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 statements of historical fact. They include statements that give our current expectations, guidance or forecasts of future events, production and well connection forecasts, estimates of operating costs, anticipated capital and operational efficiencies, planned development drilling and expected drilling cost reductions, general and administrative expenses, capital expenditures, the timing of anticipated noncore asset sales and proceeds to be received therefrom, projected cash flow and liquidity, our ability to enhance our cash flow and financial flexibility, plans and objectives for future operations (including our ability to optimize base production and execute gas gathering, processing and transportation commitments), the ability of our employees, portfolio strength and operational leadership to create long-term value, and the assumptions on which such statements are based. Although we believe the expectations and forecasts reflected in the 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.

Factors that could cause actual results to differ materially from expected results include those described under “Risk Factors” in Item 1A of our annual report on Form 10-K and any updates to those factors set forth in Chesapeake's subsequent quarterly reports on Form 10-Q or current reports on Form 8-K (available at http://www.chk.com/investors/sec-filings). These risk factors include: the volatility of oil, natural gas and NGL prices; the limitations our level of indebtedness may have on our financial flexibility; our inability to access the capital markets on favorable terms; the availability of cash flows from operations and other funds to finance reserve replacement costs or satisfy our debt obligations; our credit rating requiring us to post more collateral under certain commercial arrangements; write-downs of our oil and natural gas asset carrying values due to low commodity prices; our ability to replace reserves and sustain production; uncertainties inherent in estimating quantities of oil, natural gas 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; commodity derivative activities resulting in lower prices realized on oil, natural gas and NGL sales; the need to secure derivative liabilities and the inability of counterparties to satisfy their obligations; adverse developments or losses from pending or future litigation and regulatory proceedings, including royalty claims; charges incurred in response to market conditions and in connection with our ongoing actions to reduce financial leverage and complexity; drilling and operating risks and resulting liabilities; effects of environmental protection laws and regulation on our business; legislative and regulatory initiatives further regulating hydraulic fracturing; our need to secure adequate supplies of water for our drilling operations and to dispose of or recycle the water used; impacts of potential legislative and regulatory actions addressing climate change; federal and state tax proposals affecting our industry; potential OTC derivatives regulation limiting our ability to hedge against commodity price fluctuations; competition in the oil and gas exploration and production industry; a deterioration in general economic, business or industry conditions; negative public perceptions of our industry; limited control over properties we do not operate; pipeline and gathering system capacity constraints and transportation interruptions; terrorist activities and/or cyber-attacks adversely impacting our operations; potential challenges by SSE's former creditors of our spin-off of in connection with SSE's recently completed bankruptcy under Chapter 11 of the U.S. Bankruptcy Code; an interruption in operations at our headquarters due to a catastrophic event; the continuation of suspended dividend payments on our common stock; the effectiveness of our remediation plan for a material weakness; certain anti-takeover provisions that affect shareholder rights; and our inability to increase or maintain our liquidity through debt repurchases, capital exchanges, asset sales, joint ventures, farmouts or other means.

In addition, disclosures concerning the estimated contribution of derivative contracts to our future results of operations are based upon market information as of a specific date. These market prices are subject to significant volatility. Our production forecasts are also dependent upon many assumptions, including estimates of production decline rates from existing wells and the outcome of future drilling activity. Expected asset sales may not be completed in the time frame anticipated or at all. 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 any of the information provided in this presentation, except as required by applicable law. In addition, this presentation contains time-sensitive information that reflects management's best judgment only as of the date of this presentation.
OUR STRATEGY
STRONG THROUGH COMMODITY PRICE CYCLES

BUSINESS STRATEGIES:

Financial Discipline
Business Development
Profitable and Efficient Growth from Captured Resources
Exploration

Near-term focus – What we are doing now

Margin expansion – oil growth driven by the PRB, new Eagle Ford completions, cash cost leadership

Increased return on capital – optimize lateral lengths, testing more value-driven completions

Portfolio management – reduced debt ~$900 million\(^{(1)}\), removed ~$590 million of marketing commitments, planned Mid-Con asset sales

Safety and environmental stewardship

(1) YTD through March 31, 2017
2017 CAPITAL ALLOCATION
FLEXIBLE PROGRAM – VALUE FOCUSED

Capital allocation drivers

- High-margin production growth
- Cash-generating capability
- Operational efficiency

2017 Projected TILs

- South Texas
- Mid-Continent
- Marcellus
- Rockies
- Utica
- Gulf Coast

Powder River Basin
2 Rigs / 1 Frac Crew
D&C Asset Funding: 10%

Mid-Continent
4 Rigs / 2 Frac Crews
D&C Asset Funding: 15%

Utica Shale
2 Rigs / 2 Frac Crews
D&C Asset Funding: 15%

Haynesville Shale
3 Rigs / 2 Frac Crews
D&C Asset Funding: 20%

Marcellus Shale
1 Rig / 1 Frac Crew
D&C Asset Funding: 5%

Eagle Ford Shale
6 Rigs / 3 Frac Crews
D&C Asset Funding: 30%
POWDER RIVER BASIN
WHY THE POWDER RIVER BASIN MATTERS

~2.7 bboe
Of resource potential
~2,600 risked locations

Average 80% W.I.
90% undeveloped

307,000 acres
80% HBP/HBU/HBO
48% Federal acreage

> Parkman
175 mmboe resource base
200+ undrilled locations
2,640' spacing

> Sussex
150 mmboe resource base
150+ undrilled locations
1,320' spacing

> Niobrara
470 mmboe resource base
575+ undrilled locations
1,320' spacing

> Turner
375 mmboe resource base
300+ undrilled locations
2,640' spacing

> Mowry
1,450 mmboe resource base
550+ undrilled locations
1,320’ spacing

Other future potential formations – Teapot, Surrey, and Frontier
POWDER RIVER BASIN – TURNER UPDATE
OUTSTANDING INITIAL RESULTS

Turner – 1st well
TIL 3/16/2017 – 7,100’ lateral
Peak rate – 2,560 boe/d (78% oil)
30-day cumulative – 36 mbo, 58 mmcf

Turner – 2nd well
TIL 5/17/2017 – 4,500’ lateral
~17 miles from Sundquist location
Peak rate – 2,550 boe/d (55% oil)
POWDER RIVER BASIN – TURNER UPDATE
WHAT WE KNOW

What we know today

- Continuous reservoir across acreage
  - 100 vertical industry penetrations
  - 3-D seismic
- Pressure gradient confirmed
- Proven deliverability with varied laterals

~10 wells
Up to 10 wells in 2017
~$35/bbl breakeven\(^{(1)}\)
Single-well ROR: ~45%\(^{(2)}\)

---

(1) PV10 positive breakeven price assuming $3 gas price
(2) Assumes $3 gas and $50 oil flat
SUSSEX SANDSTONE
MOVING TO DEVELOPMENT MODE

• Targeted development
  > Single-well ROR: 25 – 50% (1)
  > Currently drilling 3- and 6-well Sussex pads, 12 total TILs in Q3 (3 DUCs)
  > Drilling ~20 wells in 2017

• $35 – $45/bbl oil breakeven (2)

#1 PRB Sussex well
>700 mboe of production in ~3 years

(1) Assumes $3 gas and $50 oil prices flat
(2) PV10 positive breakeven price assuming $3 gas price
**2017 Pending Tests**

- **Additional Turner results**
  - Option to add a rig to focus on Turner development exclusively

- **First Parkman result encouraging**
  - Second Parkman well flowing back

- **First Sussex pad results in Q3**
  - Production ramp from 9 to 12 wells

- **First Mowry test in Q3**
  - Completion in June

- **~150 permits in hand**
  - 100 permits in the process

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**Net Production Potential**

- **Current Prod**
- Oil
- NGL
- Natural Gas

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**2017E**

- **2018E**

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**2 – 4 Rigs**
500+ locations
Across Meramec play in Major and Woodward counties

Strong well results
Average IP 30 = ~1,100 boe/d, ~60% oil
~90 locations in a focus area covering ~22,000 net acres
UTICA SHALE
BACK TO A GROWTH TRAJECTORY

Enhanced completions
Average completed lateral length in 2017 ~9,600′,
70 – 80 TILs planned in 2017,
Activity split 50/50 in wet and dry focus areas

~$150mm
Projected free cash flow through 2018(1)

Utica Net Production

2017 Focus Areas

(1) Assumes $3 / $48 for 2017 and $3 / $50 in 2018, excluding hedges
SOUTH TEXAS
BATCH DEVELOPMENT – ENHANCED COMPLETIONS

Faith Ranch ~21,000 net acres
221 producing wells
163 lower Eagle Ford inventory

70% of project has new completion designs

~$34/bbl breakeven (1)
~70% ROR (2) on enhanced completions

(1) PV10 positive breakeven price assuming $3 gas price
(2) Economics ran at $3/mcf and $50/bbl flat

(1) PV10 positive breakeven price assuming $3 gas price
(2) Economics ran at $3/mcf and $50/bbl flat
SOUTH TEXAS UPDATE
INCREASING OUR RETURN ON CAPITAL

Notable performance
Blakeway 1C DIM 2H
TIL 3/22/2017 – 9,833' lateral

☑ Peak rate – 3,184 boe/d (88% oil)
☑ ~2,025 boe/d – 30-day rate
☑ ~1,775 bo/d – 30-day rate
☑ Enhanced completion

Testing new completion designs and executing shorter cycle times

Blakeway 1C DIM 2H

Cum Oil (MBO)

Days

0 10 20 30 40 50 60

0 20 40 60 80 100 120

Blakeway Cum Oil (60 Days)
CHK Offsets - Avg Cum Oil
Competitor Normalized Average Cum Oil
Doing more in 2H 2017

PRB – Turner and Parkman results, 9 – 12 Sussex wells, Mowry test

Mid-Continent – Meramec moves to development, begin testing Chester

Appalachia – Enhanced completions in Marcellus and Utica Dry, Utica oil TILs

South Texas – Upper Eagle Ford test, Austin Chalk test, more enhanced completions

Gulf Coast – 5 Haynesville refracs, Bossier 10,000' lateral, Haynesville 15,000' lateral
Resilient, strong, diverse portfolio
- PRB – Stacked oil growth opportunities
- Mid-Continent – Emerging Wedge play
- Marcellus – FCF machine, best gas rock in country
- Utica – Resource optionality
- Eagle Ford – Ebitda engine
- Haynesville – Improved cash cycle time

Oil growth on track – margin growth to follow

Cost leadership

Balance sheet improvement
2016 Production Expense (1)

$2.50 – $2.70/boe
2017 production expense guidance
~15% improvement YOY

$3.05/boe
2016 production expense

(1) Production expense defined as the total of lease operating expenses, ad valorem taxes and other production expenses
Peer Group includes: APC, APA, COP, DVN, ECA, EOG, HES, MRO, MUR, NBL and OXY
~298 bcf hedged in 2018 with swaps at an average price of $3.16
~47 bcf hedged in 2018 with collars at an average price of $3.00/$3.25
~1.8 mmbbl of oil hedged in 2018 with swaps at an average price of $51.43

(1) As of 5/19/17, using midpoints of total production from 5/3/2017 Outlook
REDUCED DEBT AND PUSHED BACK MATURITIES

$11.7 billion
Principal balance at 9/30/2015

$9.1 billion
Principal balance at 3/31/2017

$2.6 billion debt reduction over 18 months

Graph showing debt reduction and maturation dates.

(1) Based on EUR-USD exchange rate of €1.1177 to $1.0 as of 9/30/15
CORPORATE INFORMATION

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Oklahoma City, OK 73118
WEBSITE: www.chk.com

CORPORATE CONTACTS
BRAD SYLVESTER, CFA
Vice President – Investor Relations and Communications

DOMENIC J. DELL’OSSO, JR.
Executive Vice President and Chief Financial Officer

Investor Relations department can be reached at ir@chk.com

PUBLICLY TRADED SECURITIES

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2017 UBS GLOBAL OIL AND GAS CONFERENCE | 20