KODIAK

OIL & GAS CORP.

Investor Presentation

June 2014

Exploring, developing and producing oil and natural gas in the Williston Basin.

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Forward-looking Statement

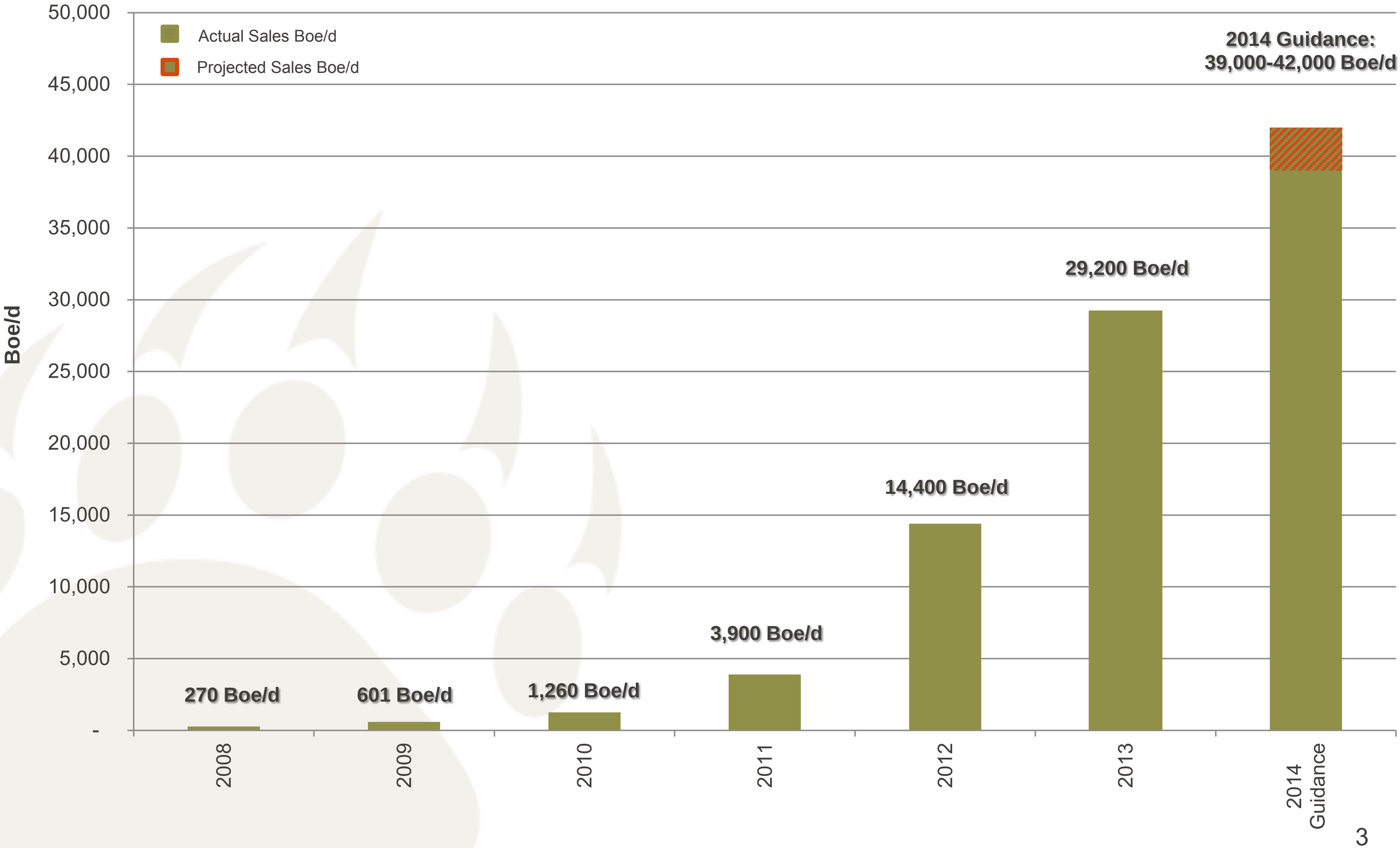
This presentation includes statements that may constitute "forward-looking" statements, usually containing the words "believe," "estimate," "project," "expect" or similar expressions. These statements are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. Forward-looking statements inherently involve risks and uncertainties that could cause actual results to differ materially from the forward-looking statements. Forward looking statements are statements that are not historical facts and are generally, but not always, identified by the words "expects," "plans," "anticipates," "believes," "intends," "estimates," "projects," "potential" and similar expressions, or that events or conditions "will," "would," "may," "could" or "should" occur. Forward-looking statements in this presentation include statements regarding the Company's exploration, drilling and development programs and plans, including the Company's pilot project on wellbore spacing, the Company's expectations regarding the timing and success of such programs, the Company's expectations regarding future oil and gas sales volumes, the Company's expectations regarding infrastructure capacity in the Williston Basin, the Company's capital plans, the expected benefits therefrom and the timing and availability of financing to satisfy the capital requirements, the Company's expectations regarding the size and benefits of its commodity hedging program, and the Company's expectations regarding the future production of its oil & gas properties. Factors that could cause or contribute to such differences include, but are not limited to, fluctuations in the prices of oil and gas, uncertainties inherent in estimating quantities of oil and gas reserves and projecting future rates of production and timing of development activities, competition, operating risks, acquisition risks, uncertainties regarding the Company's liquidity and capital requirements and the availability and cost of capital necessary to fund the Company's current plan of operations, the effects of governmental regulation, adverse changes in the market for the Company's oil and gas production, dependence upon third-party vendors, and other risks detailed in the Company's periodic report filings with the Securities and Exchange Commission.

Kodiak Overview

Williston Basin Acreage:	171,000 net acres
2014E Rig Count:	7 Operated and 1-3 Non-Operated
2014E Capex:	$940MM
2014 Production Guidance:	39,000-42,000 Boe/d
Proved Reserves:	167.3 MMBoe (83% Oil)
Proved PV-10 Value:	$3.5 B
Market Cap:	$3.3 B[1]
Debt:	$1.55 B Senior Notes; ~$700MM drawn on $1.35B Facility
Liquidity:	$650MM available under Revolver

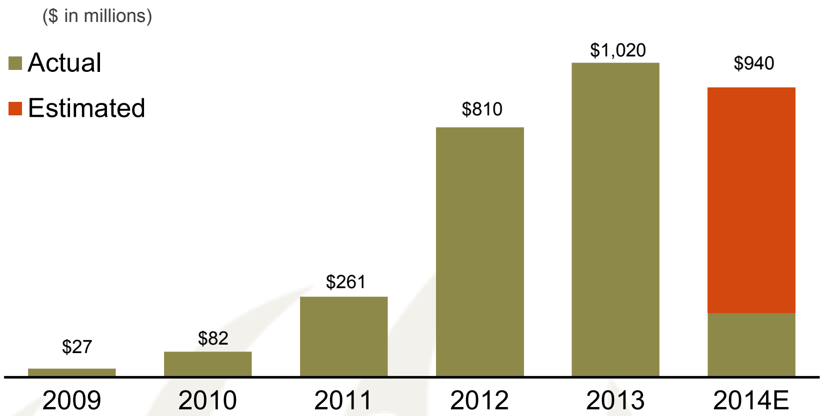
[1] As of May 28, 2014

Consistent Production Growth



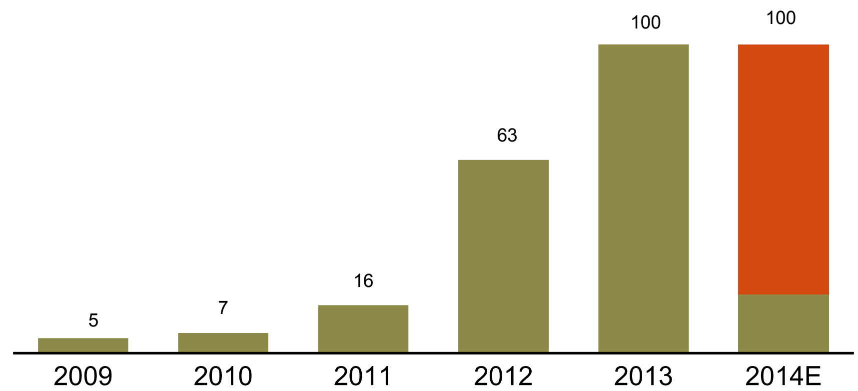
Capital Investment Overview

Capital Expenditures[1]

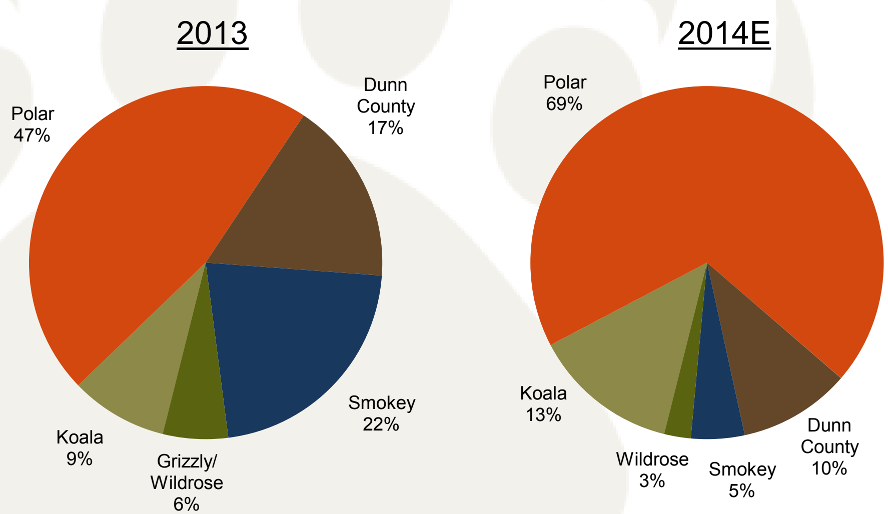


[1] Capex excludes any potential acquisitions

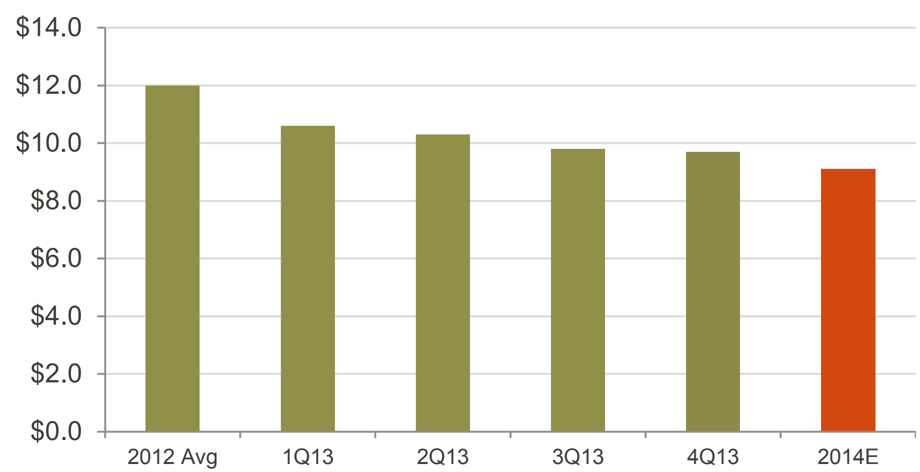
Completed Net Wells Per Year



2013 & 2014E Operated Wells by Area



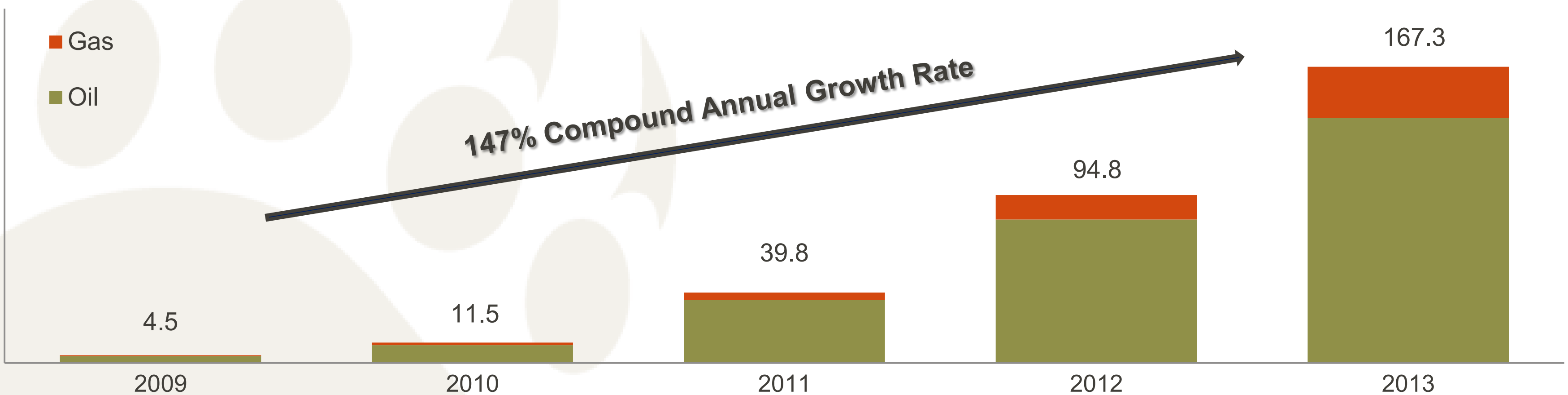
Completed Well Costs ($mm)



Proved Reserve Summary
12/31/2013 Proved Reserves[1] and PV-10

Kodiak Net Proved Reserves as of December 31, 2013				
Reserve Category	**Oil** (MMbbls)	**Gas** (Bcf)	**Total** (MMboe)	**SEC PV-10** ($B)
Proved Developed Producing	63.9	78.8	77.1	$2.4
Proved Undeveloped	74.3	95.2	90.2	1.0
Total Proved Reserves	**138.3**	**174.0**	**167.3**	**$3.5**

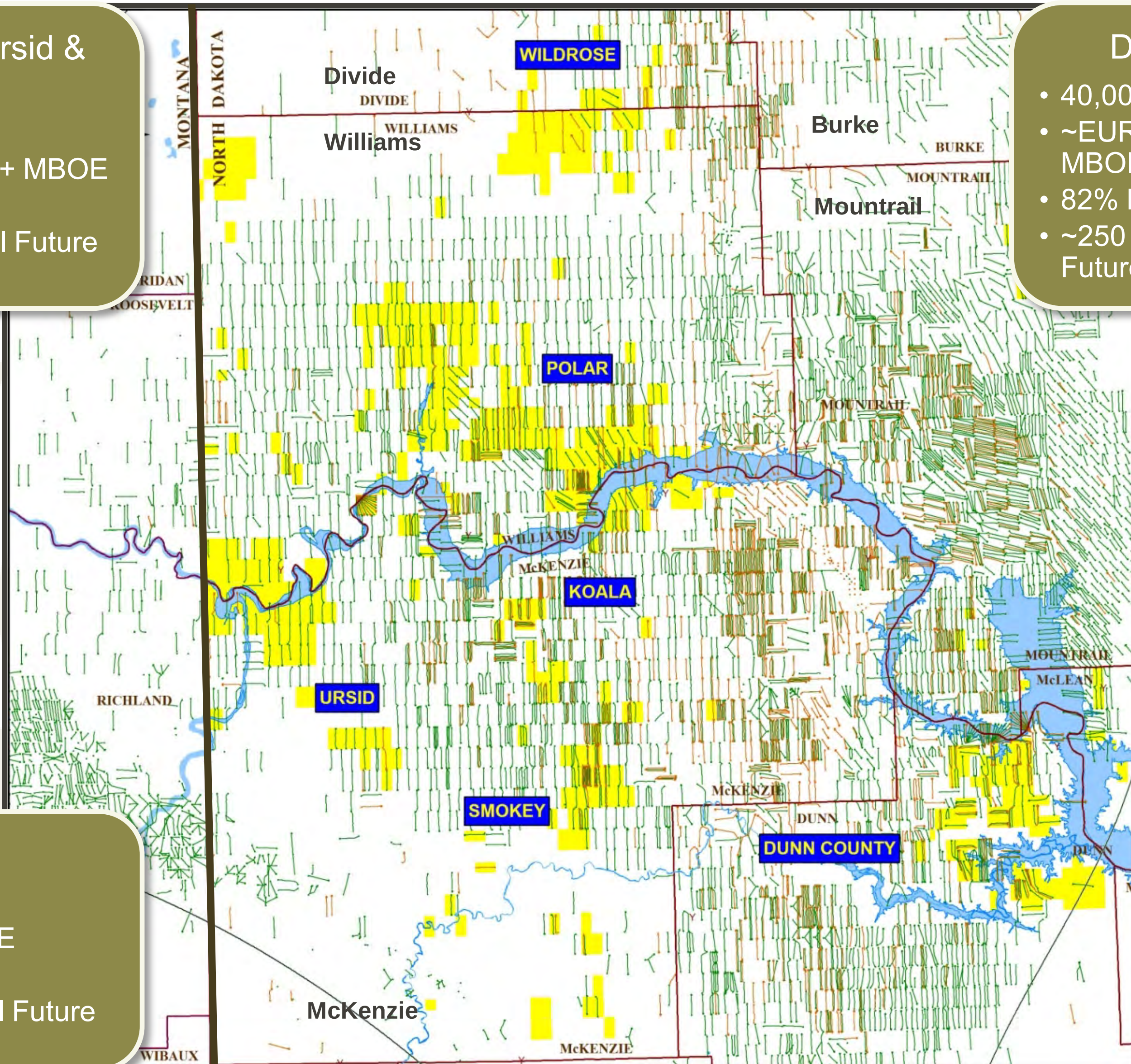
Consistent Reserves Growth (MMBoe)



[1] Reserves prepared by Netherland, Sewell & Associates, Inc.

Williston Asset Overview
171,000 Net Acre Position

Polar, Koala, Ursid & Smokey
- 111,000 Net Acres
- ~EURs: 600 - 950+ MBOE
- ~ 80% NRI
- ~950 Net Potential Future Drilling Locations



Dunn County
- 40,000 Net Acres
- ~EURs: 800 - 950+ MBOE
- 82% NRI
- ~250 Net Potential Future Drilling Locations

Wildrose
- 20,000 Net Acres
- ~EURs: 350 MBOE
- 80% NRI
- ~100 Net Potential Future Drilling Locations

Well Economics Overview

Bakken Long Lateral – 900 MBOE

WTI ($/bbl)	Differential ($/bbl)	Well Cost ($MM)	NPV-10 ($MM)	IRR	Payout (months)
$95	$10	$8.7	$16.4	86%	11
85	10	8.7	13.4	69%	14
75	10	8.7	10.4	53%	18

Bakken Long Lateral – 800 MBOE

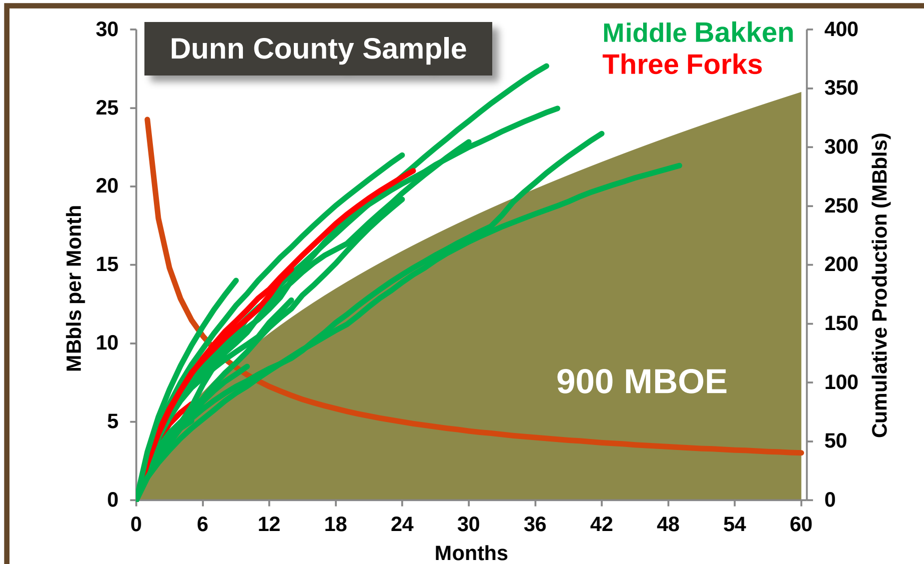
WTI ($/bbl)	Differential ($/bbl)	Well Cost ($MM)	NPV-10 ($MM)	IRR	Payout (months)
$95	$10	$8.7	$13.5	70%	14
85	10	8.7	10.9	56%	17
75	10	8.7	8.2	43%	21

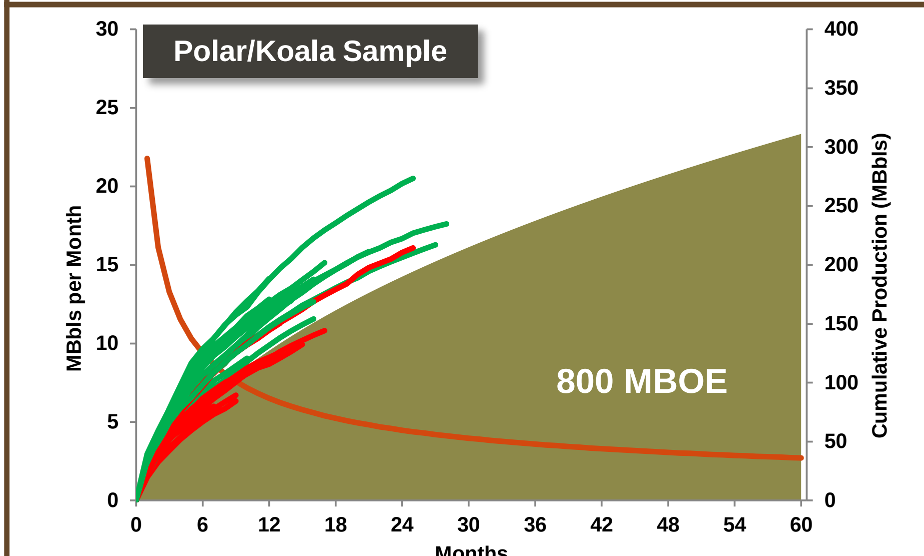
Bakken Long Lateral – 700 MBOE

WTI ($/bbl)	Differential ($/bbl)	Well Cost ($MM)	NPV-10 ($MM)	IRR	Payout (months)
$95	$10	$8.7	$10.7	55%	17
85	10	8.7	8.3	44%	21
75	10	8.7	6.0	33%	27

Bakken Long Lateral – 600 MBOE

WTI ($/bbl)	Differential ($/bbl)	Well Cost ($MM)	NPV-10 ($MM)	IRR	Payout (months)
$95	$10	$8.7	$7.9	42%	22
85	10	8.7	5.8	33%	27
75	10	8.7	3.8	24%	36

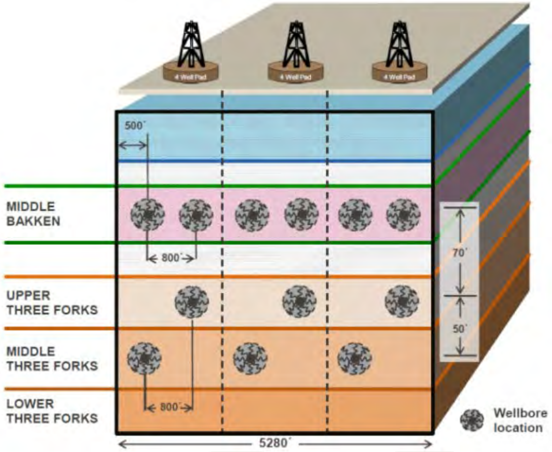




Note: Based on management projections utilizing current cost and differential assumptions
Actual well results depicted on graphs are long lateral well completions normalized for non-producing days.

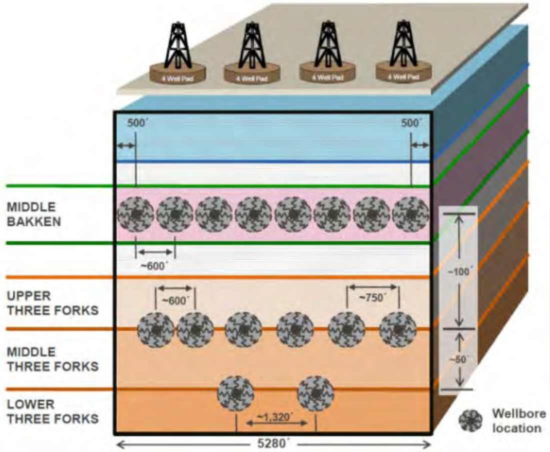
Type Curve Assumptions: Percentage Gas: ~15%
Hyperbolic Exponent (B-Factor): 1.8
Effective Day 1 Initial Decline (Tangent): 99.9%
Effective Year 1 Initial Decline (Secant): 76.4%

Pilot Program Production Update



Polar Pilot 1.0

	Average Production per Well (BOE/d)						
	30 Days	60 Days	90 Days	120 Days	150 Days	180 Days	210 Days
Middle Bakken (6 wells)	1,020	845	735	666	611	562	518
Three Forks (6 wells)	933	751	645	570	519	471	432



Polar Pilot 2.0

	30 Days	60 Days	90 Days
Middle Bakken (2 wells)	1,040	790	663
Three Forks (2 wells)	792	606	535

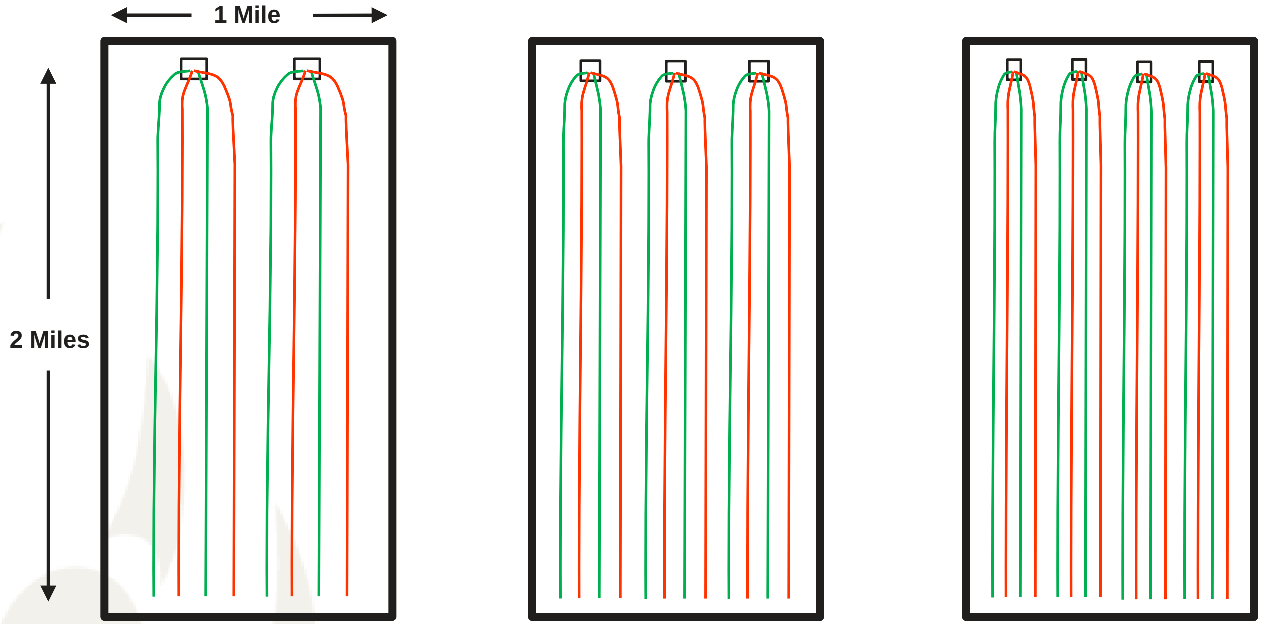
Smokey Pilot

Smokey Pilot

	30 Days	60 Days	90 Days	120 Days	150 Days	180 Days
Middle Bakken (6 wells)	940	738	648	566	506	460
Three Forks (6 wells)	659	516	417	357	316	286

Polar: Maximizing the Economics of DSUs – Hypothetical Outcomes

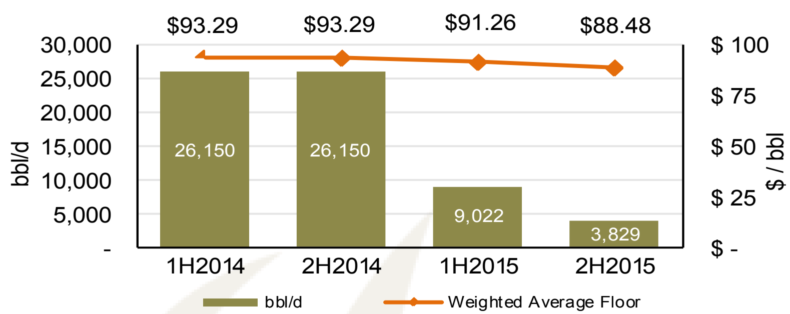
"A Conventional View of an Unconventional Reservoir"



		8 Wells per DSU	12 Wells per DSU	16 Wells per DSU
Well Spacing		~1,000 Feet 320 Acres	~800 Feet 210 Acres	~600 Feet 160 Acres
EUR per Well	**Middle Bakken:** **Three Forks:**	750 - 850 MBOE 650 - 750 MBOE	650 - 750 MBOE 550 - 650 MBOE	600 - 700 MBOE 500 - 600 MBOE
EUR per DSU		**5.5 - 6.5 MMBOE**	**7.0 - 8.5 MMBOE**	**9.0 - 10.5 MMBOE**
Per Well Economics	**Well Cost:** **Payout:**	$8.7MM 9 - 18 Months	$8.5MM 12 - 21 Months	$8.2MM 18 - 27 Months
NPV per DSU		**$100 - 115MM**	**$120 - 150MM**	**$140 - 170MM**

Financial Strategy

Hedges



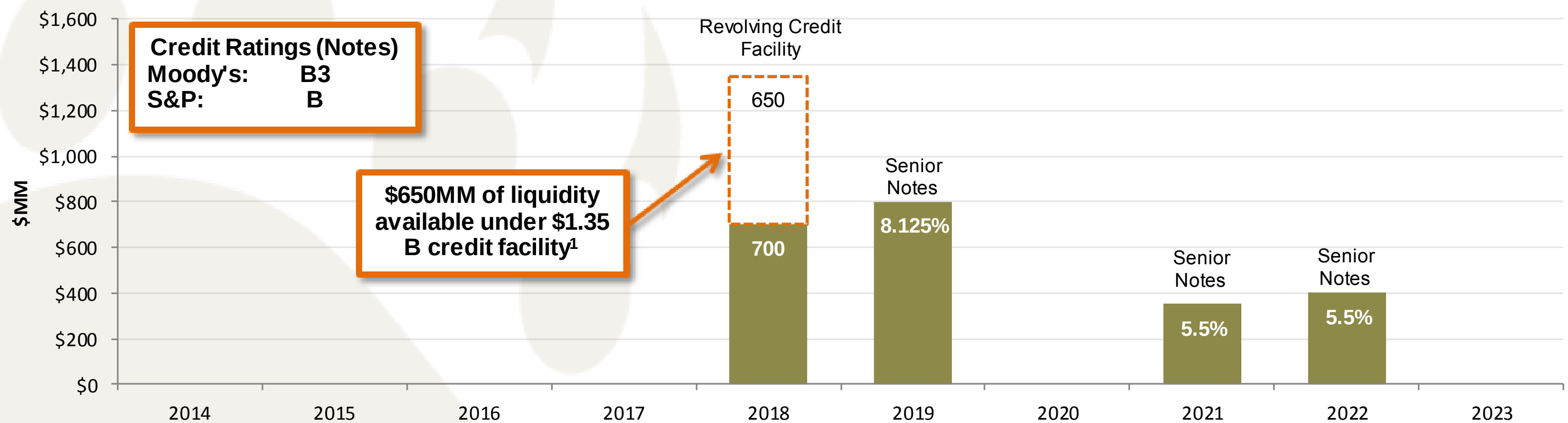
Strive to maintain conservative balance sheet which preserves financial flexibility

- Liquidity of $650 million
- Growth in EBITDA reducing long-term debt

Commodity hedging program

- Designed to protect cash flow / support fixed cost coverage and capital program
- Hedge additional volumes as wells are completed and additional production added
- No near-term debt maturities

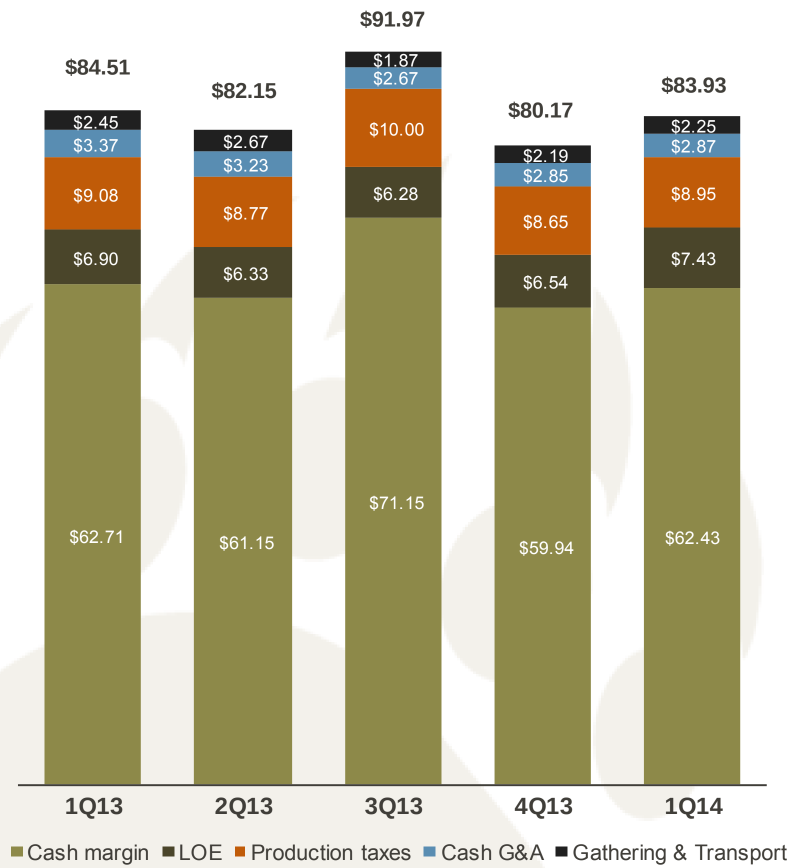
Debt Maturity Schedule



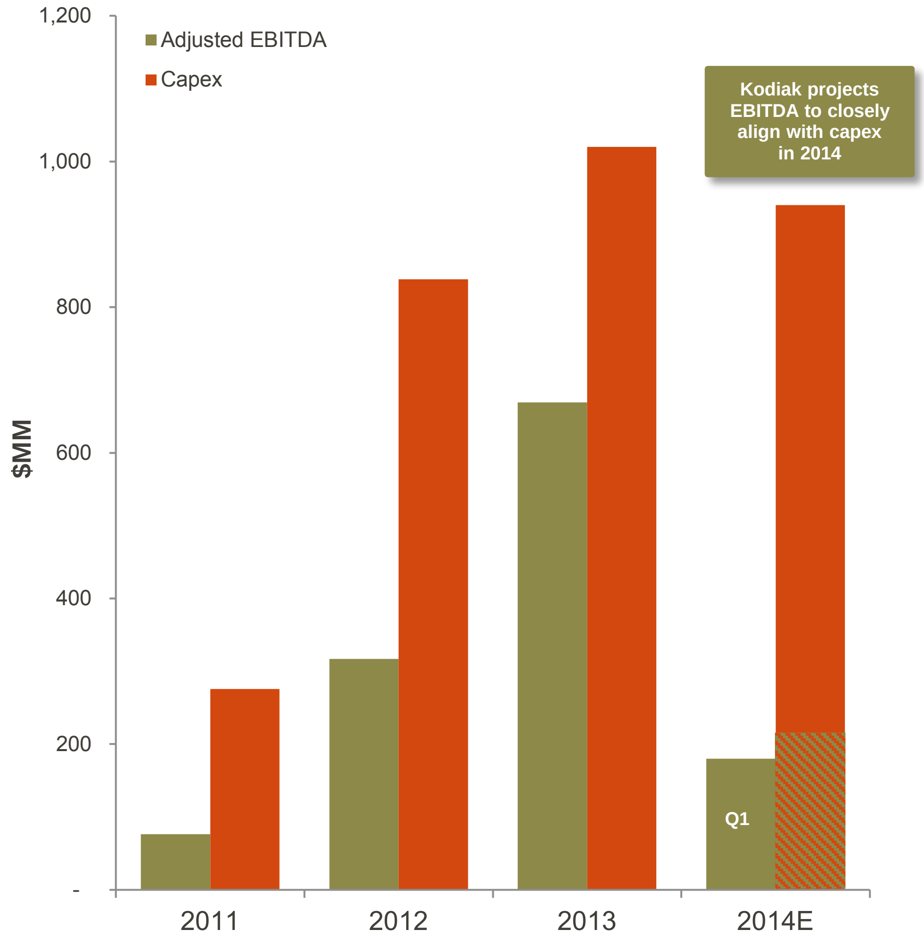
Kodiak Has Historically Employed a Conservative Financial Strategy

Approaching Cash Flow Breakeven

Unhedged Cash Margin ($/BOE)

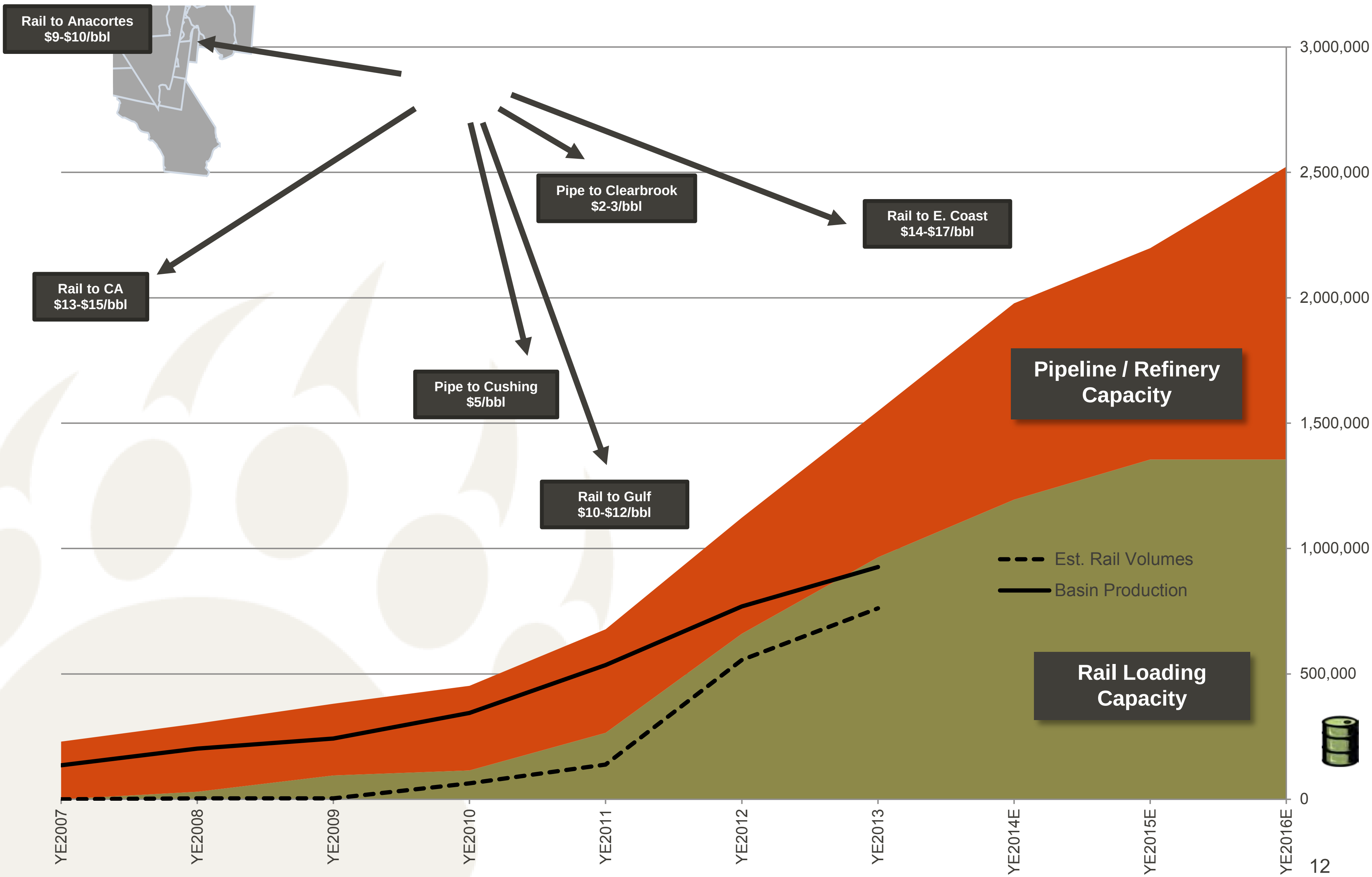


Capital Expenditures and Adjusted EBITDA[1]



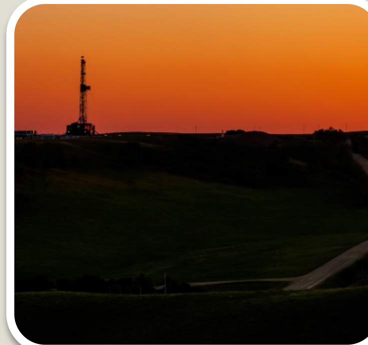
[1] Adjusted EBITDA excludes unrealized gains/losses on derivatives and adjusts for non-recurring items. See slide 19 for a full reconciliation.

Moving Crude Out of North Dakota



Source: North Dakota Pipeline Authority and North Dakota Industrial Commission

Key Investment Highlights



Drill-bit focused producer with large acreage position in oil-levered Williston Basin

Development of low-risk drilling inventory with attractive economics drives rapid production growth

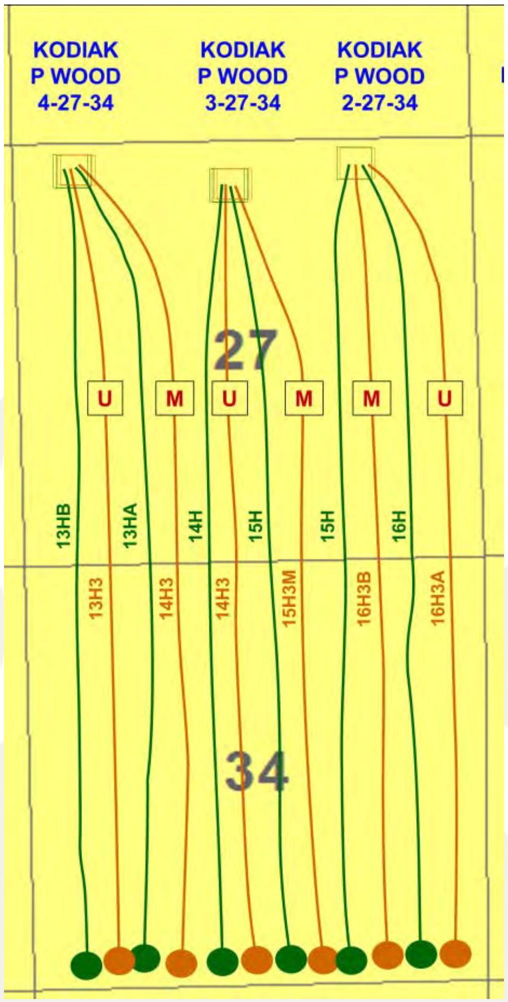
Asset scale, technical knowledge and infrastructure investments enhance operating results and margins

Conservative financial philosophy and proactive liquidity management

Appendix

Polar Pilot 1.0 Project

Kodiak completed two downspacing pilot programs in 2013 with 12-wells in each 1280-acre drilling spacing unit (DSU) testing 800 foot spacing between wellbores.

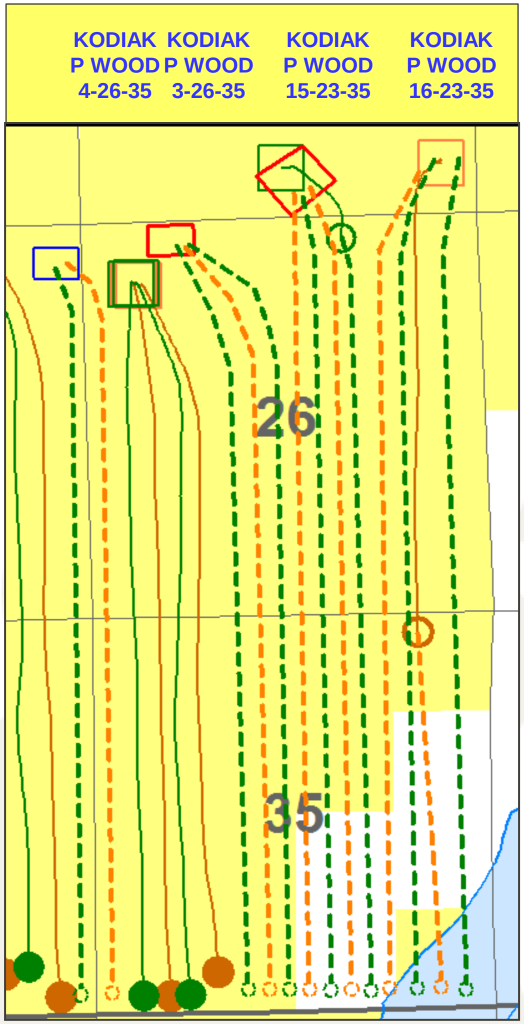


Polar Pilot 1.0 Production Rates

Well Name	Formation	IP 24-hour Test (BOE/d)	30 Day Average (BOE/d)	60 Day Average (BOE/d)	90 Day Average (BOE/d)	120 Day Average (BOE/d)	150 Day Average (BOE/d)	180 Day Average (BOE/d)	210 Day Average (BOE/d)
P Wood 154-98-2-27-34-15H	MB	2,693	1,027	820	724	680	613	555	508
P Wood 154-98-2-27-34-16H	MB	2,912	1,099	883	760	670	597	539	497
P Wood 154-98-3-27-34-14H	MB	2,403	954	798	674	627	608	568	521
P Wood 154-98-3-27-34-15H	MB	2,666	931	722	620	555	541	512	475
P Wood 154-98-4-27-34-13HA	MB	2,771	1,092	903	793	707	659	600	551
P Wood 154-98-4-27-34-13HB	MB	2,982	1,017	947	836	757	645	597	556
Average Middle Bakken		**2,738**	**1,020**	**845**	**735**	**666**	**611**	**562**	**518**
P Wood 154-98-2-27-34-16H3A	UTF	2,205	887	730	660	583	552	499	458
P Wood 154-98-2-27-34-16H3B	MTF	2,525	923	768	642	567	510	465	435
P Wood 154-98-3-27-34-14H3	UTF	2,457	933	704	637	582	536	479	434
P Wood 154-98-3-27-34-15H3M	MTF	1,204	779	702	631	550	483	436	397
P Wood 154-98-4-27-34-13H3	UTF	3,482	1,231	979	797	721	657	604	553
P Wood 154-98-4-27-34-14H3	MTF	2,289	847	622	501	419	374	342	315
Average Three Forks		**2,360**	**933**	**751**	**645**	**570**	**519**	**471**	**432**
Average All Wells		**2,549**	**977**	**798**	**690**	**618**	**565**	**516**	**475**

Polar Pilot 2.0 Project

Kodiak is currently pursuing a second downspacing pilot program in 2014 with 16-wells in a 1280-acre drilling spacing unit (DSU) testing 600-650 foot spacing between wellbores.

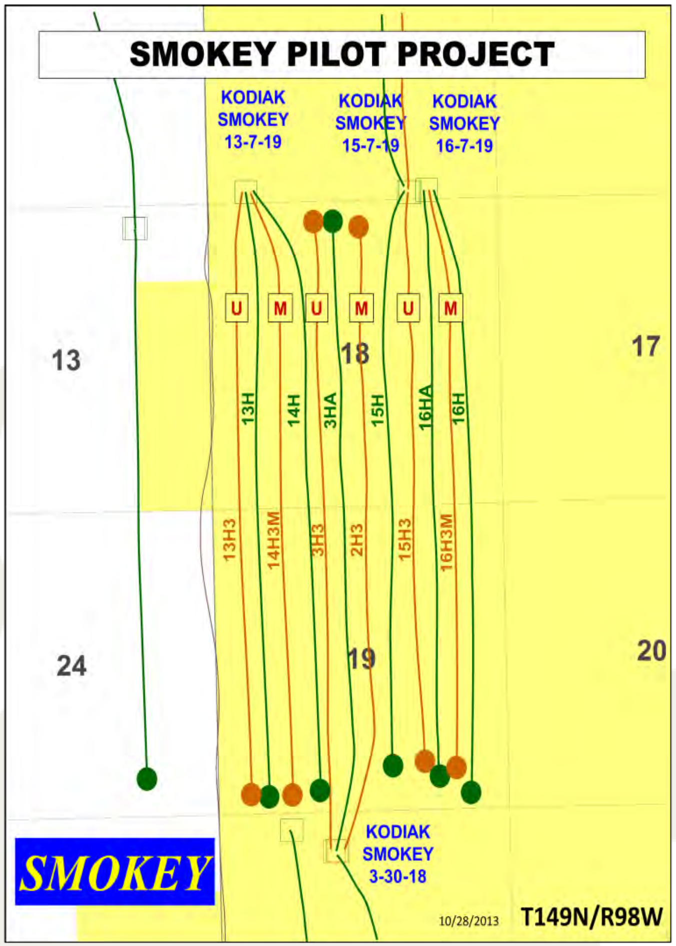


Polar Pilot 2.0 Production Rates

Well Name	Formation	IP 24-hour Test (BOE/d)	30 Day Average (BOE/d)	60 Day Average (BOE/d)	90 Day Average (BOE/d)
P Wood 154-98-4-26-35-13H	MB	2,529	1,071	840	706
P Wood 154-98-4-26-35-14H	MB	2,534	1,009	740	619
Average Middle Bakken		**2,532**	**1,040**	**790**	**663**
P Wood 154-98-4-26-35-13H3	TF	2,439	835	644	564
P Wood 154-98-4-26-35-14H3	TF	2,325	750	568	506
Average Three Forks		**2,382**	**792**	**606**	**535**
Average All Wells		**2,457**	**916**	**698**	**599**

Smokey Pilot Project

Kodiak completed two downspacing pilot programs in 2013 with 12-wells in each 1280-acre drilling spacing unit (DSU) testing 800 foot spacing between wellbores.



Smokey Pilot Production Rates

Well Name	Formation	IP 24-hour Test (BOE/d)	30 Day Average (BOE/d)	60 Day Average (BOE/d)	90 Day Average (BOE/d)	120 Day Average (BOE/d)	150 Day Average (BOE/d)	180 Average (BOE/d)
Smokey 13-7-19-13H	MB	1,880	870	689	636	556	496	446
Smokey 13-7-19-14H	MB	1,322	831	643	576	507	459	412
Smokey 15-7-19-15H	MB	1,950	940	760	634	561	511	443
Smokey 16-7-19-16H	MB	1,859	1,079	865	750	665	585	529
Smokey 16-7-19-16HA	MB	1,445	935	768	693	569	495	446
Smokey 3-30-18-3HA	MB	1,830	983	701	597	538	492	483
Average Middle Bakken		**1,714**	**940**	**738**	**648**	**566**	**506**	**460**
Smokey 13-7-19-13H3	UTF	1,668	677	537	434	371	331	298
Smokey 13-7-19-14H3M	MTF	1,330	681	506	400	338	297	268
Smokey 15-7-19-15H3	UTF	1,466	831	555	481	412	364	336
Smokey 16-7-19-16H3M	MTF	709	389	354	270	222	198	180
Smokey 3-30-18-2H3	MTF	1,284	675	583	477	413	369	332
Smokey 3-30-18-3H3	UTF	1,294	699	558	438	384	338	300
Average Three Forks		**1,292**	**659**	**516**	**417**	**357**	**316**	**286**
Average All Wells		**1,503**	**799**	**627**	**532**	**461**	**411**	**373**

Cash Margin Reconciliation

Reconciliation of Cash Margin (non-GAAP) to Gross Margin (GAAP)				
	Three Months Ended			
	2Q13	3Q13	4Q13	1Q14
Unhedged Sales Price				
Oil ($/Bbls)	$ 88.88	$ 98.19	$ 85.09	$ 88.62
Gas ($/Mcf) [1]	6.16	6.32	6.61	8.56
BOE ($/BOE)	82.15	91.97	80.17	83.93
Costs and Expenses				
Gathering, transportation and marketing	$ 2.67	$ 1.87	$ 2.19	$ 2.25
Lease operating expenses	6.33	6.28	6.54	7.43
Production and property taxes	8.77	10.00	8.65	8.95
Oil and gas DD&A	29.56	29.81	30.18	29.27
G&A expenses	4.89	3.86	4.22	4.54
Gross Margin (GAAP)	$ 29.93	$ 40.15	$ 28.39	$ 31.49
Oil and gas DD&A	29.56	29.81	30.18	29.27
Stock based compensation	1.66	1.19	1.37	1.67
Cash Margin (non-GAAP)	**$ 61.15**	**$ 71.15**	**$ 59.94**	**$ 62.43**

[1] Average gas price received at the wellhead includes proceeds from natural gas liquids under percentage of proceeds contracts

Note: Cash Margin per BOE (a non-GAAP measure) is calculated by adjusting gross margin per BOE (a GAAP measure) to exclude DD&A. Management believes this presentation may be helpful to investors as it represents the cash generated by our oil and gas production that is available for, among other things, capital expenditures and debt service. Management uses this information to analyze operating trends for comparative purposes within the industry. This measure is not intended to replace the GAAP statistic but rather to provide additional information that may be helpful in evaluating trends and performance.

Adjusted EBITDA Reconciliation

Reconciliation of Adjusted EBITDA (non-GAAP) to Net Income (GAAP)								
		2Q13		3Q13		4Q13		1Q14
Net Income	$	44,250	$	31,150	$	46,572	$	29,112
Add back:								
Depreciation, depletion, amortization and accretion		62,409		97,094		100,335		89,629
Amortization of deferred financing costs and debt premium		828		1,239		1,337		1,391
(Gain) loss on commodity price risk management activities, net		(22,667)		60,108		(8,157)		24,805
Settlements on commodity derivative instruments		1,757		(18,674)		(1,383)		(12,089)
Stock based compensation expense		3,501		3,880		4,560		5,120
Income tax expense		26,100		19,500		34,200		18,790
Interest expense		14,970		19,824		22,284		23,174
Adjusted EBITDA	$	131,148	$	214,121	$	199,748	$	179,932

Note: In evaluating its business, Kodiak considers earnings before interest, income taxes, depletion, depreciation, amortization, and accretion, amortization of deferred financing costs and debt premium, impairment, gains or losses on foreign currency, gains or losses on commodity price risk management activities, and stock-based compensation expense, ("Adjusted EBITDA") as a key indicator of financial operating performance and as a measure of the ability to generate cash for operational activities, future capital expenditures and an indication of our potential borrowing base under our credit facility. Adjusted EBITDA is not a Generally Accepted Accounting Principle ("GAAP") measure of performance. The Company uses this non-GAAP measure to compare its performance with other companies in the industry that make a similar disclosure, as a measure of its current liquidity, in developing our capital expenditure budget, to evaluate our compliance with covenants under our credit facility and as a component of the corporate objectives to which we tie the vesting of equity-based awards made to senior executives. The Company believes that this measure may also be useful to investors for the same purpose and for an indication of the Company's ability to generate cash flow at a level that can sustain or support our operations and capital investment program, and that disclosure of this measure provides investors with visibility as to the corporate objectives that affect our executive compensation program. Investors should not consider this measure, or other non-GAAP measures such as net income excluding the effect of unrealized derivative losses, in isolation or as a substitute for operating income or loss, cash flow from operations determined under GAAP or any other measure for determining the Company's operating performance that is calculated in accordance with GAAP. In addition, because Adjusted EBITDA is not a GAAP measure, it may not necessarily be comparable to similarly titled measures employed by other companies.