

BOLD MOVES
BIG FUTURE



AUGUST 2012
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 give our current expectations or forecasts of future events. They include estimates of our natural gas and liquids reserves and resources, expected natural gas and liquids production and future expenses, assumptions regarding future natural gas and liquids prices, planned asset sales, budgeted capital expenditures for drilling and other anticipated cash outflows, as well as statements concerning anticipated cash flow and liquidity, business strategy and other plans and objectives for future operations. Disclosures of the estimated realized effects of our hedging positions on natural gas and liquids sales are based upon market prices that 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. 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 assumptions or by known or unknown risks and uncertainties.
- Factors that could cause actual results to differ materially from expected results are described in Item 1A "Risk Factors" in our 2011 Form 10-K filed with the U.S. Securities and Exchange Commission on February 29, 2012. These risk factors include the volatility of natural gas and liquids prices; the adverse effect of lower prices for an extended period of time on our business; the limitations our level of indebtedness may have on our financial flexibility, including a reduced ability to borrow or raise additional capital as a result of lower natural gas and liquids prices; declines in the values of our natural gas and liquids properties resulting in ceiling test write-downs; the availability of capital on an economic and timely basis from planned asset monetization transactions and other sources to fund reserve replacement costs and other capital expenditures; our ability to replace reserves and sustain production; uncertainties inherent in estimating quantities of natural gas and liquids reserves and projecting future rates of production and the amount and timing of development expenditures; inability 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 and liquids 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 those relating to hydraulic fracturing; general economic conditions negatively impacting us and our business counterparties; oilfield services shortages and transportation capacity constraints and interruptions that could adversely affect our revenues and cash flow; and adverse results in pending or future litigation.
- 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.

2Q '12 EARNINGS SUMMARY



- **Top-tier production growth**
 - › 2Q '12 total production averaged ~3.8 bcfe/d, up 25% YOY and 4% sequentially
 - › 2Q '12 liquids production of ~130,200 bbls/d, up 65% YOY and 15% sequentially
- **Liquids now 21% of total production and 70% of unhedged revenue**
- **2Q '12 financial performance**
 - › ~\$803 mm of adjusted ebidta⁽¹⁾
 - › ~\$895 mm of operating cash flow⁽¹⁾
- **Anticipate entering into asset sales of ~\$7.0 Billion in 3Q'12, bringing expected 2012 sales through 3Q'12 to ~\$11.7 billion**
- **Raised 2012 sales goal to \$13-14 billion**
 - › Proceeds to fully fund cap-ex budget and reduce long-term debt to \$9.5 billion by YE 2012
- **Cap-ex for drilling, completion and leasehold to be significantly reduced from 2Q '12 levels during remainder of 2H'12 and in 2013**
- **Increased natural gas hedges for last half of 2012**

(1) Reconciliations of non-GAAP financial measures to comparable GAAP measures appear on pages 47-48

We are focused on executing our transformation to a more balanced asset base between liquids and natural gas - it's not easy with \$2/mcf wellhead natural gas, but we are doing it

CHK MID-YEAR 2012 UPDATE



2012 = Profound change at CHK

■ January 2012:

- › Strategy shift from asset identification and capture to asset harvest; initiated in 2011 now fully under way

■ March 2012:

- › Natural gas prices dropped from the “winter that wasn’t”
- › 900 Bcf storage oversupply YOY causing dramatic drop in natural gas prices in 2012 and beyond

■ June 2012:

- › Five new members, including an independent chairman, Archie Dunham, join CHK Board of Directors

■ August 2012:

- › Second quarter results demonstrate shift to a more liquids-focused production profile is well underway and successful
- › Raised 2012 asset sales goal to \$13-14 billion
- › Storage overhang already reduced by 410 bcf



BACKGROUND AND BENEFITS OF MOVING TO HARVEST PHASE

- Over the last seven years CHK has helped lead an unconventional asset revolution, first in natural gas, now in liquids
- In 2012, CHK moves full speed into asset harvest mode and will drill almost exclusively for oil and NGLs until natural gas prices recover to levels that make natural gas drilling competitive
- **Results:**
 - › 1Q'10 liquids production = 43 mbbls/d; 10% of total production
 - › 2Q'12 liquids production = 130 mbbls/d; 21% of total production
 - › January 2010 operating 122 total rigs: natural gas = 100; liquids = 22
 - › August 2012 operating 125 total rigs: natural gas = 11; liquids = 114, a complete reversal in 30 months
 - › 2010 leasehold cap-ex = \$5.8 billion; 2013E = \$400 million
- **Strategy shift to harvest mode, from capture mode, will lead to higher returns on invested capital, lower cap-ex and a more simple company to follow**



ASSET SALES STRATEGY

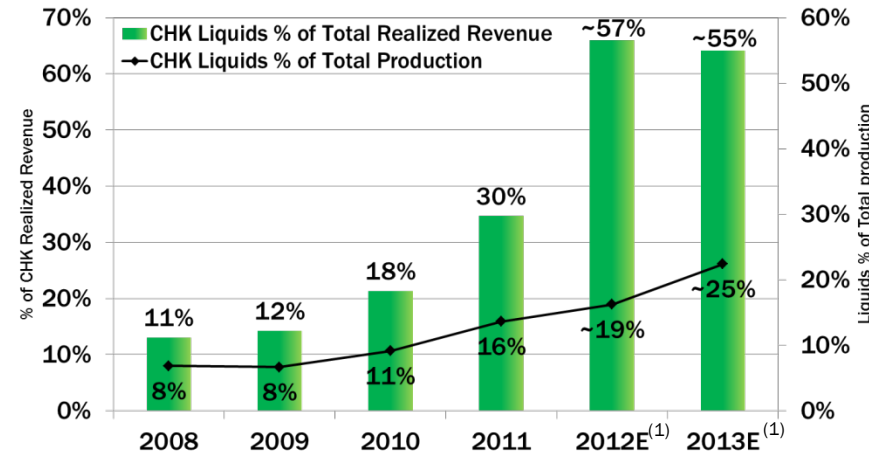
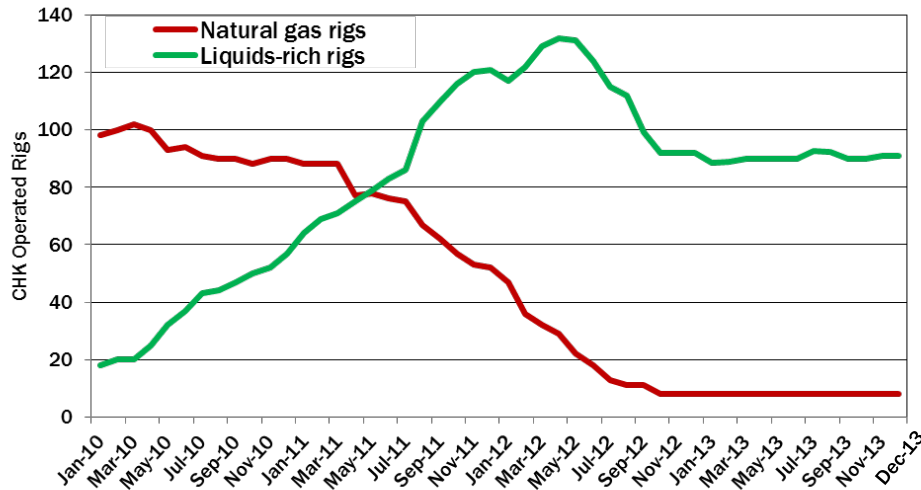
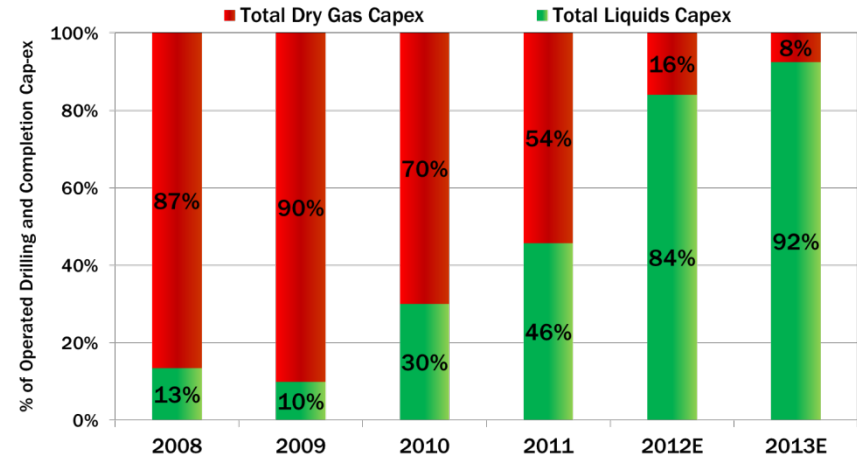


- Goal is to reduce debt to investment grade levels and to fund conversion of company's asset base from only 10% liquids in 2010 to 35% by 2015
- CHK now targeting asset sales of \$13-14 billion in 2012 and \$4.25-5.0 billion in 2013
- CHK expects to have asset sales of \$11.7 billion completed or announced by end of 3Q'12
- Despite these large asset sales, CHK expects production in 2012 will exceed 2011's by 18%
- CHK is committed to selling non-core assets so that it can focus its drilling in the "core of the core" of its 10 key plays:
 - › Eagle Ford Shale
 - › Marcellus Shale
 - › Utica Shale
 - › Anadarko Basin (Granite Wash, Cleveland, Tonkawa Tight Sands)
 - › Mississippi Lime
 - › Powder River Basin Niobrara Shale
 - › Haynesville/Bossier Shale
 - › Barnett Shale

AGGRESSIVE SHIFT OF CAPITAL TO LIQUIDS-RICH PLAYS HAS PAID OFF



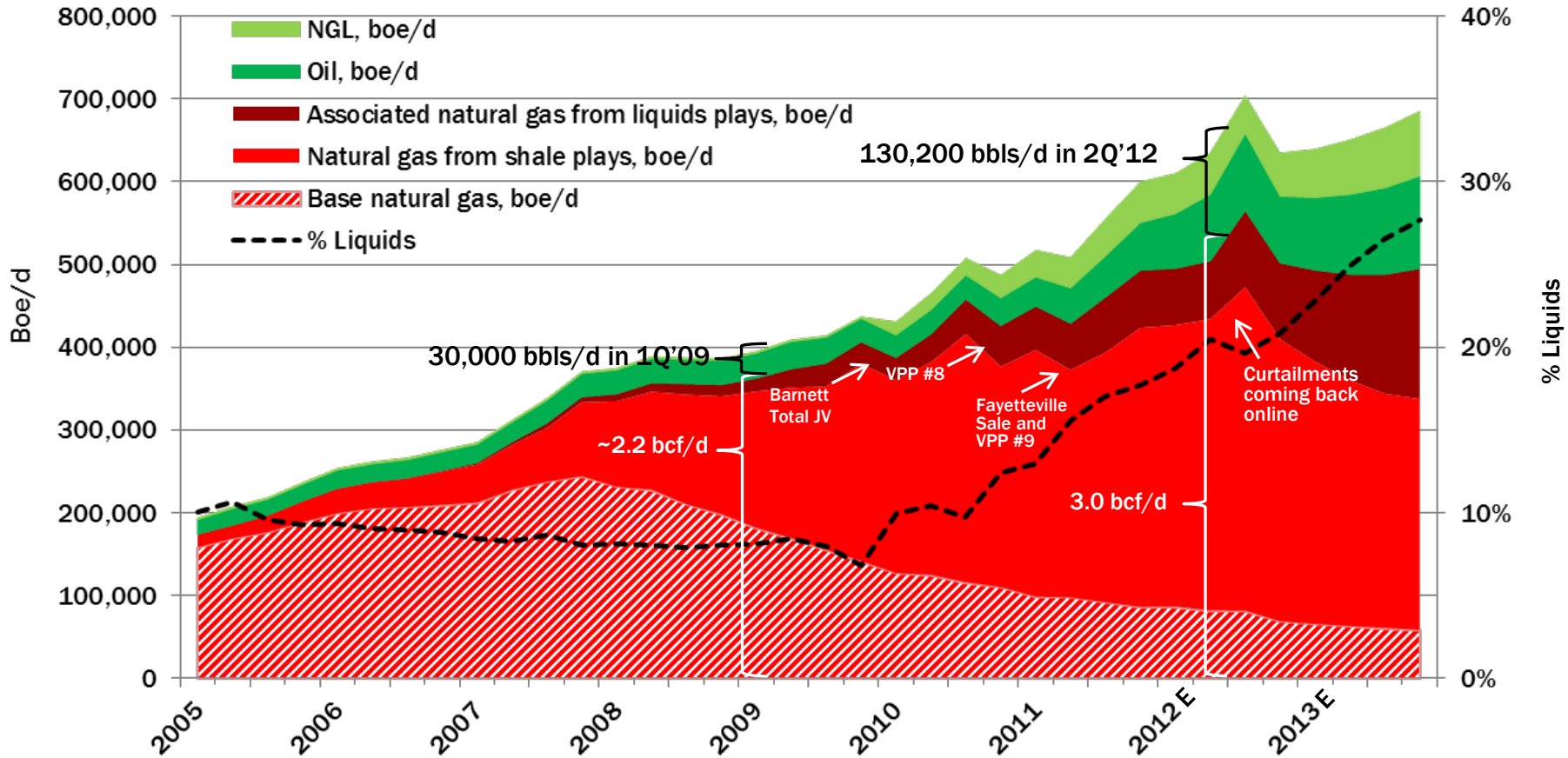
- **CHK's drilling cap-ex in 2012 is ~15%/85% between natural gas plays and liquids-rich plays, respectively**
 - › Expect to average ~100 operated rigs on liquids-rich plays in second half of 2012
- **Improving drilling rates of return and per unit profitability**
- **Liquids expected to be ~25% of total production and ~55% of total realized revenue in 2013**



(1) Assumes NYMEX prices of \$3.00-\$3.25 and \$3.25-\$4.25/mcf in 2012 and 2013, respectively; oil prices of \$90/bbl in 2012 and 2013

CHK has been very responsive to market signals and aggressively shifted capital to higher return liquids-rich plays

CHK'S FUTURE PRODUCTION GROWTH IS 100% LIQUIDS



CHK is targeting net liquids production to average 130,000 bbls/d, 170,000 bbls/d, 250,000 bbls/d in 2012, 2013 and 2015, respectively

TOP 20 U.S. LIQUIDS PRODUCERS

Daily U.S. Liquids Production⁽¹⁾⁽²⁾

Company	Ticker	2Q'12	1Q'12	2Q'11	2011 Reported	2011 Reported	Proved U.S. Liquids Reserves (MMBBL)	RP Ratio ⁽³⁾	2011 Reported	U.S.	U.S.	U.S. Liquids Rigs
					2Q'12 vs. 1Q'12 % Change	2Q'12 vs. 2Q'11 % Change			Proved U.S. Liquids Reserves	Liquids Reserves Ranking	Liquids Rigs Drilling on 07/27/12 ⁽⁴⁾	Liquids Rigs Drilling on 1/1/10 ⁽⁴⁾
1	BP	465	454	465	2.4%	0.0%	2,858	17	1	3	5	(40%)
2	Chevron	461	456	478	1.1%	(3.6%)	1,311	8	5	15	5	200%
3	ExxonMobil	419	426	429	(1.6%)	(2.3%)	2,372	16	2	16	4	300%
4	ConocoPhillips	404	427	383	(5.4%)	5.5%	2,009	14	3	25	6	317%
5	Occidental	322	316	297	1.9%	8.4%	1,751	15	4	25	11	127%
6	Anadarko	233	218	206	6.9%	13.1%	1,034	12	6	15	5	200%
7	Shell	209	228	221	(8.3%)	(5.4%)	838	11	7	9	4	125%
8	EOG	205	181	131	13.1%	56.9%	722	10	9	47	13	262%
9	Apache	157	148	139	6.1%	13.1%	794	14	8	50	2	2400%
10	Devon	146	157	138	(6.8%)	5.6%	693	13	10	26	7	271%
11	Chesapeake	130	114	79	14.6%	64.7%	546	11	12	116	15	673%
12	Hess	124	109	90	13.8%	37.8%	293	6	16	21	4	425%
13	Continental	95	60	40	57.9%	134.2%	326	9	14	35	26	35%
14	Marathon	93	90	72	3.3%	29.2%	279	8	17	29	5	480%
15	BHP	89	118	86	(24.6%)	3.0%	267	8	18	12	0	1000%
16	Pioneer	88	85	58	3.8%	53.2%	641	20	11	34	8	325%
17	Whiting	69	69	53	0.4%	31.1%	298	12	15	25	7	257%
18	Denbury	67	67	60	0.5%	12.8%	358	15	13	5	1	400%
19	Noble	62	59	52	5.1%	19.2%	244	11	19	5	1	400%
20	Plains	60	50	49	20.4%	23.2%	244	11	20	7	0	700%
Totals / Average		3,899	3,831	3,525	1.8%	10.6%	17,877			520	129	303%
Other Producers										889	246	261%
Total										1,409	375	276%

(1) Based on 2Q'12 company reports

(2) In mbbbls/day

(3) Based on annualized production

(4) Source: Smith Bits, a Schlumberger Company

TOP 20 U.S. NATURAL GAS PRODUCERS



Daily U.S. Natural Gas Production⁽¹⁾⁽²⁾

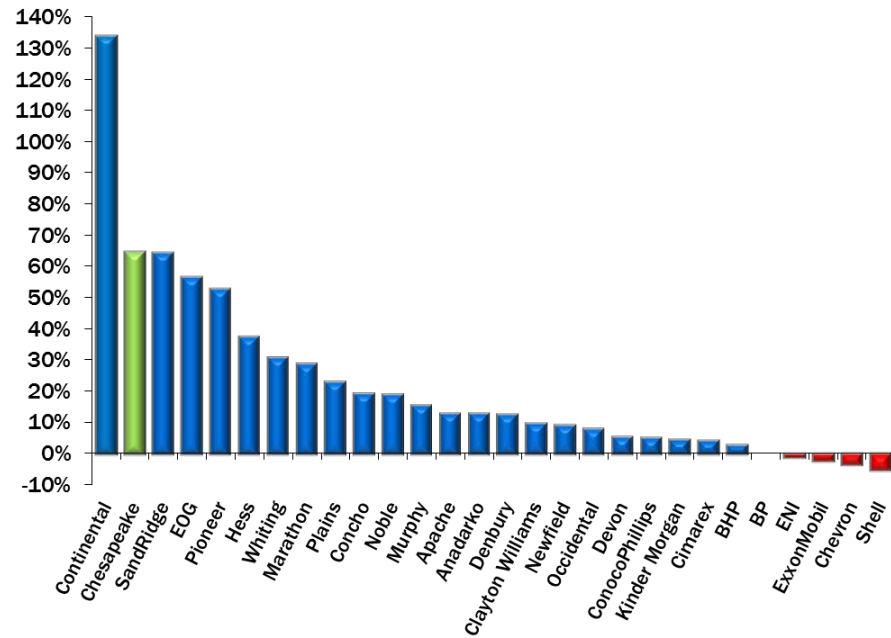
Company	Ticker	2Q'12	1Q'12	2Q'11	2Q'12	2Q'12	2011 Reported	RP	2011 Reported	U.S.	U.S.	U.S. Gas Rigs	
					vs. 1Q'12	vs. 2Q'11	U.S. Net		Proved U.S.				Gas Rigs
						% Change	% Change	Gas Reserves	Ratio ⁽³⁾	Reserves	Drilling on	Drilling on	% Drilling
								(BCFE)		Ranking	07/27/12 ⁽⁴⁾	1/1/10 ⁽⁴⁾	Change Since
													1/1/10
1	ExxonMobil	XOM	3,897	3,932	3,842	(0.9%)	1.4%	26,366	19	1	33	52	(37%)
2	Chesapeake	CHK	3,027	2,978	2,575	1.6%	17.6%	15,515	14	2	12	110	(89%)
3	Anadarko	APC	2,544	2,416	2,326	5.3%	9.4%	8,365	9	7	20	24	(17%)
4	Devon	DVN	2,050	2,071	2,029	(1.0%)	1.1%	9,513	13	5	29	34	(15%)
5	BP	BP	1,833	1,820	1,833	0.7%	0.0%	13,552	20	3	6	12	(50%)
6	EnCana	ECA	1,565	1,779	1,864	(12.0%)	(16.0%)	8,432	15	6	11	40	(73%)
7	ConocoPhillips	COP	1,512	1,561	1,651	(3.1%)	(8.4%)	10,148	18	4	5	10	(50%)
8	Southwestern	SWN	1,508	1,465	1,347	2.9%	11.9%	5,893	11	9	16	16	0%
9	BHP	BHP	1,374	1,378	856	(0.3%)	60.5%	2,730	5	18	22	19	16%
10	Chevron	CVX	1,186	1,170	1,299	1.4%	(8.7%)	3,646	8	12	7	1	600%
11	WPX	WPX	1,142	1,133	1,203	0.8%	(5.1%)	3,983	10	11	9	14	(36%)
12	EOG	EOG	1,070	1,062	1,114	0.8%	(3.9%)	6,046	15	8	9	31	(71%)
13	Shell	RDS	997	1,051	903	(5.1%)	10.4%	3,196	9	14	14	14	0%
14	Apache	APA	844	834	880	1.2%	(4.1%)	2,976	10	15	5	8	(38%)
15	Occidental	OXY	840	834	761	0.7%	10.4%	3,365	11	13	2	1	100%
16	QEP	QEP	703	661	626	6.4%	12.3%	2,749	11	17	10	15	(33%)
17	Ultra	UPL	693	732	627	(5.4%)	10.5%	4,779	19	10	2	11	(82%)
18	EP Energy	EP	688	688	676	0.0%	1.8%	2,566	10	19	2	8	(75%)
19	Cabot	COG	651	620	474	5.0%	37.4%	2,910	12	16	5	12	(58%)
20	Equitable	EQT	619	558	482	11.0%	28.6%	0	0	9	7	19	(63%)
Totals / Average			29,272	29,264	27,856	0.0%	5.1%	138,021			233	464	(50%)
Other Producers											218	340	(36%)
Total											451	804	(44%)

- (1) Based on 2Q'12 company reports
(2) In mcf/day
(3) Based on annualized production
(4) Source: Smith Bits, a Schlumberger Company

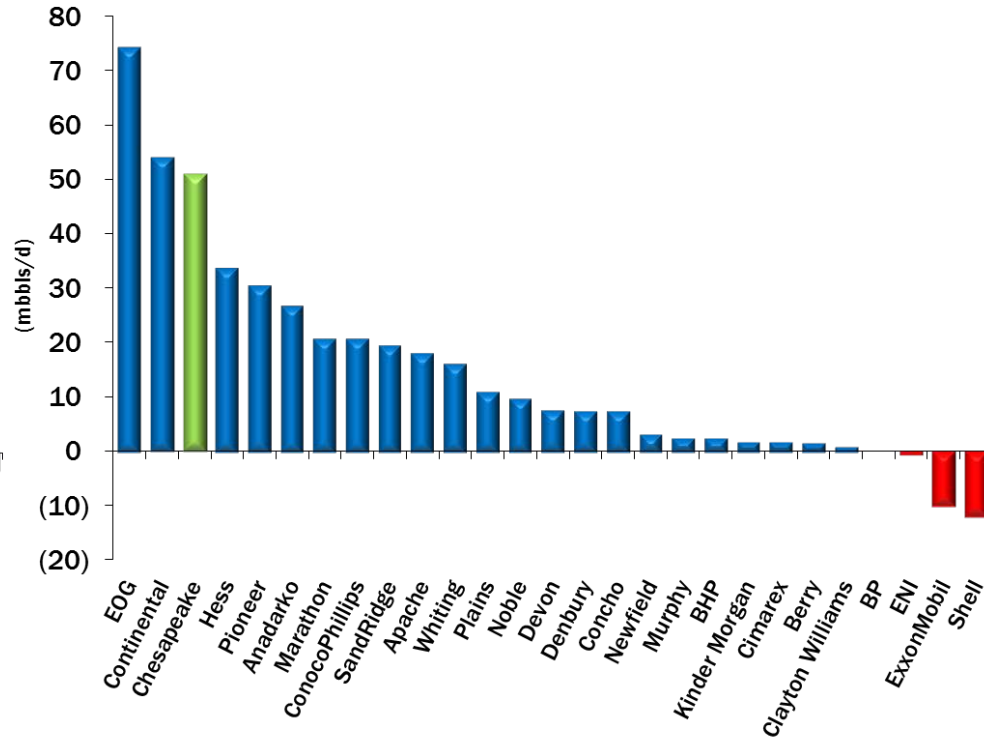
ONE OF THE BEST LIQUIDS GROWTH STORIES IN THE INDUSTRY



U.S. Liquids Growth 2Q'11 – 2Q'12 (%)



U.S. Liquids Growth 2Q'11 – 2Q'12 (mmbbls/d)



Over the past year, CHK's liquids production growth is up 65%, or 51.2 mmbbl/d, all from organic drilling

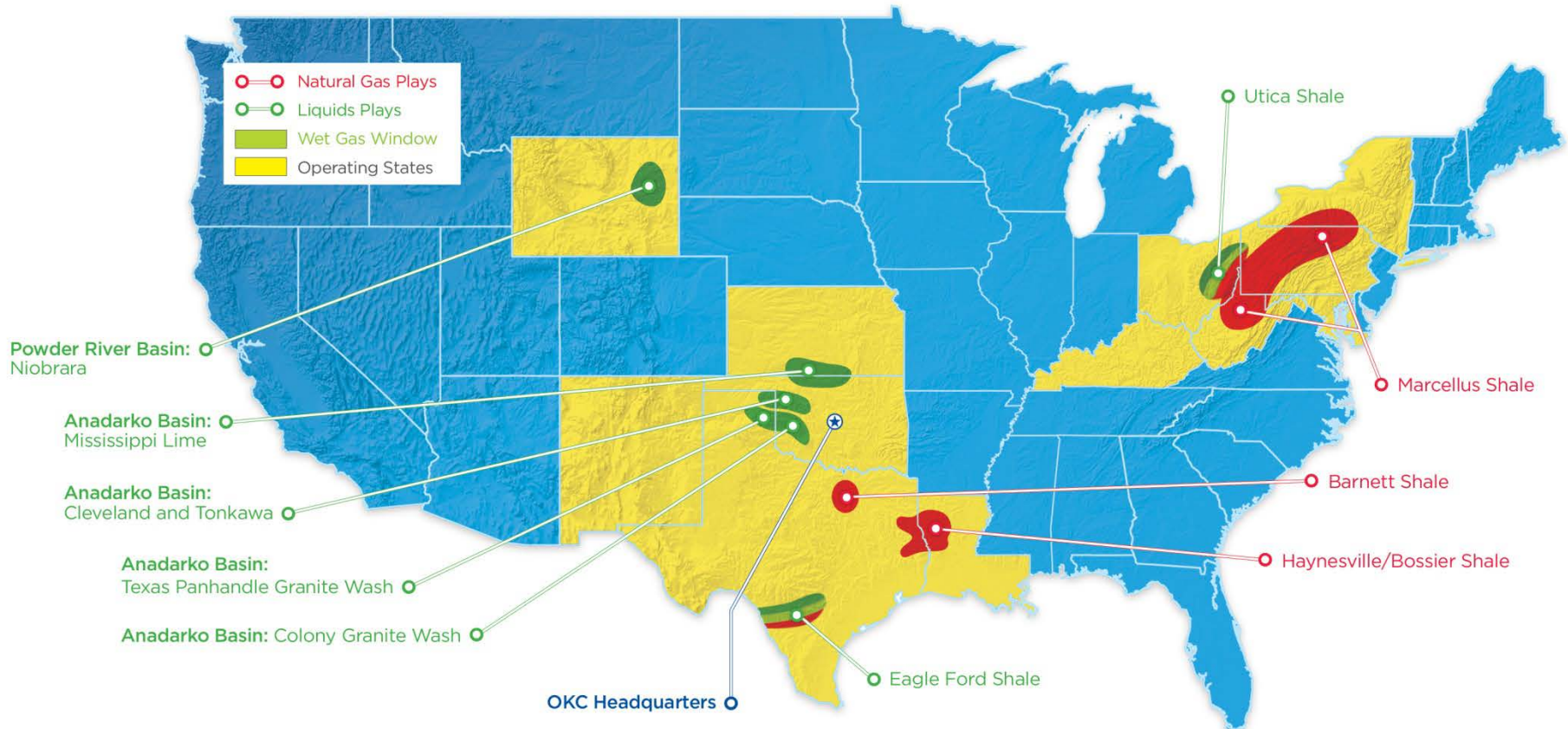


CHK OWNS THE PREMIER COLLECTION OF U.S. E&P ASSETS



CHK'S 10 KEY PLAYS

Low-risk, U.S. onshore asset base; not exposed to economic, geopolitical or technological risks internationally or in the Gulf of Mexico



Once our asset sales are complete we will nearly exclusively focus on 10 leading plays in which we have a #1 or #2 position

THE PREMIER COLLECTION OF E&P ASSETS IN THE U.S.

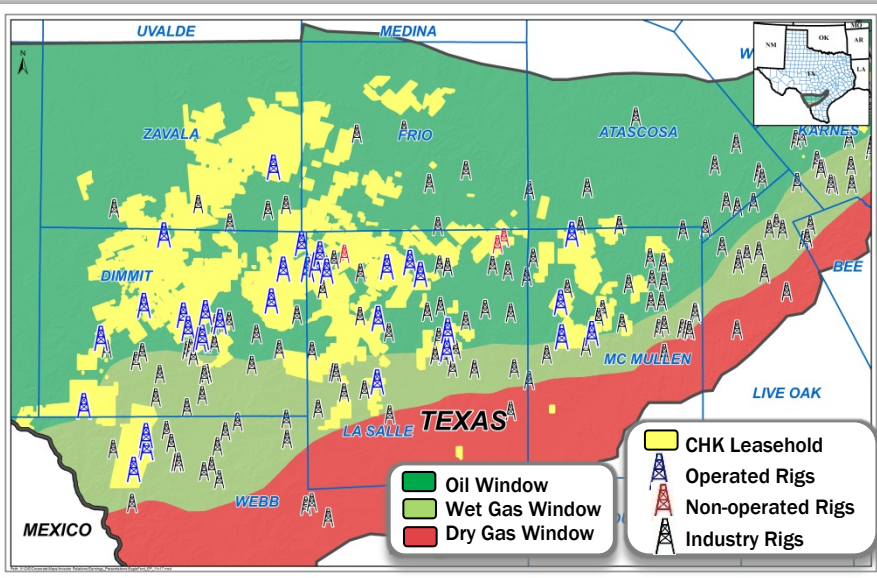


- During past seven years of “Unconventional Resource Revolution” in the U.S., CHK captured America’s largest natural gas and liquids resource base
 - › 17.4 tcf or 2.9 Bboe of proved reserves⁽¹⁾
- Unparalleled inventory of U.S. onshore leasehold and 3D seismic
 - › >15 mm net acres of U.S. onshore leasehold and >30 mm acres of 3D seismic data
- Concentrated focus through owning #1 or #2 position in 10 key plays
- High quality assets
 - › PXP, BP, STO, TOT, CNOOC JVs and BHP Fayetteville sale validate asset quality and value
 - › Exclusive focus onshore U.S. where the highest risk-adjusted returns in the industry are available

(1) Based on the trailing 12-month average first-day-of-the-month prices as of 6/30/12

EAGLE FORD SHALE OVERVIEW

- CHK is the second-largest leasehold owner in the play with ~475,000 net acres
- CHK has allocated ~30% of 2012 and 2013 drilling cap-ex budgets to EFS
- Net production for 2Q'12 averaged ~36,300 boe/d, up 615% YOY and 58% sequentially
- ~66% of total Eagle Ford production during 2Q'12 was oil, 17% NGL and 17% natural gas
- Brought online 121 wells in 2Q '12
 - › 110 of those having peak rates of more than 500 boe/d, including 37 with more than 1,000 boe/d
- Expect price realizations to improve by ~\$5 per bbl in October '12 as new oil gathering pipeline and other infrastructure are completed
- Efficiency gains in drilling cycles and certain reductions in service costs have resulted in cost savings of ~15% per well
- Currently operating 28 rigs in the play, plan to exit 2012 with 25 operated rigs and average 22 rigs in 2013

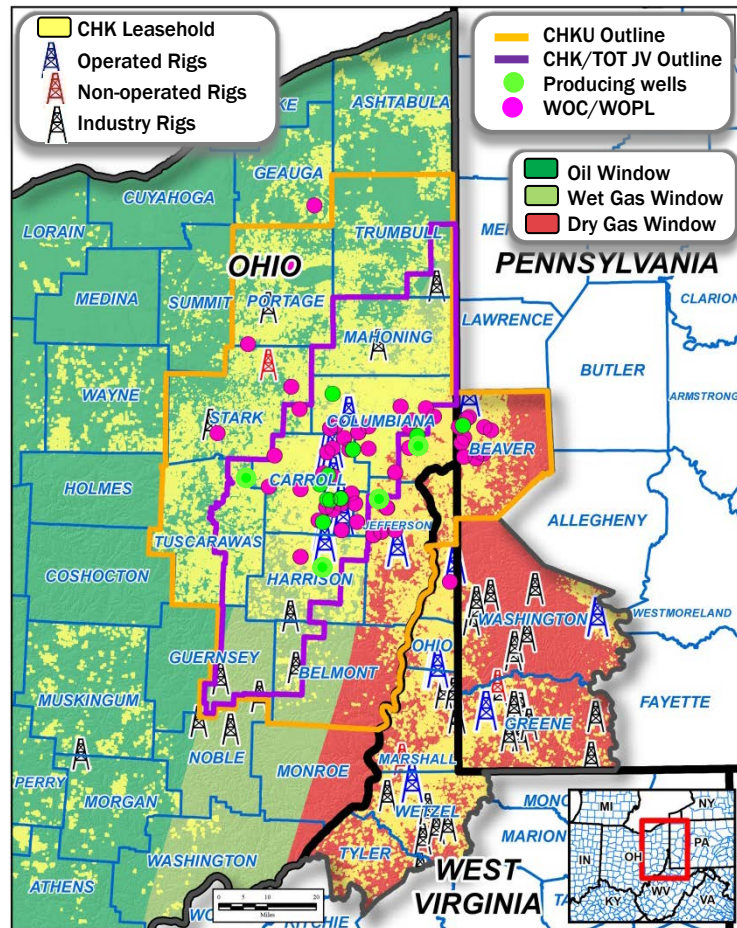


2Q '12 Eagle Ford Shale Completion Highlights⁽¹⁾:

Well Name	County	Oil (bbls)	NGLs (bbls)	Gas (mmcf)	BOE/D
Gates 010-CHK-B TR1-D6H	Webb	710	665	4.2	2,070
Holubar Dim C 2H	Dimmit	1,730	110	0.4	1,900
Foley MCM A 1H	McMullen	1,335	55	0.6	1,500

(1) Peak rate

UTICA SHALE OVERVIEW



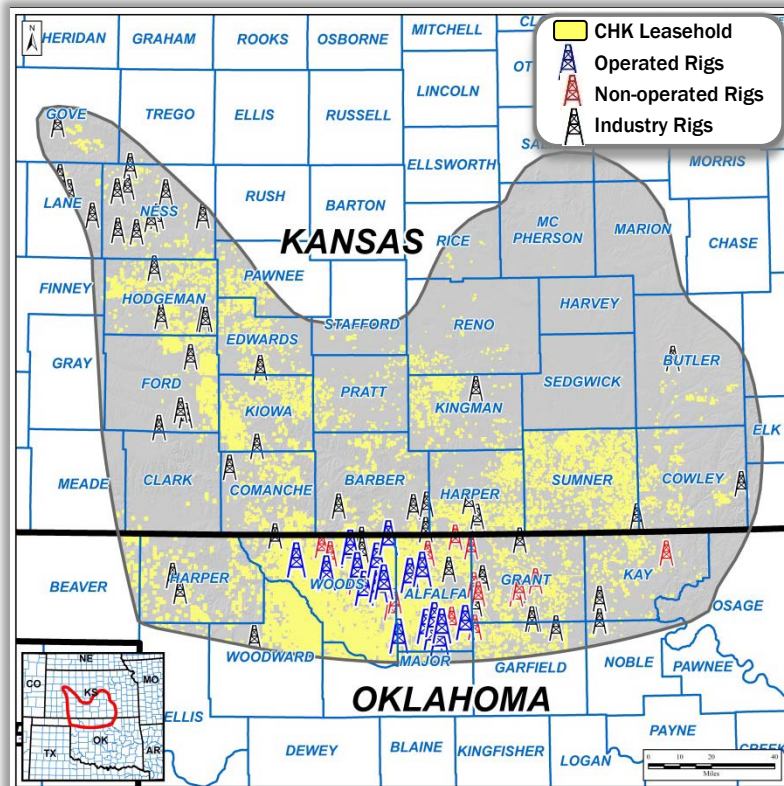
- **CHK is largest leasehold owner in the play with more than 1.0 mm net acres**
- **CHK has drilled a total of 87 wells in the play, of which 28 wells with production information in the focus area have average peak rates of ~1,000 boe/d**
 - On a post-processing basis, peak rates averaged ~205 bbls/d of oil, 150 bbls/d of NGL and 3.8 mmcf/d of natural gas, or ~1,000 boe/d
 - As of 6/30/12, there were 28 additional CHK wells waiting on pipeline connection or in various stages of completion
- **Currently operating 11 rigs in the play, plan to exit 2012 with 16 operated rigs**
- **Remaining drilling carry from Total was ~\$1.35 billion at 6/30/12; anticipate using 100% of the drilling carry by year-end 2014**
 - Carry will pay for 60% of CHK's drilling costs during that time

20'12 Utica Shale Completion Highlights⁽¹⁾:

Well Name	County	Oil (bbls)	NGLs (bbls)	Gas (mmcf)	BOE/D
Brown 10H	Jefferson	0	0	8.7	1,445
Bailey 35-12-4 3H	Carroll	205	270	5.7	1,420
Snoddy 11-13-5 6H	Carroll	320	250	4.2	1,260

(1) Peak rate

MISSISSIPPI LIME OVERVIEW



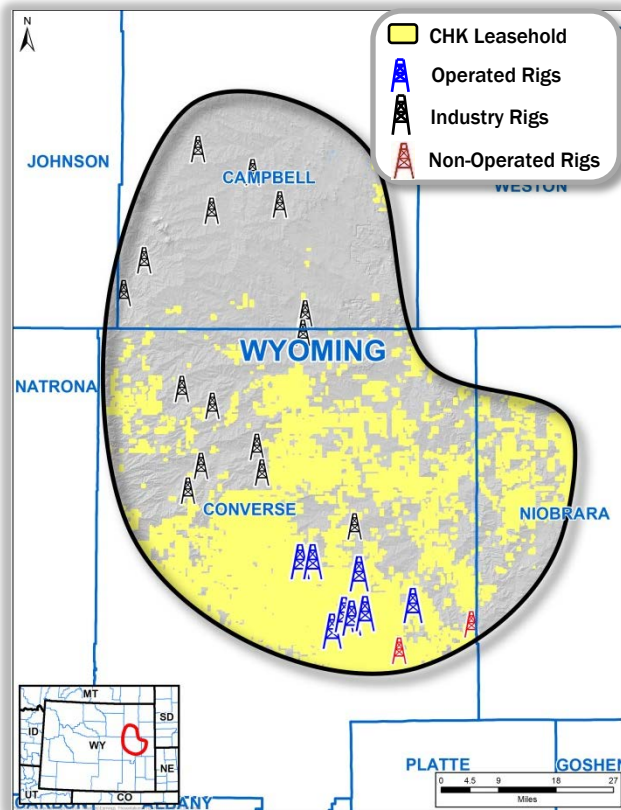
- CHK is largest leasehold owner in the play with ~2.0 mm net acres
- Production for 2Q'12 averaged ~20,000 boe/d, up 198% YOY and 56% sequentially
- ~39% of total Mississippi Lime production during 2Q '12 was oil, 12% NGL and 49% natural gas
- CHK has drilled 158 horizontal producing wells since 2009 with results that have been attractive and consistent
- Well costs in the Mississippi Lime are >50% less than in Bakken play, resulting in very strong rates of return
- Continue to pursue a JV and/or sale of a portion of its Mississippi Lime leasehold and expect to announce a transaction in the next few months
- Currently operating 18 rigs in the play

2Q '12 Mississippi Lime Completion Highlights⁽¹⁾:

Well Name	County	Oil (bbls)	NGLs (bbls)	Gas (mmcf)	BOE/D
Smith 27-28-9 1H	Alfalfa	1,655	70	2.8	2,190
Loy Puffingarger 29-28-9 1H	Alfalfa	1,100	80	2.7	1,630
MWK 16-27-12 1H	Alfalfa	800	90	2.4	1,290

(1) Peak rate

POWDER RIVER BASIN NIOBRARA OVERVIEW



- **CHK was the early mover and has amassed the largest leasehold position in the Southern Powder River Basin Niobrara Shale Play with ~350,000 net acres**
- **Results steadily improving with focus on a newly identified core area that has much higher pressures and hydrocarbons in place than in other portions of the play**
 - › 44 locations drilled to date in entire play; 18 wells in the identified core area of the play and ~1,000 wells left to drill in this focus area in the years to come
- **Currently operating 8 rigs in the play, plan to exit 2012 with 11 operated rigs**
- **Remaining drilling carry from CNOOC was ~\$520 mm at 6/30/12; anticipate using 100% of the drilling carry by year-end 2014**
 - › Carry will pay for 67% of CHK's drilling costs during that time

2Q '12 PRB Completion Highlights⁽¹⁾:

Well Name	County	Oil (bbls)	NGLs (bbls)	Gas (mmcf)	BOE/D
Combs Ranch 1-H	Converse	1,120	575	4.6	2,460
York Ranch Unit 33-69 19-1H	Converse	1,020	370	3.4	1,950
Northwest Fetter Unit 33-71 7-1H	Converse	1,150	125	1.1	1,460

(1) Peak rate



FINANCIAL SUMMARY



2012 AND 2013 OUTLOOK SUMMARY



	2011	YE 2012E	YE 2013E
Production			
Natural gas (bcf)	1,004	1,120 - 1,140	1,030 - 1,070
Oil (mbbls)	16,964	29,000 - 30,000	36,000 - 38,000
NGL (mbbls)	14,712	17,000 - 18,000	24,000 - 26,000
Natural gas equivalent (bcfe)	1,194	1,396 - 1,428	1,390 - 1,454
Daily natural gas equivalent midpoint (mmcf)	3,272	3,855	3,895
YOY production increases	15%	18%	1%
YOY production increase from oil	55%	74%	25%
YOY production increase from NGL	97%	19%	43%
% Production from liquids	16%	20%	25%
% Realized revenues from liquids ⁽¹⁾	30%	57%	55%
% Production increase (decrease) from gas	9%	13%	(7%)
Operating costs per mcf			
Production expense, production taxes and G&A ⁽²⁾	\$1.44	\$1.49 - \$1.69	\$1.59 - \$1.79

(1) Assumes NYMEX prices of \$3.00-\$3.25 and \$3.25-\$4.25/mcf in 2012 and 2013, respectively; oil prices of \$90/bbl in 2012 and 2013

(2) Excluding stock based compensation

2012 FINANCIAL PROJECTIONS AT VARIOUS NATURAL GAS PRICES



As of 08/06/12 Outlook

(\$ in mm; oil at ~\$90 NYMEX)

	\$2.00	\$3.00	\$4.00
O/G revenue (unhedged) @ 1,412 bcfe ⁽¹⁾	\$4,580	\$4,950	\$5,330
Hedging effect ⁽²⁾	660	390	80
Marketing and other	290	290	290
Production taxes 5%	(230)	(250)	(270)
LOE (@ \$1.00/mcfe)	(1,410)	(1,410)	(1,410)
G&A (@ \$0.47/mcfe) ⁽³⁾	(660)	(660)	(660)
Ebitda	3,230	3,310	3,360
Interest expense incl. capitalized interest (@ \$0.08/mcfe)	(110)	(110)	(110)
Operating cash flow⁽⁴⁾	3,120	3,200	3,250
Oil and gas depreciation (@ \$1.50/mcfe)	(2,120)	(2,120)	(2,120)
Depreciation of other assets (@ \$0.25/mcfe)	(350)	(350)	(350)
Income taxes (39% rate)	(250)	(280)	(300)
Net income attributable to noncontrolling interest	(190)	(190)	(190)
Net income	\$210	\$260	\$290
Net income to common per fully diluted shares	\$0.28	\$0.34	\$0.38
MEV/operating cash flow⁽⁵⁾	4.4x	4.3x	4.3x
EV/ebitda⁽⁶⁾	10.3x	10.1x	9.9x
PE ratio⁽⁷⁾	64.3x	52.9x	47.4x

(1) Before effects of unrealized hedging gain or loss

(2) Includes the non-cash effect of lifted hedges and financing derivatives

(3) Includes expenses related to stock based compensation

(4) Before changes in assets and liabilities

(5) MEV (Market Equity Value) = \$13.8 billion (\$18.00/share x 769 mm fully diluted shares as of 6/30/12)

(6) EV (Enterprise Value) = \$33.3 billion (MEV plus \$13.9 billion in net long-term debt, \$2.4 billion in NCLs and \$3.2 billion working capital deficit and other LT liabilities as of 6/30/12)

(7) Assuming a common stock price of \$18.00/share

2013 FINANCIAL PROJECTIONS AT VARIOUS NATURAL GAS PRICES



As of 08/06/12 Outlook

(\$ in mm; oil at \$90 NYMEX)

	\$3.00	\$4.00	\$5.00
O/G revenue (unhedged) @ 1,422 bcfe ⁽¹⁾	\$5,640	\$6,690	\$7,740
Hedging effect ⁽²⁾	30	30	30
Marketing and other	290	290	290
Production taxes 5%	(280)	(330)	(390)
LOE (@ \$1.00/mcfe)	(1,420)	(1,420)	(1,420)
G&A (@ \$0.47/mcfe) ⁽³⁾	(660)	(660)	(660)
Ebitda	\$3,600	\$4,600	\$5,590
Interest expense incl. capitalized interest (@ \$0.08/mcfe)	(110)	(110)	(110)
Operating cash flow⁽⁴⁾	\$3,490	\$4,490	\$5,480
Oil and gas depreciation (@ \$1.60/mcfe)	(2,280)	(2,280)	(2,280)
Depreciation of other assets (@ \$0.28/mcfe)	(400)	(400)	(400)
Income taxes (39% rate)	(320)	(710)	(1,090)
Net income attributable to noncontrolling interest	(220)	(220)	(220)
Net income	\$270	\$880	\$1,490
Net income to common per fully diluted shares	\$0.36	\$1.16	\$1.96
MEV/operating cash flow⁽⁵⁾	4.0x	3.1x	2.5x
EV/ebitda⁽⁶⁾	9.3x	7.2x	6.0x
PE ratio⁽⁷⁾	50.0x	15.5x	9.2x

(1) Before effects of unrealized hedging gain or loss

(2) Includes the non-cash effect of lifted hedges and financing derivatives

(3) Includes expenses related to stock based compensation

(4) Before changes in assets and liabilities

(5) MEV (Market Equity Value) = \$13.8 billion (\$18.00/share x 769 mm fully diluted shares as of 6/30/12)

(6) EV (Enterprise Value) = \$33.3 billion (MEV plus \$13.9 billion in net long-term debt, \$2.4 billion in NCLs and \$3.2 billion working capital deficit and other LT liabilities as of 6/30/12)

(7) Assuming a common stock price of \$18.00/share



CASH IN AND OUT SUMMARY

	YE 2012E	YE 2013E
Operating cash flow (\$mm)⁽¹⁾⁽²⁾	\$3,200 - \$3,250	\$3,750 - \$4,750
Well costs on proved and unproved properties	(\$8,000 - \$8,500)	(\$5,750 - \$6,250)
Acquisition of unproved properties, net	(\$2,000)	(\$400)
Investment in oilfield services, midstream and other	(\$2,800 - \$3,100)	(\$850 - \$1,100)
Subtotal of net investment	(\$12,800) - (\$13,600)	(\$7,000) - (\$7,750)
Asset sales and other transactions	\$13,000 - \$14,000	\$4,250 - \$5,000
Interest, dividends and cash taxes	(\$1,100 - \$1,350)	(\$1,000 - \$1,250)
Total budgeted cash flow surplus	\$2,300	\$0 - \$750

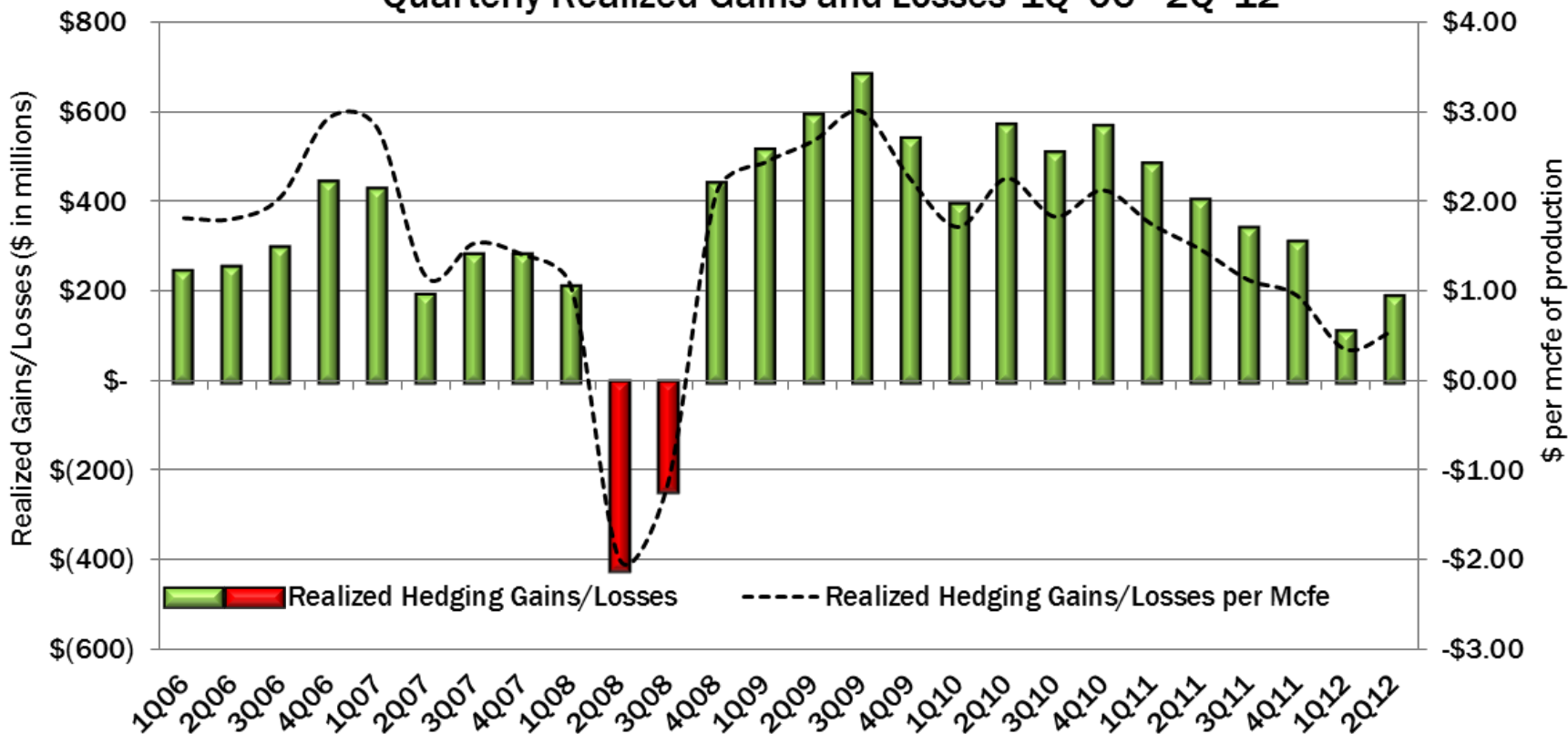
(1) A non-GAAP financial measure defined as cash flow provided by operating activities before changes in assets and liabilities. We are unable to provide a reconciliation to projected cash provided by operating activities, the most comparable GAAP measure, because of uncertainties associated with projecting future changes in assets and liabilities

(2) Assumes NYMEX prices of \$3.00-\$3.25 and \$3.25-\$4.25/mcf in 2012 and 2013, respectively; oil prices of \$90/bbl in 2012 and 2013

CHK HEDGING PROGRAM- BEST IN INDUSTRY



Quarterly Realized Gains and Losses 1Q '06 - 2Q '12



We don't hedge just to say we're hedged, we hedge to make money. Have successfully done so 24 of the past 26 quarters as realized cash hedging gains since January 1, 2006 have been \$8.7 billion, or \$1.46 per mcf

HEDGING POSITION⁽¹⁾



Natural Gas

	% of Forecasted Production	\$ NYMEX Natural Gas
3Q - 4Q 2012	64%	\$3.03
2013	—	—

Liquids

	% of Forecasted Production	\$ NYMEX Oil WTI
3Q - 4Q 2012	31%	\$101.34
2013	5%	\$94.06

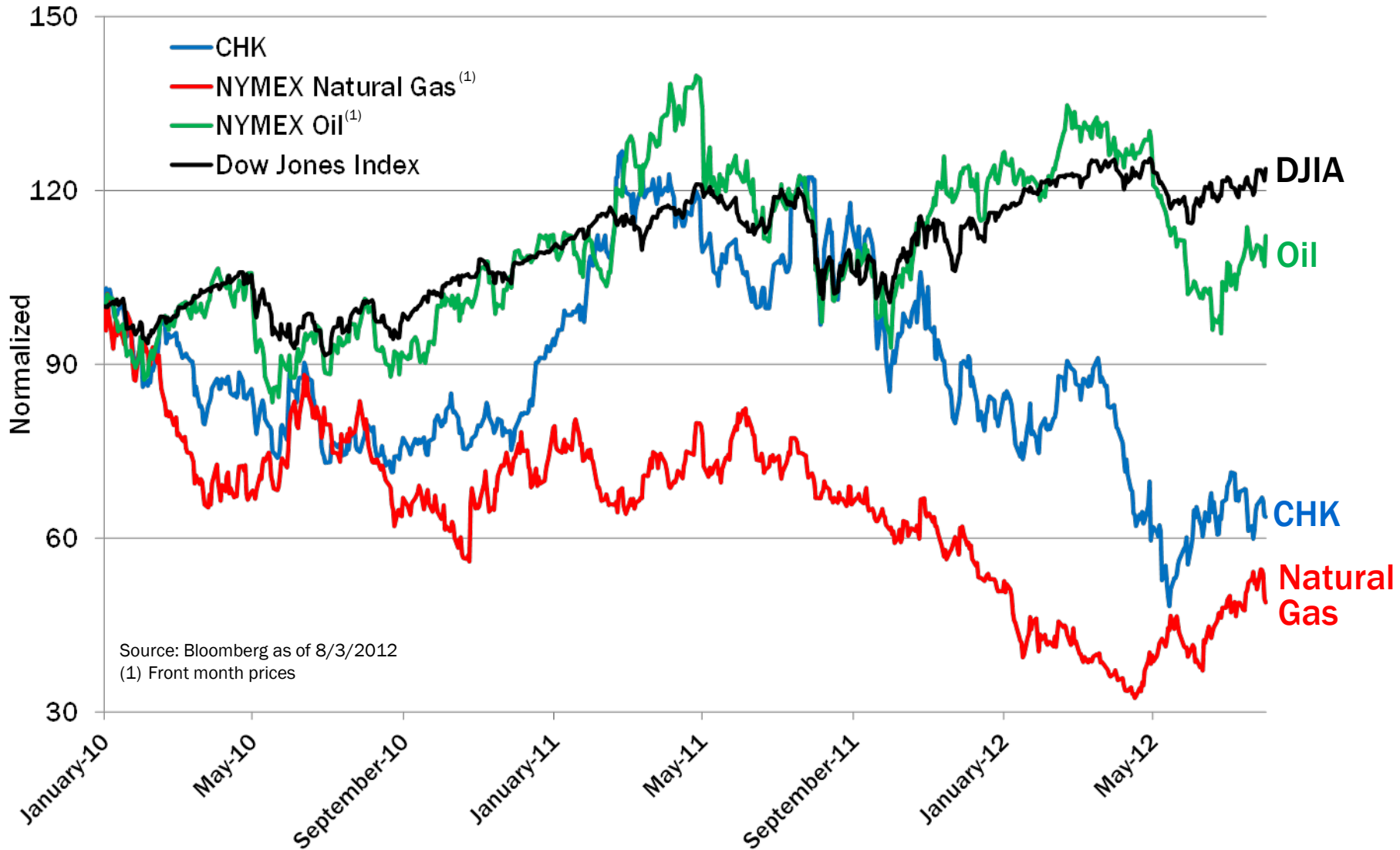
(1) Swap positions based on Outlook as of 8/6/2012



SUMMARY



CHK HISTORICALLY LINKED TO NATURAL GAS, NOW PORTFOLIO MORE OIL AND NGL FOCUSED



VALUE OPPORTUNITY FOR TODAY'S INVESTORS



(\$ in millions except share price)

	\$15.00	\$20.00	\$25.00
Price per share	\$15.00	\$20.00	\$25.00
Fully diluted common shares @ 3/31/12⁽¹⁾	769	769	769
Market capitalization	\$11,500	\$15,400	\$19,200
Plus: Long-term debt (net of cash)	\$13,900	\$13,900	\$13,900
Plus: net working capital and other long-term liabilities	\$3,200	\$3,200	\$3,200
Noncontrolling interests	\$2,400	\$2,400	\$2,400
Enterprise value	\$31,000	\$34,900	\$38,700
PV-10 of proved reserves @ 6/30/12⁽²⁾	(\$25,100)	(\$25,100)	(\$25,100)
PV-10 of future JV drilling carries on unproved resources	(\$1,500)	(\$1,500)	(\$1,500)
Book value of Midstream, Oilfield service and other assets	(\$6,900)	(\$6,900)	(\$6,900)
Derivative liabilities @ 6/30/12	\$1,000	\$1,000	\$1,000
Implied value of risked unproved leasehold	(\$1,500)	\$2,400	\$6,200

(1) Assumes 100% conversion of preferred stock outstanding

(2) Based on 10-year average NYMEX prices at 6/30/2012

At today's stock price, investors receive implied value of CHK's unproved leasehold for free

WHY INVEST IN CHK?

- **High quality assets**
 - › CHK has captured America's largest natural gas and liquids resource base
 - › ~17.4 tcf or ~2.9 bboe of proved reserves and >15 mm net acres of U.S. onshore leasehold
- **Strong operational performance**
 - › Achieved 25% YOY production growth in 2Q '12, despite curtailments and asset sales
 - › Added ~4.2 tcf, or ~690 mmboe, of proved reserves YTD at a drilling and completion cost of \$1.14 per mcf, or \$6.84 per bbl
 - › PV10 value of added proved reserves was \$10.2 billion, or ~\$7 per share of NAV
- **Greater focus**
 - › Exclusively focused on 10 key plays with a #1 or #2 ownership position
 - › Shifting from asset identification and capture to more manufacturing-like operations designed for optimal efficiency and maximizing returns as CHK shifts into harvest mode
- **Greater balance of natural gas and liquids production**
 - › Improving margins and returns from shifting drilling and completion cap-ex to ~90% liquids
 - › ~25% of production and >50% of revenues to come from liquids in 2013
 - › Likely to become a top 5 U.S. liquids producer and remain a top 2 natural gas producer by 2015
- **Reducing financial leverage and complexity**
 - › Anticipated 2012 asset sales enable CHK to reduce long-term debt to \$9.5 billion by YE '12
 - › Substantial reductions in 2013 drilling, completion and leasehold cap-ex will simplify strategy execution
- **Value opportunity for investors – trade at a substantial discount to NAV and equity book value**
- **Likely tailwinds from recovering U.S. natural gas market after four years of headwinds**

CHK management is focused on creating NAV and ebitda, reducing debt, selling non-core assets, keeping its share count flat, maintaining its low cost structure and delivering best in class future stock price performance to its investors

CORPORATE INFORMATION

Chesapeake Headquarters

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Oklahoma City, OK 73118
Web site: www.chk.com

CHK
LISTED
NYSE

FORTUNE
100
BEST
COMPANIES
TO WORK FOR
2012
5TH YEAR IN A ROW!

Other Publicly Traded Securities

	<u>CUSIP</u>	<u>Ticker</u>
7.625% Senior Notes due 2013	#165167BY2	CHKJ13
9.5% Senior Notes due 2015	#165167CD7	CHK15K
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
6.775% Senior Notes due 2019	N/A	N/A
6.625% Senior Notes due 2020	#165167CF2	CHK20A
6.875% Senior Notes due 2020	#165167BU0	CHK20
6.125% Senior Notes Due 2021	#165167CG0	CHK21
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

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FACEBOOK.COM/CHESAPEAKE



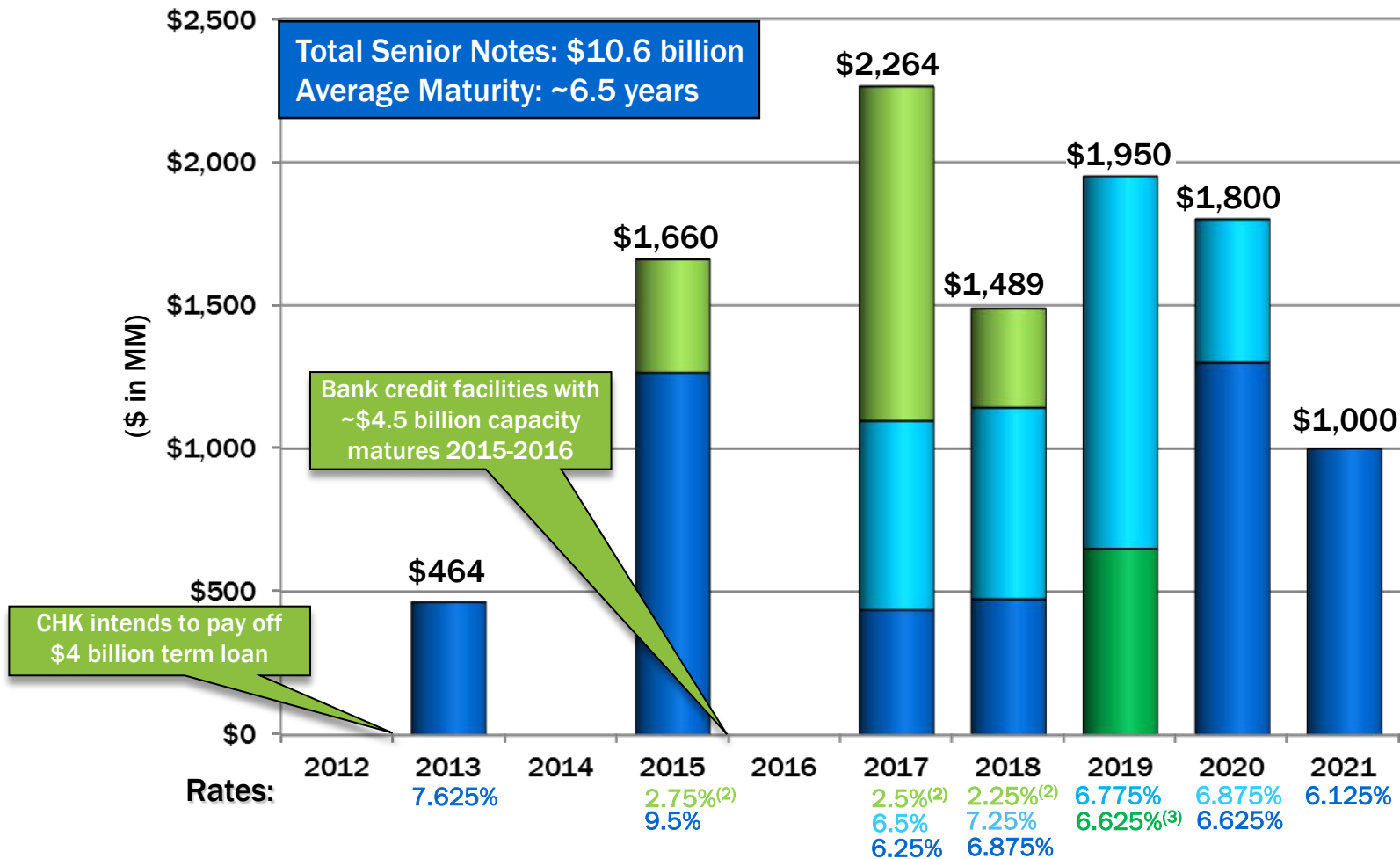
YOUTUBE.COM/CHESAPEAKEENERGY



APPENDIX



SENIOR NOTE MATURITY SCHEDULE⁽¹⁾



(1) As of 6/30/12

(2) Recognizes earliest investor put option as maturity for the 2.75% 2035, 2.5% 2037 and 2.25% 2038 Convertible Senior Notes

(3) COO debt issuance of \$650 mm Senior Notes due 2019

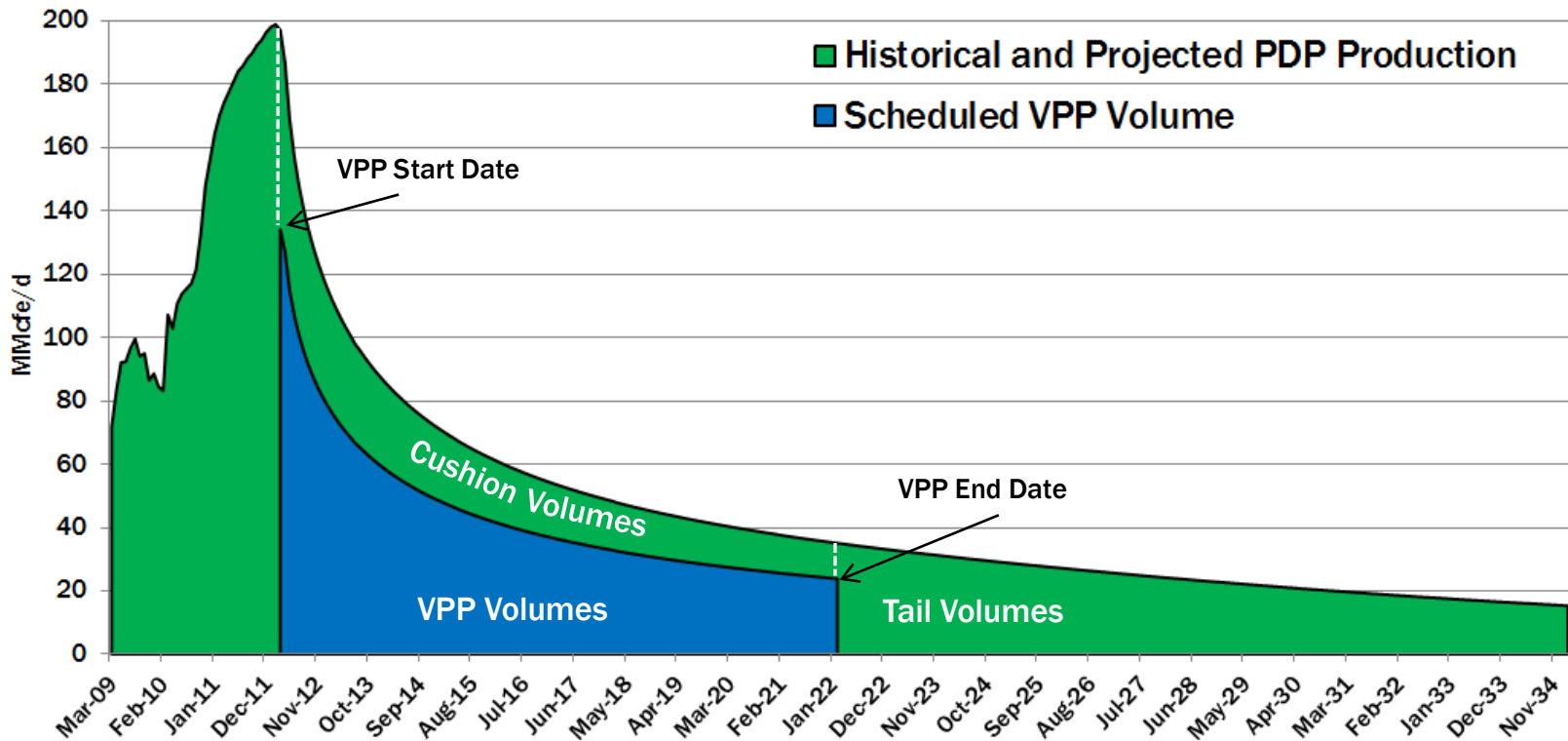
VOLUMETRIC PRODUCTION PAYMENTS (VPP): OVERVIEW



- A VPP is the sale of an overriding royalty interest in oil and natural gas reserves, carved out of seller's working interest in specified leases, that entitles the buyer to receive scheduled production volumes over a fixed term from producing well bores on such leases
- Overriding royalty interests are common and well understood in the E&P industry, and have been in use for more than 50 years
- VPPs allow the seller to sell a portion of the future production stream from highly predictable proved developed producing well bores. Cash received can then be re-deployed to areas with higher potential ROR's, to pay down debt or for other projects of greater strategic importance
- VPP buyers are generally commercial/investment banks or specialized investment funds seeking a predictable cash flow stream and attractive investment yield at relatively low risk
- Seller retains the obligation to operate the wells
- Seller almost always preserves drilling rights for geologic zones above and below the producing zone and the production "tail"

VPPs are designed to achieve important economic benefits and are accounted for as sales under GAAP

SAMPLE VPP PRODUCTION PROFILE



- In above example, 160 Bcfe of total reserves are conveyed to VPP buyer over term of agreement, representing ~35% of estimated ultimate recoverable reserves from wells in VPP
- During term of VPP, seller retains a minority interest in the assigned wells (the “cushion volumes”) which provides cash flow to cover operating costs and production taxes for the VPP, as well as to cover potential shortfalls in production if a defined group of producing wells do not perform as expected
- Upon completion of the VPP, seller reverts back to its original net revenue interest in the wells and receives “tail” production and reserves
- Unlike an outright sale, VPP’s allow us to defer recognition of the tax gain we would otherwise recognize immediately from a sale, as well as retain our basis in the properties

VPPs: BENEFITS TO SELLER/BUYER

Seller

- Accelerates cash flow from producing assets at attractive discount rate (low cost of capital)
- Transfers production risk to buyer – recourse is only to specified lease or well bore and only for specified volumes
- Retains ownership and control of leases and receives post VPP expiration production “tail”
- Typically retains rights to all geologic horizons above and below designated production zone
- Tax efficient – treated as a mortgage loan with proceeds effectively recognized in taxable income over VPP term vs. upfront as with an outright sale
- No financial covenants; buyer can’t accelerate “repayment”

Buyer

- Entitled to volumes (revenue) associated with generally low-risk future production stream (PDPs)
- “First priority” on production from specified lease or well bore
- Commodity prices associated with contract volumes can be hedged upfront to generate predictable ROR
- No responsibility for future operating costs, production taxes or cap-ex
- Bears no seller credit risk; in event of VPP seller’s insolvency, the bankruptcy code recognizes the VPP as separate from the seller’s estate
- Typically seen as an investment grade risk with higher return than an investment grade bond

VPPs: RISKS AND RESPONSIBILITIES



Seller

- Meet prudent operator standard⁽¹⁾
- Obligated to pay all future operating costs, production taxes and cap-ex for the VPP wells
- Comply with specific schedule of reserves and production reporting requirements to buyer
- Typically responsible for hedging VPP volumes prior to close – hedges novated to buyer upon close

Buyer

- Assumes traditional E&P reserve and production risk
- No recourse to seller's assets/cash outside the VPP
- Commodity price risk (to the extent volumes not initially hedged)

(1) Similar to typical industry-standard JOA language

REVIEW OF CHK'S VPPs

- In last 5 years, CHK has completed 10 VPPs raising \$6.4 billion at an average implied price of \$4.64/mcfe
- CHK has never had a production shortfall on any of its 10 VPPs

(\$ in mm, reserves in bcfe)

CHK's VPP Summary	VPP1	VPP2	VPP3	VPP4	VPP5	VPP6	VPP7	VPP8	VPP9	VPP10	Total
Location	KY, WV	KS, OK, TX	OK	AR, OK	TX	LA, TX	NM, TX	TX	OK	OK, TX	Various
Effective Date	Dec. 2007	May 2008	Aug. 2008	Dec. 2008	Aug. 2009	Feb. 2010	Jun. 2010	Sep. 2010	May 2011	Mar. 2012	Various
Original Term (years)	15	11	11	8	7.5	10	10	5	10	10	5 - 15
Gross Proceeds	\$ 1,100	\$ 622	\$ 600	\$ 412	\$ 370	\$ 180	\$ 335	\$ 1,150	\$ 853	\$ 744	\$ 6,366
Netback Price (\$/mcfe) ⁽¹⁾	\$ 5.29	\$ 6.53	\$ 6.38	\$ 4.19	\$ 5.46	\$ 3.95	\$ 8.73	\$ 2.93	\$ 4.82	\$ 4.68	\$ 4.64
Quantity Sold (Bcfe)	208	94	93	98	68	46	38	390	177	160	1,372
Remaining Volumes to be Delivered ⁽²⁾	130	38	45	44	31	31	27	216	149	151	862
Term PDP Coverage Ratio ⁽³⁾	1.56	2.21	1.70	1.82	1.46	1.23	2.00	1.59	1.37	1.47	1.57
Remainder PDP Reserves ⁽⁴⁾⁽⁵⁾	438	167	131	217	82	52	95	1,544	299	227	3,251
Remainder All Proved Reserves ⁽⁴⁾⁽⁶⁾⁽⁷⁾	471	175	159	258	186	71	118	1,646	431	227	3,742

(1) Gross Proceeds / Quantity Sold

(2) As of 6/30/2012

(3) Ratio of total expected production to remaining production to be delivered

(4) Based on 6/30/2012 reserves at 6/29/2012 strip pricing

(5) Total PDP production less remaining VPP required production of 6/30/2012, inclusive of remainder (PDP reserves)

(6) All proved reserves include: PDP, PBP, PNP, SI, PUD

(7) Total proved reserves less remaining VPP required production as of 6/30/2012, inclusive of remainder (all proved reserves)

VPP ACCOUNTING CONSIDERATIONS

- VPP volumes are removed from CHK's PV10 and standardized measure calculations as well as CHK's future production guidance
- Future operating costs and cap-ex (if any) associated with VPP volumes are included in CHK's PV10 and standardized measure calculations as well as CHK's future cost guidance
- CHK accounts for VPPs as asset sales in accordance with GAAP
 - › Cash proceeds reflected as reduction of oil and gas properties (debit: cash; credit: oil & gas properties)
 - › No gain or loss on sale is recognized; no deferred revenue liabilities
- **Income statement effects of VPPs**
 - › No oil and gas revenue is booked for the VPP volumes when produced
 - › Majority of expenses associated with sold VPP volumes flow through production expense/production tax lines, exactly the same as production expense/production tax treatment for all royalty volumes
 - › ~\$0.17/mcfe of CHK's \$0.97 /mcfe production expenses as reported for 2Q '12 were related to volumes delivered to buyers under VPPs
- **Cash flow statement effects of VPPs**
 - › Initial proceeds booked to "Investing Cash Flow"
 - › Ongoing production expenses and severance taxes flow through "Operating Cash Flow"
 - › "Financing Cash Flow" unaffected

CHK adheres to GAAP accounting requirements regarding VPPs and includes retained cost obligations in its guidance projections and in its reserve report and PV10 estimates



MIDSTREAM COMMITMENTS OVERVIEW

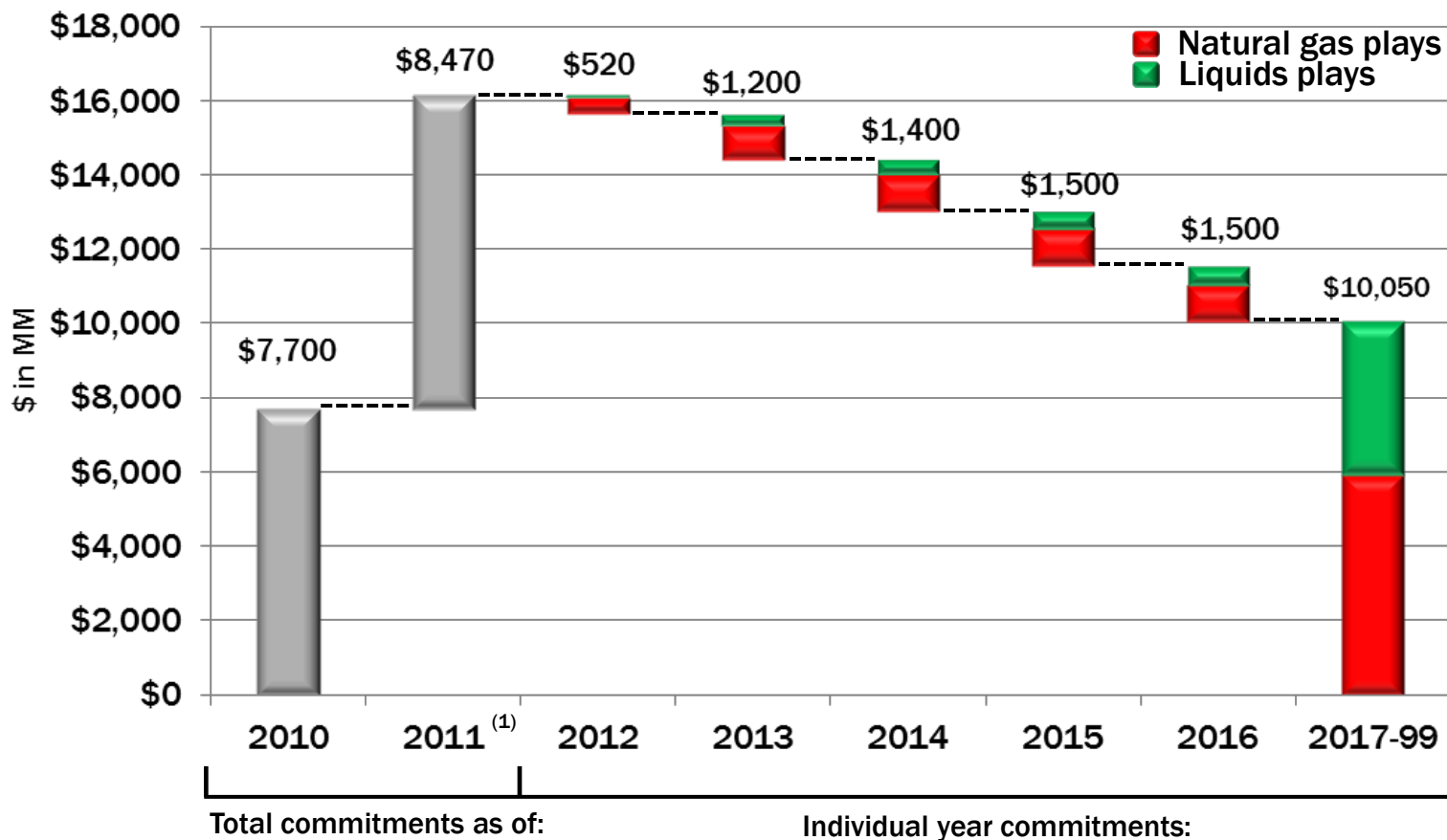


MIDSTREAM COMMITMENTS

- **CHK has entered into various midstream transportation commitments commensurate with its estimated future production levels and drilling plans**
- **Total gross midstream commitments as of 2Q '12: \$16.2 billion, of which \$9.0 billion is attributable to CHK net production, \$2.4 billion for royalty interest owners and \$4.8 billion attributable to partner/other working interest owners⁽¹⁾**
 - › Gross gathering and processing commitments total \$10.0 billion and \$6.1 billion in interstate transportation
 - No change to commitments due to sale of CHKM units or planned sale of CMD
- **CHK is America's premier discoverer and developer of new onshore plays**
 - › Newly discovered basins typically lack basic gathering and processing infrastructure
 - › Anchor developers like CHK provide minimum commitments to ensure new construction of infrastructure to reach marketing hubs
 - › Speed and pace of midstream accessibility accelerates overall play PV for operators and partners
 - › Firm transport provides deliverability and price security
 - › Anchor shippers given most attractive rates (often most favored nation status)
- **CHK is the largest gross producer of natural gas in the U.S. (~10% of onshore volumes)**
 - › Transportation arrangements for production volumes contracted in excess of net production in order to satisfy royalty and sizable working interest owner volumes, which ensures orderly delivery of production
 - › Without firm transport arrangements, a producer can often pay higher transportation costs by being an interruptible shipper or possibly not having ability to ship product (i.e. shut-ins)
 - › In the event of over commitment, the contracted fixed costs are allocated to actual volumes delivered, resulting in wider differentials/lower netbacks

(1) Stated commitments range from 2012 - 2099

TOTAL GROSS MIDSTREAM COMMITMENTS



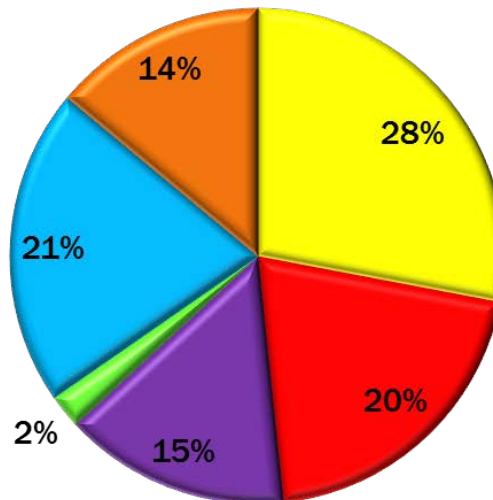
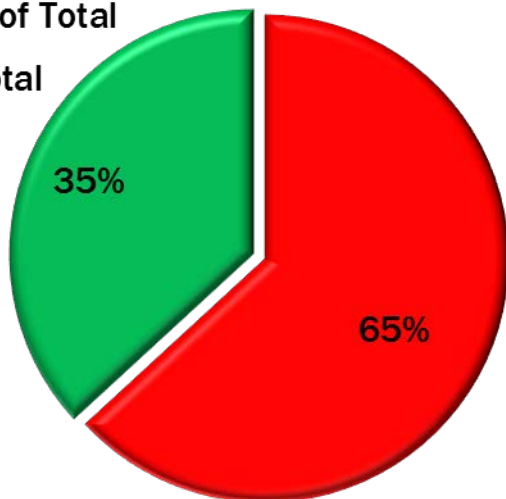
(1) Pro forma for 6/30/2012

2011-12 Commitments primarily associated with liquids growth and related transportation requirements

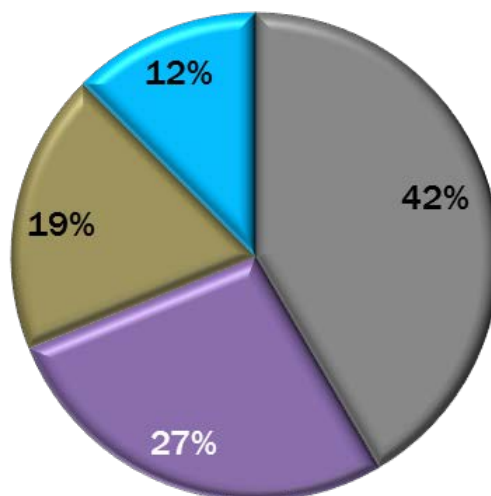
TOTAL GROSS MIDSTREAM COMMITMENTS BREAKDOWN



- Natural Gas of Total
- Liquids of Total

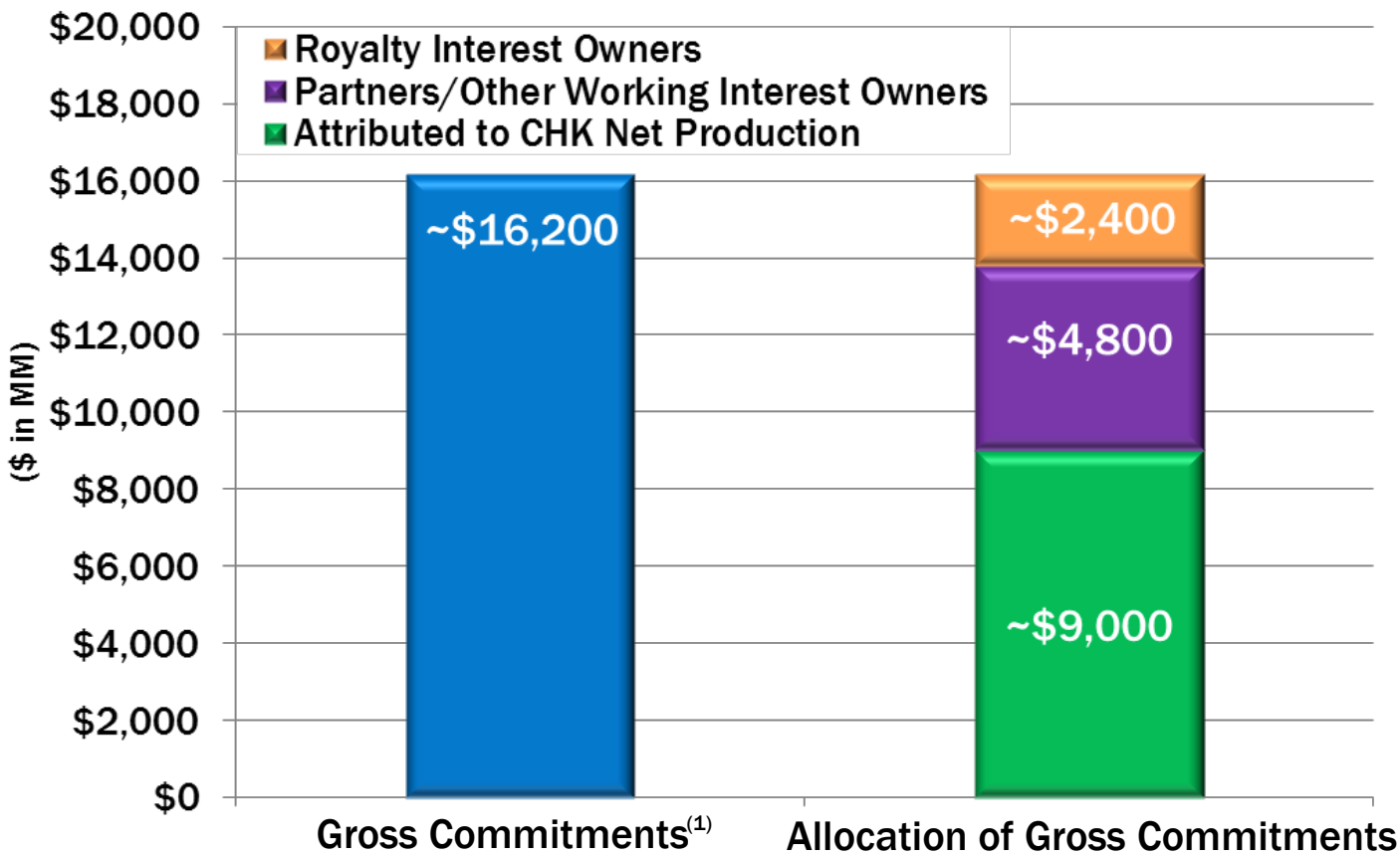


- Barnett
- Marcellus North
- Haynesville
- MidContinent
- Eagle Ford
- Marcellus South/Utica



- Natural gas transportation
- Crude oil transportation
- Gathering
- Processing

TOTAL COMMITMENTS GROSS VS. NET



- Potential excess gathering and transportation capacity may increase CHK's average differential to NYMEX by ~\$0.04/mcfe and ~\$0.10/mcfe in 2H' 12 and 2013, respectively⁽²⁾

(1) Stated commitments range from 2012 - 2099

(2) Based on CHK's midstream commitments as of 6/30/12 and most recent internal production estimates



DRILLING RIG AND COMPRESSOR SALE/LEASEBACK COMMITMENTS



DRILLING RIG AND COMPRESSOR SALE/LEASEBACK COMMITMENTS



Simple financing mechanism by which the company sold drilling rigs and compressors to a varied group of financial counter-parties, implied leaseback rates below CHK cost of capital and do not have any embedded operational utilization requirements

■ Drilling rigs

- › Sold 93 rigs over the past 6 years for proceeds of ~\$800 mm
 - \$389 mm of aggregate undiscounted future lease payments remaining and current quarter run-rate of \$27 mm of lease expense
 - 70% of the drilling rigs have options for repurchase beginning in early 2013
- › Ongoing accounting treatment: COS expenses the operating lease payment. CHK capitalizes the drilling expenditure to the full cost pool for CHK's net working interest portion, net of internal profit

■ Compressors

- › Sold 2,542 compressors over the past 5 years for proceeds of \$635 mm
 - \$458 mm of aggregate undiscounted future lease payments remaining and current quarter run-rate of \$18 mm of lease expense
- › Ongoing accounting treatment: CHK, via Mid-Con Compression subsidiary, expenses the operating lease. If compression occurs at the wellhead, then CHK expenses compression through production cost, if compression is needed for gathering, CHK's realized price is reduced by the fee charged for compression

RECONCILIATION TO OPERATING CASH FLOW AND EBITDA



(\$ in millions)(unaudited)

THREE MONTHS ENDED:	June 30, 2012	March 31, 2012	June 30, 2011
CASH PROVIDED BY OPERATING ACTIVITIES	\$ 755	\$ 274	\$ 1,375
Changes in assets and liabilities	140	636	(168)
OPERATING CASH FLOW^(a)	<u>\$ 895</u>	<u>\$ 910</u>	<u>\$ 1,207</u>

THREE MONTHS ENDED:	June 30, 2012	March 31, 2012	June 30, 2011
NET INCOME (LOSS)	\$ 1,037	\$ (3)	\$ 510
Income tax expense (benefit)	663	(2)	325
Interest expense	14	12	25
Depreciation and amortization of other assets	83	84	63
Natural gas, oil and NGL depreciation, depletion and amortization	588	506	366
EBITDA^(b)	<u>\$ 2,385</u>	<u>\$ 597</u>	<u>\$ 1,289</u>

THREE MONTHS ENDED:	June 30, 2012	March 31, 2012	June 30, 2011
CASH PROVIDED BY OPERATING ACTIVITIES	\$ 755	\$ 274	\$ 1,375
Changes in assets and liabilities	140	636	(168)
Interest expense	14	12	25
Unrealized gains (losses) on natural gas, oil and NGL derivatives	810	(270)	106
Gains (losses) on sales and impairments of fixed assets	(243)	2	(8)
Gains (losses) on investments	943	(33)	19
Stock-based compensation	(31)	(32)	(39)
Other items	(3)	8	(21)
EBITDA^(b)	<u>\$ 2,385</u>	<u>\$ 597</u>	<u>\$ 1,289</u>

(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:	June 30, 2012	March 31, 2012	June 30, 2011
EBITDA	\$ 2,385	\$ 597	\$ 1,289
Adjustments:			
Unrealized (gains) losses on natural gas, oil and NGL derivatives	(810)	270	(106)
(Gains) losses on sales and impairments of fixed assets	243	(2)	8
Net income attributable to noncontrolling interests	(65)	(25)	—
Losses on purchases or exchanges of debt	—	—	174
Gains on investments	(957)	—	—
Other	7	(2)	—
Adjusted EBITDA^(a)	<u>\$ 803</u>	<u>\$ 838</u>	<u>\$ 1,365</u>

(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.