Investor Update

April 2015

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RESOURCES

Forward-Looking Information

Cautionary Statement for the Purpose of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995

This presentation includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements included in this press release other than statements of historical fact, including, but not limited to, forecasts or expectations regarding the Company's business and statements or information concerning the Company's future operations, performance, financial condition, production and reserves, schedules, plans, timing of development, returns, budgets, costs, business strategy, objectives, and cash flow, are forward-looking statements. When used in this press release, the words "could," "may," "believe," "anticipate," "intend," "estimate," "expect," "project," "budget," "plan," "continue," "potential," "guidance," "strategy," and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements are based on the Company's current expectations and assumptions about future events and currently available information as to the outcome and timing of future events. Although the Company believes these assumptions and expectations are reasonable, they are inherently subject to numerous business, economic, competitive, regulatory and other risks and uncertainties, most of which are difficult to predict and many of which are beyond the Company's control. No assurance can be given that such expectations will be correct or achieved or that the assumptions are accurate. The risks and uncertainties include, but are not limited to, commodity price volatility; the geographic concentration of our operations; financial market and economic volatility; the inability to access needed capital; the risks and potential liabilities inherent in crude oil and natural gas drilling and production and the availability of insurance to cover any losses resulting therefrom; difficulties in estimating proved reserves and other revenue-based measures; declines in the values of our crude oil and natural gas properties resulting in impairment charges; our ability to replace proved reserves and sustain production; the availability or cost of equipment and oilfield services; leasehold terms expiring on undeveloped acreage before production can be established; our ability to project future production, achieve targeted results in drilling and well operations and predict the amount and timing of development expenditures; the availability and cost of transportation, processing and refining facilities; legislative and regulatory changes adversely affecting our industry and our business, including initiatives related to hydraulic fracturing; increased market and industry competition, including from alternative fuels and other energy sources; and the other risks described under Part I, Item 1A. Risk Factors and elsewhere in the Company's Annual Report on Form 10-K for the year ended December 31, 2014, registration statements and other reports filed from time to time with the SEC, and other announcements the Company makes from time to time.

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date on which such statement is made. Should one or more of the risks or uncertainties described in this press release occur, or should underlying assumptions prove incorrect, the Company's actual results and plans could differ materially from those expressed in any forward-looking statements. All forward-looking statements are expressly qualified in their entirety by this cautionary statement. Except as otherwise required by applicable law, the Company undertakes no obligation to publicly correct or update any forward-looking statement whether as a result of new information, future events or circumstances after the date of this report, or otherwise.

Readers are cautioned that initial production rates are subject to decline over time and should not be regarded as reflective of sustained production levels. In particular, production from horizontal drilling in shale oil and natural gas resource plays and tight natural gas plays that are stimulated with extensive pressure fracturing are typically characterized by significant early declines in production rates.

We use the term "EUR" or "estimated ultimate recovery" to describe potentially recoverable oil and natural gas hydrocarbon quantities. We include these estimates to demonstrate what we believe to be the potential for future drilling and production on our properties. These estimates are by their nature much more speculative than estimates of proved reserves and require substantial capital spending to implement recovery. Actual locations drilled and quantities that may be ultimately recovered from our properties will differ substantially. EUR data included herein remain subject to change as more well data is analyzed.

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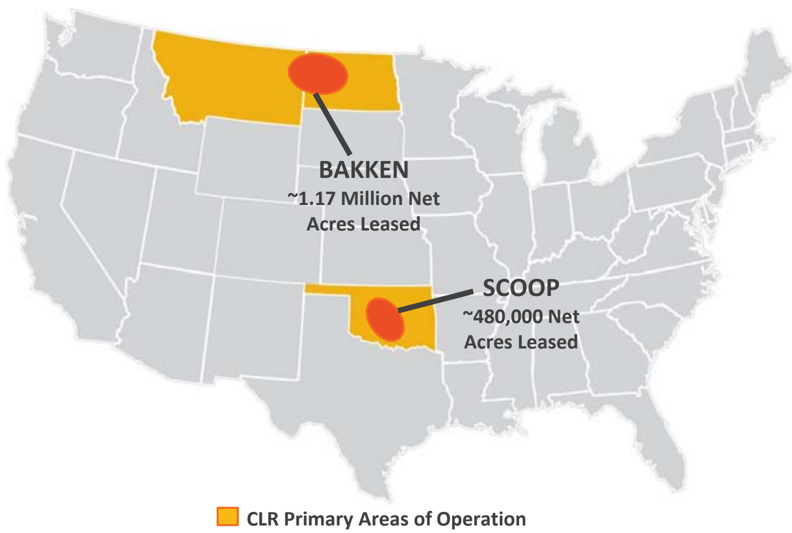


Founded in 1967 by Harold Hamm

New York Stock Exchange listed, went public in 2007 at $7.50 per share (split adjusted), ticker symbol: CLR

~$22 billion enterprise value(1)

- Market cap: ~$16B
- Total debt: ~$6B

Pure play E&P: oil focused, with liquids-rich optionality

- Exploration based: Organic, drill bit growth
- Independent: Dedicated to finding & producing onshore light, sweet oil

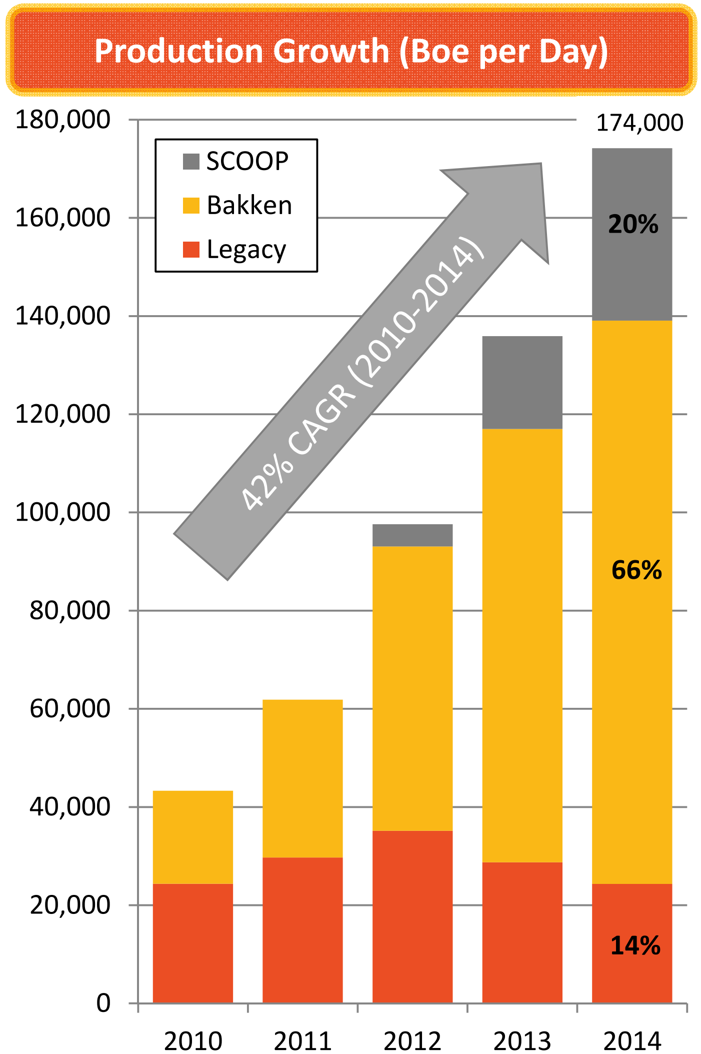
Size and scalability: focused in two premier plays

- The Bakken in ND & MT
- The SCOOP (South Central Oklahoma Oil Province) in the Springer & Woodford

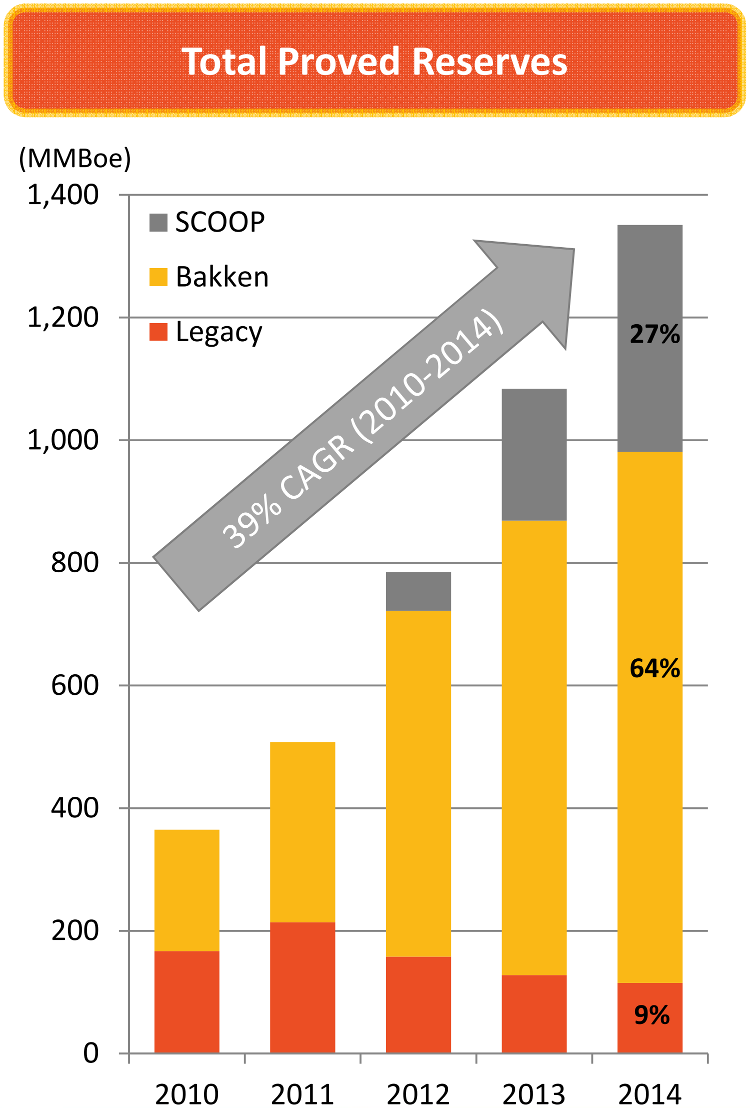
(1) Market cap as of 3/31/15 and total debt as of 2/17/2015

Two World-Class Platforms for Growth

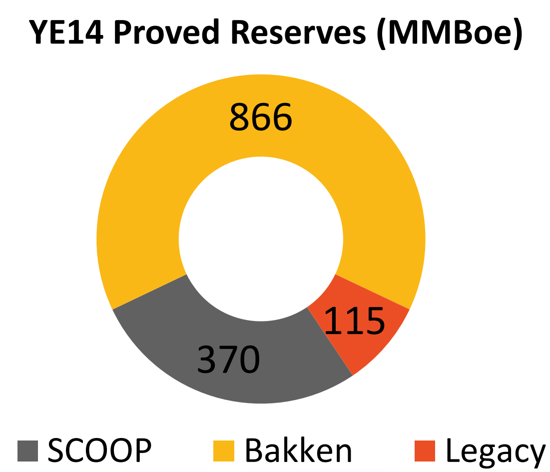
- **Leading positions in both the Bakken and SCOOP**
  - Scalable economics from large leasehold and production volumes
    - Bakken ~1.17 million net acres
    - SCOOP ~480,000 net acres
    - Captured "core of the basin" leasehold as an early entrant and first mover in both plays
- **FY14 production totaled over 174,000 Boe per day, +28% over FY13**
  - Production mix:
    - 70% crude oil, or ~122,000 barrels of oil per day
    - 30% natural gas and NGLs, or ~313,000 Mcf per day
  - Reached net production milestone of 200,000 Boe per day in December 2014



Consistent Proved Reserves Growth



- **Proved reserves totaled 1.35 billion Boe at YE14, +25% over YE13**
  - PV-10 of $22.8 billion at YE14, +13% over YE13[1]
  - PDP reserves of 490 MMBoe at YE14, +21% over YE13
  - 2,994 gross (1,565 net) proved undeveloped (PUD) locations at YE14
- **Repeatable, low-risk inventory to fuel future growth in Bakken and SCOOP**



(1) See appendix for disclosure regarding PV-10 reconciliation to GAAP

2015: Embracing Market Change

- **Revised 2015 capex and production guidance**
  - $2.7 billion non-acquisition capex (reduced 48% from original budget) with flexibility
  - Targeting cash flow neutrality by mid-year 2015
  - 16%-20% YOY production growth
- **Priorities**
  - Maintain strong balance sheet and financial flexibility
  - Align capex near discretionary cash flow
  - Maximize returns and growth by focusing on high rate-of-return (ROR) inventory
  - Defer completions until additional reductions in service costs are recognized and commodity prices improve
- **Opportunities**
  - Reduce well and service costs
    - Projecting 5%-10% cycle time improvements in spud to rig release by year end
    - Expect overall service costs to decline by at least 15% by mid-year and by at least 20% by year-end 2015
  - Build efficiencies
    - Service quality enhancements through high-grading of service company personnel and equipment as a result of consolidation
    - Lower overall industry rig count will allow advances in research and drilling and completions technologies to emerge
  - Remain opportunistic

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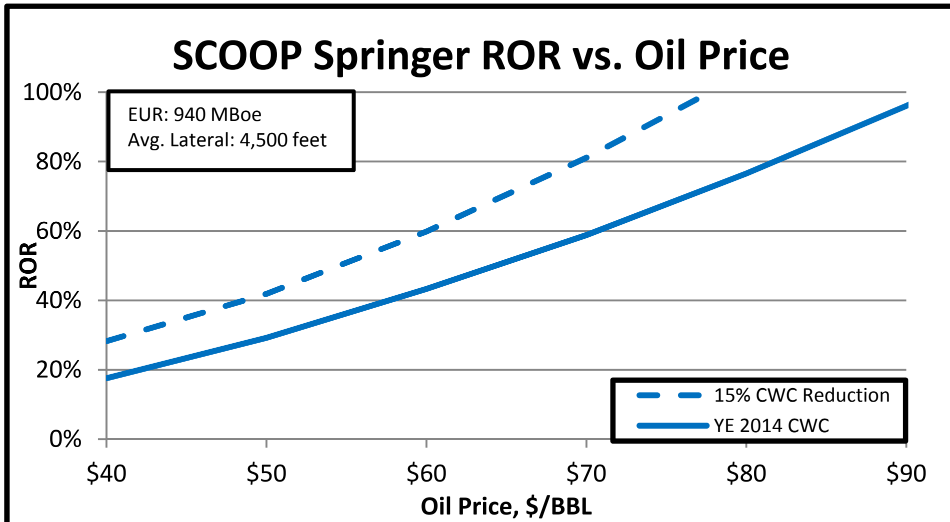
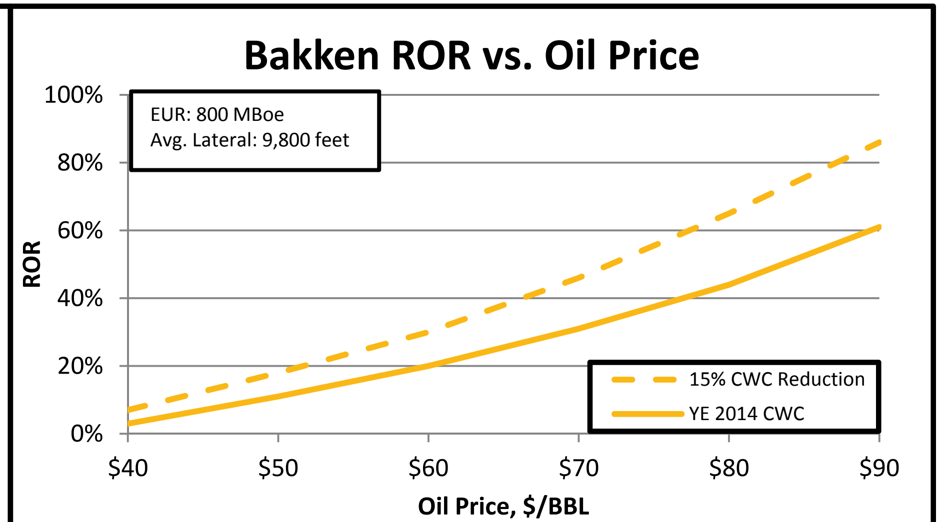
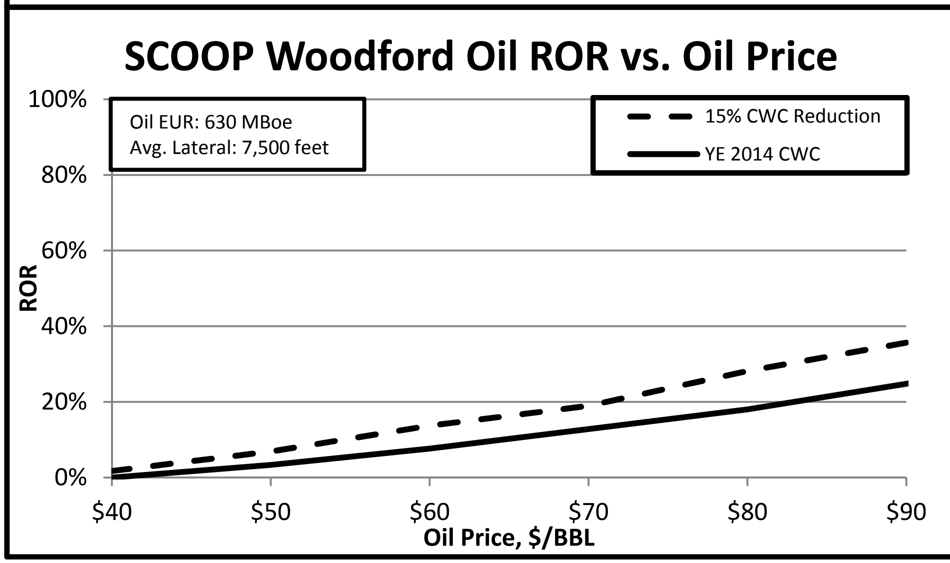
Utilizing Strengths and Flexibility

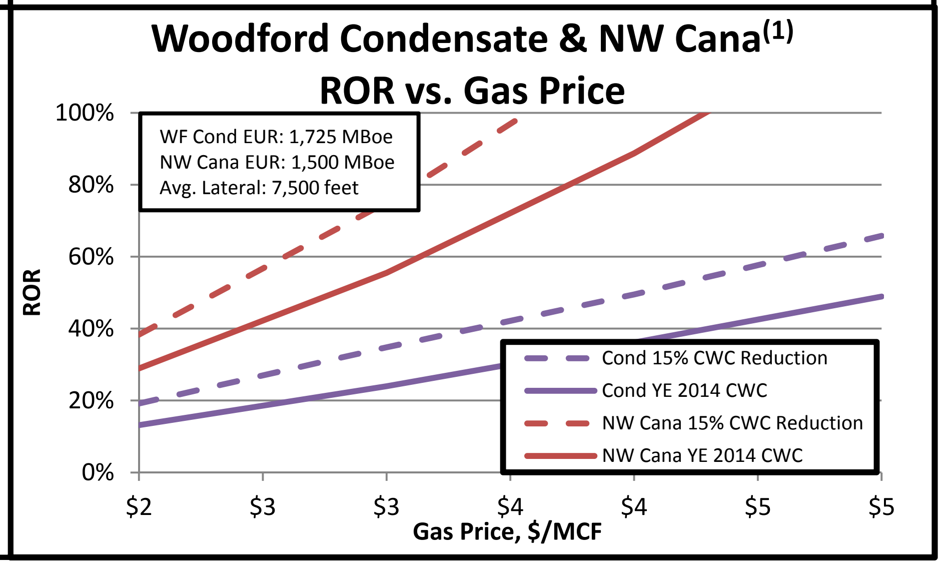
- **Asset Strength**
  - High-quality, high-ROR assets in Bakken and SCOOP
  - 2015 drilling program targeting ~40% ROR based on an average 15% reduced completed well cost ("CWC") at $60 oil and $3.00 natural gas
- **Inventory Flexibility**
  - Deep and diverse inventory provides optionality in oil and liquids-rich plays
  - Flexibility to deliver high ROR in changing commodity price environments
- **Operational Flexibility**
  - Reducing operated rig count by ~40% (50 rigs at YE14 to average 31 rigs in 2015)
  - Reducing non-drilling capex by ~40% (land, seismic and facilities)
  - Deferring portion of planned Bakken completion activity in 1Q 2015
- **Financial Strength**
  - Ample liquidity with revolver, upsized to $2.5 billion in February 2015
    - ~$605 million drawn on the revolver as of 2/17/15
  - No near-term debt maturities (earliest is $200 million in 2020)
  - Investment grade credit rating
- **Organizational Strength**
  - Strong track record of execution and leadership in various commodity environments
  - Lean, low-cost, high-margin operator

High-Quality, High-ROR Assets









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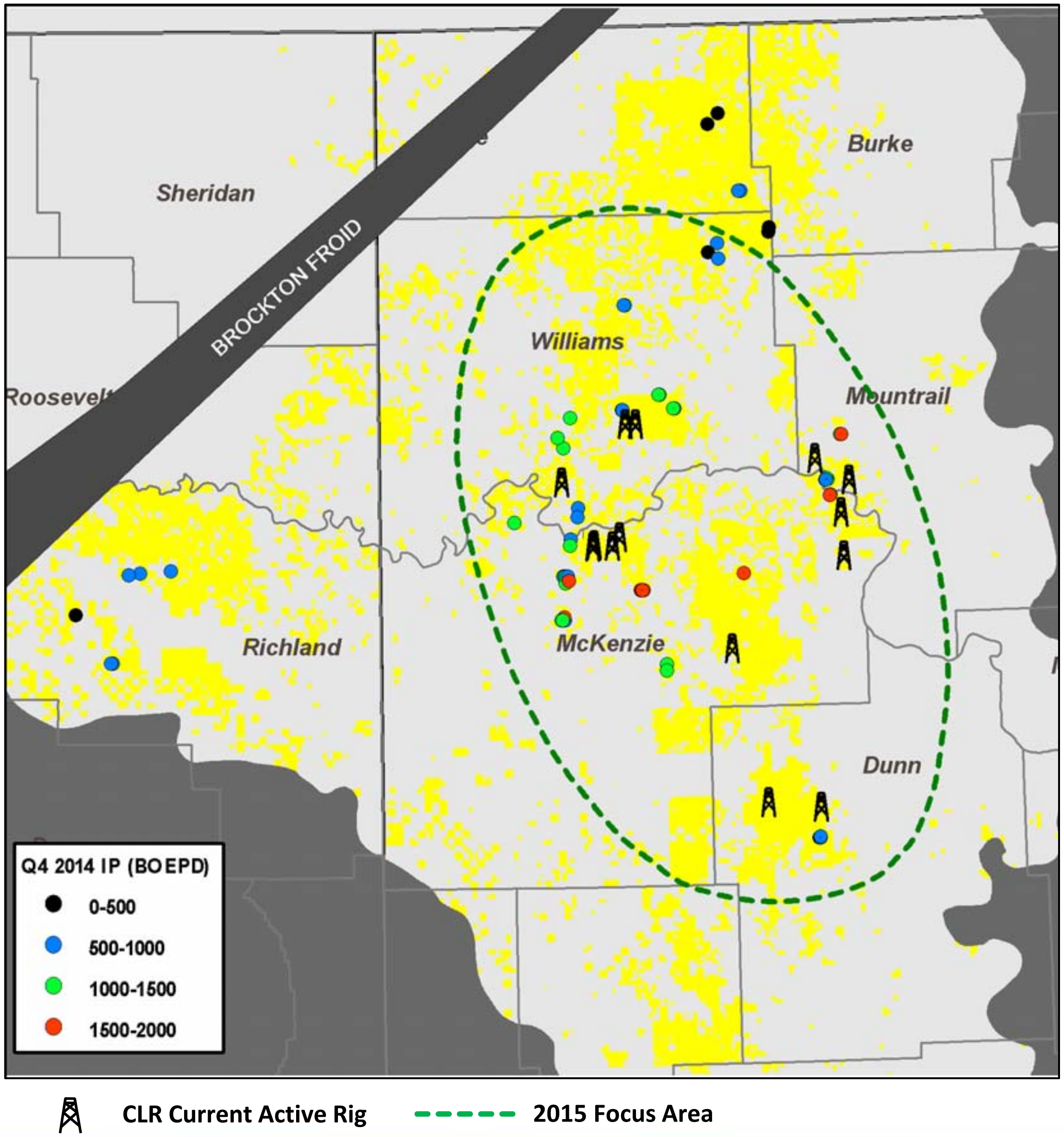
**Stated EURs based on $60/bbl, $3.00/Mcf and regional specific differentials*
(1) NW Cana economics factor in a ~50% carry from JV partner

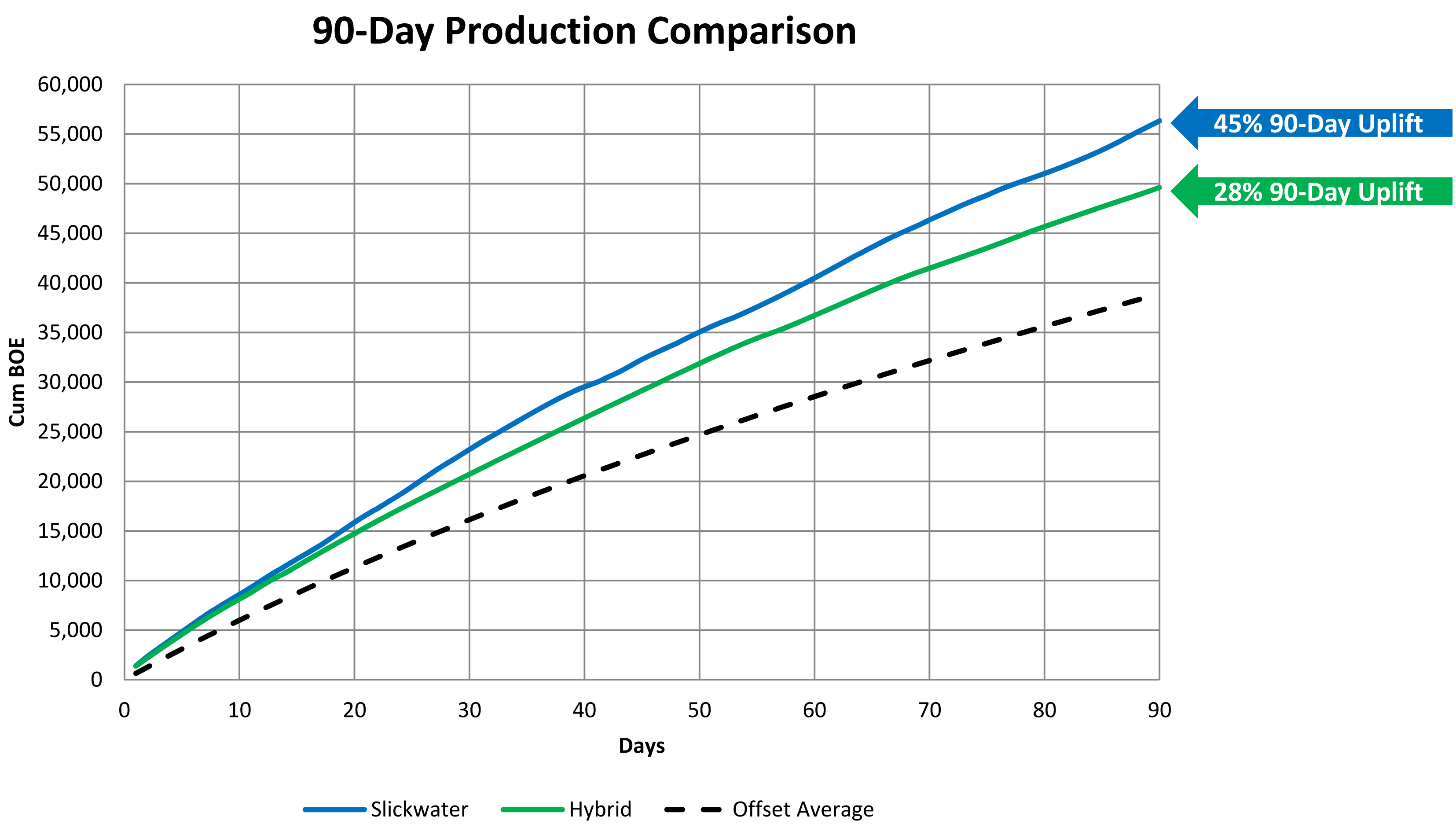
2015 Bakken Drilling Program: Focused on High ROR Core

- **800 MBoe/well projected average EUR**
  - 15% increase in EUR due to high-graded 2015 drilling program
  - Program includes ~100% 30-stage enhanced completions
- **Expanding footprint of enhanced 30-stage completions**
  - Results from Williams & northern McKenzie counties
    - 30%-45% increase in 90-day rates
    - 25%-30% increase in EUR
  - Plan to expand into Dunn and Mountrail Counties
- **2015 projected average operated rigs**
  - 13 rigs in February
  - ~10 rigs in 2Q15 through 4Q15
- **Currently 127 gross operated wells have been drilled and are waiting on completion ("WOC")**
  - Plan to exit 2015 with less than 100 gross operated wells WOC in the Bakken



Enhanced Completions Update

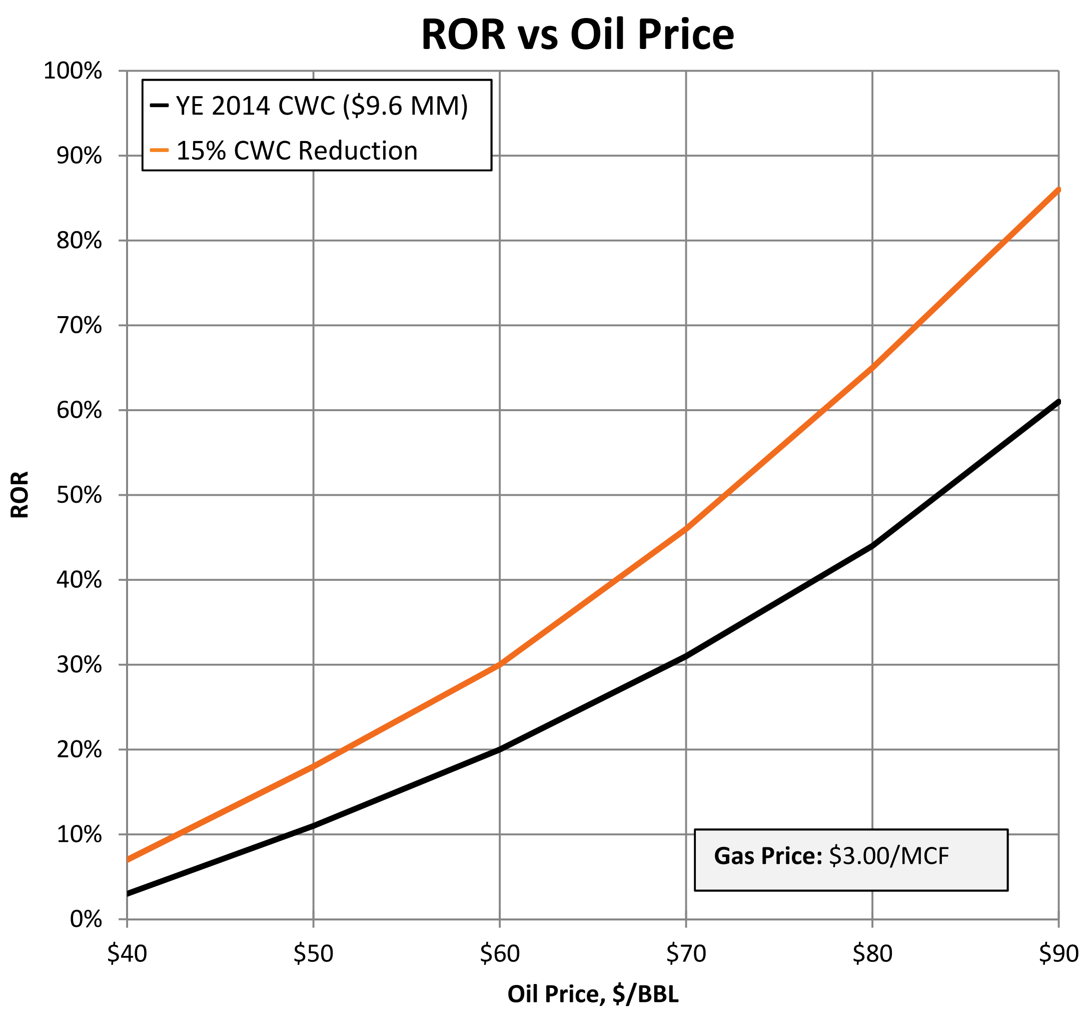
Williams & McKenzie Counties: 30-Stage Completions



- Slickwater includes 12 MB & 4 TF1 wells
- Hybrid includes 9 MB & 11 TF1 wells, ~$500,000 lower CWC than slickwater

Bakken Continues to Deliver Solid Economics

2015 Drilling Program: Targeting 800 MBoe EUR/well

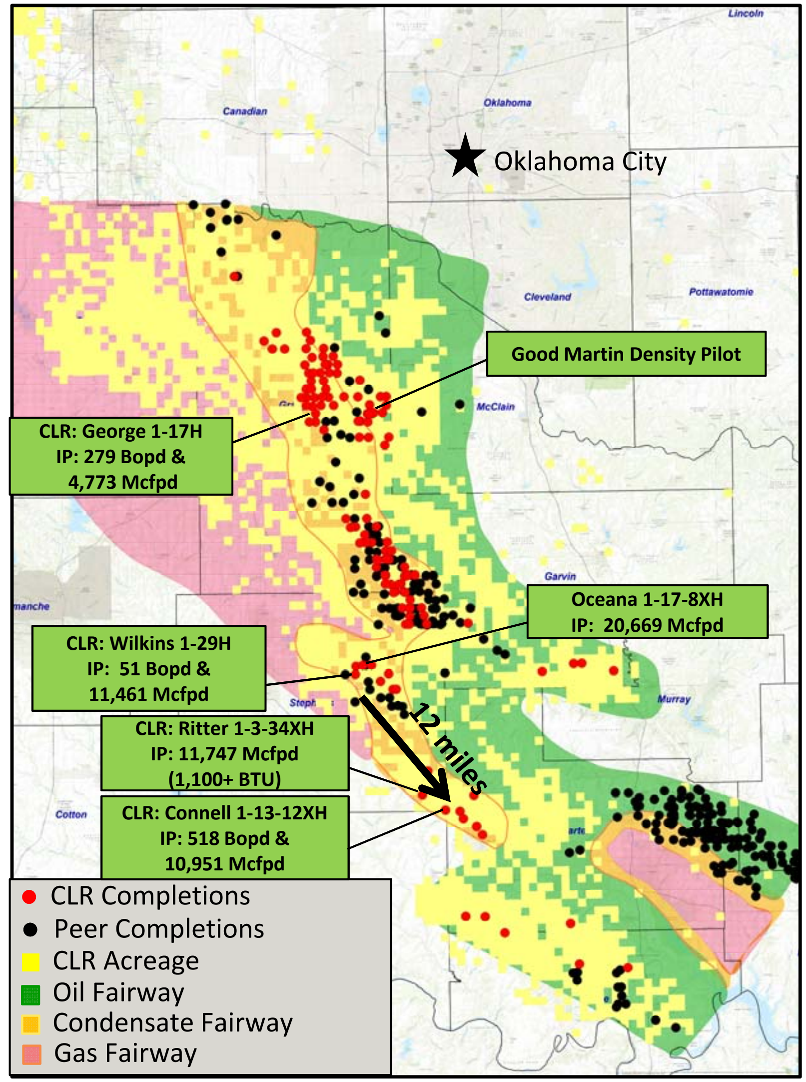


800 MBoe Model Parameters	
2 Mile Lateral Length	
Oil IP Rate, bbl/day	1,066
Oil 30 day IP Rate, bbl/day	855
Oil Initial Decline	80%
Oil b factor	1.50
Oil EUR, MBo	664
Gas IP Rate, Mcf/day	1050
Gas 30 Day IP Rate, Mcf/day	809
Gas Initial Decline	80%
Gas b factor	1.75
Gas EUR, MMcf	820
Equivalent EUR, MBoe	800
Minimum Decline	6% oil 4% gas

Anticipate at least ~15% or more reduction in CWC as service costs adjust to lower commodity prices

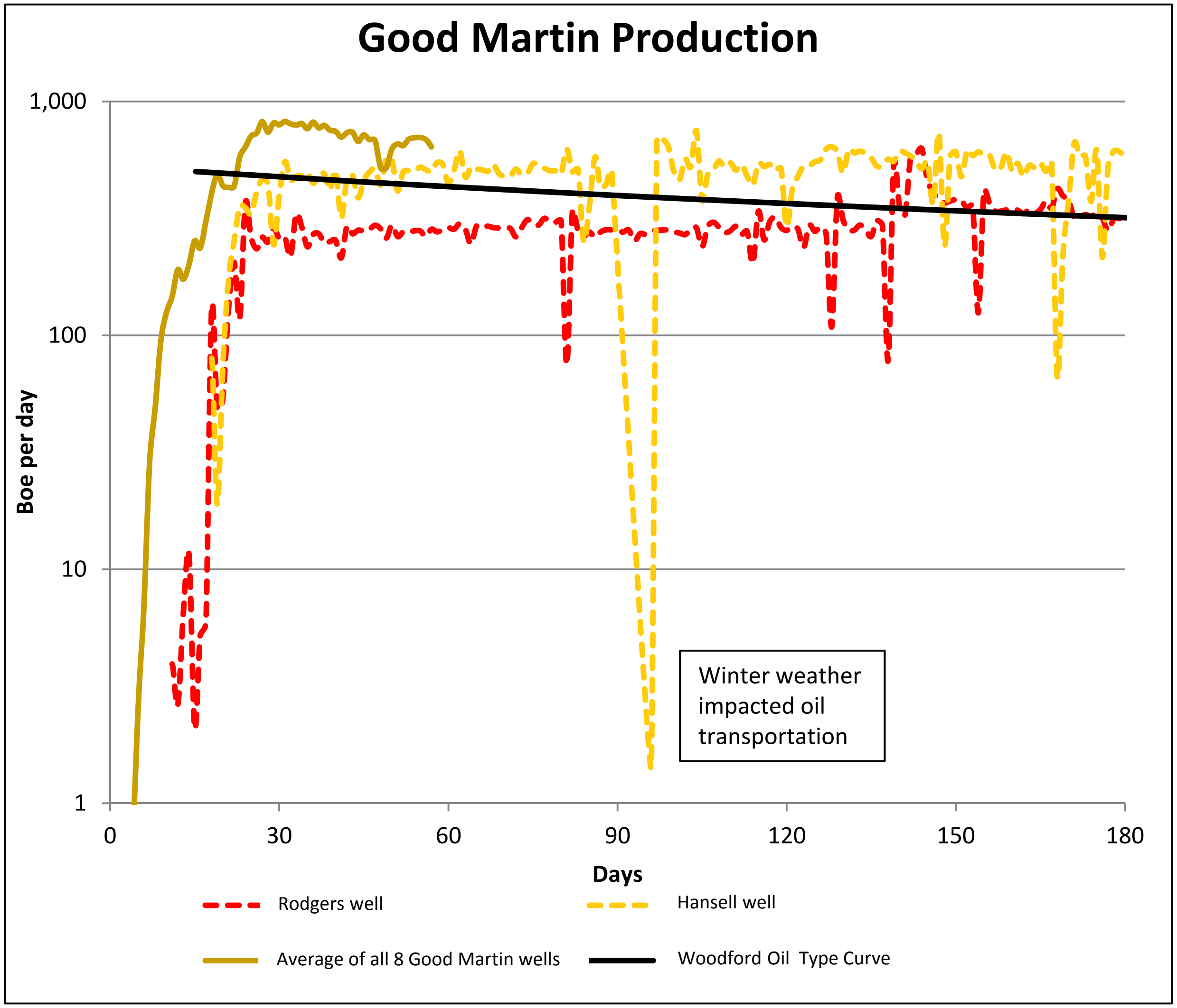
SCOOP Woodford: Continues to Grow

- **Excellent production extended another 12 miles south**
  - Connell 1-13-12XH: IP 10,951 Mcfpd and 518 Bopd
    - 9,500' lateral
  - Ritter 1-3-34XH: IP 11,747 Mcfpd
    - 6,500' lateral
    - Rich gas – 1,100+ BTU
- **Continue to see strong production moving west**
  - Wilkins 1-29H: IP 11,461 Mcfpd and 51 Bopd
    - 4,700' lateral
  - Oceana 1-17-8XH IP: 20,669 Mcfpd
    - 9,200' lateral
- **Plan to average ~10-13 operated rigs in 2015**



Good Martin 8-Well Density Pilot

SCOOP Woodford



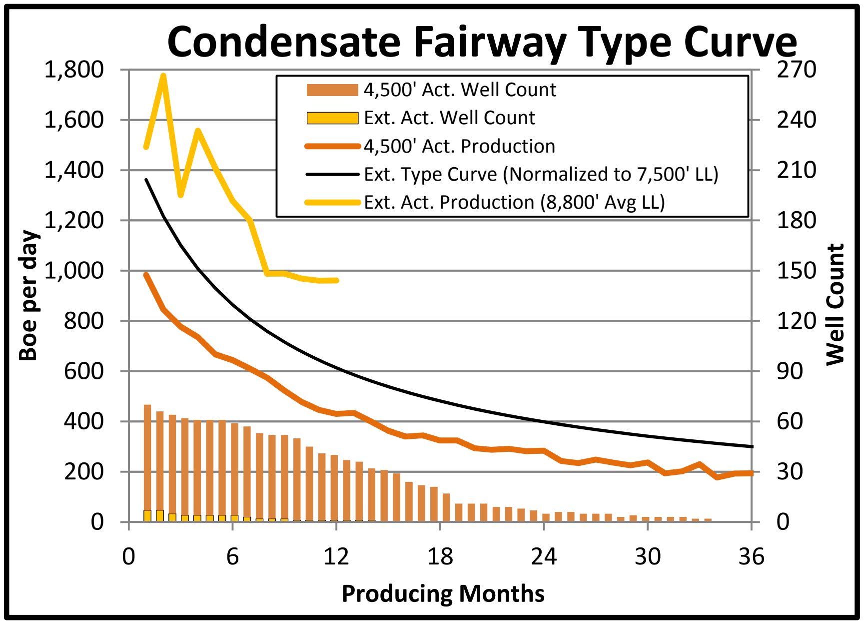
- **The 8 Good Martin wells had an average 24-hour IP of 820 Boe per well, with 75% oil**
- **The average IP of the 8 Good Martin wells outperforms the 7,500 foot lateral adjusted IPs of the Rodgers (597 Boe per day) and Hansell (693 Boe per day) offset wells**

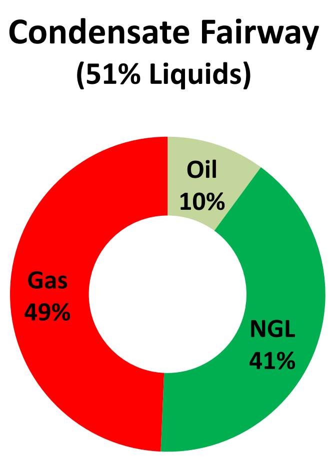
All wells were normalized to 7,500 foot lateral with down days removed

Higher Returns With Extended Laterals

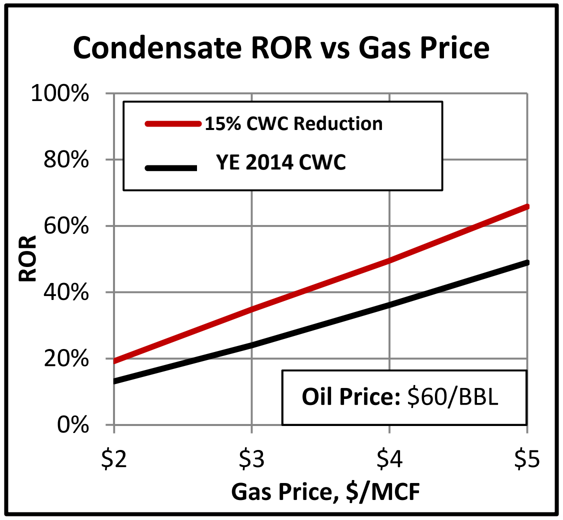
SCOOP Woodford Condensate Fairway

- **Approximately 85% of 2015 wells will be extended laterals**
  - 7,500’ on average (10,000’ where possible)
- **EUR: 1,725 MBoe (normalized to 7,500’)**
- **YE 2014 completed well cost: $12.2 MM**
  - Anticipate at least ~15% or more reduction during 2015



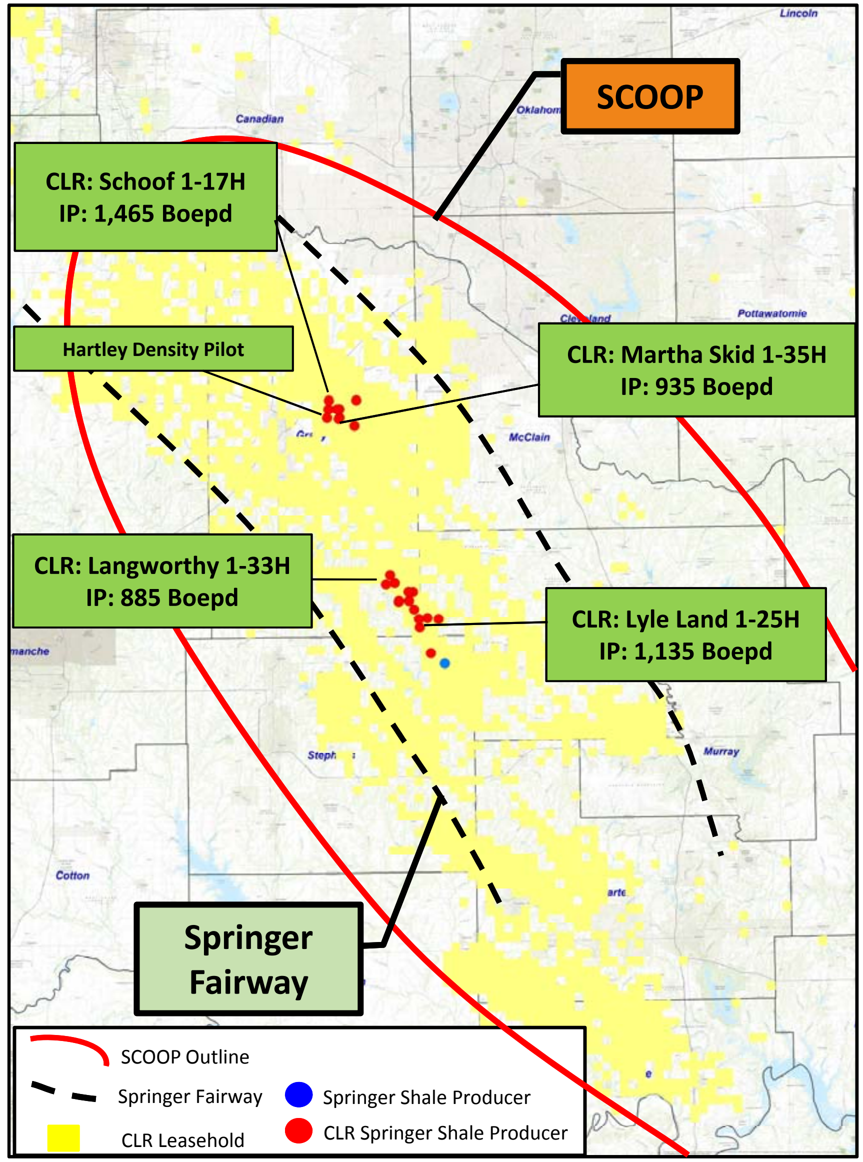


1,725 MBoe Model Parameters	
7500’ Lateral Length	
Oil IP Rate, Bbl/day	280
Oil 30 day IP Rate, bbl/day	262
Oil Initial Decline	61%
Oil b factor	1.1
Oil EUR, MBo	295
Gas IP Rate, Mcf/day	7,000
Gas 30 day IP Rate, MCF/day	6,595
Gas Initial Decline	58%
Gas b factor	1.2
Gas EUR, MMcf	8,580
Equivalent EUR, MBoe	1,725
Minimum Decline	6%
Capital, $MM	12.2



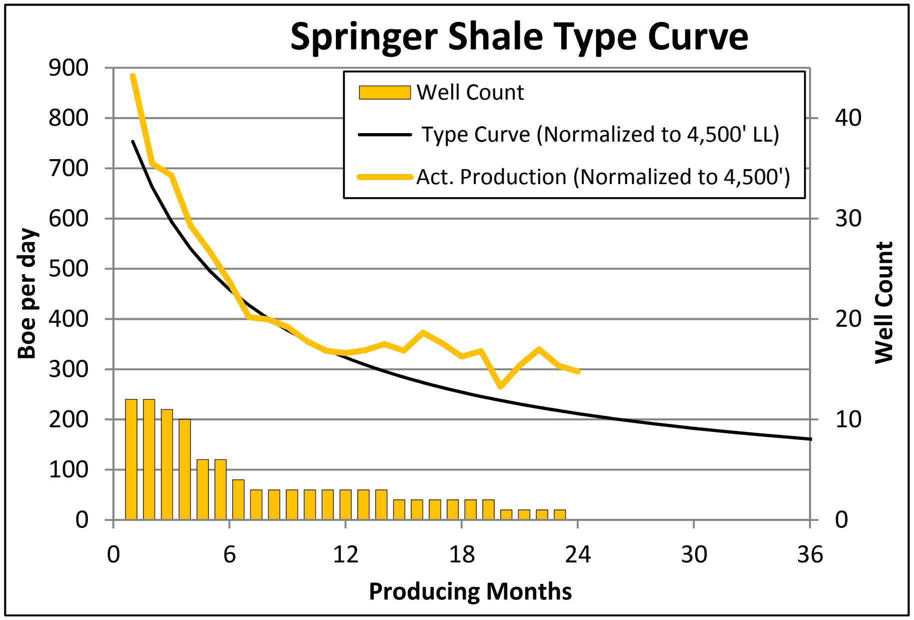
SCOOP Springer: Expanding Oil Discovery

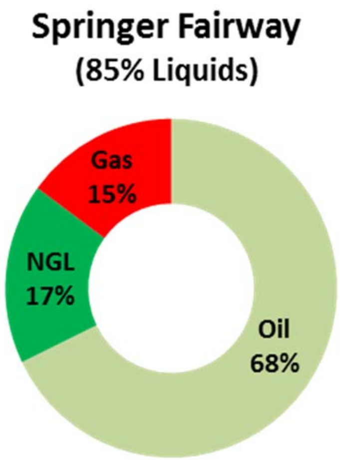
- **Continued success with oil fairway step-outs**
  - Schoof 1-17H: IP 1,465 Boepd
  - Lyle Land 1-25H: IP 1,135 Boepd
  - Martha Skid 1-35H: IP 935 Boepd
  - Langworthy 1-33H: IP 885 Boepd
  - Wells average ~4,500' laterals and 76% oil
- **First extended lateral test TD'd and WOC**
- **200,000 net acres in the heart of SCOOP**
  - 123,000 net acres in oil fairway
    - 46,000 net acres de-risked
      - 127 MMBoe net unrisked resource potential
      - 188 net (252 gross) operated locations
      - 27 net (147 gross) non-operated locations
    - 77,000 net acres of additional upside being tested
  - 77,000 net acres in gas fairway to be tested
- **5 rigs currently drilling**
- **Plan to average ~3-6 operated rigs in 2015**



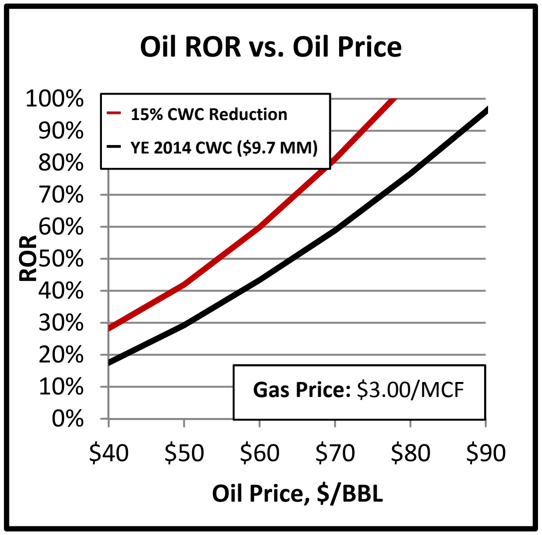
SCOOP Springer Oil: Exceptional Economics

- **Current EUR/well model: 940 MBoe**
- **4,500' lateral**
- **YE 2014 completed well cost: $9.7 MM**
  - Expect at least ~15% or more reduction in cost during 2015



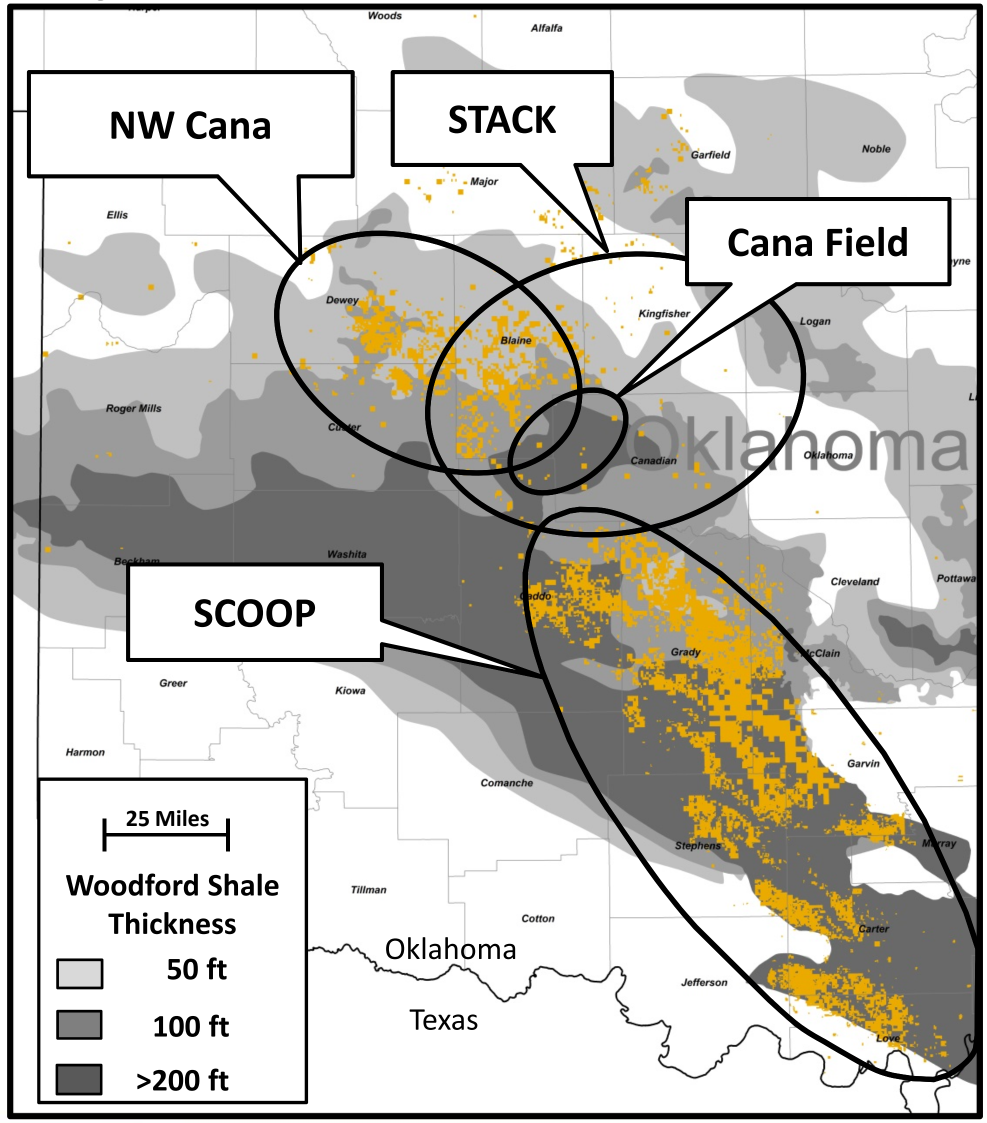


940 MBoe Model Parameters	
4,500' Lateral Length	
Oil IP Rate, Bbl/day	670
Oil 30 day IP Rate, bbl/day	618
Oil Initial Decline	62%
Oil b factor	1.25
Oil EUR, MBo	735
Gas IP Rate, Mcf/day	867
Gas 30 day IP Rate, MCF/day	810
Gas Initial Decline	56%
Gas b factor	1.4
Gas EUR, MMcf	1,230
Equivalent EUR, MBoe	940
Minimum Decline	6%
Capital, $MM	9.7



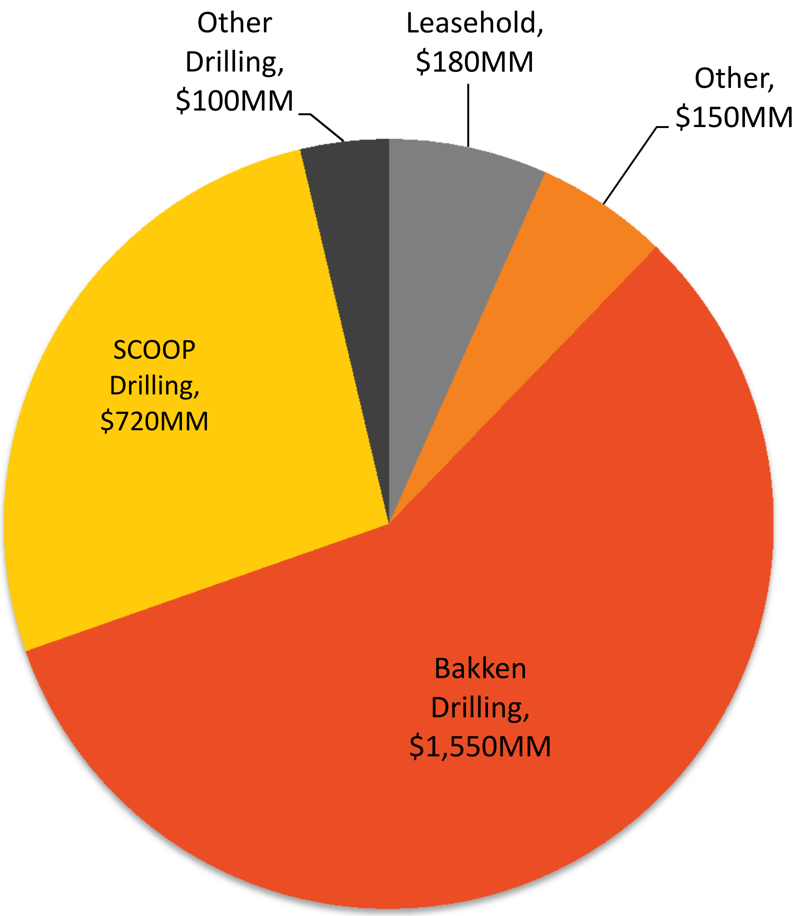
Incremental Value Captured Through NW Cana Joint Development Agreement ("JDA")

- **Formed JDA with SK E&S (South Korean based)**
- **Sold 49.9% interest in 44,000 acres and 37 producing wells for total consideration of $360 million**
  - $90 million cash at closing
  - 5-year $270 million carry for 50% of CLR's future D&C capital
- **Plan to operate 4 rigs in 2015**
- **Blaine County**
  - Carried returns of 53% at current CWC and over 72% for target CWC at $3.00/Mcf & $60 oil
  - EUR: 1,872 MBoe
  - YE 2014 CWC: $11.8 MM
- **Dewey County**
  - Carried returns of 56% at YE 2014 CWC and over 76% for target CWC at $3.00/Mcf and $60 oil
  - EUR: 1,525 MBoe
  - YE 2014 CWC: $10.3 MM



2015 Capital Expenditures Budget

Non-Acquisition Capital Expenditures: $2.7B

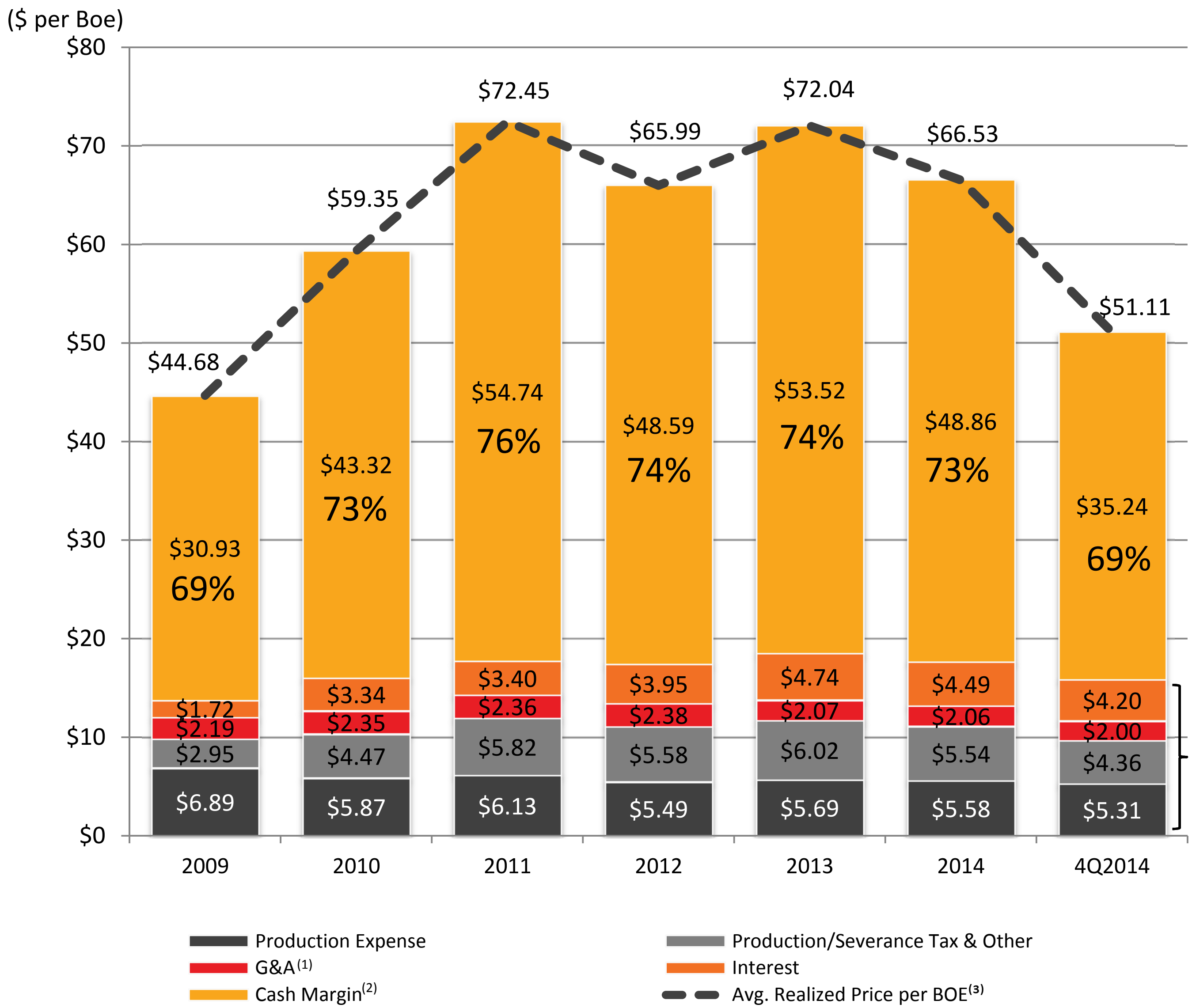


- **Drilling capital allocation:**
  - Bakken: 65%
  - SCOOP: 31%
    - Woodford: 24%
    - Springer: 7%
  - NW Cana JV & Other: 4%
- **Average 31 operated rigs in 2015**
- **2015 YOY production growth of 16-20%**

	Average Operated Rigs	**Net Wells[1]**
Bakken	11	191
SCOOP Woodford	10-13	~63
SCOOP Springer	3-6	~18
NW Cana JV & Other	4	11
Totals	31	~283

(1) Includes operated and non-operated wells with first production

Low Cash Cost Drives Excellent Margins



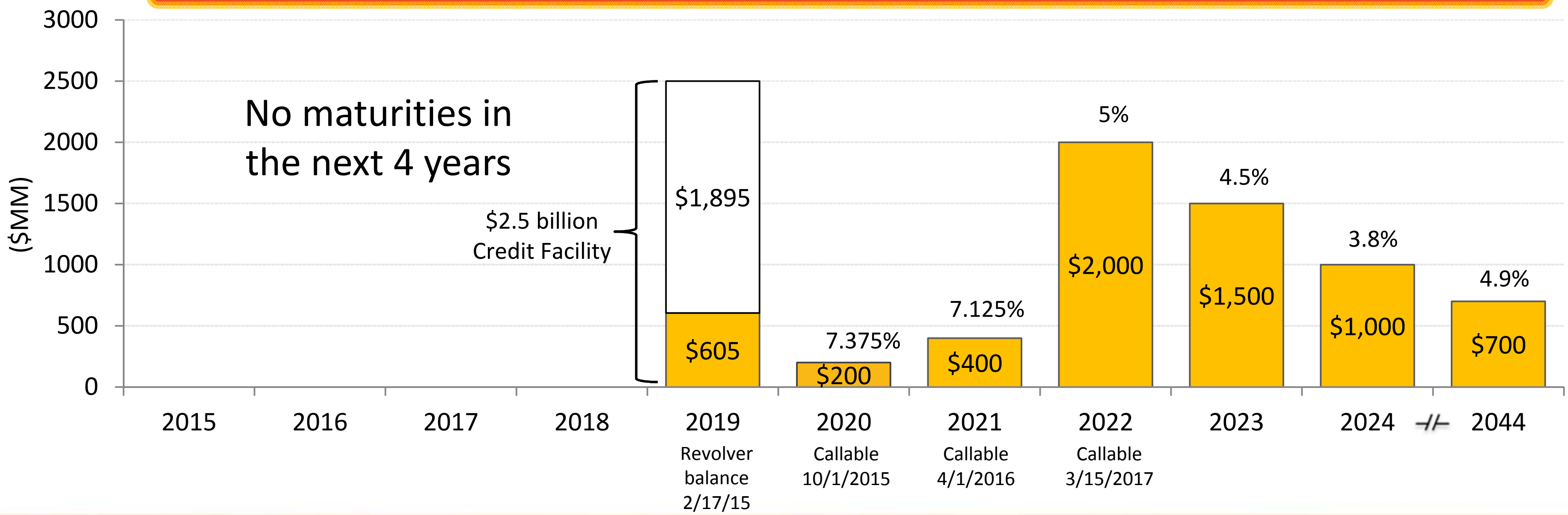
Low cash cost of ~$16 per barrel

(1) *Excludes G&A related to Equity based compensation and relocation expense*
(2) *See "Continuing to Deliver Excellent Margins" in the Appendix for the method of calculating cash margin*
(3) *Based on average oil equivalent price (excluding derivatives and including natural gas)*

Strong Liquidity and Financial Profile

Financial Ratios and Ratings[1]					
				Agency	Credit Ratings
Net Debt/ TTM EBITDAX[2]	1.58x	Leveraged Cash Margin [3]	$48.86	Moody's	Baa3
Net Debt/YE14 Proved Reserves	$4.42	3 Year All-in F&D ($/Boe) (YE14)	$13.33	S&P	BBB-
Net Debt/Dec. Avg. Daily Production	$30,226	3 Year Avg. Recycle Ratio (YE14)	3.7x	**Investment Grade**	

Debt Maturities Summary



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(1) All ratios are as of 12/31/14
(2) See appendix for reconciliation of GAAP net income and operating cash flows to EBITDAX.
(3) See "Continuing to Deliver Excellent Margins" in the Appendix for the method of calculating cash margin.

Updated 2015 Guidance

As of February 24, 2015

	2015
Production growth (YOY)	16% to 20%
Capital expenditures (non-acquisition, in $ billions)	$2.7
Operating Expenses:	
Production expense per Boe	$5.50 to $6.00
Production tax (% of oil & gas revenue)	7.5% to 8.5%
G&A expense per Boe	$2.00 to $2.50
Non-cash equity compensation per Boe	$0.75 to $0.95
DD&A per Boe	$20.00 to $22.50
Average Price Differentials:	
NYMEX WTI crude oil (per barrel of oil)	($7.00) to ($10.00)
Henry Hub natural gas[1] (per Mcf)	**$0.00 to ($0.50)**
Income tax rate	**38%**
Deferred taxes	90% to 95%

* Bold items above denote a change from previous guidance disclosed on December 22, 2014.

(1) Includes natural gas liquids production in differential range

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Appendix

Continuing to Deliver Excellent Margins

	2009	2010	2011	2012	2013	2014	4Q2014
Realized oil price ($/Bbl)	$54.44	$70.69	$88.51	$84.59	$89.93	$81.26	$61.53
Realized natural gas price ($/Mcf)	$2.95	$4.26	$4.87	$3.73	$4.87	$5.40	$4.36
Oil production (Bopd)	27,459	32,385	45,121	68,497	95,859	121,999	136,972
Natural gas production (Mcfpd)	59,194	65,598	100,469	174,521	240,355	313,137	338,907
Total production (Boepd)	37,324	43,318	61,865	97,583	135,919	174,189	193,456
EBITDAX ($000's) (1)	$450,648	$810,877	$1,303,959	$1,963,123	$2,839,510	$3,776,051	$1,185,070
Key Operational Statistics (per Boe) (2)							
Average oil equivalent price (excludes derivatives)	$44.68	$59.35	$72.45	$65.99	$72.04	$66.53	$51.11
Production expense	$6.89	$5.87	$6.13	$5.49	$5.69	$5.58	$5.31
Production tax and other	$2.95	$4.47	$5.82	$5.58	$6.02	$5.54	$4.36
G&A (3)	$2.19	$2.35	$2.36	$2.38	$2.07	$2.06	$2.00
Interest	$1.72	$3.34	$3.40	$3.95	$4.74	$4.49	$4.20
Total cash costs	**$13.75**	**$16.03**	**$17.71**	**$17.40**	**$18.52**	**$17.67**	**$15.87**
Cash margin	**$30.93**	**$43.32**	**$54.74**	**$48.59**	**$53.52**	**$48.86**	**$35.24**
Cash margin %	**69%**	**73%**	**76%**	**74%**	**74%**	**73%**	**69%**

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1) *See "EBITDAX Reconciliation to GAAP" in Appendix for a reconciliation of GAAP net income and operating cash flows to EBITDAX.*
2) *Average costs per Boe have been computed using sales volumes and exclude any effect of derivative transactions.*
3) *Excludes G&A related to Equity based compensation and relocation expense.*

EBITDAX Reconciliation to GAAP

We use a variety of financial and operational measures to assess our performance. Among these measures is EBITDAX. We define EBITDAX as earnings (net income) before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, non-cash gains and losses resulting from the requirements of accounting for derivatives, non-cash equity compensation expense, and losses on extinguishment of debt. EBITDAX is not a measure of net income or operating cash flows as determined by GAAP.

Management believes EBITDAX is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. Further, we believe that EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet future debt service requirements, if any. We exclude the items listed above from net income in arriving at EBITDAX because those amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired.

EBITDAX should not be considered as an alternative to, or more meaningful than, net income or operating cash flows as determined in accordance with GAAP or as an indicator of a company's operating performance or liquidity. Certain items excluded from EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of EBITDAX. Our computations of EBITDAX may not be comparable to other similarly titled measures of other companies.

See the following page for reconciliations of our net income and operating cash flows to EBITDAX for the applicable periods.

EBITDAX Reconciliation to GAAP

The following tables provide reconciliations of our net income and operating cash flows to EBITDAX for the periods presented:

In thousands	2009	2010	2011	2012	2013	2014	4Q2014
Net income	$ 71,338	$ 168,255	$ 429,072	$ 739,385	$ 764,219	$ 977,341	$ 114,048
Interest expense	23,232	53,147	76,722	140,708	235,275	283,928	74,200
Provision for income taxes	38,670	90,212	258,373	415,811	448,830	584,697	77,682
Depreciation, depletion, amortization and accretion	207,602	243,601	390,899	692,118	965,645	1,358,669	395,260
Property impairments	83,694	64,951	108,458	122,274	220,508	616,888	393,803
Exploration expenses	12,615	12,763	27,920	23,507	34,947	50,067	20,535
Impact from derivative instruments:							
Total (gain) loss on derivatives, net	1,520	130,762	30,049	(154,016)	191,751	(559,759)	(387,958)
Total cash received (paid), net	569	35,495	(34,106)	(45,721)	(61,555)	385,350	482,567
Non-cash (gain) loss on derivatives, net	2,089	166,257	(4,057)	(199,737)	130,196	(174,409)	94,609
Non-cash equity compensation	11,408	11,691	16,572	29,057	39,890	54,353	14,934
Loss on extinguishment of debt	--	--	--	--	--	24,517	--
EBITDAX	$ 450,648	$ 810,877	$ 1,303,959	$ 1,963,123	$ 2,839,510	$ 3,776,051	$ 1,185,071

In thousands	2009	2010	2011	2012	2013	2014	4Q2014
Net cash provided by operating activities	$ 372,986	$ 653,167	$ 1,067,915	$ 1,632,065	$ 2,563,295	$ 3,355,715	$ 1,077,864
Current income tax provision	2,551	12,853	13,170	10,517	6,209	20	(2,258)
Interest expense	23,232	53,147	76,722	140,708	235,275	283,928	74,200
Exploration expenses, excluding dry hole costs	6,138	9,739	19,971	22,740	25,597	26,388	5,998
Gain (loss) on sale of assets, net	709	29,588	20,838	136,047	88	600	1,552
Excess tax benefit from stock-based compensation	2,872	5,230	--	15,618	--	--	--
Other, net	(3,890)	(3,513)	(4,606)	(7,587)	(1,829)	(17,279)	(4,429)
Changes in assets and liabilities	46,050	50,666	109,949	13,015	10,875	126,679	32,144
EBITDAX	$ 450,648	$ 810,877	$ 1,303,959	$ 1,963,123	$ 2,839,510	$ 3,776,051	$ 1,185,071

Adjusted Earnings Reconciliation to GAAP

Our presentation of adjusted earnings and adjusted earnings per share that exclude the effect of certain items are non-GAAP financial measures. Adjusted earnings and adjusted earnings per share represent earnings and diluted earnings per share determined under U.S. GAAP without regard to non-cash gains and losses on derivative instruments, property impairments, gains and losses on asset sales, corporate relocation expenses and losses on extinguishment of debt. Management believes these measures provide useful information to analysts and investors for analysis of our operating results on a recurring, comparable basis from period to period. In addition, management believes these measures are used by analysts and others in valuation, comparison and investment recommendations of companies in the oil and gas industry to allow for analysis without regard to an entity's specific derivative portfolio, impairment methodologies, and property dispositions. Adjusted earnings and adjusted earnings per share should not be considered in isolation or as a substitute for earnings or diluted earnings per share as determined in accordance with U.S. GAAP and may not be comparable to other similarly titled measures of other companies. The following table reconciles earnings and diluted earnings per share as determined under U.S. GAAP to adjusted earnings and adjusted diluted earnings per share for the periods presented.

	4Q 2014		4Q 2013		2014		2013	
In thousands, except per share data	After-Tax $	Diluted EPS	After-Tax $	Diluted EPS	After-Tax $	Diluted EPS	After-Tax $	Diluted EPS
Net income (GAAP)	$ 114,048	$ 0.31	$ 132,824	$ 0.36	$ 977,341	$ 2.64	$ 764,219	$ 2.07
Adjustments, net of tax:								
Non-cash (gain) loss on derivatives, net	59,603	0.16	58,312	0.16	(109,878)	(0.30)	82,023	0.22
Property impairments	248,096	0.67	36,885	0.10	388,640	1.05	138,920	0.38
(Gain) loss on sale of assets, net	(977)	-	15	-	(378)	-	(55)	-
Loss on extinguishment of debt	-	-	-	-	15,446	0.04	-	-
Corporate relocation expenses	-	-	96	-	-	-	1,018	-
Adjusted net income (Non-GAAP)(1)	$ 420,770	$ 1.14	$ 228,132	$ 0.62	$ 1,271,171	$ 3.43	$986,125	$ 2.67
Weighted average diluted shares outstanding	370,545		370,014		370,758		369,698	
Adjusted diluted net income per share (Non-GAAP)(1)	$ 1.14		$ 0.62		$ 3.43		$ 2.67	

(1) Balances for the 2014 periods include $348 million of pre-tax gains ($219 million after tax, or $0.59 per diluted share) recognized from crude oil derivative contracts that were monetized in the 2014 fourth quarter prior to their contractual maturities scheduled for 2015 and 2016.

PV-10 Disclosure

The Company's PV-10 value, a non-GAAP financial measure, is derived from the Standardized Measure of discounted future net cash flows, which is the most directly comparable financial measure computed using U.S. GAAP. PV-10 generally differs from Standardized Measure because it does not include the effects of income taxes on future net revenues. At December 31, 2014, our PV-10 totaled approximately $22.77 billion. The Standardized Measure of our discounted future net cash flows was approximately $18.43 billion at December 31, 2014, representing a $4.34 billion difference from PV-10 due to the effect of deducting estimated future income taxes in arriving at Standardized Measure. We believe the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to proved reserves held by companies without regard to the specific income tax characteristics of such entities and is a useful measure of evaluating the relative monetary significance of our crude oil and natural gas properties. Investors may utilize PV-10 as a basis for comparing the relative size and value of our proved reserves to other companies. PV-10 should not be considered as a substitute for, or more meaningful than, the Standardized Measure as determined in accordance with U.S. GAAP. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our crude oil and natural gas properties.

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