JULY 2013
INVESTOR PRESENTATION

FORWARD-LOOKING STATEMENTS

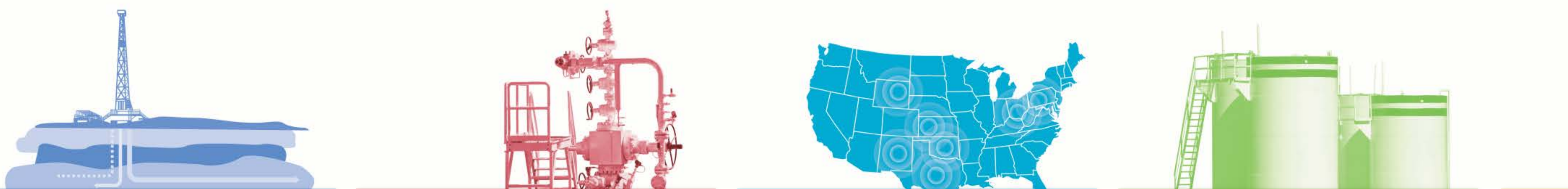
- This presentation includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are statements other than those of historical fact that give our current expectations or forecasts of future events. They include estimated natural gas and liquids proved reserves, production forecasts, estimated operating costs, assumptions regarding future natural gas and liquids prices, effects of anticipated asset sales, planned drilling activity and drilling and completion capital expenditures (including the use of joint venture drilling carries), and other anticipated cash outflows, as well as projected cash flow and liquidity, effects of planned debt reduction, business strategy and other plans and objectives for future operations.
- Disclosures concerning the estimated contribution of derivative contracts to our future results of operations are based upon market information as of a specific date, and such market prices are subject to significant volatility. Our production forecasts are dependent upon many assumptions, including estimates of production decline rates from existing wells and the outcome of future drilling activity. Pending sales transactions are subject to closing conditions and may not be completed in the time frame anticipated. We do not have binding agreements for all of our planned asset sales. Our ability to consummate each of these transactions is subject to changes in market conditions and other factors. If one or more of the transactions is not completed in the anticipated time frame or at all or for less proceeds than anticipated, our ability to fund budgeted capital expenditures and reduce our indebtedness as planned could be adversely affected. For sale transactions that have closed, we may not be able to satisfy all the requirements necessary to receive proceeds subject to title and other contingencies.
- Factors that could cause actual results to differ materially from expected results are described under "Risk Factors" in Item 1A of our 2012 annual report on Form 10-K filed with the U.S. Securities and Exchange Commission on March 1, 2013. These risk factors include the volatility of natural gas, oil and NGL prices; the limitations our level of indebtedness may have on our financial flexibility; declines in the prices of natural gas and oil potentially resulting in a write-down of our asset carrying values; the availability of capital on an economic basis, including through planned asset sales, to fund reserve replacement costs; our ability to replace reserves and sustain production; uncertainties inherent in estimating quantities of natural gas, oil and NGL reserves and projecting future rates of production and the amount and timing of development expenditures; our ability to generate profits or achieve targeted results in drilling and well operations; leasehold terms expiring before production can be established; hedging activities resulting in lower prices realized on natural gas, oil and NGL sales; the need to secure hedging liabilities and the inability of hedging counterparties to satisfy their obligations; drilling and operating risks, including potential environmental liabilities; legislative and regulatory changes adversely affecting our industry and our business, including initiatives related to hydraulic fracturing, air emissions and endangered species; current worldwide economic uncertainty which may have a material adverse effect on our results of operations, liquidity and financial condition; oilfield services shortages, gathering system and transportation capacity constraints and various transportation interruptions that could adversely affect our revenues and cash flow; losses possible from pending or future litigation and regulatory investigations; cyber attacks adversely impacting our operations; and the loss of key operational personnel or inability to maintain our corporate culture.
- Although we believe the expectations and forecasts reflected in forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate or changed assumptions or by known or unknown risks and uncertainties. We caution you not to place undue reliance on our forward-looking statements, which speak only as of the date of this presentation, and we undertake no obligation to update this information.

UNIQUELY POSITIONED

- 2nd largest U.S. natural gas producer (net), ~4% of total
- Largest U.S. natural gas producer (gross), ~9% of total
- 11th largest U.S. liquids (oil and NGL) producer
- #1 driller of horizontal shale wells in the world
- Largest onshore U.S. leasehold and 3-D seismic owner
- Industry's only proprietary Reservoir Technology Center #1 inventory of shale core data, ~60,000 ft.
- Discovered Haynesville Shale, Utica Shale, Powder River Niobrara, Tonkawa and Mississippi Lime unconventional plays—industry's best record of unconventional exploration success

CHK has captured the largest U.S. oil and natural gas resource bases and is now working to deliver value to its shareholders

PHASES OF CHESAPEAKE



GROWTH
Through the Drillbit
1989–1998

GO LONG GAS
1999–2003

GAS SHALE
Identification and Capture
2004–2009

BALANCE
Assets Through Finding Unconventional Oil
2010–2012

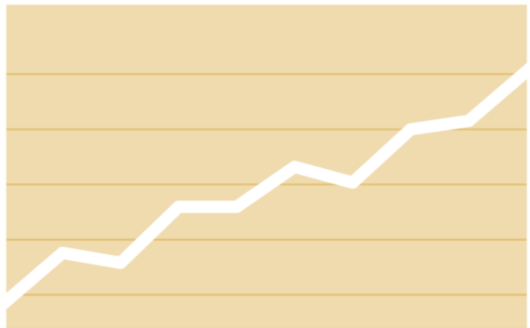
Previous Strategy

New play identification

Asset capture

Held by production (HBP) drilling

Frequent funding requirements



VALUE REALIZATION ❯

2013–FUTURE

The Path Forward

- Develop existing assets
- Operational excellence
- Capital efficiency
- Financial discipline

VALUE REALIZATION PHASE

› DEVELOP EXISTING ASSETS

- Focus on the core of the core
- Improve liquids production mix
- Optimize portfolio and sell noncore assets

› CAPITAL EFFICIENCY

- Pad drilling efficiencies
- Leverage first well investments
- Capitalize on oil service vertical integration advantages

› OPERATIONAL EXCELLENCE

- Safety
- Regulatory compliance
- Environmental stewardship
- Process improvement
- Cycle time reductions
- Lean manufacturing concepts

› FINANCIAL DISCIPLINE

- Improve returns on capital
- Increase capital allocation to drilling and completion activity
- Reduce/eliminate funding gaps
- Reduce financial risk and complexity
- Reduce costs

EXPECT TO DELIVER STRONG RESULTS IN 2013

ADJ. NET INCOME

282% YOY

2012 $285 million
2013E $1,090 million

ADJ. EBITDA

31% YOY

2012 $3.75 billion
2013E $4.92 billion

TOTAL CAPEX

43% YOY

2012 $13.4 billion
2013E $7.6 billion

OIL PRODUCTION

22% YOY

2012 31,265 mbbls
2013E 38,000 mbbls

TOTAL PRODUCTION

2% YOY

2012 1,422 bcfe
2013E 1,447 bcfe

NET WELLS TO SALES

14% YOY

2012 1,071 net wells
2013E 917 net wells

2013 efforts are leading to increased profitability

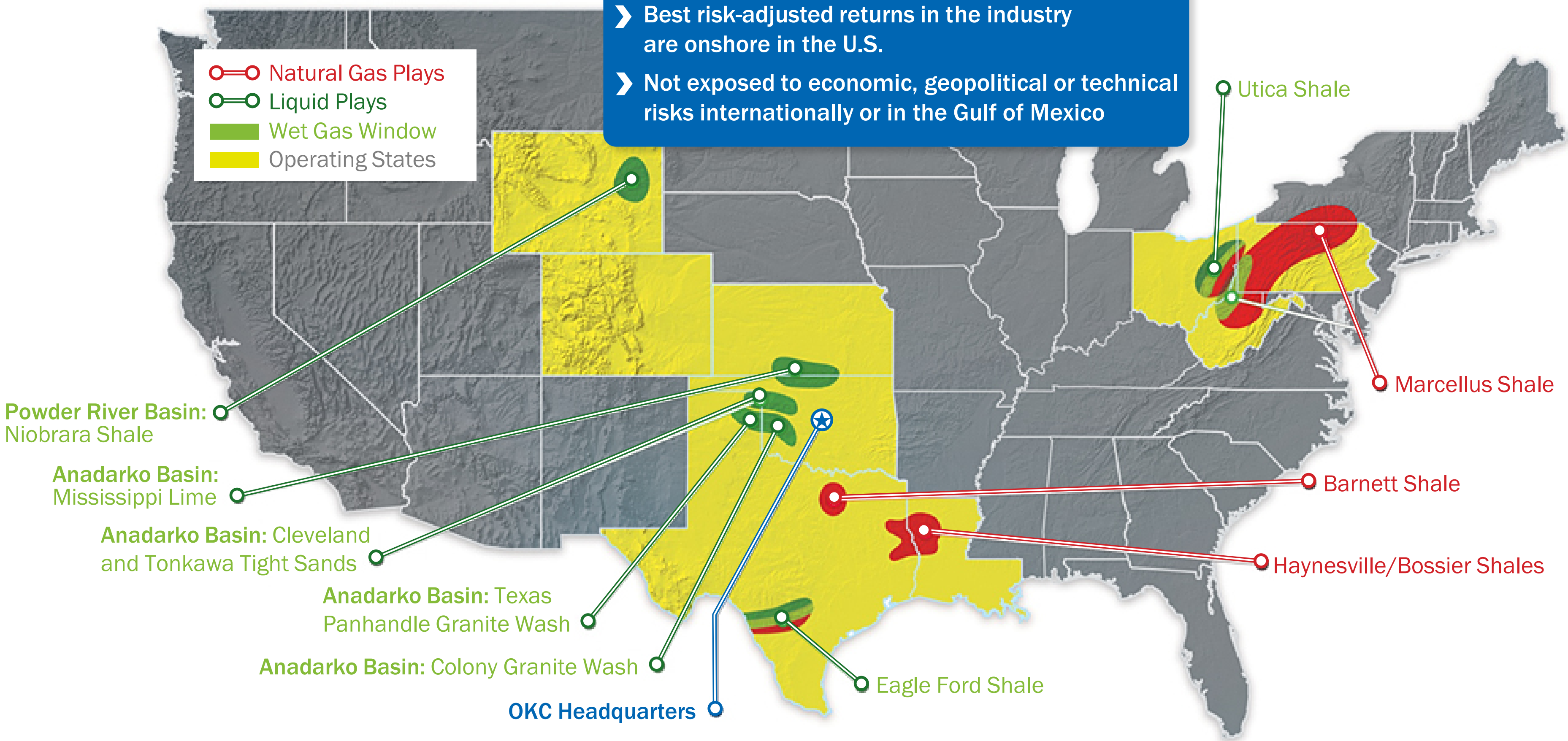
- Reconciliations of financial projections on pages 35 and 36
- Based on the midpoint of the 5/1/2013 outlook on page 24

DEVELOPING EXISTING ASSETS

Chesapeake
ENERGY

DOMINANT U.S. LEASEHOLD POSITIONS

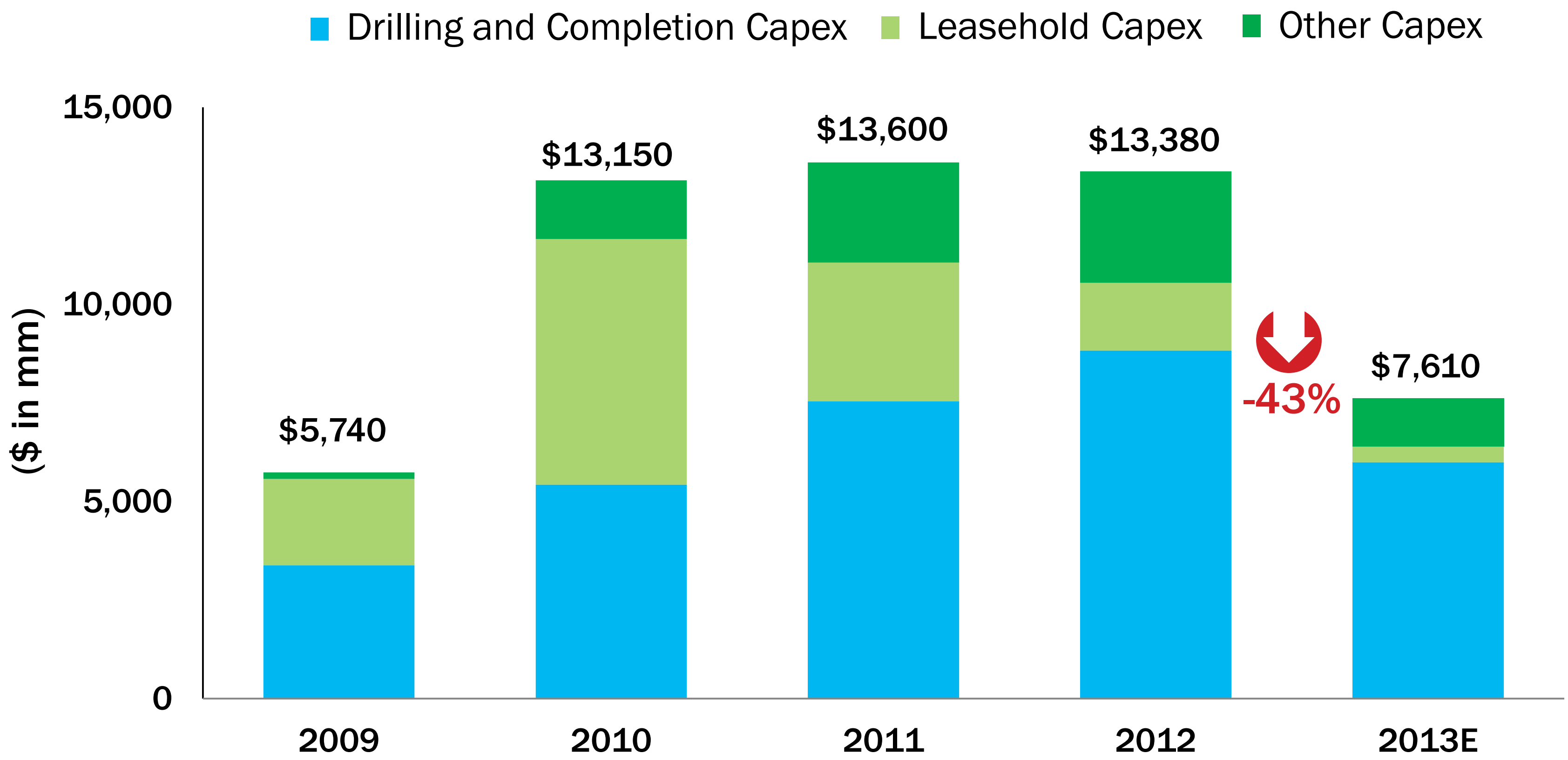
- Best risk-adjusted returns in the industry are onshore in the U.S.
- Not exposed to economic, geopolitical or technical risks internationally or in the Gulf of Mexico



- 19.6 tcfe of proved reserves(1)
- 4.0 bcfe/d of production
- 14 mm net acres of leasehold

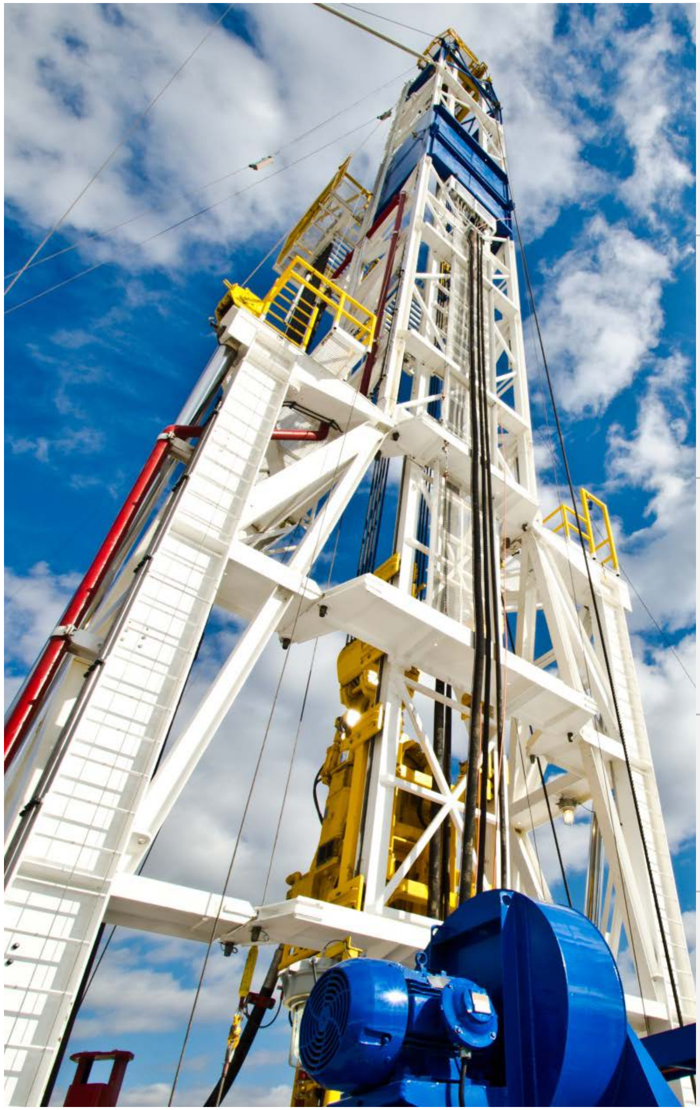
(1) Based on 10-year average NYMEX strip prices as of 12/31/12; 15.7 tcfe based on SEC pricing

ALLOCATION OF CAPITAL



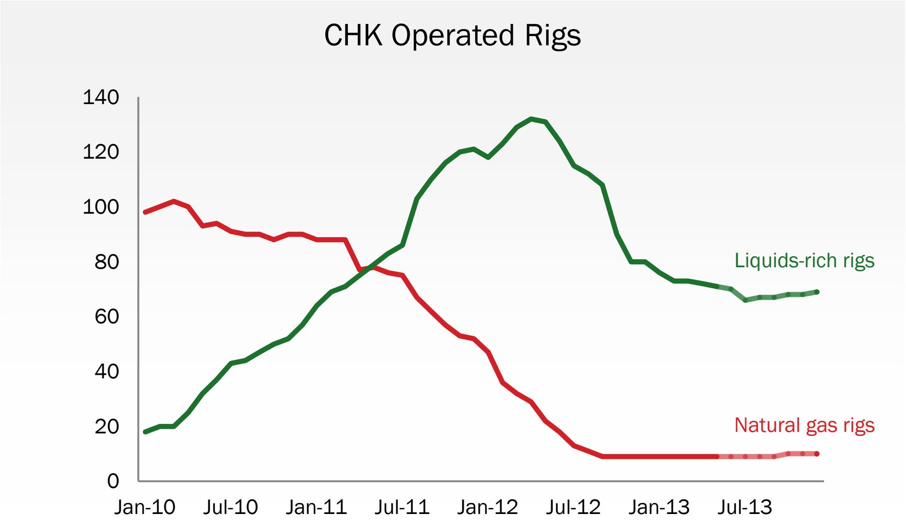
Devoting >80% capex to drilling and completion activities in 2013
vs. an average of ~50% over last three years

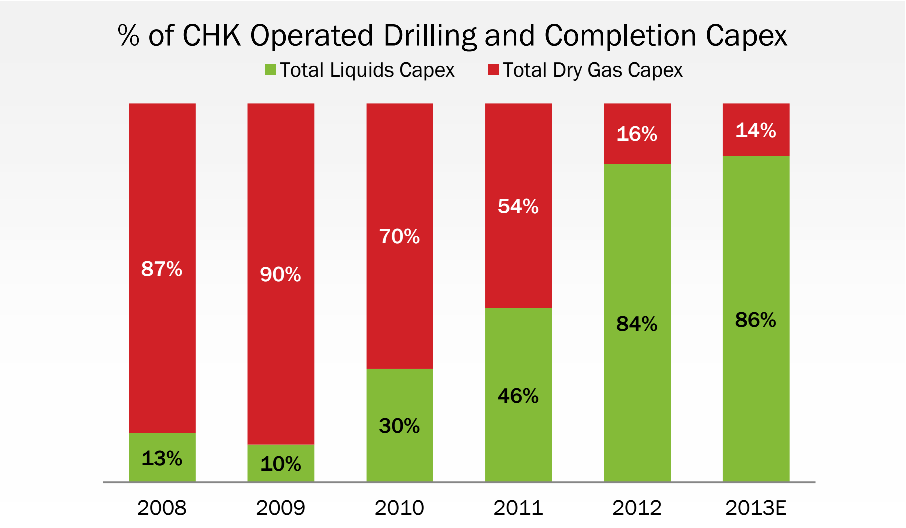
UNIQUE OPPORTUNITY FOR DIFFERENTIAL RETURNS ON CAPITAL

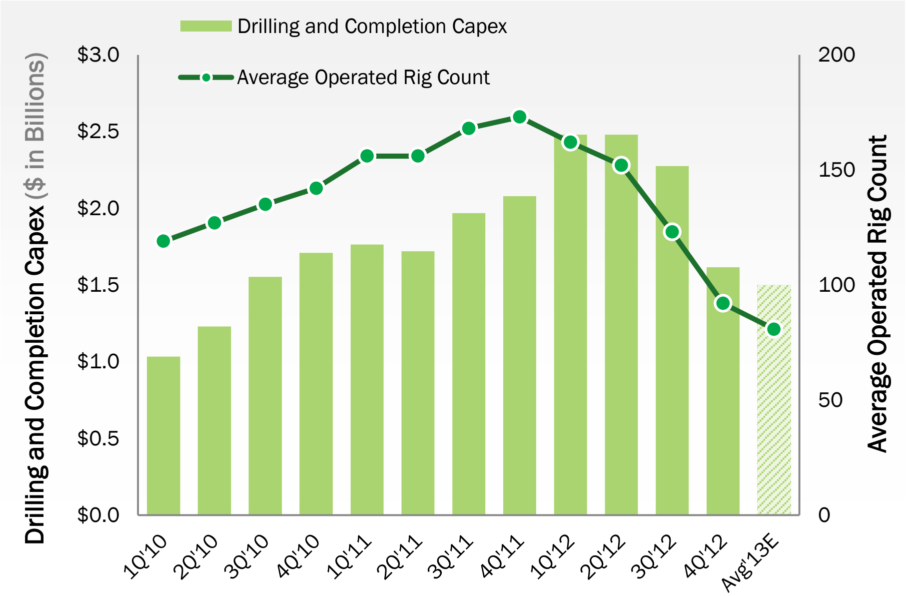


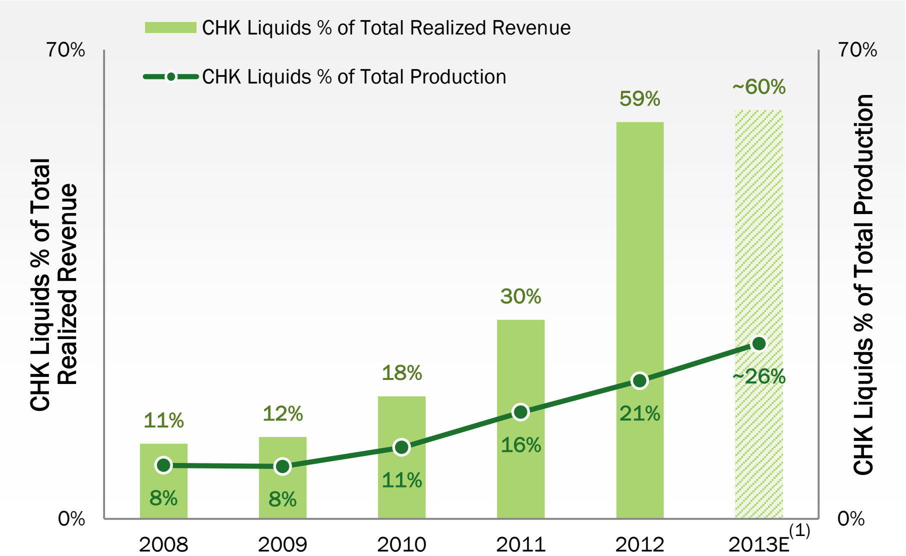
1. Focus on core of the core
2. Capitalize on pad drilling efficiencies of 15 - 30%
3. Continue to utilize drilling carries from JVs
4. Work off excess well inventories
5. Advantages of vertical integration

SHIFTING TO HIGHER RETURN LIQUIDS-RICH PLAYS IS PAYING OFF



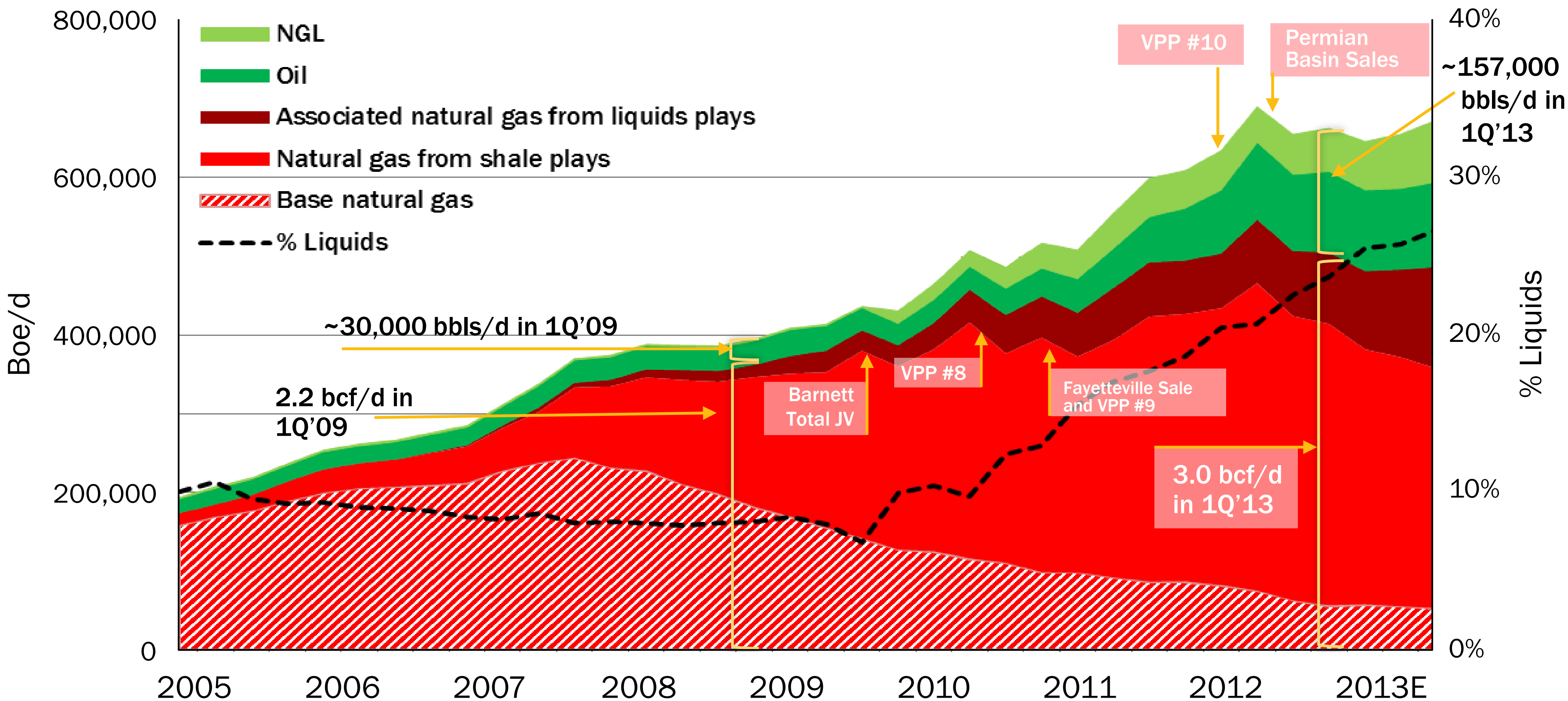






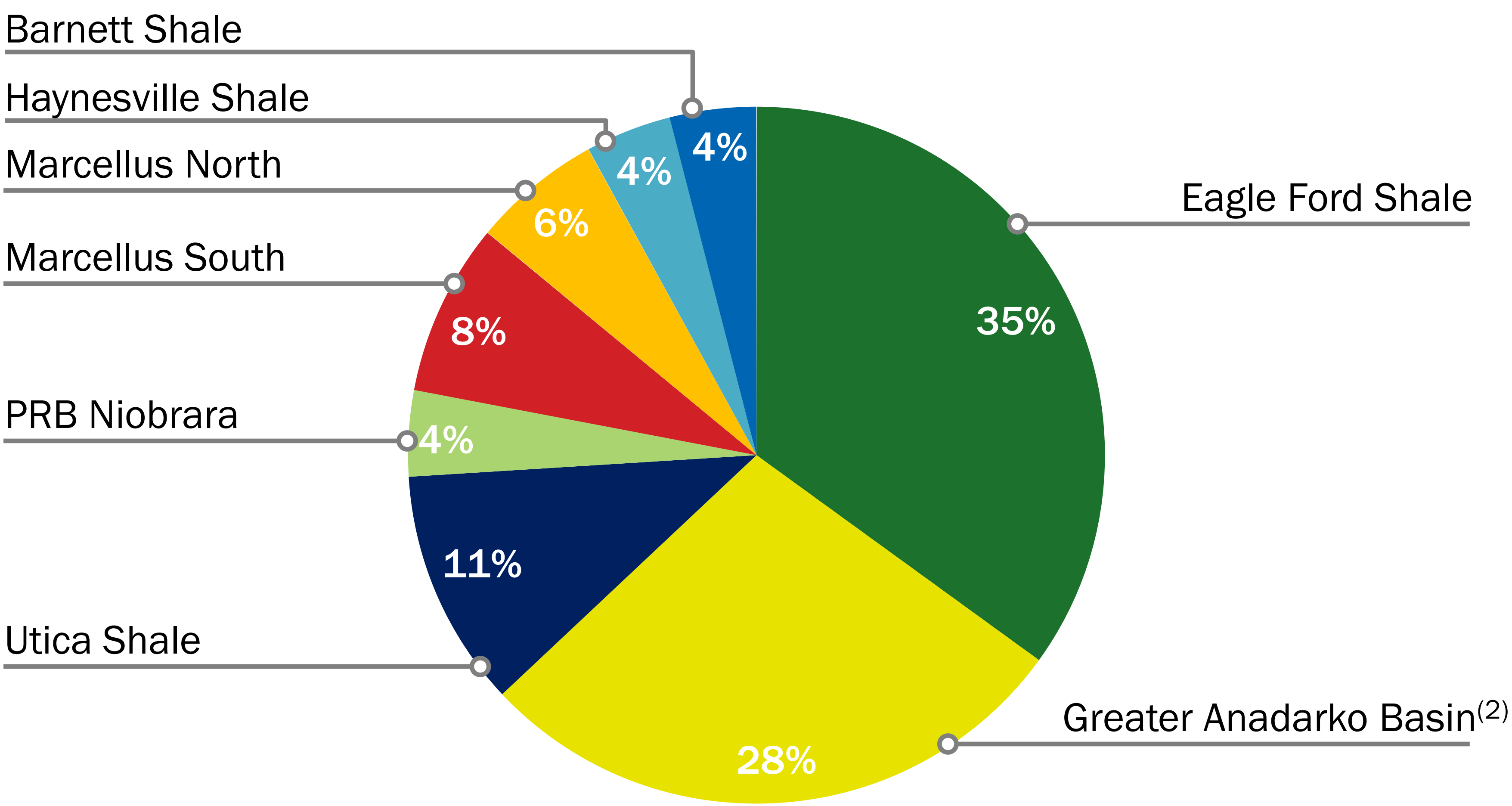
(1) Assumes NYMEX natural gas and oil prices of $4.25/mcf and $90/bbl in 2013

LIQUIDS DRIVEN PRODUCTION GROWTH



Drillbit production growth outpacing asset sales

2013 DRILLING AND COMPLETION CAPEX ALLOCATION BY PLAY(1)



>85% of 2013 drilling and completion capital expenditures are focused on liquids plays

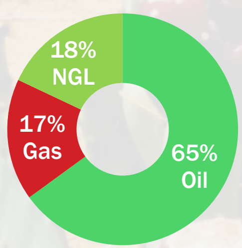
(1) Net of drilling carries
(2) Greater Anadarko Basin includes: Mississippi Lime , Granite Washes, Cleveland, Tonkawa and Hogshooter

EAGLE FORD SHALE

1Q'13 daily net production of 75 mboe/d, up 225% YOY

- Liquids averaged 62 mboe/d, up 251% YOY
- Targeting exit rate at YE'13 of ~71 mboe/d of liquids and total production of 92 mboe/d

1Q'13 Production Mix



Drilled 887 wells in the Eagle Ford[1]

- Includes 650 producing, 34 WOPL and 203 wells in various stages of completion
- Drilled 91 new wells in 1Q'13
- Average peak daily rates of 111 wells that commenced first production during 1Q'13 was ~950 boe/d

Spud-to-spud cycle times down 28% YOY, from 25 to 18 days

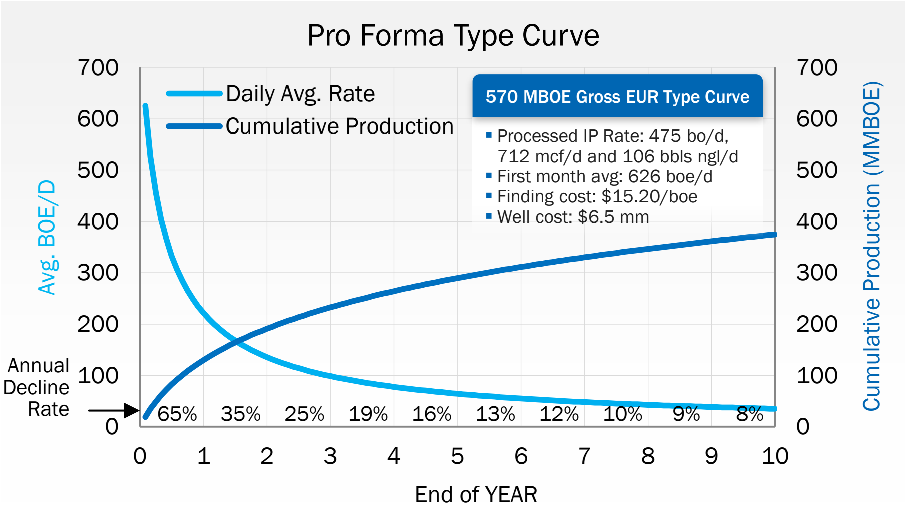
- Targeting 13 days long-term once in full pad drilling development mode
- Anticipate 50% of drilling on multi-well pads in 2H'13 and >75% in 2014

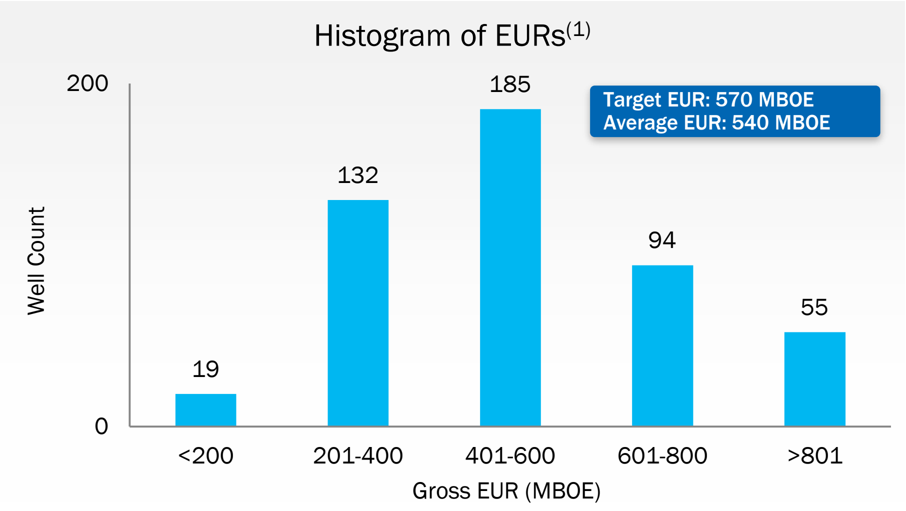
~3,500 future drilling locations on acreage CHK plans to retain

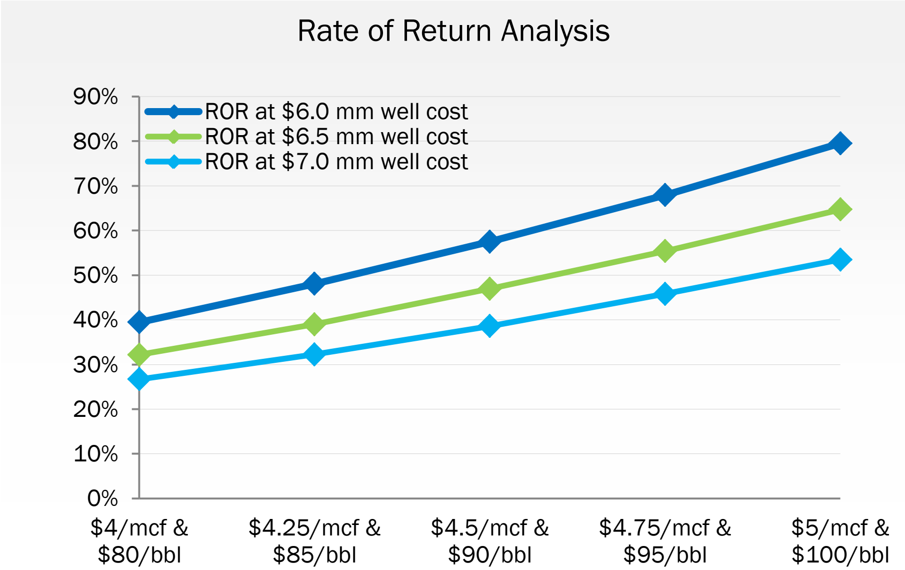
- >10 year drilling inventory based on current activity level
- Currently operating 15 rigs with plans to reduce to 13 in 2H'13

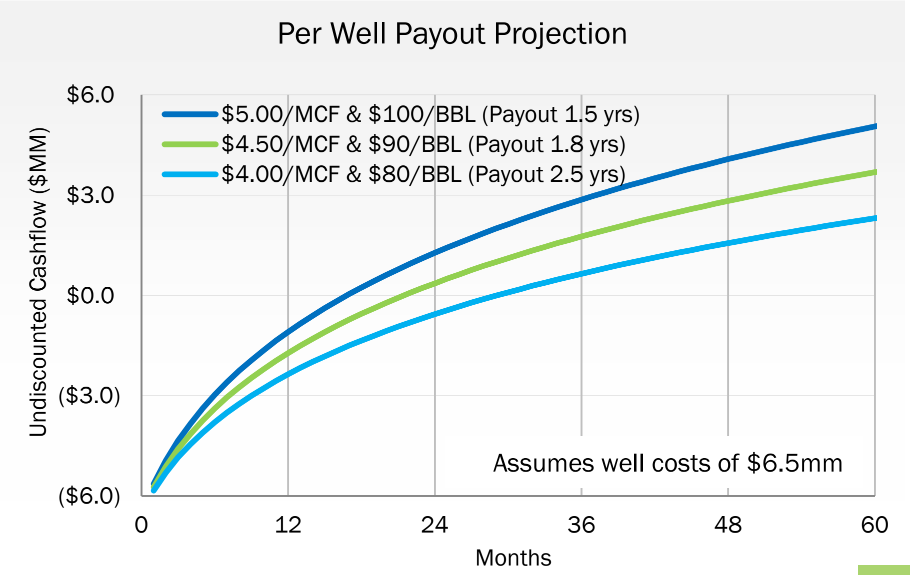
(1) As of 3/31/2013

CHK EAGLE FORD CORE ECONOMICS









(1) Includes 485 wells completed since 12/31/2011

UTICA SHALE

1Q'13 daily net production of ~60 mmcfe/d

- Targeting YE'13 exit rate of 330 mmcfe/d
- Average peak daily rate of 13 wells that commenced first production during 1Q'13 was ~1,200 boe/d

Drilled 249 wells in the Utica play to date

- Includes 66 producing wells, 86 WOPL and 97 wells in various stages of completion

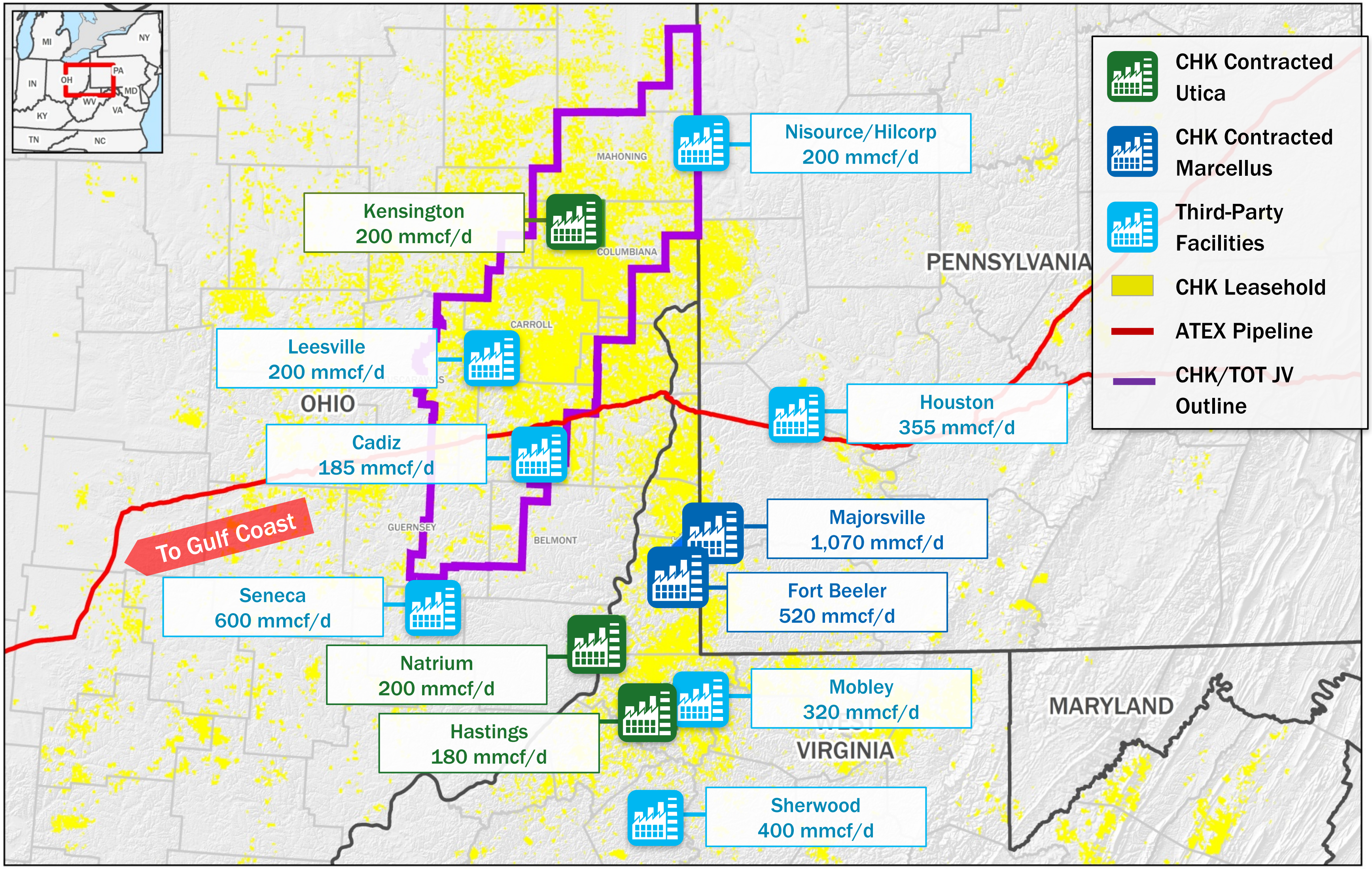
Multi-well pad efficiency gains evident in Coe unit in Carroll County, Ohio

- 1st well drilled for nearly \$8.5 mm (including infrastructure costs), next 5 wells averaged \$5.9 mm—a 30% decrease

Projecting EURs of 5–10 bcfe in wet gas window

Currently operating 14 rigs in the play

UTICA AND MARCELLUS SOUTH PROCESSING PLANTS(1)



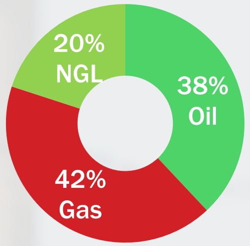
(1) CHK contracted plants reflect plant capacity, not CHK's contract volumes. Note: Natrium's phase one projected to be online in 2Q'13 with future system capacity to reach ~600 mmcf/d. Kensington phase one of ~200 mmcf/d projected to be online in mid-year 2013 with future system capacity to reach 600 mmcf/d.
Source: Company records

GREATER ANADARKO BASIN

Focusing on five plays: Mississippi Lime, Granite Wash, Cleveland, Tonkawa and Hogshooter

- 1Q'13 aggregate net production of 114 mboe/d, up 30% YOY and up 9% sequentially despite 5 mboe/d weather related downtime

1Q'13 Combined Production Mix



- Average peak daily rate of 90 wells that commenced first production during 1Q'13 was ~900 boe/d
- Currently operating 28 rigs in the five plays

Substantially completed water disposal trunk line infrastructure and salt water disposal well network in Mississippi Lime play—will improve efficiencies and costs

Successfully extended Hogshooter play further east and have identified >50 remaining drilling locations

- Average peak daily rates of 14 wells that commenced first production during 1Q'13 was ~2,380 boe/d

MARCELLUS SHALE

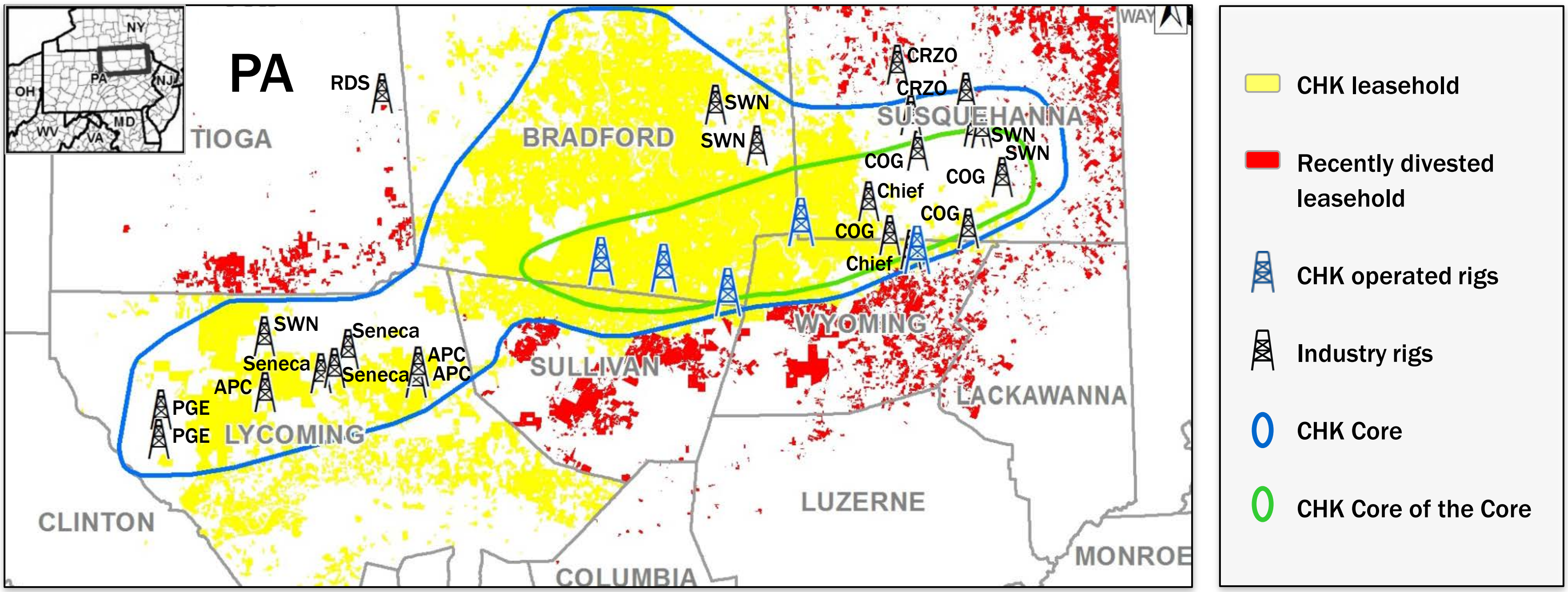
Industry's largest producer where CHK recently achieved gross operated milestone of >2 bcfe/d

1Q'13 daily net production:

- Northern dry gas portion: 710 mmcfe/d, up 70% YOY, 10% sequentially
  - Avg. peak rate of 39 wells that commenced first production, 8.0 mmcfe/d
  - >10 year drilling inventory based on current activity level
- Southern wet gas portion:
  - ~170 mmcfe/d, up 21% YOY, 9% sequentially
  - Avg. peak rate of 13 wells that commenced first production, 6.0 mmcfe/d

Currently operating 5 rigs in northern Marcellus and 3 rigs in southern Marcellus

NORTHERN MARCELLUS – CHK CORE OF THE CORE

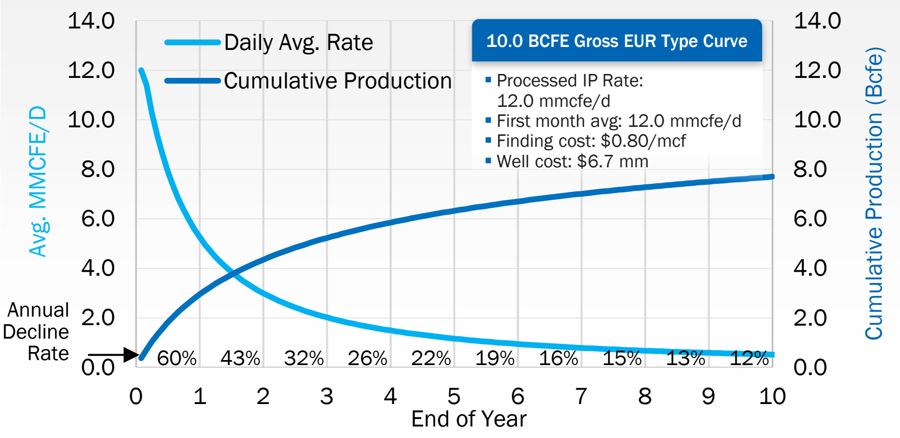


CHK owns ~100,000 net acres with >1,000 remaining drilling locations in the core of the core

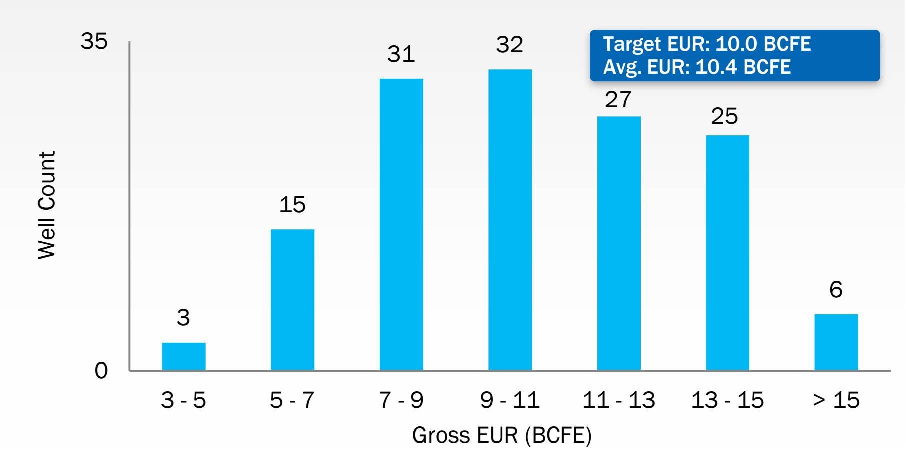
CHK MARCELLUS – CORE OF THE CORE ECONOMICS

Chesapeake ENERGY

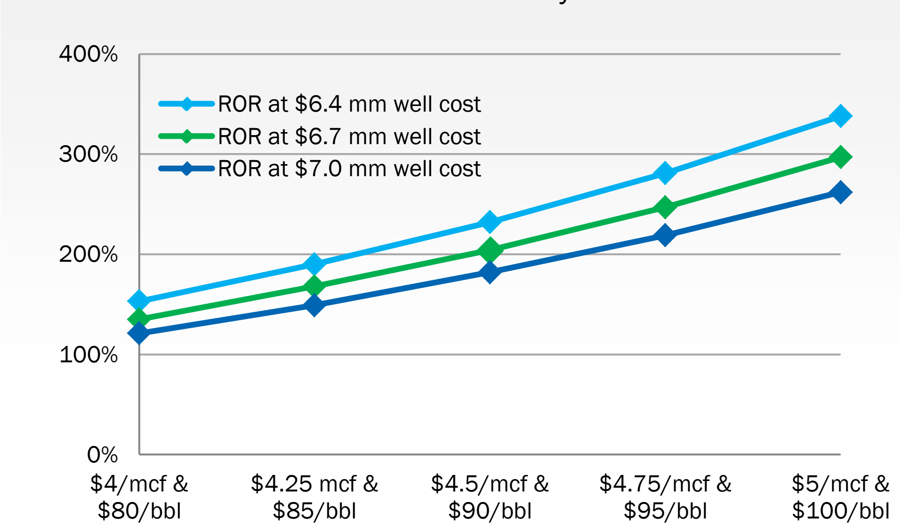
Pro Forma Type Curve



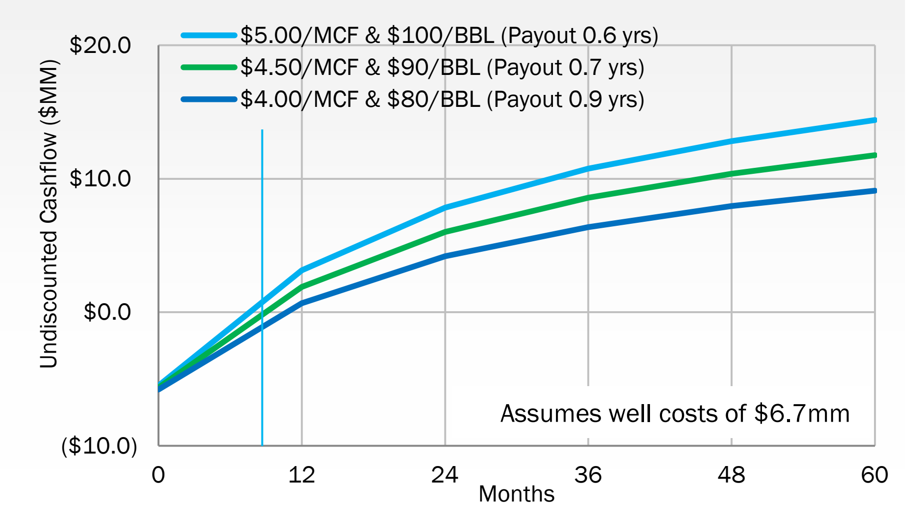
Histogram of EURs



Rate of Return Analysis



Per Well Payout Projection



Note: Data above reflects CHK internal estimates of ultimate recoverable reserves from 139 wells in CHK's Marcellus Shale "core of the core"

FINANCIAL SUMMARY

OUTLOOK SUMMARY

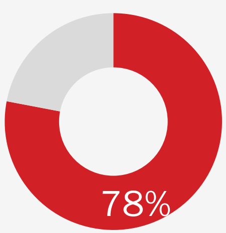
PRODUCTION	2012	YE 2013E
Natural gas (bcf)	1,129	1,060–1,090
Oil (mbbls)	31,265	37,000-39,000
NGL (mbbls)[(1)]	17,615	23,000-25,000
Natural gas equivalent (bcfe)	**1,422**	**1,420–1,474**
YOY production increase (adjusted for planned asset sales)	**19%**	**2%**
Natural gas production increase (decrease)	**12%**	**(5%)**
Liquids YOY production increase	**54%**	**27%**
% production from liquids	20%	26%
% realized revenues from liquids[(2)]	59%	60%
Operating costs per mcfe: Production expense, productions taxes and G&A[(3)]	$1.38	$1.35–$1.50
Operating cash flow ($mm)[(2)(4)]	**$4,053**	**$5,200-$5,300**
Well costs on proved and unproved properties ($mm)	**($8,831)**	**($5,750-$6,250)**
Acquisition of unproved properties, net ($mm)	**($1,718)**	**($400)**

(1) Assumes no ethane rejection
(2) Assumes NYMEX prices on open contracts of $4.00 to $4.50/mcf and $90.00/bbl in 2013
(3) Excluding noncash stock-based compensation
(4) 2012 reflects $2,837 mm cash provided by operating activities before changes in assets and liabilities of $1,216 mm, reconciliation to historical figures available on page 35; 2013E cash provided by operating activities before changes in assets and liabilities of $5,200-$5,300 mm reconciliation available on page 36

2013 FINANCIAL PROJECTIONS[1]

As of 5/1/2013 Outlook ($ in mm; oil at $90 NYMEX)	NYMEX Natural Gas Prices		
	$3.00	$4.00	$5.00
O/G revenue[2]	$6,190	$6,900	$7,620
Adjusted Ebitda	$4,770	$4,920	$5,040
Operating cash flow[3]	$5,050	$5,200	$5,320
Adjusted net income	$1,000	$1,090	$1,160
Adjusted net income per fully diluted share	$1.31	$1.43	$1.53

2Q–4Q 2013 Downside Hedge Protection[4]

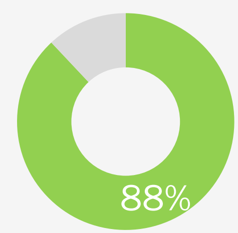


NATURAL GAS

$3.72
NYMEX

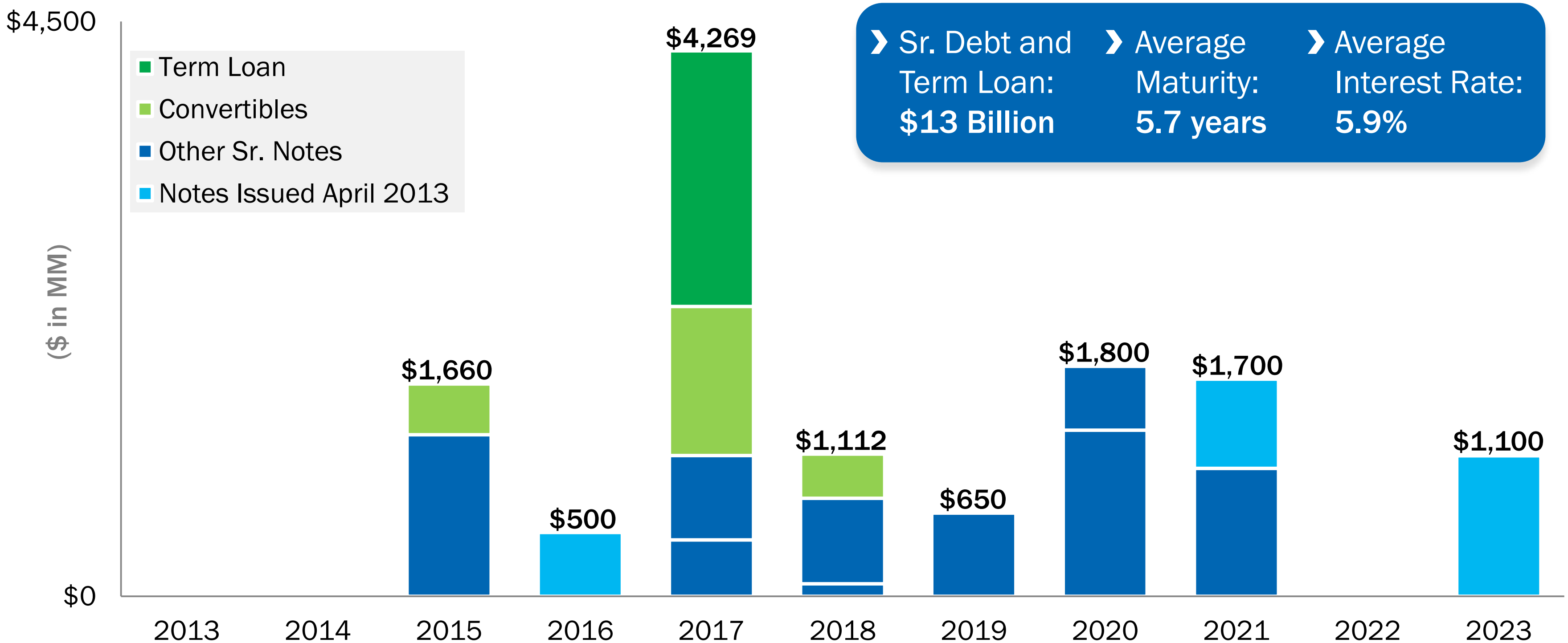
OIL

$95.43
NYMEX



(1) Reconciliations of financial projections on pages 36&37
(2) Excludes effects of estimated realized and unrealized hedging gains and losses
(3) Before changes in assets and liabilities
(4) Hedged positions based on Outlook as of 5/1/2013; 7% of 2013 gas production is hedged under collar arrangements with exposure below $3.03/mcf

SENIOR NOTE PROFILE[1]



- Sr. Debt and Term Loan: **$13 Billion**
- Average Maturity: **5.7 years**
- Average Interest Rate: **5.9%**

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Rates			2.75%(3) 9.5%	3.25%	5.75%(4) 2.5%(3) 6.5% 6.25%	2.25%(3) 7.25% 6.875%	6.625%(5)	6.875% 6.625%	5.375% 6.125%		5.75%

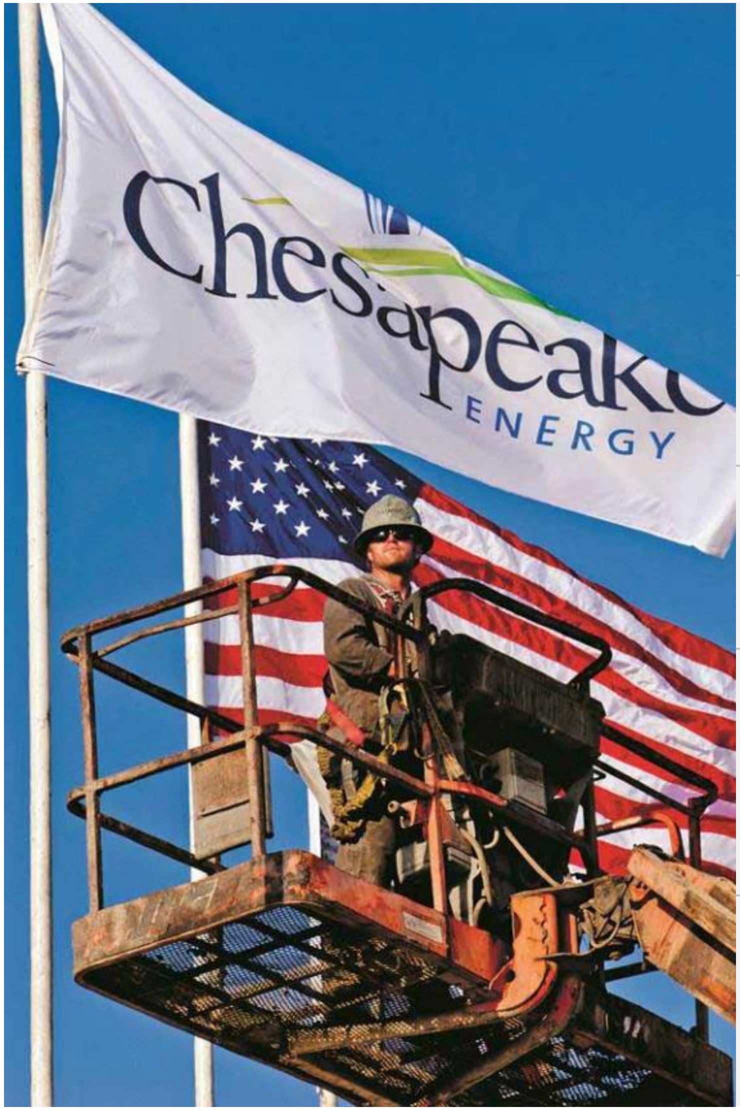
(1) As of 3/31/2013 pro forma for 4/13/2013 tenders and issuances, successful redemption of $1.3 billion Senior Notes due 2019 at par and payment at maturity of remaining 7.625% Senior Notes due July 2013 following April 2013 tender.
(2) Includes unrestricted cash and borrowing availability under revolving credit facilities as of 3/31/2013
(3) Recognizes earliest investor put option as maturity for the 2.75% 2035, 2.5% 2037 and 2.25% 2038 Contingent Convertible Senior Notes
(4) Interest at LIBOR plus 4.50%; LIBOR rate is subject to a floor of 1.25% per annum
(5) COO $650 mm Senior Notes due 2019

SUMMARY

Chesapeake
ENERGY

A NEW ERA OF VALUE REALIZATION

Chesapeake ENERGY



- **CAPITALIZING** on best assets in the business to deliver greater shareholder returns
- **INCREASING** liquids mix to generate higher margins and returns
- **BENEFITING** from recovering U.S. natural gas market
- **IMPROVING** capital efficiency through increased pad drilling and reduced acreage / infrastructure spending
- **REDUCING** financial risk and complexity

CORPORATE INFORMATION

CHK LISTED NYSE

FORTUNE 100 BEST COMPANIES TO WORK FOR 2013 6TH YEAR IN A ROW!

Chesapeake ENERGY

CHESAPEAKE HEADQUARTERS

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OTHER PUBLICLY TRADED SECURITIES	CUSIP	TICKER
7.625% Senior Notes due 2013	#165167BY2	CHKJ13
9.5% Senior Notes due 2015	#165167CD7	CHK15K
3.25% Senior Notes due 2016	#165167CJ4	CHK16
6.25% Senior Notes due 2017	#027393390	N/A
6.50% Senior Notes due 2017	#165167BS5	CHK17
6.875% Senior Notes due 2018	#165167CE5	CHK18B
7.25% Senior Notes due 2018	#165167CC9	CHK18A
6.625% Senior Notes due 2020	#165167CF2	CHK20A
6.875% Senior Notes due 2020	#165167BU0	CHK20
6.125% Senior Notes Due 2021	#165167CG0	CHK21
5.375% Senior Notes Due 2021	#165167CK1	CHK21A
5.75% Senior Notes Due 2023	#165167CL9	CHK23
2.75% Contingent Convertible Senior Notes due 2035	#165167BW6	CHK35
2.50% Contingent Convertible Senior Notes due 2037	#165167BZ9/ 165167CA3CHK37/ CHK37A	
2.25% Contingent Convertible Senior Notes due 2038	#165167CB1	CHK38
4.5% Cumulative Convertible Preferred Stock	#165167842	CHK PrD
5.0% Cumulative Convertible Preferred Stock (Series 2005B)	#165167826	N/A
5.75% Cumulative Convertible Preferred Stock	#165167776/ U16450204	N/A
5.75% Cumulative Convertible Preferred Stock (Series A)	#165167784/ U16450113	N/A

Chesapeake ENERGY

APPENDIX

RECONCILIATION OF ADJUSTED NET INCOME AVAILABLE TO COMMON STOCKHOLDERS

Chesapeake ENERGY

($ in millions, except per-share data)(unaudited)

THREE MONTHS ENDED:	March 31, 2013	December 31, 2012	March 31, 2012
Net income (loss) available to common stockholders	$ 15	$ 257	$ (71)
Adjustments, net of tax:			
Unrealized (gains) losses on derivatives	94	(78)	167
Net gains on sales of fixed assets	(30)	(166)	(1)
Impairments of fixed assets and other	16	36	—
Impairment of investment	6	—	—
Employee retirement expense and other termination benefits	83	2	—
Gain on sale of investment	—	(19)	—
Losses on purchases of debt	—	122	—
Other	(1)	(1)	(1)
Adjusted net income available to common stockholders[a]	183	153	94
Preferred stock dividends	43	43	43
Total adjusted net income	$ 226	$ 196	$ 137
Weighted average fully diluted shares outstanding[b]	758	754	752
Adjusted earnings per share assuming dilution[a]	$ 0.30	$ 0.26	$ 0.18

(a) Adjusted net income available to common stockholders and adjusted earnings per share assuming dilution exclude certain items that management believes affect the comparability of operating results. The company discloses these non-GAAP financial measures as a useful adjunct to GAAP earnings because:

i. Management uses adjusted net income available to common stockholders to evaluate the company's operational trends and performance relative to other natural gas and oil producing companies.
ii. Adjusted net income available to common stockholders is more comparable to earnings estimates provided by securities analysts.
iii. Items excluded generally are one-time items or items whose timing or amount cannot be reasonably estimated. Accordingly, any guidance provided by the company generally excludes information regarding these types of items.

(b) Weighted average fully diluted shares outstanding include shares that were considered antidilutive for calculating earnings per share in accordance with GAAP.

RECONCILIATION OF OPERATING CASH FLOW AND EBITDA

($ in millions)(unaudited)

THREE MONTHS ENDED:	March 31, 2013	December 31, 2012	March 31, 2012
CASH PROVIDED BY OPERATING ACTIVITIES	$ 924	$ 858	$ 274
Changes in assets and liabilities	252	271	636
OPERATING CASH FLOW[(a)]	$ 1,176	$ 1,129	$ 910

THREE MONTHS ENDED:	March 31, 2013	December 31, 2012	March 31, 2012
NET INCOME (LOSS)	$ 102	$ 344	$ (3)
Interest expense	21	14	12
Income tax expense (benefit)	63	219	(2)
Depreciation and amortization of other assets	78	71	84
Natural gas, oil and NGL depreciation, depletion and amortization	648	651	506
EBITDA[(b)]	$ 912	$ 1,299	$ 597

THREE MONTHS ENDED:	March 31, 2013	December 31, 2012	March 31, 2012
CASH PROVIDED BY OPERATING ACTIVITIES	$ 924	$ 858	$ 274
Changes in assets and liabilities	252	271	636
Interest expense	21	14	12
Unrealized gains (losses) on natural gas, oil and NGL	(146)	125	(270)
Net gains on sales of fixed assets	49	272	2
Impairments of fixed assets and other	(27)	(59)	—
Employee retirement and other termination benefits	(105)	(3)	—
Gain on sale of investment	—	31	—
Losses on investments	(29)	(18)	(33)
Impairment of investment	(10)	—	—
Stock-based compensation	(32)	(27)	(37)
Losses on purchases of debt	—	(200)	—
Other items	15	35	13
EBITDA[(b)]	$ 912	$ 1,299	$ 597

(a) Operating cash flow represents net cash provided by operating activities before changes in assets and liabilities. Operating cash flow is presented because management believes it is a useful adjunct to net cash provided by operating activities under accounting principles generally accepted in the United States (GAAP). Operating cash flow is widely accepted as a financial indicator of a natural gas and oil company's ability to generate cash which is used to internally fund exploration and development activities and to service debt. This measure is widely used by investors and rating agencies in the valuation, comparison, rating and investment recommendations of companies within the natural gas and oil exploration and production industry. Operating cash flow is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operating, investing or financing activities as an indicator of cash flows, or as a measure of liquidity.

(b) Ebitda represents net income before income tax expense, interest expense and depreciation, depletion and amortization expense. Ebitda is presented as a supplemental financial measurement in the evaluation of our business. We believe that it provides additional information regarding our ability to meet our future debt service, capital expenditures and working capital requirements. This measure is widely used by investors and rating agencies in the valuation, comparison, rating and investment recommendations of companies. Ebitda is also a financial measurement that, with certain negotiated adjustments, is reported to our lenders pursuant to our bank credit agreements and is used in the financial covenants in our bank credit agreements. Ebitda is not a measure of financial performance under GAAP. Accordingly, it should not be considered as a substitute for net income, income from operations, or cash flow provided by operating activities prepared in accordance with GAAP.

RECONCILIATION OF ADJUSTED EBITDA

($ in millions)(unaudited)

THREE MONTHS ENDED:	March 31, 2013	December 31, 2012	March 31, 2012
EBITDA	$ 912	$ 1,299	$ 597
Adjustments:			
Unrealized (gains) losses on natural gas, oil and NGL derivatives	146	(125)	270
Impairment of investment	10	—	—
Net gains on sales of fixed assets	(49)	(272)	(2)
Impairments of fixed assets and other	27	59	—
Net income attributable to noncontrolling interests	(44)	(44)	(25)
Gain on sale of investment	—	(31)	—
Losses on purchases of debt	—	200	—
Employee retirement expense and other termination benefits	133	3	—
Other	(1)	—	(2)
Adjusted EBITDA[a]	$ 1,134	$ 1,089	$ 838

(a) Adjusted ebitda excludes certain items that management believes affect the comparability of operating results. The company discloses these non-GAAP financial measures as a useful adjunct to ebitda because:

i. Management uses adjusted ebitda to evaluate the company's operational trends and performance relative to other natural gas and oil producing companies.
ii. Adjusted ebitda is more comparable to estimates provided by securities analysts.
iii. Items excluded generally are one-time items or items whose timing or amount cannot be reasonably estimated. Accordingly, any guidance provided by the company generally excludes information regarding these types of items.

RECONCILIATION OF OPERATING CASH FLOW AND EBITDA

Chesapeake ENERGY

($ in millions)(unaudited)

TWELVE MONTHS ENDED:		December 31, 2012		December 31, 2011
CASH PROVIDED BY OPERATING ACTIVITIES	$	2,837	$	5,903
Changes in assets and liabilities		1,216		(594)
OPERATING CASH FLOW[(a)]	$	4,053	$	5,309

TWELVE MONTHS ENDED:		December 31, 2012		December 31, 2011
NET INCOME (LOSS)	$	(594)	$	1,757
Income tax expense (benefit)		(380)		1,123
Interest expense		77		44
Depreciation and amortization of other assets		304		291
Natural gas, oil and NGL depreciation, depletion and amortization		2,507		1,632
EBITDA[(b)]	$	1,914	$	4,847

TWELVE MONTHS ENDED:		December 31, 2012		December 31, 2011
CASH PROVIDED BY OPERATING ACTIVITIES	$	2,837	$	5,903
Changes in assets and liabilities		1,216		(594)
Interest expense		77		44
Unrealized gains (losses) on natural gas, oil and NGL derivatives		561		(789)
Impairment of natural gas and oil properties		(3,315)		—
Net gains on sales of fixed assets		267		437
Impairments of fixed assets and other		(316)		(46)
Gains (losses) on investments		(180)		41
Stock-based compensation		(120)		(153)
Gains on sales of investments		1,092		—
Losses on purchases of debt		(200)		(5)
Other items		(5)		9
EBITDA[(b)]	$	1,914	$	4,847

(a) Operating cash flow represents net cash provided by operating activities before changes in assets and liabilities. Operating cash flow is presented because management believes it is a useful adjunct to net cash provided by operating activities under accounting principles generally accepted in the United States (GAAP). Operating cash flow is widely accepted as a financial indicator of a natural gas and oil company's ability to generate cash which is used to internally fund exploration and development activities and to service debt. This measure is widely used by investors and rating agencies in the valuation, comparison, rating and investment recommendations of companies within the natural gas and oil exploration and production industry. Operating cash flow is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operating, investing or financing activities as an indicator of cash flows, or as a measure of liquidity.

(b) Ebitda represents net income (loss) before income tax expense, interest expense and depreciation, depletion and amortization expense. Ebitda is presented as a supplemental financial measurement in the evaluation of our business. We believe that it provides additional information regarding our ability to meet our future debt service, capital expenditures and working capital requirements. This measure is widely used by investors and rating agencies in the valuation, comparison, rating and investment recommendations of companies. Ebitda is also a financial measurement that, with certain negotiated adjustments, is reported to our lenders pursuant to our bank credit agreements and is used in the financial covenants in our bank credit agreements. Ebitda is not a measure of financial performance under GAAP. Accordingly, it should not be considered as a substitute for net income, income from operations or cash flow provided by operating activities prepared in accordance with GAAP.

RECONCILIATION OF 2013 FINANCIAL PROJECTIONS: ADJUSTED EBITDA TO OPERATING CASH FLOW

	NYMEX Natural Gas Prices		
As of 5/1/2013 Outlook ($ in mm; oil at ~$90 NYMEX)	$3.00	$4.00	$5.00
O/G revenue (unhedged)	$6,190	$6,900	$7,620
Hedging effect[(1)]	540	-	(570)
Marketing, service operations and other	290	290	290
Production taxes ~4%	(240)	(260)	(290)
Production cost (LOE)	(1,270)	(1,270)	(1,270)
G&A[(2)]	(540)	(540)	(540)
Net income attributable to noncontrolling interests	(200)	(200)	(200)
Adjusted Ebitda	**$4,770**	**$4,920**	**$5,040**
Interest expense incl. capitalized interest	(110)	(110)	(110)
Non-cash interest expense	60	60	60
Stock-based compensation	130	130	130
Net income attributable to noncontrolling interests	200	200	200
Operating cash flow[(3)]	**$5,050**	**$5,200**	**$5,320**

(1) Includes effects of estimated realized hedging gains and losses and excludes effects of unrealized hedging gains and losses
(2) Includes expense related to noncash stock-based compensation
(3) Before changes in assets and liabilities

RECONCILIATION OF 2013 FINANCIAL PROJECTIONS: OPERATING CASH FLOW TO ADJUSTED NET INCOME

	NYMEX Natural Gas Prices		
As of 5/1/2013 Outlook ($ in mm; oil at ~$90 NYMEX)	$3.00	$4.00	$5.00
Operating cash flow[1]	$5,050	$5,200	$5,320
Oil and gas depreciation	(2,530)	(2,530)	(2,530)
Depreciation of other assets	(400)	(400)	(400)
Income taxes (38% rate)	(730)	(790)	(840)
Non-cash interest expense	(60)	(60)	(60)
Stock-based compensation	(130)	(130)	(130)
Net income attributable to noncontrolling interests	(200)	(200)	(200)
Adjusted net income to common stockholders	$1,000	$1,090	$1,160
Adjusted earnings per fully diluted share	$1.31	$1.43	$1.53

(1) Before changes in assets and liabilities