with the HEYCO transaction or two associated joint ventures.
(2) Borrowing base redetermined to $300 million on May 3, 2016.

Matador

2016 Capital Investment Plan – Summary

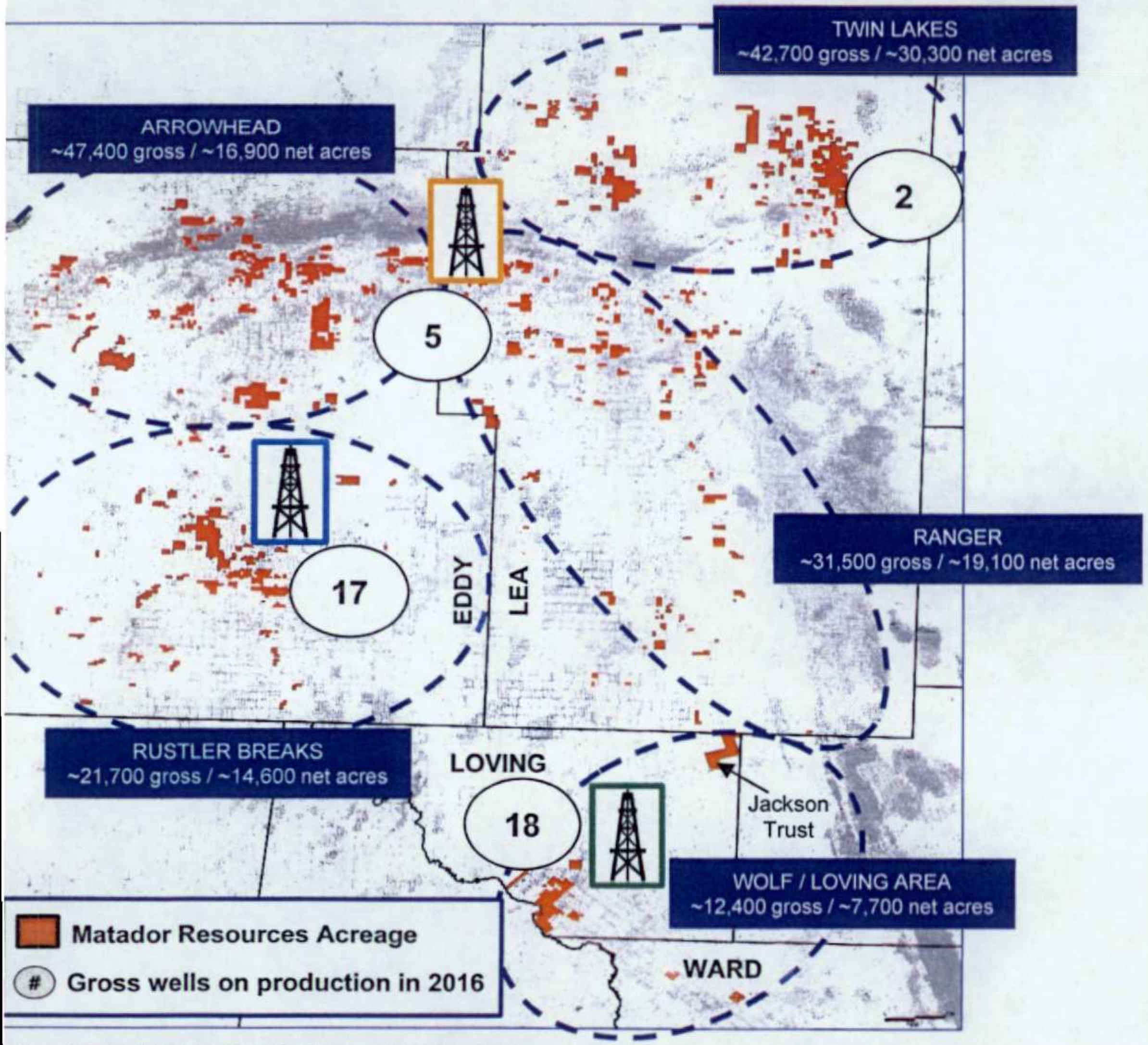
- **We expect to grow oil production by about 11% and keep natural gas production close to flat; total BOE production growth of about 4% as compared to 2015**

- **We expect to outspend cash flow by ~$230 million in 2016, including outspend associated with midstream and land, but anticipate funding most or all of this outspend without incurring significant additional debt by year-end**

- **We anticipate funding most or all of this outspend through a combination of:**
  - *Additional operational efficiencies and cost savings*
  - *Improved well performance*
  - *Potential rise in oil and natural gas prices throughout the year*
  - *Certain asset sales, including midstream assets and other non-strategic properties*
  - *Joint ventures and creative land deals*
  - *Additional equity*
  - *Additional borrowings under our undrawn credit facility*

- **We raised ~$142 million in a March 2016 follow-on equity offering covering most of the 2016 projected outspend**

Matador's 2016 Delaware Basin Operated Drilling Plan: 3-Rig Case[1]



ote: All acreage at June 30, 2016. Some tracts not shown on map.

Wolf/Loving Area

- *20 gross (16.8 net) wells planned for 2016*
- *18 gross (15.8 net) wells on production, including 10 Wolfcamp A-XY, 2 Wolfcamp A-Lower and 6 2nd Bone Spring wells*

Rustler Breaks

- *19 gross (15.8 net) wells planned for 2016*
- *17 gross (14.5 net) wells on production, including 8 Wolfcamp A-XY and 9 Wolfcamp B wells*

Ranger/Arrowhead

- *7 gross (4.9 net) wells planned for 2016*
- *5 gross (3.9 net) wells on production, including 2 2nd Bone Spring and 3 3rd Bone Spring wells*

Twin Lakes

- *2 gross (2.0 net) well planned for 2016*
- *Strawn vertical well and initial Wolfcamp D horizontal well*

Total 3-Rig Program

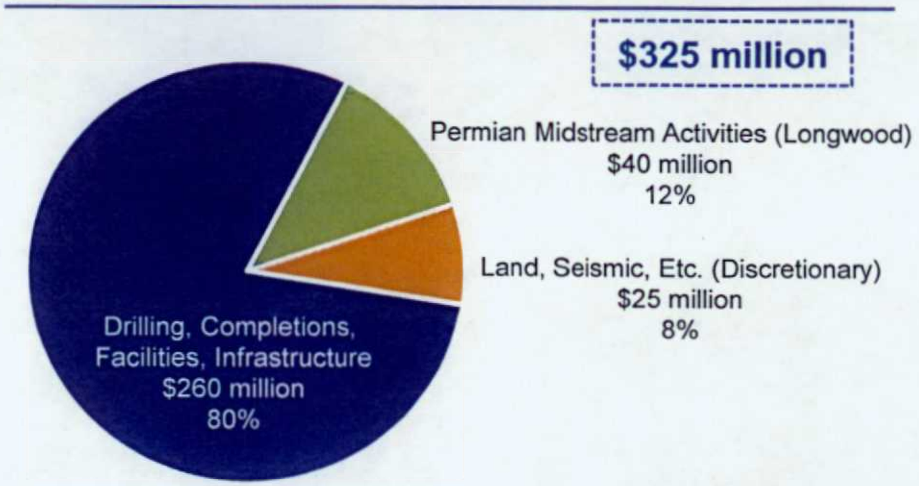
- *48 gross (39.5 net) wells planned for 2016*
- *42 gross (36.7 net) wells on production, including 30 Wolfcamp wells and 11 Bone Spring wells*

(1) Updated May 3, 2016.

2016 Capital Investment Plan Summary

2016E CapEx

(3 rigs in the Delaware Basin throughout 2016)



- **2016E CapEx of ~$325 million**
  - *Decrease of ~33% from 2015 capital expenditures of $482 million(1)*
  - *Includes estimated efficiency and cost savings of 15 to 20% throughout 2016, but additional savings may be realized*
- **CapEx for Q1 was 15% less than expected – Q1 and Q2 essentially "flip-flopped"**
  - *Lower than expected well costs in Q1*
  - *Also reflects fewer wells being completed in Q1 in Wolf and Rustler Breaks than originally planned – completion costs incurred early in Q2 instead*

2016E CapEx by Quarter – Original Guidance

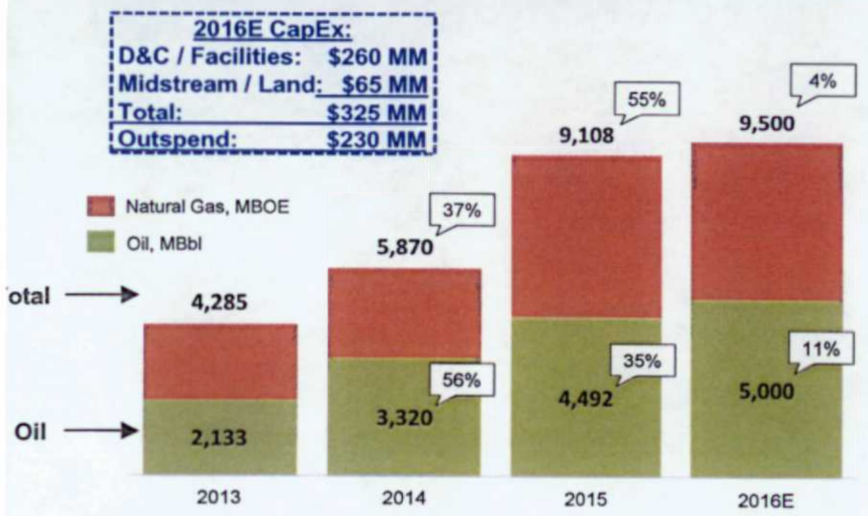
(As presented at Analyst Day on February 3, 2016)

2016E CapEx by Quarter – Revised Expectations

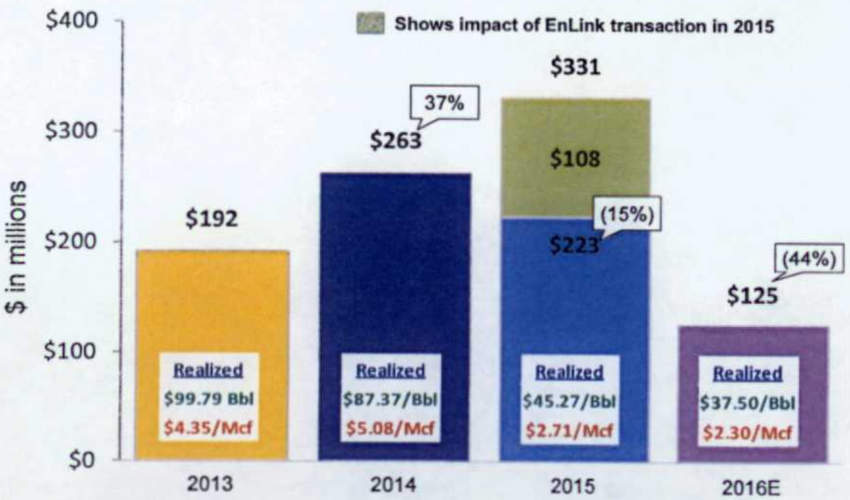
(1) For operations only. Does not include capital expenditures associated with the HEYCO transaction or two associated joint ventures.

2016 Oil and Natural Gas Production and Adjusted EBITDA Estimates

Oil and Natural Gas Production



Adjusted EBITDA[(1)(2)]



2016E Oil Production

- Estimated oil production of 4.9 to 5.1 million barrels
  - *11% increase from 2015 to midpoint of 2016 range*
- Average daily oil production of 13,700 Bbl/d, up from 12,300 Bbl/d in 2015
  - *73% Delaware Basin; 27% Eagle Ford*
- Q2 2016 up ~10 to 12% sequentially; Q4 2016 up 34% over Q4 2015

2016E Natural Gas Production

- Estimated natural gas production of 26.0 to 28.0 Bcf
  - *3% decrease from 2015 to midpoint of 2016 range*
- Average daily natural gas production of 74.0 MMcf/d, compared to 75.9 MMcf/d in 2015
  - *48% Haynesville/Cotton Valley; 40% Delaware Basin; 12% Eagle Ford*
- Q2 2016 up ~5 to 7% sequentially; may decline in 2H 2016

2016E Adjusted EBITDA[(1)(2)]

- Estimated Adjusted EBITDA[(1)(2)] of $120 to $130 million
  - *Decrease of ~44% from $223 million in 2015*

(1) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net (loss) income and net cash provided by operating activities, see Appendix.
(2) Estimated 2016 Adjusted EBITDA is based upon the midpoint of 2016 production guidance range as provided on February 3, 2016 and affirmed on May 3, 2016. Estimated average realized prices for oil and natural gas used in these estimates were $39.75/Bbl (WTI oil price of $43.75/Bbl less $4.00/Bbl of estimated price differentials) and $2.37/Mcf (NYMEX Henry Hub natural gas price assuming regional differentials and uplifts from natural gas processing roughly offset), respectively, for the period April through December 2016.

Hedging Profile

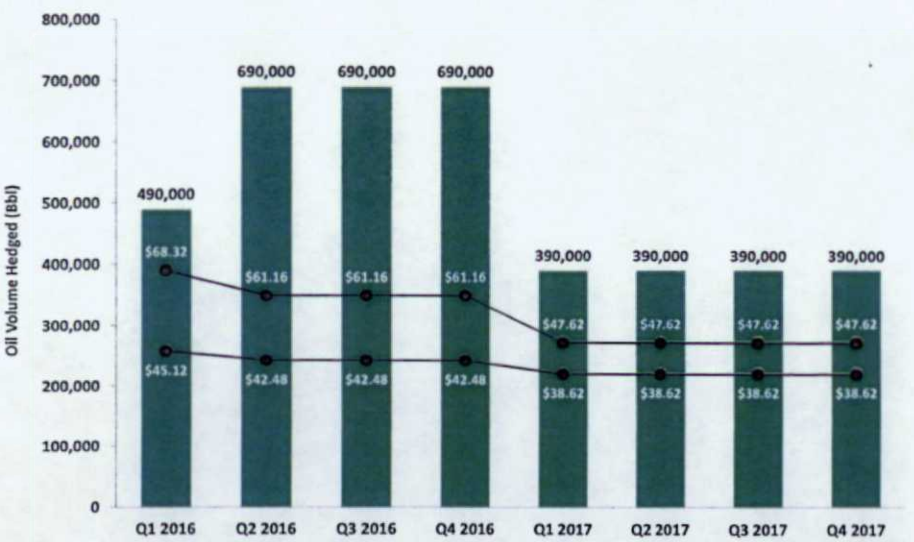
Remainder of 2016 Hedges[1]

- **Oil**: ~1.4 million barrels of oil hedged for remainder of 2016 at weighted average floor and ceiling prices of $42/Bbl and $61/Bbl, respectively – Over 50% of oil hedged for remainder of 2016
- **Natural Gas**: 7.2 Bcf of natural gas hedged for remainder of 2016 at weighted average floor and ceiling of $2.63/MMBtu and $3.61/MMBtu, respectively – Over 55% of natural gas hedged for remainder of 2016

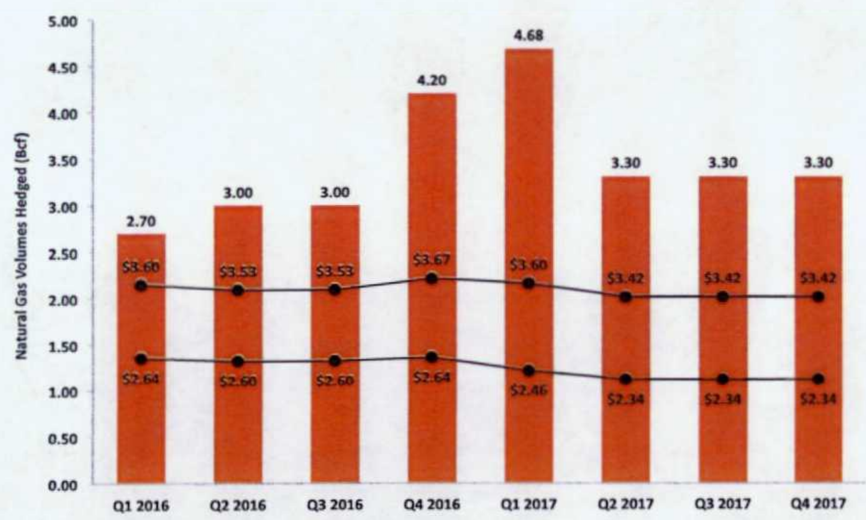
2017 Hedges[1]

- **Oil**: ~1.6 million barrels of oil hedged for 2017 ($39/Bbl floor and $48/Bbl ceiling)
- **Natural Gas**: ~14.6 Bcf of natural gas hedged for 2017 ($2.38/MMBtu floor and $3.48/MMBtu ceiling)

Oil Hedges (Costless Collars)



Natural Gas Hedges (Costless Collars)



(1) At July 18, 2016.

Credit Agreement Status

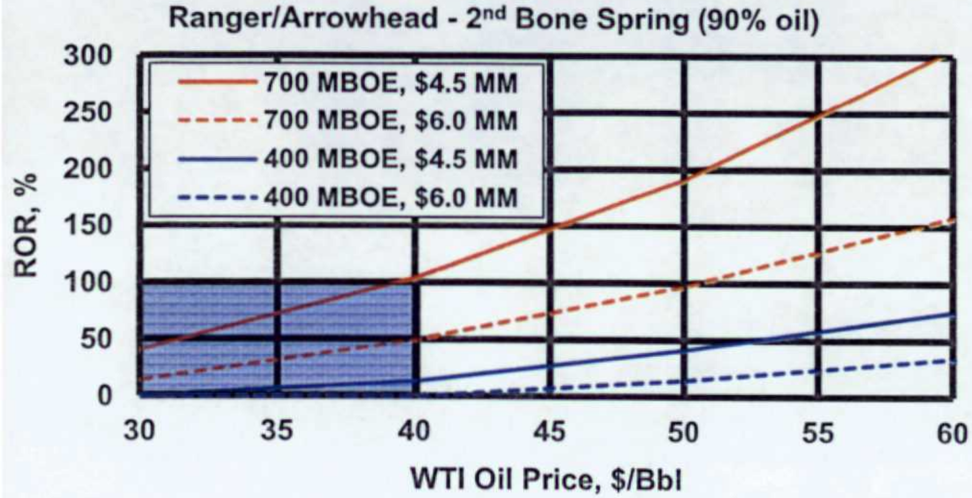
- **Strong, supportive bank group led by Royal Bank of Canada (group includes eight banks)**
- **Borrowing base set at $300 million on May 3, 2016 based on December 31, 2015 reserves and using commodity price estimates prescribed by bank group**
  - *All other provisions remain unchanged, including costs to borrow funds*
  - *No further restrictions on Matador's ability to access borrowings available under revolving credit facility*
- **No borrowings outstanding at July 18, 2016**
- **Net Debt/LTM Adjusted EBITDA(1)(2) of 1.5x at March 31, 2016**

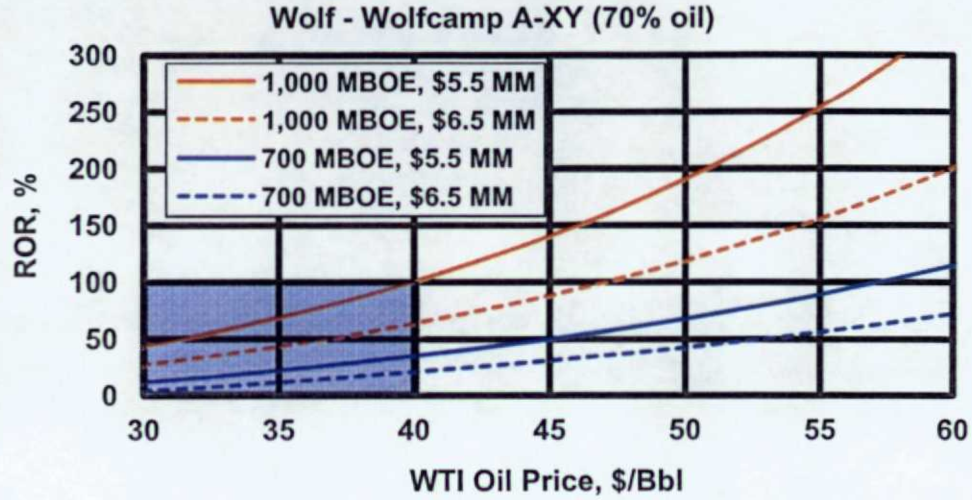
TIER	Conforming Borrowing Base Utilization	LIBOR Margin	BASE Margin	Commitment Fee
Tier One	x < 25%	150 bps	50 bps	37.5 bps
Tier Two	25% < or = x < 50%	175 bps	75 bps	37.5 bps
Tier Three	50% < or = x < 75%	200 bps	100 bps	50 bps
Tier Four	75% < or = x < 90%	225 bps	125 bps	50 bps
Tier Five	90% < or = x < 100%	250 bps	150 bps	50 bps

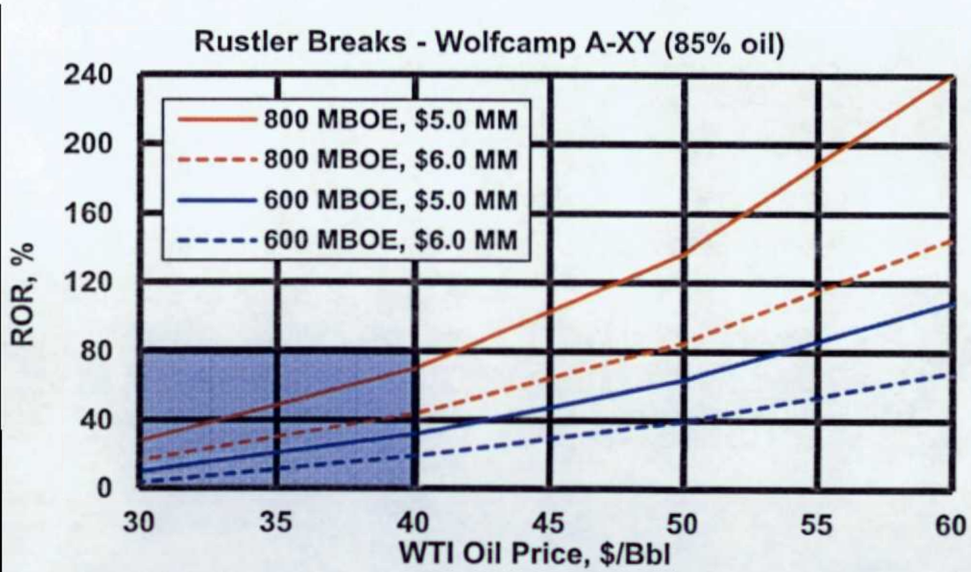
- **Financial covenant**
  - *Maximum Total Debt to LTM Adjusted EBITDA(2) Ratio of not more than 4.25:1.00*

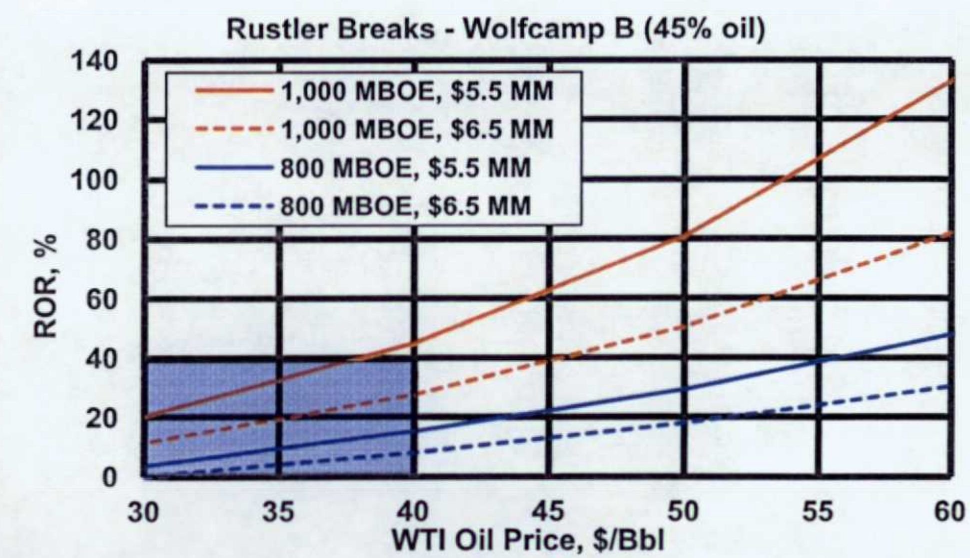
(1) Net debt is equal to debt outstanding less available cash.
(2) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA an a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see Appendix.

Delaware Basin – Sensitivities to Oil Price(1) and Cost Savings









Note: $2.50/Mcf natural gas price used in all graphs, less differentials. Costs include total estimated drilling, completion, production and facilities costs for a typical development well in each area.
Note: High end of cost range reflects Q1 2016 estimated costs; low end of cost range reflects 2016 target.
(1) Oil price shown is West Texas Intermediate oil price (WTI). Differentials to WTI oil price are included in all graphs for each area.

Summary and 2016 Guidance (as Affirmed May 3, 2016)

- **Plan to run 3 rigs in the Delaware Basin throughout 2016**
- **Delaware Basin drilling expected to focus on Wolf and Rustler Breaks Wolfcamp development and further delineation of Ranger, Arrowhead and Twin Lakes prospect areas**
- **No Eagle Ford and minimal Haynesville non-operated drilling activity expected in 2016**
- **Q1 2016 production results were consistent with forecasts; steadier growth profile for Q2 through Q4 expected rather than uneven or "lumpy" production projected at Analyst Day**
  - *Estimate oil production to be up ~10 to 12% sequentially in Q2; estimate Q4 2016 will be 34% higher than Q4 2015*
  - *Estimate natural gas production to be up ~5 to 7% sequentially in Q2; may decline in 2H 2016*

	Actual 2015 Results	*2016 Guidance*	*% Change*
Capital Spending	\$482 million(1)	\$325 million	- 33%
Total Oil Production	4.5 million Bbl	4.9 to 5.1 million Bbl	+ 11%
Total Natural Gas Production	27.7 Bcf	26.0 to 28.0 Bcf	- 3%
Total Oil Equivalent Production	9.1 million BOE	9.2 to 9.8 million BOE	+ 4%
Adjusted EBITDA(2)	\$223 million	\$120 to \$130 million(3)	- 44%

(1) For operations only. Does not include capital expenditures associated with the HEYCO merger or two associated joint ventures.
(2) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see Appendix.
(3) Estimated 2016 Adjusted EBITDA is based upon the midpoint of 2016 production guidance range as provided on February 3, 2016 and affirmed on May 3, 2016. Estimated average realized prices for oil and natural gas used in these estimates were \$39.75/Bbl (WTI oil price of \$43.75/Bbl less \$4.00/Bbl of estimated price differentials) and \$2.37/Mcf (NYMEX Henry Hub natural gas price assuming regional differentials and uplifts from natural gas processing roughly offset), respectively, for the period April through December 2016.

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Appendix

Matador History

Predecessor Entities

Foran Oil & Matador Petroleum

- Founded by Joe Foran in 1983 – most participants are still shareholders today
- Foran Oil funded with $270,000 in contributed capital from 17 friends and family members; evolved into Matador Petroleum Corporation
- Sold Matador Petroleum Corporation to Tom Brown, Inc.(1) in June 2003 for an enterprise value of $388 million in an all-cash transaction

Matador Today

Matador Resources Company Timeline

Matador has grown almost entirely through the drill bit, with a focus on unconventional reservoir plays

Pre – IPO

2003 // 2008 2009 2010 2011 2012

2003
Founded by Joe Foran with $6 million, a proven management and technical team and board of directors

2008
Sold Haynesville rights in ~9,000 net acres to CHK for ~$180 million; retained 25% participation interest, carried working interest and overriding royalty interest

2010-2011
Redeployed capital into the Eagle Ford early in the play, acquiring over 30,000 net acres for ~$100 million

2012, 2013 and 2014 capital spending focused primarily on developing Eagle Ford and transitioning to oil

Assembling Delaware acreage position; begin delineation drilling program

Post – IPO

2012 2013 2014 2015 2016

February 2012
'O at $12.00; net cash
:eeds of ~$136 million

September 2013
Follow-on Offering at $15.25; net cash proceeds of ~$142 million

May 2014
Follow-on Offering at $25.00; net cash proceeds of ~$181 million

February 2015
HEYCO Combination

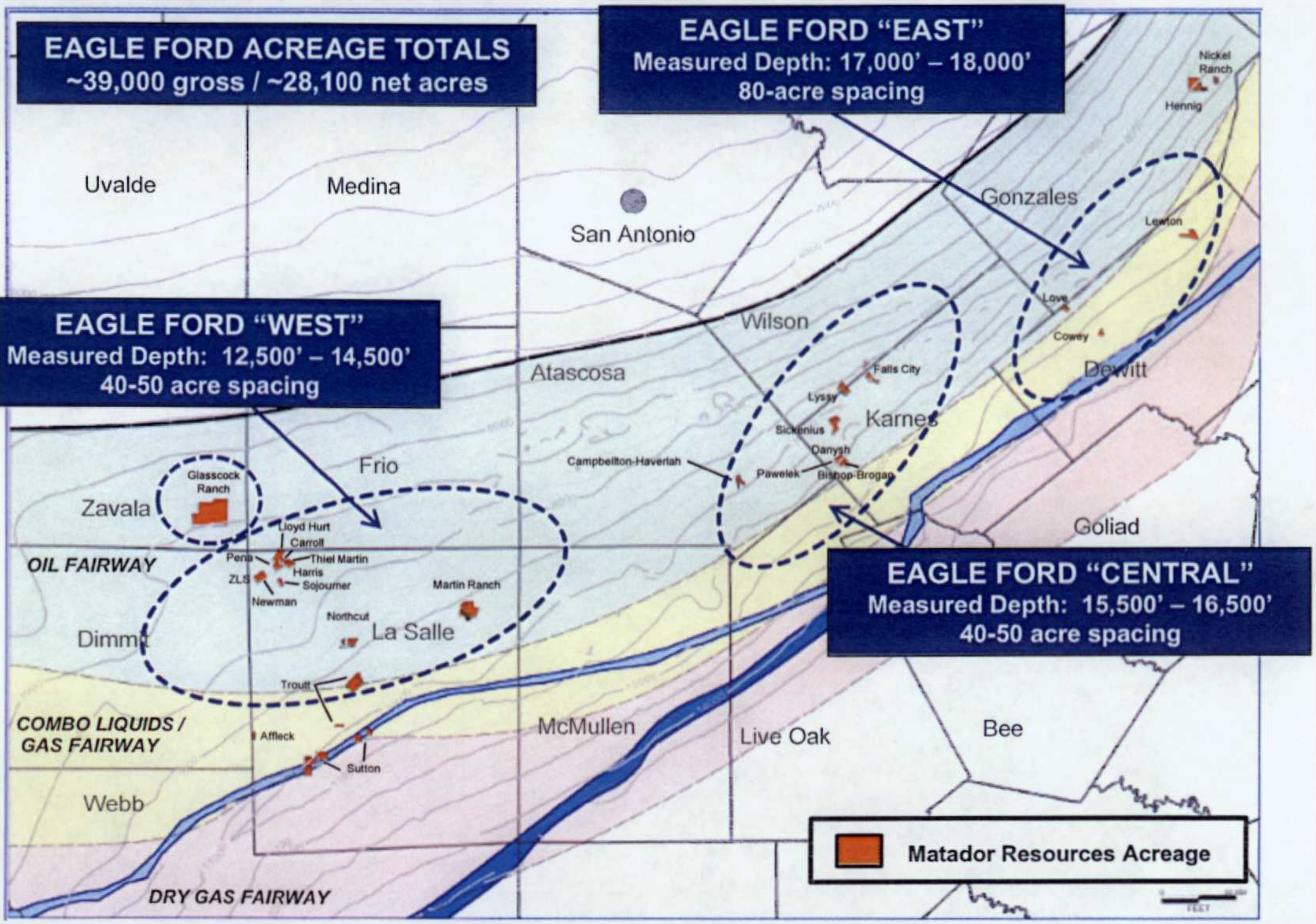
April 2015
Inaugural High-Yield Offering of $400 million;
Follow-on Offering at ~$27.00; net cash proceeds of ~$187 million

October 2015
Sale of certain Loving County midstream assets for ~$143 million(2)

March 2016
Follow-on Offering at ~$19.00; net cash proceeds of ~$142 million

(1) Tom Brown acquired by Encana in 2004.
(2) Excluding customary purchase price adjustments.

Eagle Ford – "Oil Bank"

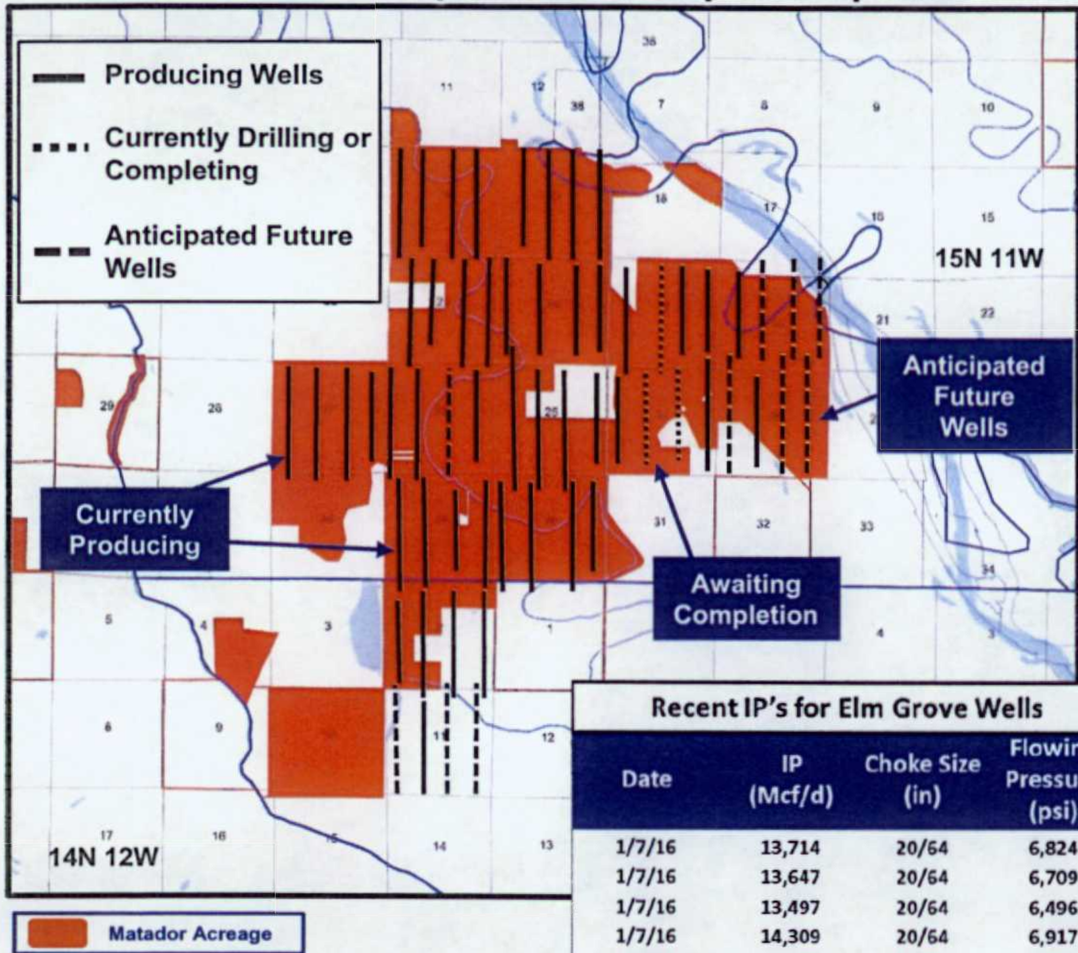


Note: All acreage at June 30, 2016. Some tracts not shown on map.

Matador

Haynesville Operations

Elm Grove Development – Chesapeake Operated



Recent IP's for Elm Grove Wells

Date	IP (Mcf/d)	Choke Size (in)	Flowing Pressure (psi)
1/7/16	13,714	20/64	6,824
1/7/16	13,647	20/64	6,709
1/7/16	13,497	20/64	6,496
1/7/16	14,309	20/64	6,917
1/7/16	14,123	20/64	6,725
1/7/16	12,632	18/64	6,959
1/14/16	13,497	20/64	6,798
1/14/16	14,374	20/64	6,907
1/15/16	11,884	18/64	7,186

Note: All acreage at June 30, 2016.

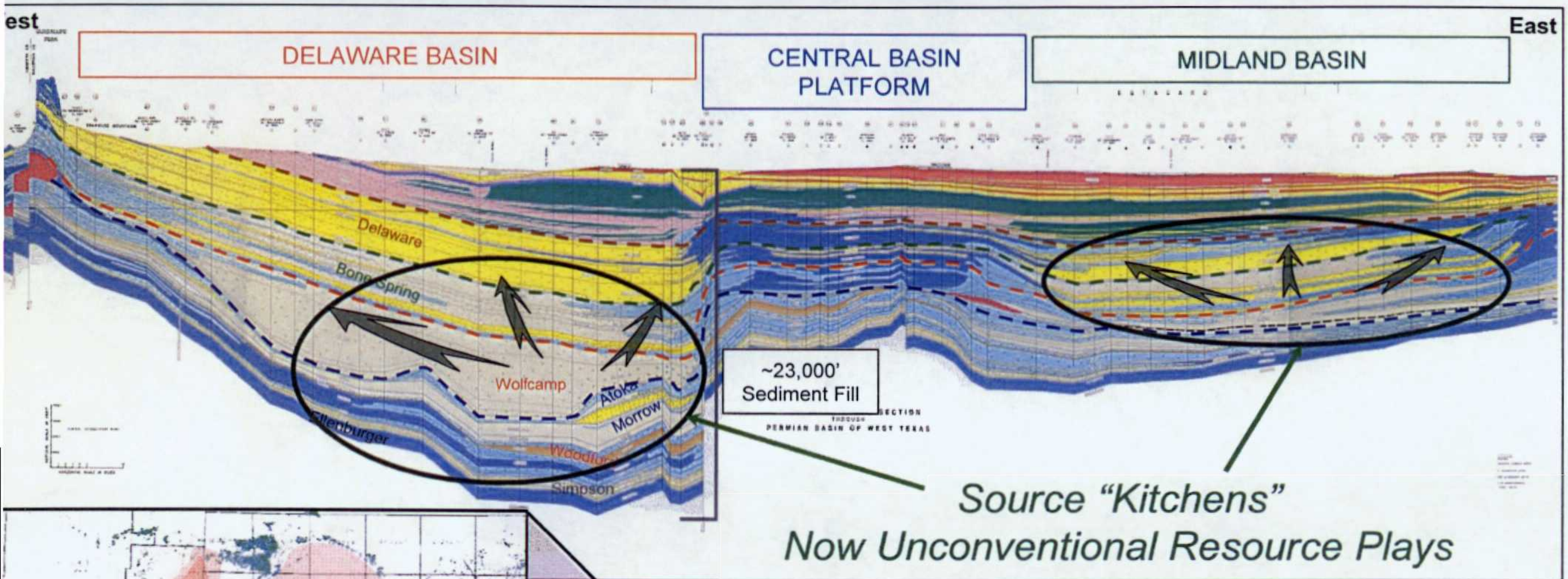
2015 Haynesville Non-Op Program

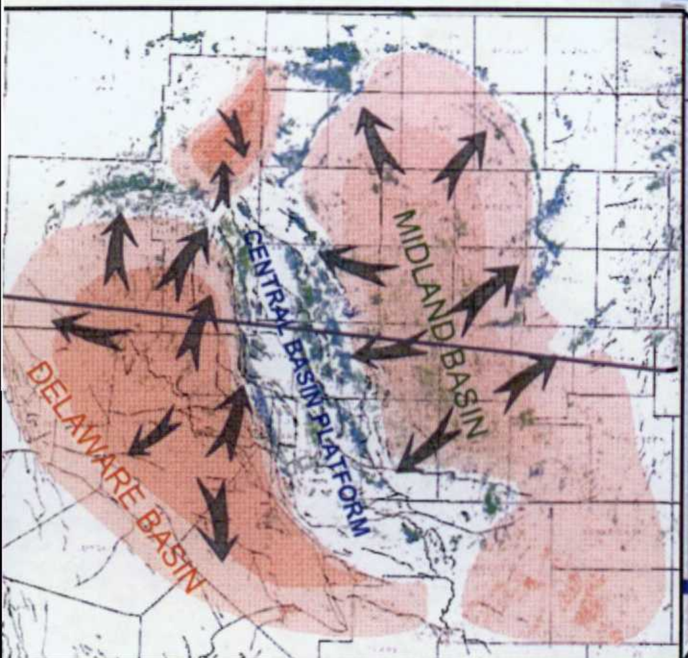
- 22 gross (1.9 net) wells turned to sales throughout Tier 1 Haynesville in 2015
- Includes 9 gross (1.6 net) wells turned to sales on Elm Grove properties operated by Chesapeake in 2015 (shown on map at left)
  - *Chesapeake deferred first production on 9 gross (1.9 net) Elm Grove wells drilled and completed in 2015 until early Q1 2016*

2016 Haynesville Non-Op Program

- 5 gross (0.6 net) wells expected to be drilled and completed in the Haynesville in 2016
- Estimated capital expenditures of ~$4 million
- 9 gross (1.9 net) Elm Grove wells operated by Chesapeake turned to sales in early 2016
  - *Initial rates of ~13.5 MMcf/d of natural gas with drilling and completion costs under $7 million per well*
- Haynesville and Cotton Valley average daily natural gas production of 46.7 MMcf/d in Q1 2016, a 14% sequential increase as compared to 41.0 MMcf/d in Q4 2015

Delaware Basin – A "World Class" Hydrocarbon System





- 70,000 square mile area
- Up to 25,000 feet of multiple, stacked, petroleum systems
- Extensive drilling, coring and geological studies since 1920s
- >1,500 conventional reservoirs with cumulative production >1.0 million Bbl each
- Cumulative production from 1,500 conventional reservoirs, as of year 2000 (pre-horizontal drilling) >30.0 billion Bbl(1)

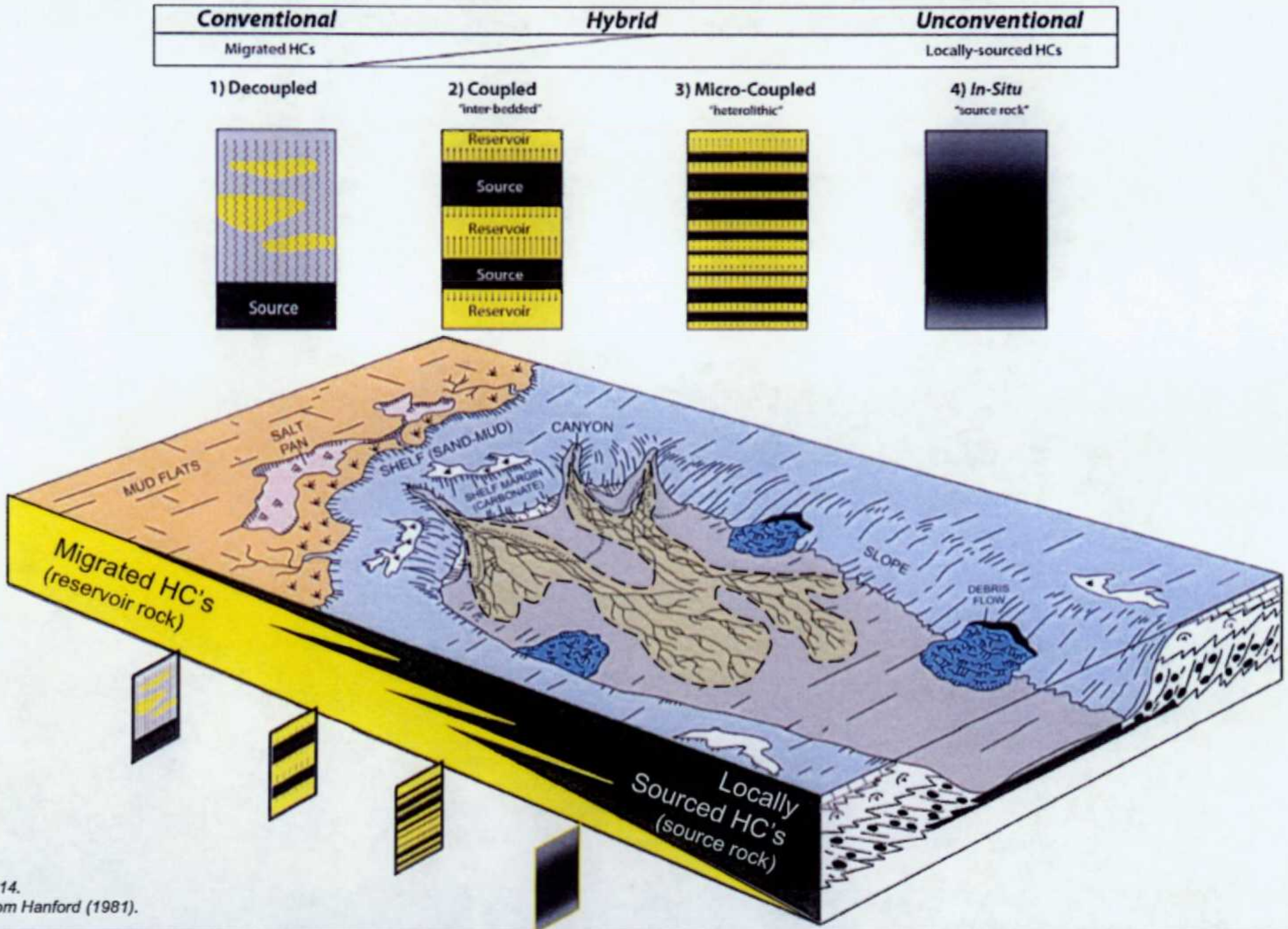
(1) Dutton et al, AAPG 2005.

Spectrum of Unconventional Play Types

In general there is no consensus on the what an "unconventional" reservoir is…

At Matador, we think of an unconventional reservoir as a spectrum of play types.

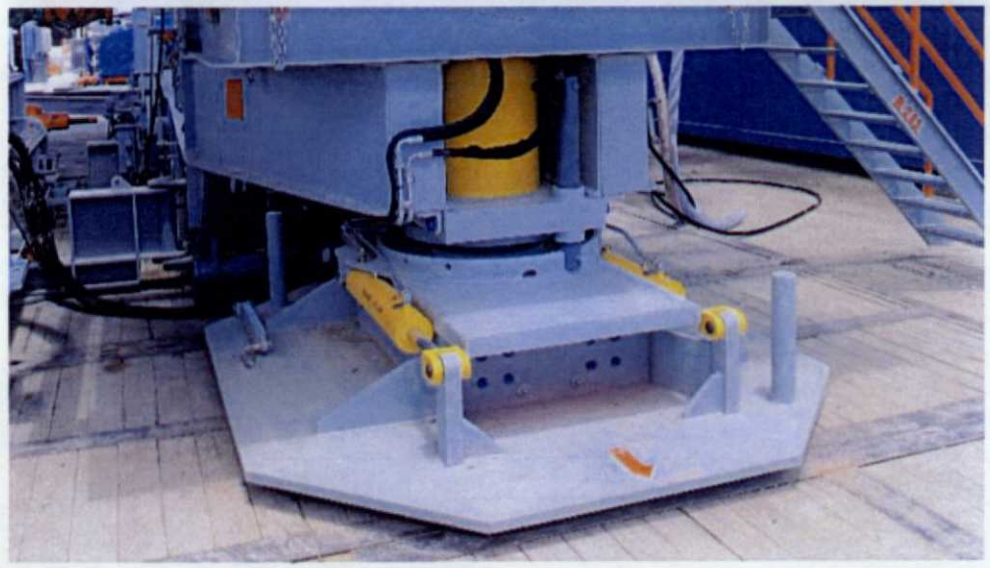
The distribution and quality of these play types are both spatially and temporally variable.



Play types from Bishop 2014.
Block diagram modified from Hanford (1981).

New Rig Technology for Horizontal Drilling – Saving Time and Money!

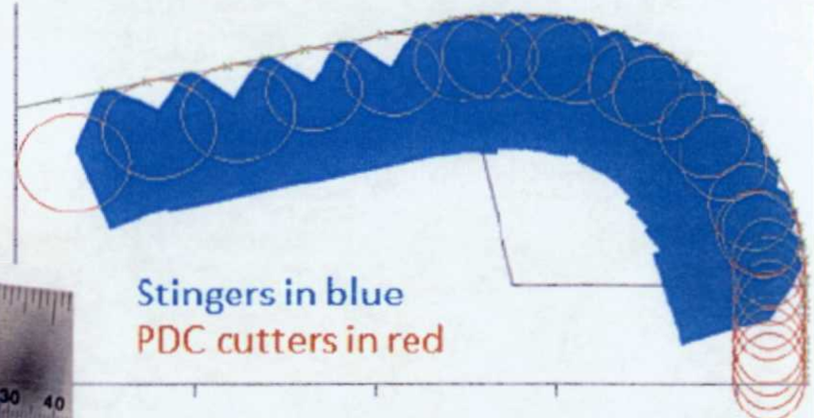
- **7,500 psi Pressure Rating**
  - Estimated reduction in drilling time of 20 to 25% in the lateral on Wolfcamp wells
- **Telescoping Flex-joint**
  - Estimated reduction in drilling time of 12 to 18 hours per well
- **Integrated Mud-Gas Separator**
  - Estimated savings of 50% compared to rental separator
- **BOP Wrangler**
  - Estimated reduction in drilling time of 12 hours per well
- **Walking System & V-door turned 90°**
  - Allows for batch-drilling and simultaneous operations
- **Reduced Downtime**



Future Bit Technology – The Evolution of the PDC bit

- Matador continues to be at the forefront of new bit technology
- Smith Bits latest technology StingBlade design
- StingBlade design features
  - *Alternating Stinger/PDC cutters*
  - *Stinger cutters cut troughs in the formation with the PDC cutters coming behind and removing the ridges*
  - *Stinger cutters do the hard work, PDC cutters keep the speed*
  - *Ultimate combination of speed, durability and steerability*



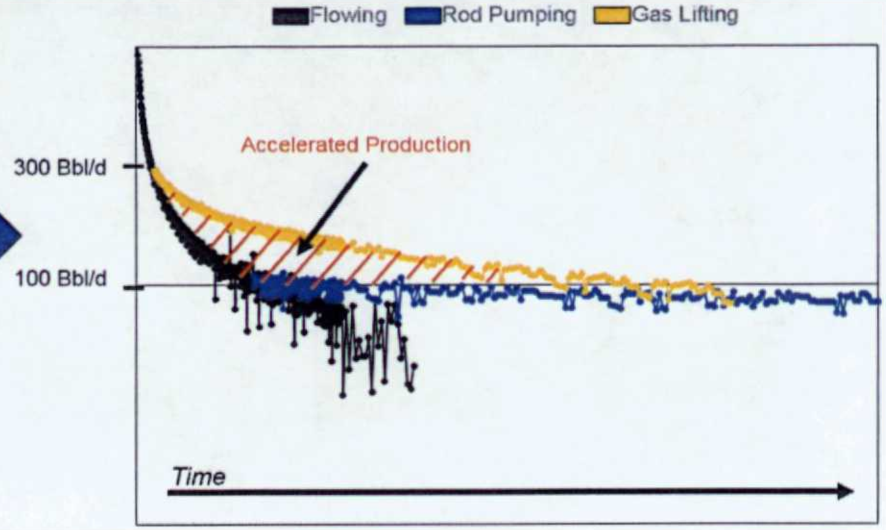


Matador

Optimizing Artificial Lift Operations Across the Delaware Basin

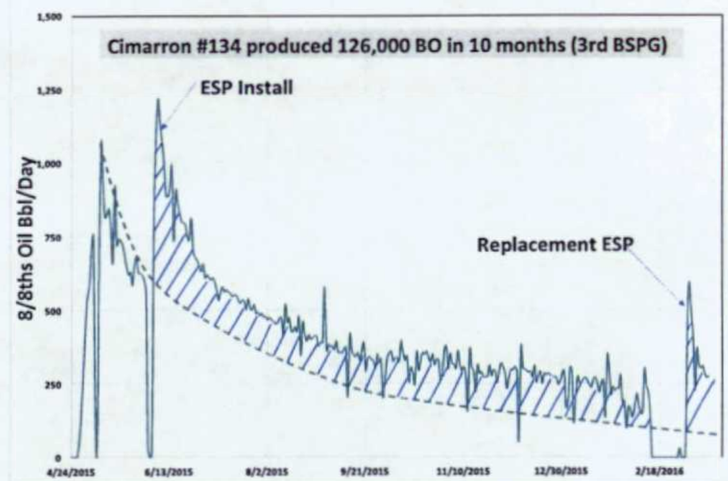
Optimizing Gas Lift Operations

- Numerous 2nd Bone Spring wells on gas lift
- Accelerates production while reducing LOE
- Lower maintenance costs than beam pump
- Helps wells recover faster from offset fracs
- Very efficient with high GOR wells



Using ESP's to Optimize Production

- Accelerated production while maintaining a controlled drawdown of bottomhole pressure
- BHP gauges aid in analyzing 3rd Bone Spring reservoir properties
- Quick startup after shut in for maintenance = minimal downtime
- Quiet operation in environmentally sensitive areas
- Able to unload offset frac water even more effectively than gas lift in wells with lower GOR and high reservoir deliverability



Note: Graph and data in gas lift figure above is for illustrative purposes only and not meant to reflect historical or forecasted data from actual well.

Proven Management Team – Experienced Leadership

Management Team	Background and Prior Affiliations	Industry Experience	Matador Experience
Joseph Wm. Foran Founder, Chairman and CEO	- Matador Petroleum Corporation, Foran Oil Company, James Cleo Thompson Jr.	35 years	Since Inception
Matthew V. Hairford President, Chair of Operating Committee	- Samson, Sonat, Conoco	31 years	Since 2004
David E. Lancaster EVP and CFO	- Schlumberger, S.A. Holditch & Associates, Inc., Diamond Shamrock	37 years	Since 2003
Craig N. Adams EVP – Land, Legal & Administration	- Baker Botts L.L.P., Thompson & Knight LLP	23 years	Since 2012
Van H. Singleton, II EVP – Land	- Southern Escrow & Title, VanBrannon & Associates	19 years	Since 2007
Bradley M. Robinson SVP of Reservoir Engineering and CTO	- Schlumberger, S.A. Holditch & Associates, Inc., Marathon	39 years	Since Inception
Billy E. Goodwin SVP of Operations	- Samson, Conoco	31 years	Since 2010
G. Gregg Krug SVP and Head of Marketing and Midstream	- Williams Companies, Samson, Unit Corporation	32 years	Since 2005
Matthew D. Spicer VP and General Manager of Midstream	- Matador Resources Company	2 years	Since 2014
Trent W. Green VP – Production	- HEYCO, Bass Enterprises, Schlumberger, S.A. Holditch & Associates, Inc., Amerada Hess	27 years	Since 2015
Robert T. Macalik VP and CAO	- Pioneer Natural Resources, PricewaterhouseCoopers (PwC)	13 years	Since 2015
Kathryn L. Wayne Controller and Treasurer	- Matador Petroleum Corporation, Mobil	31 years	Since Inception

Board of Directors – Expertise and Stewardship

Board Members	Professional Experience	Business Expertise
Reynald A. Baribault Lead Director	- Vice President / Engineering and Co-founder, North Plains Energy, LLC - President and CEO, IPR Energy Partners, LLC - Former Vice President, Netherland, Sewell & Associates, Inc.	Oil and Gas Exploration & Development
Craig T. Burkert Director	- CFO, ROMCO Equipment Co.	Business and Finance
William M. Byerley Director	- Retired Partner, PricewaterhouseCoopers (PwC)	Accounting
Joe A. Davis Director	- Retired EVP, General Counsel and Secretary, EnLink Midstream, LLC and EnLink Midstream Partners, LP - Former Partner, Hunton & Williams LLP	Law and Business
David M. Laney Director	- Past Chairman, Amtrak Board of Directors - Former Partner, Jackson Walker LLP	Law and Investments
Gregory E. Mitchell Director	- President and CEO, Toot'n Totum Food Stores	Petroleum Retailing
Dr. Steven W. Ohnimus Director	- Retired Vice President and General Manager, Unocal Indonesia	Oil and Gas Operations
Carlos M. Sepulveda, Jr. Director	- Chairman of the Board, Triumph Bancorp, Inc. - Retired President and CEO, Interstate Battery System International, Inc. - Director and Audit Chair, Cinemark Holdings, Inc.	Business and Finance
Margaret B. Shannon Director	- Retired Vice President and General Counsel, BJ Services Co. - Former Partner, Andrews Kurth LLP	Law and Corporate Governance
George M. Yates Director	- Chairman & CEO of HEYCO Energy Group, Inc.	Oil and Gas Exploration & Development

Special Board Advisors – Expertise and Stewardship

Special Board Advisors	Professional Experience	Business Expertise
Ronney F. Coleman	- Retired President – North America, Archer - Former Vice President North America Pumping, BJ Services Co.	Oilfield Services
Marlan W. Downey	- Retired President, ARCO International - Former President, Shell Pecten International - Past President of American Association of Petroleum Geologists	Oil and Gas Exploration
John R. Gass	- VP, Eastern Hemisphere Operations, Nabors Drilling International Limited based in Dubai, UAE - Previously spent 28 years with Parker Drilling Company in various management roles	Oil and Gas Drilling
David F. Nicklin	- Retired Executive Director of Exploration, Matador Resources Company	Oil and Gas Exploration
Wade I. Massad	- Managing Member, Cleveland Capital Management, LLC - Formerly with KeyBanc Capital Markets and RBC Capital Markets	Capital Markets
Greg L. McMichael	- Retired Vice President and Group Leader – Energy Research of A.G. Edwards	Capital Markets
Dr. James D. Robertson	- Retired VP Exploration, Chief Geophysicist, ARCO International	Oil and Gas Exploration
James A. Rolfe	- Of Counsel, Kendall Law Group - Retired United States Attorney, Northern District of Texas	Law
Michael C. Ryan	- Retired Partner, Berens Capital Management - Former Director, Matador Resources Company	International Business and Finance

Adjusted EBITDA Reconciliation

This investor presentation includes the non-GAAP financial measure of Adjusted EBITDA. Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of the Company's consolidated financial statements, such as industry analysts, investors, lenders and rating agencies. "GAAP" means Generally Accepted Accounting Principles in the United States of America. The Company believes Adjusted EBITDA helps it evaluate its operating performance and compare its results of operations from period to period without regard to its financing methods or capital structure. The Company defines Adjusted EBITDA as earnings before interest expense, income taxes, depletion, depreciation and amortization, accretion of asset retirement obligations, property impairments, unrealized derivative gains and losses, certain other non-cash items and non-cash stock-based compensation expense, and net gain or loss on asset sales and inventory impairment. Adjusted EBITDA is not a measure of net income (loss) or net cash provided by operating activities as determined by GAAP.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income (loss) or net cash provided by operating activities as determined in accordance with GAAP or as an indicator of the Company's operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components of understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure. Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner. The following table presents the calculation of Adjusted EBITDA and the reconciliation of Adjusted EBITDA to the GAAP financial measures of net income (loss) and net cash provided by operating activities, respectively, that are of a historical nature. Where references are pro forma, forward-looking, preliminary or prospective in nature, and not based on historical fact, the table does not provide a reconciliation. The Company could not provide such reconciliation without undue hardship because the forward-looking Adjusted EBITDA numbers included in this investor presentation are estimations, approximations and/or ranges. In addition, it would be difficult for the Company to present a detailed reconciliation on account of many unknown variables for the reconciling items.

Adjusted EBITDA Reconciliation

The following table presents our calculation of Adjusted EBITDA and reconciliation of Adjusted EBITDA to the GAAP financial measures of net income (loss) and net cash provided by operating activities, respectively.

(In thousands)	1Q 2011	2Q 2011	3Q 2011	4Q 2011	1Q 2012	2Q 2012	3Q 2012	4Q 2012	1Q 2013	2Q 2013	3Q 2013	4Q 2013
Unaudited Adjusted EBITDA reconciliation to Net (Loss) Income:												
Net (loss) income	$ (27,596)	$ 7,153	$ 6,194	$ 3,941	$ 3,801	$ (6,676)	$ (9,197)	$ (21,188)	$ (15,505)	$ 25,119	$ 20,105	$ 15,374
Interest expense	106	184	171	222	308	1	144	549	1,271	1,609	2,038	768
Total income tax provision (benefit)	(6,906)	(46)	-	1,430	3,064	(3,713)	(593)	(188)	46	32	2,563	7,056
Depletion, depreciation and amortization	7,111	8,180	7,287	9,176	11,205	19,914	21,680	27,655	28,232	20,234	26,127	23,802
Accretion of asset retirement obligations	39	57	62	51	53	58	59	86	81	80	86	100
Full-cost ceiling impairment	35,673	-	-	-	-	33,205	3,596	26,674	21,230	-	-	-
Unrealized (gain) loss on derivatives	1,668	(332)	(2,870)	(3,604)	3,270	(15,114)	12,993	3,653	4,825	(7,526)	9,327	606
Stock-based compensation expense	53	128	1,234	991	(363)	191	(51)	363	492	1,032	1,239	1,134
Net loss (gain) on asset sales and inventory impairment	-	-	-	154	-	60	-	425	-	192	-	-
Adjusted EBITDA	**$ 10,148**	**$ 15,324**	**$ 12,078**	**$ 12,361**	**$ 21,338**	**$ 27,926**	**$ 28,631**	**$ 38,029**	**$ 40,672**	**$ 40,772**	**$ 61,485**	**$ 48,840**

(In thousands)	1Q 2011	2Q 2011	3Q 2011	4Q 2011	1Q 2012	2Q 2012	3Q 2012	4Q 2012	1Q 2013	2Q 2013	3Q 2013	4Q 2013
Unaudited Adjusted EBITDA reconciliation to Net Cash Provided by Operating Activities:												
Net cash provided by operating activities	$ 12,732	$ 6,799	$ 14,912	$ 27,425	$ 5,110	$ 46,416	$ 28,799	$ 43,903	$ 32,229	$ 51,684	$ 43,280	$ 52,278
Net change in operating assets and liabilities	(2,690)	8,386	(3,004)	(15,286)	15,920	(18,491)	(500)	(6,235)	7,126	(12,553)	15,265	(3,630)
Interest expense, net of non-cash portion	106	184	171	222	308	1	144	549	1,271	1,609	2,038	768
Current income tax (benefit) provision	-	(45)	(1)	-	- -		188	(188)	46	32	902	(576)
Net (income) loss attributable to non-controlling interest in subsidiary	-	-	-	-	-	-	-	-	-	-	-	-
Adjusted EBITDA	**$ 10,148**	**$ 15,324**	**$ 12,078**	**$ 12,361**	**$ 21,338**	**$ 27,926**	**$ 28,631**	**$ 38,029**	**$ 40,672**	**$ 40,772**	**$ 61,485**	**$ 48,840**

(In thousands)	1Q 2014	2Q 2014	3Q 2014	4Q 2014	1Q 2015	2Q 2015	3Q 2015	4Q 2015	1Q 2016
Unaudited Adjusted EBITDA reconciliation to Net (Loss) Income:									
Net (loss) income	$ 16,363	$ 18,226	$ 29,619	$ 46,563	$ (50,234)	$ (157,091)	$ (242,059)	$ (230,401)	$ (107,654)
Interest expense	1,396	1,616	673	1,649	2,070	5,869	7,229	6,586	7,197
Total income tax provision (benefit)	9,536	10,634	16,504	27,701	(26,390)	(89,350)	(33,305)	1,677	-
Depletion, depreciation and amortization	24,030	31,797	35,143	43,767	46,470	51,768	45,237	35,370	28,923
Accretion of asset retirement obligations	117	123	130	134	112	132	182	307	264
Full-cost ceiling impairment	-	-	-	-	67,127	229,026	285,721	219,292	80,462
Unrealized (gain) loss on derivatives	3,108	5,234	(16,293)	(50,351)	8,557	23,532	(6,733)	13,909	6,839
Stock-based compensation expense	1,795	1,834	1,038	857	2,337	2,794	1,755	2,564	2,243
Net loss (gain) on asset sales and inventory impairment	-	-	-	-	97	-	-	(1,005)	(1,065)
Adjusted EBITDA	**$ 56,345**	**$ 69,464**	**$ 66,814**	**$ 70,320**	**$ 50,146**	**$ 66,680**	**$ 58,027**	**$ 48,299**	**$ 17,209**

(In thousands)	1Q 2014	2Q 2014	3Q 2014	4Q 2014	1Q 2015	2Q 2015	3Q 2015	4Q 2015	1Q 2016
Unaudited Adjusted EBITDA reconciliation to Net Cash Provided by Operating Activities:									
Net cash provided by operating activities	$ 31,945	$ 81,530	$ 66,883	$ 71,123	$ 93,346	$ 20,043	$ 72,535	$ 22,611	$ 18,358
Net change in operating assets and liabilities	21,729	(15,221)	(586)	56	(45,234)	40,843	(20,846)	16,254	(8,059)
Interest expense, net of non-cash portion	1,396	1,616	673	1,649	2,070	5,869	6,678	6,285	6,897
Current income tax (benefit) provision	1,275	1,539	(156)	(2,525)	-	-	(295)	3,254	-
Net (income) loss attributable to non-controlling interest in subsidiary	-	-	-	17	(36)	(75)	(45)	(105)	13
Adjusted EBITDA	**$ 56,345**	**$ 69,464**	**$ 66,814**	**$ 70,320**	**$ 50,146**	**$ 66,680**	**$ 58,027**	**$ 48,299**	**$ 17,209**

Matador
RESOURCES COMPANY

Adjusted EBITDA Reconciliation

The following table presents our calculation of Adjusted EBITDA and reconciliation of Adjusted EBITDA to the GAAP financial measures of net income (loss) and net cash provided by operating activities, respectively.

(In thousands)	Year Ended December 31,							
	2008	2009	2010	2011	2012	2013	2014	2015
Unaudited Adjusted EBITDA reconciliation to Net Income (Loss):								
Net income (loss)	$103,878	($14,425)	$6,377	($10,309)	($33,261)	$45,094	$110,771	($679,785)
Interest expense	-	-	3	683	1,002	5,687	5,334	21,754
Total income tax (benefit) provision	20,023	(9,925)	3,521	(5,521)	(1,430)	9,697	64,375	(147,368)
Depletion, depreciation and amortization	12,127	10,743	15,596	31,754	80,454	98,395	134,737	178,847
Accretion of asset retirement obligations	92	137	155	209	256	348	504	734
Full-cost ceiling impairment	22,195	25,244	-	35,673	63,475	21,229	-	801,166
Unrealized loss (gain) on derivatives	(3,592)	2,375	(3,139)	(5,138)	4,802	7,232	(58,302)	39,265
Stock-based compensation expense	665	656	898	2,406	140	3,897	5,524	9,450
Net (gain) loss on asset sales and inventory impairment	(136,977)	379	224	154	485	192	-	(908)
Adjusted EBITDA	**$18,411**	**$15,184**	**$23,635**	**$49,911**	**$115,923**	**$191,771**	**$262,943**	**$223,155**

(In thousands)	Year Ended December 31,							
	2008	2009	2010	2011	2012	2013	2014	2015
Unaudited Adjusted EBITDA reconciliation to Net Cash Provided by Operating Activities:								
Net cash provided by operating activities	$25,851	$1,791	$27,273	$61,868	$124,228	$179,470	$251,481	$208,535
Net change in operating assets and liabilities	(17,888)	15,717	(2,230)	(12,594)	(9,307)	6,210	5,978	(8,980)
Interest expense, net of non-cash portion	-	-	3	683	1,002	5,687	5,334	20,902
Current income tax (benefit) provision	10,448	(2,324)	(1,411)	(46)	-	404	133	2,959
Net (income) loss attributable to non-controlling interest in subsidiary	-	-	-	-	-	-	17	(261)
Adjusted EBITDA	**$18,411**	**$15,184**	**$23,635**	**$49,911**	**$115,923**	**$191,771**	**$262,943**	**$223,155**

PV-10 Reconciliation

PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. PV-10 is not an estimate of the fair market value of the Company's properties. Matador and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies and of the potential return on investment related to the companies' properties without regard to the specific tax characteristics of such entities. PV-10 may be reconciled to the Standardized Measure of discounted future net cash flows at such dates by reducing PV-10 by the discounted future income taxes associated with such reserves.

	At March 31, 2016	At December 31, 2015	At December 31, 2014
PV-10 *(in millions)*	$501.9	$541.6	$1,043.4
Discounted Future Income Taxes *(in millions)*	(6.3)	(12.4)	(130.1)
Standardized Measure *(in millions)*	$495.6	$529.2	$913.3