Welcome and Company Overview

DOUG LAWLER
CAUTIONARY 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 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 agreements), 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 or at all; the availability of cash flows from operations and other funds to finance reserve replacement costs or satisfy our debt obligations; a further downgrade in 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 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 cyber-attacks adversely impacting our operations; potential challenges of our spin-off of Seventy Seven Energy Inc. (SSE) 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 and preferred stock; 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.

PV10 is a non-GAAP measurement used by the industry, investors and analysts to estimate present value, discounted at 10% per annum, of estimated future cash flows of our estimated proved reserves before income tax and asset retirement obligations. The most directly comparable GAAP measure is the standard measure of discounted future net cash flows. Management believes that PV10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and natural gas companies. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable for evaluating our company. PV10 should not be considered as an alternative to the standardized measure of discounted future net cash flows as computed under GAAP. With respect to PV10 calculated as of an interim date, it is not practical to calculate taxes for the related interim period because GAAP does not provide for disclosure of standardized measure on an interim basis.

The SEC requires oil and gas companies, in their filings with the SEC, to disclose proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. We use certain terms in this presentation, such as “estimated ultimate recovery” (EUR), “oil in place” (OIP), “gross recoverable resource,” “resource potential,” “type curve” and similar phrases. These estimates are by their nature more speculative than estimates of proved, probable and possible reserves and accordingly are subject to substantially greater risk of being actually realized. The SEC guidelines strictly prohibit us from including these estimates in filings with the SEC. Investors are urged to consider closely the disclosures and risk factors in our most recent Form 10-K and in other reports on file with the SEC.
Agenda

7:00 a.m. Registration and Breakfast – Poster Sessions

9:00 a.m. Doug Lawler
Welcome and Company Overview

9:15 a.m. Frank Patterson
Powder River Basin, Appalachia, Exploration, Mid-Continent

10:30 a.m. Break

10:45 a.m. Jason Pigott
Operations and Technical Services, South Texas, Gulf Coast

11:45 a.m. Break – Boxed Lunches

12:15 p.m. Nick Dell’Osso
Capital Structure and Outlook

12:45 p.m. Doug Lawler
Summary and Path Forward

1:00 p.m. Q&A/Closing Remarks

2:00 p.m. Dismiss, Poster Sessions and Tours
Rediscovering Chesapeake Energy...
FINANCIAL DISCIPLINE

BUSINESS DEVELOPMENT

EXPLORATION

PROFITABLE AND EFFICIENT GROWTH
~50% REDUCTION IN TOTAL LEVERAGE
= $10.9 BILLION
CAPITAL EFFICIENCY DEFINED

2012: $14.7
2013: $7.8
2014: $6.7
2015: $3.6
2016E: $1.65 – $1.75

(1) 2016E represents 10/20 Outlook ranges
FINANCIAL DISCIPLINE

EXPLORATION

BUSINESS DEVELOPMENT

PROFITABLE AND EFFICIENT GROWTH
$1.3B asset sales closed or pending

2016 total expected > $2B

*Represents gross proceeds from asset sales
Exploration Opportunities

- Prospects adding value to current HBP position: 17
- Growth opportunities in CHK-operated basins: 15
- New basin-entry plays: 11
PROFITABLE AND EFFICIENT GROWTH

FINANCIAL DISCIPLINE

BUSINESS DEVELOPMENT

EXPLORATION
~17,600 LOCATIONS
Remain to be drilled

~10,500 LOCATIONS
Above 20% ROR (1)

~5,600 LOCATIONS
Above 40% ROR (1)

» RISKED LOCATIONS
» DOWNSPACING UPSIDE
» PROVEN RESERVOIRS
» TREMENDOUS EXPLORATION AND TECHNOLOGY UPSIDE

(1) Economics assume $3/mcf and $60/bbl flat
POWER OF THE PORTFOLIO

11.3 BBOE TOTAL NET recoverable resources

» RISKED LOCATIONS

» DOWNSPACING » PROVEN RESERVOIRS

» TREMENDOUS EXPLORATION AND TECHNOLOGY UPSIDE
Includes Upper Eagle Ford and Austin Chalk locations; operated gross risked locations

PV10 positive breakeven price assuming $3 gas price
75% undeveloped

10x more productive

$2.35/mcf breakeven (PV10)

2,070 locations remain to be drilled

18.9 TCF net recoverable resources

(1) Includes all Gulf Coast locations; operated gross risked locations
MID-CONTINENT

1.5 mm acres under lease after $1 billion in 2016 divestitures

170% ROR Oswego economics

>1.0 BBOE net recoverable resources

< $40/bbl breakeven (PV10)

15 targeted horizons

---

(1) Price deck at $3 and $60 flat  
(2) PV10 positive breakeven price assuming $3 gas price
MARCELLUS

1.8 BCF/D flat gross production with minimal capital spend

2,900 LOCATIONS remain to be drilled

11.2 TCF net recoverable resources

$2.00/mcf breakeven (PV10)

(1) Operated gross risked locations
90% of gas flows out of basin

1,575 locations remain to be drilled\(^{(1)}\)

1.6 BBBOE net recoverable resources

$2.15/mcf Utica dry breakeven (PV10)

$37/bbl Utica wet breakeven (PV10)\(^{(2)}\)

---

\(1\) Operated gross risked locations
\(2\) PV10 positive breakeven price assuming $3 gas price
Operated gross risked locations

PV10 positive breakeven price assuming $3 gas price

1.7 BB0E net recoverable resources

2,600 locations remain to be drilled

730k acres equivalent stacked acreage

$35-$45/bbl breakeven (PV10)

---

(1) Operated gross risked locations
(2) PV10 positive breakeven price assuming $3 gas price
70% improvement in employee and contractor total recordable incident rate

2015: 0.69
2016 YTD: 0.21
Done more, doing more, more to do.
WHAT YOU NEED TO KNOW…

> Large acreage position that is largely held, so no longer drilling just to hold acreage, but drilling to deliver value

> We are expanding the economic core in several plays and have more remaining locations to drill than we have drilled in our history

> Stacked potential in almost every play

> Leading drilling and completion technology in several plays – technological advances rapidly being deployed throughout the portfolio

> Multiple oil growth opportunities in portfolio

Our program today will build on this foundation and more…
POWDER RIVER BASIN:
Emerging Oil Growth Giant

FRANK PATTERSON
POWDER RIVER BASIN – WHAT HAS CHANGED?

• Renegotiated midstream agreement unlocks a material development opportunity

• Leveraged learnings throughout CHK to optimize performance

• Petroleum systems-based analysis provides new stacked-play opportunities

Development program commences November 2016
~2.7 BBOE RESOURCE POTENTIAL

- One vertical mile of opportunity
  > 8+ stacked formations
- ~2,600 risked locations
- The next oil growth asset

### Net Production Potential

<table>
<thead>
<tr>
<th>Year</th>
<th>Oil (mb/d)</th>
<th>NGL (mb/d)</th>
<th>Natural Gas (mb/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017E</td>
<td>20</td>
<td>10</td>
<td>50</td>
</tr>
<tr>
<td>2018E</td>
<td>30</td>
<td>20</td>
<td>60</td>
</tr>
<tr>
<td>2019E</td>
<td>40</td>
<td>30</td>
<td>70</td>
</tr>
<tr>
<td>2020E</td>
<td>50</td>
<td>40</td>
<td>80</td>
</tr>
<tr>
<td>2021E</td>
<td>60</td>
<td>50</td>
<td>90</td>
</tr>
<tr>
<td>2022E</td>
<td>70</td>
<td>60</td>
<td>100</td>
</tr>
</tbody>
</table>

**2016E CHK Eagle Ford Equivalent**

---

### Gross Recoverable Resource Potential

- **Oil**: 260 mmbce
- **NGL**: 110 mmbce
- **Natural Gas**: 1,450 mmbce

---

**Resource Mix**
- **Oil**: 49%
- **NGL**: 35%
- **Natural Gas**: 16%
307,000 ACRES OF GROWTH POTENTIAL

- ~90% undeveloped locations
- 98% of leases cover all depths
- 10 operated federal units
  - Single-operator control
  - Minimal drilling obligations
  - Long-lateral development

**Acreage Type**
- Federal: 7%
- Fee: 45%
- State: 48%

**Acreage Status**
- HBO/HBP/HBU: 20%
- Non-Producing: 80%

**Locations**
- Remaining Development: 10%
- Drilled: 90%
HOTSPOT ADVANTAGE

- CHK owns Southern PRB hotspot
- DJ Basin and Northern PRB analog
- Advantages of CHK hotspot position
  > Higher pressure
  > Greater hydrocarbon generation (maturity)
  > Exposed to all three hydrocarbon phases
SUSSEX SANDSTONE
HIGHLY ECONOMIC OIL PLAY

• Moving to development
• Dominant position in the play
• ~200 undrilled locations
  > Assumes 1,320' spacing
  > Overpressured – high deliverability
• Targeted development
  > EUR: 825 – 1,350 mboe
  > ROR: 50 – 70% (1)
  > 2017 focused drilling program

Oil breakeven price (2)
< $40

(1) Assumes $3 gas and $60 oil prices flat
(2) PV10 positive breakeven price assuming $3 gas price
**SUSSEX SANDSTONE**
**BEST IN BASIN**

- Best Sussex performance in the Powder River Basin
- Development plan optimized
  - Spacing
  - Drilling and completion design
- Competitive economics in current environment

**Best Sussex in the PRB**

**#1 PRB Sussex well**
640 mboe cumulative production

(1) IHS data
TURNER SANDSTONE  
PROVEN RESERVOIR – UNREALIZED VALUE

- Same play as northern hotspot with similar rock properties and anticipated higher pressure
- >300 industry wells drilled to date
- One of the most actively permitted sandstones in the Powder River Basin
- Offset activity proves potential, but not optimized for drilling and completion

<table>
<thead>
<tr>
<th>Turner North</th>
<th>CHK Turner</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth</td>
<td>~10,000'</td>
</tr>
<tr>
<td>Reservoir Pressure (Est.)</td>
<td>~4,800 psi</td>
</tr>
<tr>
<td>Avg. Porosity</td>
<td>7%</td>
</tr>
<tr>
<td>Avg. Water Saturation</td>
<td>45 – 60%</td>
</tr>
</tbody>
</table>
TURNER SANDSTONE
PROVEN RESERVOIR – UNREALIZED VALUE

- CHK controls 65% of southern high-grade
  > CHK position overlies thickest net pay
- ~340 undrilled locations
  > Assumes 2,640' spacing
- Targeted development through 2020
  > EUR: ~1,300 mboe
  > ROR: ~45% (1)

Oil breakeven price (2)
~$40

(1) Assumes $3 gas and $60 oil
(2) PV10 positive breakeven price assuming $3 gas price
NIOBRARA
POSITIONED FOR SUCCESS

• Premier Niobrara position in the PRB
• Oil, gas and condensate – provides flexibility
• ~580 undrilled locations
  > Assumes 1,100’ – 1,320’ spacing
• Targeted development through 2020
  > EUR: ~880 mboe
  > ROR: ~45% (1)

Outperforming all U.S. Niobrara horizontal wells to date

Oil breakeven price (2)
~$40

Production Mix

Oil breakeven price (2)
~$40

Oil
NGL
Natural Gas

34%
54%
12%

(1) Assumes $3 gas and $60 oil
(2) PV10 positive breakeven price assuming $3 gas price
(3) IHS data

Barton vs. All U.S. Niobrara Horizontals (3)

DJ Basin, Green River Basin, North Park Basin, Piceance Basin, Powder River Basin and Williston Basin

CHK Barton Test
Peak Rate of 1,600+ boe/d (85% Oil)
230 mbo 1-Year Cum.
MOWRY SHALE
HIDDEN RESOURCE GIANT

- World-class source rock
  - Overpressured
  - Three phases present
- Multiple penetrations and core data available
- ~25 horizontal wells drilled by industry since 2005

1.45 bboe
Gross recoverable resource potential

Production Mix

- Oil: 64%
- NGL: 15%
- Natural Gas: 21%
MOWRY SHALE
HIDDEN RESOURCE GIANT

- Mowry compares favorably to other prolific source rocks
- Strong relationship between competitor frac size and EUR
  > Large upside with Chesapeake-style frac
- Anticipate significantly greater reservoir pressure than northern Mowry wells

<table>
<thead>
<tr>
<th>Pressure</th>
<th>Thickness</th>
<th>Porosity</th>
<th>TOC</th>
<th>Mineralogy</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mowry is similar to…</td>
<td>Utica</td>
<td>Haynesville</td>
<td>Woodford</td>
<td>Eagle Ford</td>
</tr>
</tbody>
</table>

![Image of Mowry Porosity]

Positive Correlation of Proppant vs. EUR/ft. (1)

(1) IHS data
WHY POWDER RIVER BASIN?
ONE MILE OF OPPORTUNITY

• ~2.7 bboe gross recoverable resource potential
• ~2,600 risked locations
• Stacked potential – equivalent to 730,000 acres
• Renegotiated midstream unlocks value
• Significant exposure to Mowry upside
• The next oil growth asset

Net Production Potential

2016E CHK Eagle Ford Equivalent

Oil  NGL  Natural Gas

mboe/d


1–2 Rigs  4+ Rigs

Teapot
Parkman
E, A, B/C & Deep
Surrey
Sussex
Niobrara
Turner
Frontier
Mowry
APPENDIX
• CHK Mowry maturity 20% – 30% higher than northern Mowry
• Strong correlation with completion size and performance

(1) IHS data
PARKMAN SANDSTONES
HIGH VOLUME OIL PLAYS

- Extensive play development to north
  - BC sand produced by DVN and EOG
- CHK controls the southern extension of the Parkman BC trend
  - Similar rock quality and thickness to that in the northern area
- CHK Parkman area contains three additional, discrete sands
- EUR: 860 mboe
- ROR: ~45% (1)

Four Parkman sands
Within CHK’s position

(1) Assumes $3 gas and $60 oil flat
CHK LAND POSITION
A STRATEGIC ADVANTAGE

• CHK dominates southern Powder hotspot

• Northern hotspot shared by multiple competitors (1)

(1) Competitor leasehold sourced from Drilling Info and company press releases
NET EQUIVALENT PRODUCTION
POWDER RIVER BASIN: ~2% TOTAL PRODUCTION 2016E

Mboe/d

2013 2014 2015 2016E

Appalachia North
Appalachia South
Powder River
South Texas
Gulf Coast
Mid-Continent
Central Texas
Marcellus South

Divested - 2014
Divested - 2016
POWDER RIVER MODELING INPUTS

### Base Production

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>3Q’16E Net Production</td>
<td>14 mboe/d</td>
</tr>
<tr>
<td>4 Yr. Average Annual Decline</td>
<td>24%</td>
</tr>
</tbody>
</table>

### 2017 Expenses & Differential Estimates

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production Expense ($/boe)</td>
<td>$4.95 – $5.35</td>
</tr>
<tr>
<td>2017 GP&amp;T ($/boe)</td>
<td>$13.25 – $13.45</td>
</tr>
<tr>
<td>Future Dev. GP&amp;T ($/boe)</td>
<td>$4.75 – $6.75</td>
</tr>
</tbody>
</table>

### 2017 – 2020 Blended Development Program

#### Curve Parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>IP (Oil / Gas)</td>
<td>990 bbl/d / 1.7 mmcf/d</td>
</tr>
<tr>
<td>Decline (Oil / Gas)</td>
<td>74%/42.5%</td>
</tr>
<tr>
<td>B-factor (Oil / Gas)</td>
<td>1.0/0.9</td>
</tr>
<tr>
<td>Shrink</td>
<td>92%</td>
</tr>
<tr>
<td>NGL Yield</td>
<td>55 bbl/mmcf</td>
</tr>
<tr>
<td>EUR</td>
<td>1.2 mmboe</td>
</tr>
<tr>
<td>Lateral Length</td>
<td>8,400 ft.</td>
</tr>
</tbody>
</table>

#### Gross Capex

<table>
<thead>
<tr>
<th>Activity</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Drilling (6) (136 days to TIL)</td>
<td>$4.3mm</td>
</tr>
<tr>
<td>Completion (62 days to TIL)</td>
<td>$3.2mm</td>
</tr>
<tr>
<td>TIL</td>
<td>$1.0mm</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>$8.5mm</strong></td>
</tr>
</tbody>
</table>

#### Interest / Gross Locations

<table>
<thead>
<tr>
<th>Description</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>WI / NRI (7)</td>
<td>80%/65%</td>
</tr>
<tr>
<td>Producing</td>
<td>185</td>
</tr>
<tr>
<td>DUCs</td>
<td>15</td>
</tr>
<tr>
<td>Undrilled (8)</td>
<td>2,600</td>
</tr>
<tr>
<td>Rig Count</td>
<td>1 – 10</td>
</tr>
</tbody>
</table>

---

(1) Applies to total asset inclusive of non-operated
(2) Compound Annual Decline from 7/2016 – 6/2020
(3) Reflects net asset level production expense including LOE, overhead and Ad Val
(4) Excludes all intercompany marketing fees
(5) 30 day average IP
(6) 27 days spud to spud
(7) Assumed until well proposed
(8) All potential locations; not necessarily all drilled by 2020
NORTHEAST GAS POWERHOUSE

- Free cash flow generator
- High-quality and diverse position
- Growth potential and portfolio flexibility
- Operational excellence

4% of domestic gas production

Access to premium markets
Abundant opportunities
Significant resource optionality

~1,100,000 Net Acres in Utica

Location Count
- Drilled 30%
- Remaining Development 70%

Undrilled Locations
- Oil 415
- Dry 370
- Wet 790
CHESAPEAKE’S MARKETING ADVANTAGES
UTICA

- **Increasing basin takeaway**
  - Opportunity to acquire available capacity

- **No projected shortfalls**
  - Requires less than four rigs per year

- **Significant access to premium markets**
  - >90% of gas flows out of basin

**Projected Utica Net Marketed Volume**
(mmbtu)

- Significant access to premium markets
  - >90% of gas flows out of basin

**Opportunity to acquire available capacity**

- Requires less than four rigs per year

**Projected Utica Net Marketed Volume**
(mmbtu)
BASIN-LEADING OPERATIONAL PERFORMANCE
UTICA

Competitor data from IHS, public data and company disclosures, competitors include AR, ARU, ECR and GPOR (ARU excluded from gross well capex)

~40% increase in drilling efficiency

~50% increase in capital efficiency
DRY GAS GROWTH
UTICA

Utica Dry Locations

Drilled 10%
Remaining Development 90%

>40% ROR
Average CHK WI ~ 90%\(^{(1)}\)

$2.14
Per mcf Utica Dry PV10 breakeven

>350%
Production growth

~93% of dry gas is sent to Gulf market

\(^{(1)}\) Assumes $3/mcf gas flat
FLEXIBLE INVESTMENT OPPORTUNITIES
STRENGTH IN OPTIONALITY – UTICA

- High-quality and diverse position
- Operational excellence
- Market advantages
- Large inventory

~$200mm
Projected free cash flow through 2018 (1)

(1) Assumes $3 / $48 for 2017 and $3 / $60 in 2018, excluding hedges
MARCELLUS SHALE
THE PREMIER DOMESTIC GAS

- Growth potential in a remarkable reservoir
- Operational excellence
- Stable free cash flow

Production Mix

Marcellus Locations

Natural Gas 100%

Remaining Development 75%

Drilled 25%

~795,000 Net Acres in North Appalachia

>3.2 Tcf gross produced

Well Status | Marcellus Locations
---|---
Producng | 686
DUC\(^{(1)}\) Inventory | 85
Undrilled Inventory | 2,900

\(^{(1)}\) DUC: “Drilled uncompleted” wells
Dominant position
92% CHK acreage HBP

<table>
<thead>
<tr>
<th>CHK</th>
<th>Core (2)</th>
<th>Core Expansion (2)</th>
</tr>
</thead>
<tbody>
<tr>
<td>HBP</td>
<td>93%</td>
<td>88%</td>
</tr>
<tr>
<td>Gross</td>
<td>429,400</td>
<td>240,900</td>
</tr>
<tr>
<td>Net</td>
<td>277,400</td>
<td>148,000</td>
</tr>
</tbody>
</table>

(1) Bradford, Susquehanna, Sullivan, and Wyoming Counties PA
(2) Core and Core Expansion delineated using water saturation, porosity, permeability, pressure and thickness
GROWTH POTENTIAL AND FUTURE DEVELOPMENT

- Longer laterals
- Optimal completion designs
- Substantial Upper Marcellus fairway
- Additional upside in Utica development

<table>
<thead>
<tr>
<th></th>
<th>Lateral Length</th>
<th>Locations Remaining</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lower Marcellus Core</td>
<td>6,000'</td>
<td>780</td>
</tr>
<tr>
<td>Lower Marcellus Core Expansion</td>
<td>6,000'</td>
<td>620</td>
</tr>
<tr>
<td>Upper Marcellus</td>
<td>5,000'</td>
<td>1,500</td>
</tr>
<tr>
<td>Upper Marcellus Optimized</td>
<td>10,000'</td>
<td>~750</td>
</tr>
</tbody>
</table>

(1) Optimizing future Marcellus locations to >10,000’ lateral length where possible
CONTINUOUS IMPROVEMENT
MARCELLUS

Average Well Cost ($mm) (1)

2012 | $9.1
2013 | $8.7
2014 | $7.5
2015 | $7.0
2016E | $5.0

Lease Operating Expense (LOE) Reduction (2)

1Q'15 | $0.066
2Q'15 | $0.047
3Q'15 | $0.045
4Q'15 | $0.038
1Q'16 | $0.038
2Q'16 | $0.035
3Q'16 | $0.030

(1) Normalized to 6,000-ft. LL
(2) Gross core operated controllable LOE (excluding Ad Val taxes and overhead)

Capex: Reduced 29% YTD

LOE: Reduced 33% YTD
MARCELLUS PRODUCTION STRENGTH
SUSTAINABLE PRODUCTION WITH MINIMAL CAPITAL

• 300 mmcf/d shut-in
  > Produce into favorable market
• > 300 mmcf/d curtailed
  > Available with planned wellhead pressure reductions
• DUC focus in 2017 and 2018
  > Exceptional point forward economics
• Minimal obligations
  > 11 obligatory spuds through 2018

Remarkable productivity
Minimal capital required
MARCELLUS SHALE

• Stable free cash flow
  > Flat production generates significant free cash flow

• Operational excellence
  > Basin-leading performance

• Remarkable reservoir quality
  > Massive Marcellus upside and significant base strength

The premier domestic basin
CHK = The Core Operator
APPALACHIA – ADVANTAGE CHESAPEAKE
ONE BASIN, TWO ASSETS = OUTSTANDING VALUE

2016 – 2018 Projected Free Cash Flow\(^{(1,2)}\) and Production
(Excluding Hedges)

\(~\$700\text{mm}\)

In projected Appalachia FCF generation from 2017 – 2018

(1) Assumes $3 / $48 for 2017 and $3 / $60 in 2018
(2) Free cash flow defined as net revenue less all operating, marketing and capital expenditures

~$700mm

In projected Appalachia FCF generation from 2017 – 2018

(1) Assumes $3 / $48 for 2017 and $3 / $60 in 2018
(2) Free cash flow defined as net revenue less all operating, marketing and capital expenditures
A prolific resource
With near-term and long-term growth opportunity

<table>
<thead>
<tr>
<th>Lower Marcellus (Core)</th>
<th>EUR/ft. (mcf) (1)</th>
<th>3,000 – 4,300</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thickness (ft.)</td>
<td>125 – 145</td>
<td></td>
</tr>
<tr>
<td>Depth (ft.)</td>
<td>5,200 – 6,900</td>
<td></td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>6.0 – 8.5</td>
<td></td>
</tr>
<tr>
<td>Pressure Gradient (psi/ft.)</td>
<td>0.60 – 0.70</td>
<td></td>
</tr>
<tr>
<td>Breakeven ($) (2)</td>
<td>2.02</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Upper Marcellus</th>
<th>EUR/ft. (mcf) (1)</th>
<th>2,200 – 3,250</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thickness (ft.)</td>
<td>125 – 250</td>
<td></td>
</tr>
<tr>
<td>Depth (ft.)</td>
<td>4,800 – 6,700</td>
<td></td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>5.5 – 8.0</td>
<td></td>
</tr>
<tr>
<td>Pressure Gradient (psi/ft.)</td>
<td>0.55 – 0.70</td>
<td></td>
</tr>
<tr>
<td>Breakeven ($) (2)</td>
<td>2.43</td>
<td></td>
</tr>
</tbody>
</table>

| Utica                           |                    |                |
| Future Potential                |                    |                |

(1) Assumes 50 psi wellhead pressure
(2) PV10 based on $4.5mm capex
TREMENDOUS WELL PERFORMANCE
CONTINUAL IMPROVEMENT THROUGH TECHNOLOGY

Increased potential
Well performance outperforming expectations

Lower Marcellus optimization
>$900,000 value acceleration/well

Improving performance
Longer laterals and enhanced completions

Upper Marcellus stacked pay
Extending asset life
NET EQUIVALENT PRODUCTION
APPALACHIA: ~43% TOTAL PRODUCTION 2016E

3 bcf/d gross
~4% of U.S. gas production (1)

(1) Source EIA Jul 2016 US Dry Gas Production Monthly volumes released 9/30/16 (https://www.eia.gov/dnav/ng/hist/n9070us1m.htm)
MARCELLUS MODELING INPUTS

- **Base Production**
  - 3Q’16E Net Production: 805 mmcf/d
  - 4 Yr. Average Annual Decline: 24%

- **2017 Expenses & Differential Estimates**
  - Production Expense ($) / mcf: $0.08 – $0.11
  - GP&T ($) / mcf: $0.93 – $0.97

- **2017 – 2020 Blended Development Program**
  - **Curve Parameters**
    - IP: 28.5 mmcf/d
    - Decline: 68.5%
    - B-factor: 0.70
    - EUR: 17.1 bcf
    - Lateral Length: 6,200 ft.
  - **Gross Capex**
    - Drilling (109 days to TIL): $2.2mm
    - Completion (57 days to TIL): $1.9mm
    - TIL: $0.4mm
    - **TOTAL**: $4.5mm
  - **Interest / Gross Locations**
    - WI / NRI: 48%/41%
    - Producing: 686
    - DUCs: 85
    - Undrilled: 2,900
    - Rig Count: 0 – 2

---

1. Applies to total asset inclusive of non-operated
2. Compound Annual Decline from 7/2016 – 6/2020
3. Reflects net asset level production expense including LOE, overhead and Ad Val
4. Excludes all intercompany marketing fees
5. 30 day average IP
6. Assumes 600psi
7. 13 days spud to spud
8. Assumed until well proposed
9. All potential locations, not necessarily all drilled by 2020
UTICA DRY MODELING INPUTS

### Base Production

- **3Q’16E Net Production**: 85 mmcf/d
- **4 Yr. Average Annual Decline**: 26%

### 2017 Expenses & Differential Estimates

- **Production Expense** ($/mcf): $0.16 – $0.20
- **GP&T** ($/mcf): $1.00 – $1.10

### 2017 – 2020 Blended Development Program

**Curves Parameters**
- **IP**: 16.2 mmcf/d
- **Decline**: 67%
- **B-factor**: 1.25
- **EUR**: 16.9 bcf
- **Lateral Length**: 10,500 ft.

**Gross Capex**
- **Drilling** (93 days to TIL): $3.1mm
- **Completion** (39 days to TIL): $2.4mm
- **TIL**: $0.5mm
- **TOTAL**: $6.0mm

**Interest / Gross Locations**
- **WI / NRI**: 89%/73%
- **Producing** DUCs: 40
- **DUCs**: 25
- **Undrilled**: 370
- **Rig Count**: 0 – 1

---

(1) Applies to total asset inclusive of non-operated
(2) Compound Annual Decline from 7/2016 – 6/2020
(3) Reflects net asset level production expense including LOE, overhead and Ad Val
(4) Excludes all intercompany marketing fees
(5) 30 day average IP
(6) 15 days spud to spud
(7) Assumed until well proposed
(8) All potential locations; not necessarily all drilled by 2020
**UTICA WET MODELING INPUTS**

### Base Production

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>3Q’16E Net Production</td>
<td>110 mboe/d</td>
</tr>
<tr>
<td>4 Yr. Average Annual Decline</td>
<td>25%</td>
</tr>
</tbody>
</table>

### 2017 Expenses & Differential Estimates

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production Expense ($/boe)</td>
<td>$1.02 – $1.12</td>
</tr>
<tr>
<td>GP&amp;T ($/boe)</td>
<td>$8.50 – $9.50</td>
</tr>
</tbody>
</table>

### 2017 – 2020 Blended Development Program

#### Curve Parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>IP (Oil / Gas)</td>
<td>275 bbl/d / 7.4 mmcf/d</td>
</tr>
<tr>
<td>Decline (Oil / Gas)</td>
<td>80%/66%</td>
</tr>
<tr>
<td>B-factor (Oil / Gas)</td>
<td>0.64/1.50</td>
</tr>
<tr>
<td>Shrink</td>
<td>90%</td>
</tr>
<tr>
<td>NGL Yield</td>
<td>71 bbl/mmcf</td>
</tr>
<tr>
<td>EUR</td>
<td>2.0 mmboe</td>
</tr>
<tr>
<td>Lateral Length</td>
<td>9,000 ft.</td>
</tr>
</tbody>
</table>

#### Gross Capex

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Drilling (105 days to TIL)</td>
<td>$2.4mm</td>
</tr>
<tr>
<td>Completion (51 days to TIL)</td>
<td>$2.5mm</td>
</tr>
<tr>
<td>TIL</td>
<td>$0.6mm</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>$5.5mm</strong></td>
</tr>
</tbody>
</table>

#### Interest / Gross Locations

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>WI / NRI(7)</td>
<td>67%/54%</td>
</tr>
<tr>
<td>Producing</td>
<td>600</td>
</tr>
<tr>
<td>DUCs</td>
<td>30</td>
</tr>
<tr>
<td>Undrilled(8)</td>
<td>790</td>
</tr>
<tr>
<td>Rig Count</td>
<td>1 – 4</td>
</tr>
</tbody>
</table>

---

(1) Applies to total asset inclusive of non-operated
(2) Compound Annual Decline from 7/2016 – 6/2020
(3) Reflects net asset level production expense including LOE, overhead and Ad Val
(4) Excludes all intercompany marketing fees
(5) 30 day average IP
(6) 12 days spud to spud
(7) Assumed until well proposed
(8) All potential locations; not necessarily all drilled by 2020
EXPLORATION:


FRANK PATTERSON
EXPLORING FOR THE FUTURE

Current Exploration Opportunities

- **11** new basin-entry plays
- **15** growth opportunities in CHK-operated basins
- **17** prospects adding value to current HBP position

- Unmatched subsurface data with in-house expertise
- Petroleum systems approach generating innovative play concepts
- Building inventory of stacked play opportunities
WE ARE UNCONVENTIONAL EXPERTS

Current acreage
~7.0 million net acres

Seismic inventory
3D: 96,000 square mi.
2D: 328,000 mi.

In-house core
65,000 ft. analyzed

 CHK core lab
Accelerates exploration value

Horizontal experts
>11,000 horizontals drilled

Data leaders
2.5 million well logs

2D/3D SEISMIC COVERAGE
BASIN OUTLINES
CHK LEASEHOLD
CHK VALUE REALIZATION
ANALYSIS TO IMPLEMENTATION IN MONTHS NOT YEARS

VALUE REALIZED $
...and CHK is on to the next big play...
Wedge, Powder River, Rome Trough, Austin Chalk

...while competitors wait on data and lag behind...
DATA INTEGRATION LIMITED BY SPEED OF ACQUISITION
1,600,000 ACRES – CHK ADVANTAGE
ROME TROUGH

- Multi-zone stacked potential
  > ~1 to 4.5 bboe recoverable in single zone
- 1.4mm acres HBP/minerals
  > Two vertical core wells drilled
- Competitors de-risking around CHK HBP position
- Access to Gulf Coast markets

Oil-prone source rock and stacked reservoirs

65% of acreage
In liquids window

Target A
Target B
Oil-saturated reservoir
Target B
Hydrocarbon fluorescence
IT’S NOT ALL ABOUT SHALE

Our Future is Stacked!

Conventional sands:
- Red Fork, Springer

Source rock plays:
- Eagle Ford, Haynesville

Low-perm clastics:
- Sussex, Turner

Low-perm carbonate plays:
- Oswego

Mixed clastic/carbonate plays:
- Meramec

Fractured plays:
- Austin Chalk

Petroleum system-based approach opens new stacked potential.

Industry first focused on basin-extensive source rocks. Then moved toward hybrid source rock plays.
MID-CONTINENT:
Most Undervalued Rock in the U.S.

FRANK PATTERSON
MID-CONTINENT IS NOT WHAT YOU REMEMBER

• Shift from historical plays to new concepts and formations
• Substantial NAV value
• Legacy acreage position offers extensive opportunity
• Oswego – a bridge to oil production growth
• Actively exploiting “The Wedge” opportunity

3 – 4 rigs
Active in 2017

~1.5mm Net Acres in Mid-Continent
MASSIVE MID-CONTINENT LAND POSITION
1.5MM ACRES IN OKLAHOMA

<table>
<thead>
<tr>
<th>Chesapeake Leasehold</th>
<th>Net Acres</th>
<th>% of Total Mid-Con</th>
<th>% HBP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Anadarko Basin</td>
<td>1,150,000</td>
<td>77%</td>
<td>94%</td>
</tr>
<tr>
<td>Eastern Oklahoma</td>
<td>200,000</td>
<td>13%</td>
<td>100%</td>
</tr>
<tr>
<td>OK Panhandle</td>
<td>150,000</td>
<td>10%</td>
<td>100%</td>
</tr>
<tr>
<td><strong>Total Mid-Continent</strong></td>
<td><strong>1,500,000</strong></td>
<td><strong>100%</strong></td>
<td><strong>95%</strong></td>
</tr>
</tbody>
</table>

- Top leasehold position in Oklahoma
- Leasehold > 95% HBP
- 3,200 identified remaining drilling locations

Evaluating 15+ horizons – multiple commercial plays available
NAV CONTINUES TO GROW

Valued at $2.8 billion after $1.0 billion in 2016 asset sales

(1) Jan 2015 average of seven analysts who provided breakout of total development value remaining in CHK’s Mid-Continent asset
(2) Internal valuation based on $3/mcf gas and $60/bbl oil price flat
OSWEGO DELIVERING IMPRESSIVE RESULTS

$3.0mm/well
Development cost

~400 mboe EUR
83% liquid, average WI 53%

40 MILES

<table>
<thead>
<tr>
<th>Well</th>
<th>IP 30 Oil</th>
<th>IP 30 NGL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lightle 4-18-6 1H</td>
<td>1,098 bo/d</td>
<td>1,235 boe/d</td>
</tr>
<tr>
<td>Hasty 3-18-6 1H</td>
<td>897 bo/d</td>
<td>1,033 boe/d</td>
</tr>
<tr>
<td>Hughes Trust 33-18-3 1H</td>
<td>1,257 bo/d</td>
<td>1,326 boe/d</td>
</tr>
<tr>
<td>Farrar 11-18-6 1H</td>
<td>727 bo/d</td>
<td>852 boe/d</td>
</tr>
<tr>
<td>Caldwell 22-18-6 1H</td>
<td>1,447 bo/d</td>
<td>1,813 boe/d</td>
</tr>
<tr>
<td>Themer 6-17-6 1H</td>
<td>717 bo/d</td>
<td>832 boe/d</td>
</tr>
</tbody>
</table>
THE OSWEGO TRANSFORMATION
UNLOCKING VALUE THROUGH RAPID OPTIMIZATION

Well deliverability increased by 140%

Total well capex reduced by 19%

Single-well returns across the play of 170%

100 locations at 170% ROR and 200 upside locations

(1) Price deck: $3/mcf and $60/bbl flat
OSWEGO DELIVERING TREMENDOUS GROWTH

High-volume, low-cost production quick to market
MISS LIME CONTINUES TO DELIVER TREMENDOUS FUTURE OPTIONALITY

Transformational strategy

- Shift from statistical to technical field development approach
- New wells selected on basis of improved subsurface technical understanding
- Targeted completion design improves oil-to-water cut

Abundant potential development

- 300 development wells with >50% ROR (1)
- 700 incremental upside inventory

(1) Price deck: $3/mcf for gas and $60/bbl oil flat
The Wedge Play
A geologically defined area in NW Oklahoma that is comprised of six oil-rich stacked reservoirs under current industry development.
THE WEDGE PLAY
CHESAPEAKE’S FUTURE MID-CONTINENT GROWTH ASSET

Strong economics – large land position

- ~870,000 net acres
  > 94% HBP
- Robust economics
  > ~500 locations at 50% ROR\(^{(1,2)}\)
- Significant running room
  > ~1,400 additional upside locations
- Efficient capital spend
  > Industry actively de-risking plays

New Wedge step-out test
1,073 boe/d (51% oil)
One-mile lateral with opportunity for two-mile development

\(^{(1)}\) Location counts exclude Miss Lime locations
\(^{(2)}\) Price deck: $3/mcf for gas and $60/bbl oil flat
MID-CON GROWTH ENGINE
SCALABLE GROWTH FROM OSWEGO AND THE WEDGE

Development model only reflects the first 100 Oswego locations.
The Wedge Play
A geologically defined area in NW Oklahoma that is comprised of six oil-rich stacked reservoirs under current industry development.

- Current value of $2.8 billion plus upside
- 1.5 million acres – 95% HBP
- Oswego generating industry-leading economics
- 500 Wedge locations with 50% ROR \(^{(1)}\)
- Evaluating 15+ horizons for future growth
- Legacy acreage position allows de-risking through competitor activity

\(^{(1)}\)  Price deck: $3/mcf for gas and $60/bbl oil flat
NET EQUIVALENT PRODUCTION
MID-CONTINENT: ~11% TOTAL PRODUCTION 2016E
**OSWEGO MODELING INPUTS**

### Base Production

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>3Q’16E Net Production</td>
<td>3 mboe/d</td>
</tr>
<tr>
<td>4 Yr. Average Annual Decline</td>
<td>33%</td>
</tr>
</tbody>
</table>

### 2017 Expenses & Differential Estimates

<table>
<thead>
<tr>
<th>Description</th>
<th>Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production Expense ($/boe)</td>
<td>$3.80 – $4.20</td>
</tr>
<tr>
<td>GP&amp;T ($/boe)</td>
<td>$5.75 – $5.95</td>
</tr>
</tbody>
</table>

### 2017 – 2020 Blended Development Program

#### Curve Parameters

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>IP (Oil / Gas)</td>
<td>600 bbl/d / 700 mcf/d</td>
</tr>
<tr>
<td>Decline (Oil / Gas)</td>
<td>85.5%/79%</td>
</tr>
<tr>
<td>B-factor (Oil / Gas)</td>
<td>1.30/1.30</td>
</tr>
<tr>
<td>Shrink</td>
<td>85%</td>
</tr>
<tr>
<td>NGL Yield</td>
<td>110 bbl/mmcf</td>
</tr>
<tr>
<td>EUR</td>
<td>393 mboe</td>
</tr>
<tr>
<td>Lateral Length</td>
<td>4,800 ft.</td>
</tr>
</tbody>
</table>

#### Gross Capex

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Drilling (32 days to TIL)</td>
<td>$1.4mm</td>
</tr>
<tr>
<td>Completion (17 days to TIL)</td>
<td>$0.7mm</td>
</tr>
<tr>
<td>TIL</td>
<td>$0.9mm</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>$3.0mm</strong></td>
</tr>
</tbody>
</table>

#### Interest / Gross Locations

<table>
<thead>
<tr>
<th>Description</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>WI / NRI(7)</td>
<td>53%/42%</td>
</tr>
<tr>
<td>Producing DUCs</td>
<td>15</td>
</tr>
<tr>
<td>Undrilled(8)</td>
<td>300</td>
</tr>
<tr>
<td>Rig Count</td>
<td>1 – 2</td>
</tr>
</tbody>
</table>

---

(1) Applies to total asset inclusive of non-operated
(2) Compound Annual Decline from 7/2016 – 6/2020
(3) Reflects net asset level production expense including LOE, overhead and Ad Val
(4) Excludes all intercompany marketing fees
(5) 30 day average IP
(6) 10 days spud to spud
(7) Assumed until well proposed
(8) All potential locations; not necessarily all drilled by 2020
WEDGE AND MISS LIME MODELING INPUTS

**Base Production**
- **3Q’16E Net Production**: 52 mboe/d
- **4 Yr. Average Annual Decline**: 13%

**2017 Expenses & Differential Estimates**
- **Production Expense** ($/boe): $6.75 – $7.35
- **GP&T** ($/boe): $5.75 – $5.95

**2017 – 2020 Blended Development Program**

**Curve Parameters**
- **IP** (Oil / Gas): 380 bbl/d / 1.7 mmcf/d
- **Decline (Oil / Gas)**: 83%/64%
- **B-factor (Oil / Gas)**: 1.20/1.30
- **Shrink**: 87%
- **NGL Yield**: 72 bbl/mmcf
- **EUR**: 658 mboe
- **Lateral Length**: 5,400 ft.

**Gross Capex**
- Drilling* (41 days to TIL): $2.0mm
- Completion (18 days to TIL): $1.3mm
- TIL: $0.6mm
- **TOTAL**: $3.9mm

**Interest / Gross Locations**
- **WI / NRI**: 61%/49%
- **Producing**: 3,485
- **DUCs**: 45
- **Undrilled**: 2,900
- **Rig Count**: 3 – 10

---

(1) Applies to total asset inclusive of non-operated
(2) Compound Annual Decline from 7/2016 – 6/2020
(3) Reflects net asset level production expense including LOE, overhead and Ad Val
(4) Excludes all intercompany marketing fees
(5) 30 day average IP
(6) 18 days spud to spud
(7) Assumed until well proposed
(8) All potential locations; not necessarily all drilled by 2020
Operations Services

Drilling

Completions
Industry-Leading Operations Support

- 24x7 real-time monitoring
- Advanced processing technology
  - High-volume, high-variety, high-velocity data analytics
- Collaborative environment
  - Engineering, geology and technology expertise

Superior Well Data

- 120mm ft. Drilled
- 70 trillion Sensor data points
- 96,000 square mi. 3D seismic
- 26,000 Producing wells
- 65,000 ft. Analyzed core
- 2.5mm Well logs
- 150mm GPS readings
BETTER PLANNING REDUCES TROUBLE TIME

• Better well planning and continuous monitoring dramatically reduce trouble time
• Well road maps predict problems before they happen
• Collaborative culture improves response time when unanticipated challenges occur

~116 days per year
Efficiency gain

$14mm
Incremental value generated in 2016E
MAINTAINING TARGET ACCURACY IN LONGER LATERALS

- Continuous monitoring maintains targeting accuracy
- Minimizes impact on well recovery when drilling longer laterals

14’ – 50’
Typical target window

~45%
Longer laterals

~95%
In-zone

Diagram:
- Avg. Lateral Length
- % Drilled in Zone

Typical target window ~45%
Longer laterals ~95%
In-zone ~95%
The Chesapeake Drilling Advantage

- Extensive extra-long-lateral experience
- State-of-the-art real-time operations center
- Repeatable and sustained performance
- Industry-leading health and safety record

CHK drilled around the world – footage drilled in the last 10 years

Leading horizontal driller worldwide

>11,000 wells drilled
Drilled more lateral footage in first nine months of 2016 than all of 2015

- Maximize capital efficiency
- Less capital intensity
- Smaller surface footprint

45% – 113% gain in lateral footage drilled per rig

**Drilling Competitive Advantages**

10 Rigs is the New 35 Rigs at Chesapeake
EAGLE FORD SHIFT TO LONGER LATERALS
A CRUCIAL VALUE-CREATION DECISION

Average Lateral Length (ft.)

Source: Bloomberg, September 2016
### Superior Operational Efficiencies

**Eagle Ford Shale**

<table>
<thead>
<tr>
<th>Year</th>
<th>Stages/Day</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Single-Day Record</strong></td>
<td>16 stages/day</td>
</tr>
<tr>
<td>2017E Avg.</td>
<td>12 stages/day</td>
</tr>
<tr>
<td>2016 YTD Avg.</td>
<td>8 stages/day</td>
</tr>
<tr>
<td>2015 Avg.</td>
<td>5 stages/day</td>
</tr>
<tr>
<td>2014 Avg.</td>
<td>4 stages/day</td>
</tr>
<tr>
<td>2013 Avg.</td>
<td>5 stages/day</td>
</tr>
</tbody>
</table>

**Multiwell Frac**

1 frac crew + 2 wireline crews
19 stages/day

**Dual Well Frac**

1 frac crew + 1 wireline crew
8 – 13 stages/day

**Single Well Frac**

1 frac crew + 1 wireline crew
6 – 8 stages/day

*Continuing to break efficiency records*
**HAYNESVILLE COMPLETION OPTIMIZATION**

IT’S A WHOLE NEW BALL GAME

---

**More Productivity for Your Dollar**

Gross Completions Capital / Gross EUR

- **Vintage**
  - ≥1,500 lbs./ft.
  - Pre 2012
  - $1.21/mcf
- **Modern**
  - ≥1,750 lbs./ft.
  - 2015
  - $0.47/mcf
- **Prop-a-geddon**
  - ≥3,000 lbs./ft.
  - Current
  - $0.28/mcf

**Unlocking additional opportunities and expanding the core with completion technology**

- **76%**
  - Overall $/boe improvement from Vintage to Prop-a-geddon
- **61%**
  - Overall production increase from Vintage to Prop-a-geddon
- **40%**
  - Overall production increase from Modern to Prop-a-geddon

---

**Proven Results from Optimization**

- **70%**
  - Overall production increase from Vintage to Prop-a-geddon

---

**Prop-a-geddon**

36%

**Modern**

25%

**Vintage**

2016 ANALYST DAY – OPERATIONS & TECHNICAL SERVICES | 12
OSWEGO COMPLETION OPTIMIZATION
MORE SAND ISN’T ALWAYS THE ANSWER

Transformative Capital Efficiency
Gross Completions Capital / Gross EUR

- **Generation 1**
  - Propped frac
  - Uncemented sleeves
  - 4Q’14 – 1Q’15

- **Generation 2**
  - Diverting acid frac
  - Uncemented sleeves
  - 1Q’16 – 3Q’16

- **Generation 3**
  - Large volume acid frac
  - Modified well design
  - 2Q’16 – Present

- **Next Generation**
  - Large volume
  - Optimized acid frac
  - Modified well design

Dramatic Performance Improvement

- **Optimizing completion design adds significant value**

<table>
<thead>
<tr>
<th>Generation</th>
<th>Gross Completions Capital / Gross EUR</th>
<th>Overall $/boe improvement from Gen 1 to Gen 3</th>
<th>Overall production increase from Gen 1 to Gen 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gen 1</td>
<td>$6.34/boe</td>
<td>63%</td>
<td>140%</td>
</tr>
<tr>
<td>Gen 2</td>
<td>$4.12/boe</td>
<td>35%</td>
<td></td>
</tr>
<tr>
<td>Gen 3</td>
<td>$2.37/boe</td>
<td>42%</td>
<td></td>
</tr>
</tbody>
</table>

Optimizing completion design adds significant value
PROVEN RESULTS LEAD TO HUGE SUCCESS

Completions Cost per Foot

<table>
<thead>
<tr>
<th>Year</th>
<th>Cost per Foot</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>$557/ft.</td>
</tr>
<tr>
<td>2014</td>
<td>$529/ft.</td>
</tr>
<tr>
<td>2015</td>
<td>$463/ft.</td>
</tr>
<tr>
<td>2016 YTD</td>
<td>$278/ft.</td>
</tr>
</tbody>
</table>

~$1.8 billion saved
Total gross cost savings since 2013

50% reduction
In completion cost per foot since 2013
DELIVERING VALUE THROUGH STANDARDIZATION, PLANNING AND DESIGN

- Decreasing construction costs
- Reducing cycle time
- Improving quality
- Driving continuous improvement

50% – 80% reduction in equipment costs

(1) Base year 2012 equipment costs of $727,000 for Eagle Ford and $365,000 for Haynesville
BASE OPTIMIZATION

3.9 mmboe
Potential uplift in 2017 from downtime and decline reduction

Cum. mmboe Above Forecast

2.0 mmboe
1.9 mmboe
0.5
1
1.5
2
2.5
3
3.5
4
2017E

10% Downtime Reduction
10% Base Decline Reduction

Opportunity
Flowing 40%
Artificial Lift 60%

BASE OPTIMIZATION

10% Downtime Reduction
10% Base Decline Reduction

2016 ANALYST DAY – OPERATIONS & TECHNICAL SERVICES | 16
Proactive artificial lift program

- Anticipates well needs
- Reduces suboptimal performance
- Reduces downtime
- Improves supply chain efficiencies

Proactive well set begins January 2014
SOUTH TEXAS:
Operational Excellence, Positioned for Growth

JASON PIGOTT
Secure acreage position
Best-in-class operations
Extended laterals are working
Broad investment portfolio

~270,000 Net Acres in Eagle Ford – 99% HBP/ HBO

<table>
<thead>
<tr>
<th>Location</th>
<th>Remaining Development</th>
<th>Drilled</th>
<th>Production Mix</th>
</tr>
</thead>
<tbody>
<tr>
<td>Austin Chalk</td>
<td>1,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Upper Eagle Ford</td>
<td>1,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lower Eagle Ford</td>
<td>3,260</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

(1) Net processed production mix
**63% reduction**
In development cost per foot with 79% increase in drilled lateral

**Retain 65%**
Cost savings captured from efficiencies, not market reductions

**Extended laterals today Outperform**
At $50 oil vs. 2014 program at $80 oil

---

**Completed Lateral Length, ft.**

<table>
<thead>
<tr>
<th>Year</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016E</th>
<th>2017E</th>
</tr>
</thead>
<tbody>
<tr>
<td>Length</td>
<td>5,830</td>
<td>5,846</td>
<td>6,248</td>
<td>7,538</td>
<td>10,117</td>
</tr>
</tbody>
</table>

**Total Well Cost per Lateral Foot**

<table>
<thead>
<tr>
<th>Year</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016E</th>
<th>2017E</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost per foot</td>
<td>$1,207</td>
<td>$1,011</td>
<td>$866</td>
<td>$480</td>
<td>$435</td>
</tr>
</tbody>
</table>

**Total Well Cost, Normalized to 5,300' Lateral ($mm)**

<table>
<thead>
<tr>
<th>Year</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016E</th>
<th>2017E</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost</td>
<td>$6.4</td>
<td>$5.4</td>
<td>$4.6</td>
<td>$2.5</td>
<td>$2.3</td>
</tr>
</tbody>
</table>

---

(1) Completed lateral length based on frac date; includes 142 DUC locations with an average of 7,089 feet
(2) Average cost per foot of wells drilled and/or completed within the time period.
2016 Performance Records

- Eight days spud to rig release – for 17,446' total well depth
- 5,837' – 24-hour footage record
- $65/ft. drilling cost – lowest monthly average
- 14,289' – single-well record lateral length

(1) Drilled lateral length and drilling cost based on spud date
2016 Performance Records
- 16 stages completed in a single day
- 284 stages in one month with one crew
- 757 stages in a single quarter with one crew

2016 Testing Focus
- Reinvesting $12mm into 38 completions tests YTD
- Applying optimal completion design from test results to deliver incremental value

49% reduction
In cost per lateral foot without sacrificing well performance
CONTINUOUS FOCUS ON REDUCING LOE
LOW-COST LEADER

17% reduction in LOE
Lifted well count increase 5X since 2013

Basin LOE Pacesetter, $/boe

40% below
Average peer group LOE

(1) Data represents operated net lease production expenses excluding Ad Valorem taxes / net equivalent volume
(2) Peer group includes CRZO, DVN, EOG, MRO and MUR, data is sourced from public data bases and IR materials
TRANSFORMING THE LOWER EAGLE FORD
EXTENDED LATERALS UNLOCK VALUE IN LOW PRICE ENVIRONMENT

Well Cost vs. Production IP

Lazy A Cotulla G 4H
LL: 10,547’

Lazy A Cotulla G 5H
LL: 10,563’

Lazy A Cotulla G 3H
LL: 10,523’

Valley Wells C 6H
LL: 9,180’

Valley Wells C 4H
LL: 9,778’

2016: 6,500’ TC laterals

2016: 10,000’ TC laterals

2014: 5,000’ TC laterals

2015: 6,500’ TC laterals

40% ROR @ $50 Oil

20% ROR @ $50 Oil

(1) Assumes $3/mcf gas price flat
ACCELERATING VALUE USING EXTENDED LATERALS
CURRENT RESULTS BEATING TYPE CURVE EXPECTATIONS

West Four Corners Performance

Beating the type curve
11 of 13 extended lateral wells are outperforming the type curve

Value acceleration
Extended laterals provide 2-for-1 NPV

Cumulative 10% Discounted Cash Flow, $(mm)

- Two 5,000’ Laterals
- Single 10,000’ Lateral

Expected payout in < 2 years
Due to XL strategy execution
SOUTH TEXAS LATERAL LENGTH EVOLUTION
COMMITTED TO THE STRATEGY

Extended Laterals as a Percentage of Program

92%
Of laterals drilled in 2017 will be greater than 7,500'

12% 26% 82% 92%
2014 2015 2016 2017E
SOUTH TEXAS EXTENDED LATERAL PROGRAM
IMPACT ON 2017 WEDGE PRODUCTION

+9.8 mmbo
Oil volume increase from 2017 extended lateral investment vs. basin standard lateral

Cumulative Gross Oil, mmbo

Three-rig planned extended lateral program
Three-rig theoretical 5,000’ program
Well Count and Location

- Dimmit Volatile Oil: 65 wells
- Dimmit Black Oil: 53 wells
- McMullen Black Oil: 24 wells

142 wells
Completed and turned in line in 2016

1 million
Feet of lateral treated

Program Impact

13 mbo/d
Net annualized production

73%
Program ROR at $3/$50 pricing
WELL POSITIONED TO GROW
MASSIVE UNTAPPED RESOURCE POTENTIAL

>28 bboe
Gross total resource
OIP on CHK acreage

0.3 bboe
Gross produced from
CHK acreage

>3.6 bboe
Estimated gross undeveloped resource
MULTIZONE DEVELOPMENT POTENTIAL
AREAS OF INTEREST AND COMPETITOR ACTIVITY

**Company A**
- IP: 692 boe/d / 70% oil
- LL$: 6,700

**Company B**
- IP: 495 boe/d / 90% oil
- LL$: 5,600

**Company C**
- IP: 672 boe/d / 64% oil
- LL$: 5,700

**Company D**
- IP: 808 boe/d / 55% oil
- LL$: 5,300

**ASTN Chalk Transition**
- 18 wells

**UEGFD**
- 142 wells

**LEGFD Stacked**
- 102 wells

**Austin Chalk**

**Upper Eagle Ford**

**Lower Eagle Ford Transition**

**Wellbores**
~30 years of drilling (1)
- >5,200 undrilled locations
- >3,200 high-confidence Lower Eagle Ford locations
- >1,700 strong ROR locations

>3.6 bboe
Estimated gross undeveloped resources

$13.2 billion
Future development costs eliminated (2016 vs. 2014) (2)

Culture of excellence
- Relentless focus on capital efficiencies
- Commitment to test new concepts and technologies
- Striving to be the low-cost operator
- Leverage existing acreage and infrastructure
- Safety culture and environmental stewardship champion

(1) Based on five rigs and 36 wells/rig
(2) Value estimate is gross and undiscounted based on remaining 3,200 Lower Eagle Ford locations and 5,200 South Texas locations
NET EQUIVALENT PRODUCTION
SOUTH TEXAS: ~15% TOTAL PRODUCTION 2016E
# SOUTH TEXAS MODELING INPUTS

## Base Production

<table>
<thead>
<tr>
<th></th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>3Q’16E Net Production</td>
<td>101 mboe/d</td>
</tr>
<tr>
<td>4 Yr. Average Annual Decline(2)</td>
<td>21%</td>
</tr>
</tbody>
</table>

## 2017 Expenses & Differential Estimates

<table>
<thead>
<tr>
<th></th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production Expense(3) ($/boe)</td>
<td>$4.45 – $4.85</td>
</tr>
<tr>
<td>GP&amp;T(4) ($/boe)</td>
<td>$10.55 – $10.75</td>
</tr>
</tbody>
</table>

## 2017 – 2020 Blended Development Program

### Curve Parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>IP(5) (Oil / Gas)</td>
<td>575 bbl/d / 855 mcf/d</td>
</tr>
<tr>
<td>Decline (Oil / Gas)</td>
<td>72.5%/54%</td>
</tr>
<tr>
<td>B-factor (Oil / Gas)</td>
<td>1.18/1.18</td>
</tr>
<tr>
<td>Shrink</td>
<td>85%</td>
</tr>
<tr>
<td>NGL Yield</td>
<td>100 bbl/mmcf</td>
</tr>
<tr>
<td>EUR</td>
<td>810 mboe</td>
</tr>
<tr>
<td>Lateral Length</td>
<td>8,400 ft.</td>
</tr>
</tbody>
</table>

### Gross Capex

<table>
<thead>
<tr>
<th>Activity</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Drilling(6) (120 days to TIL)</td>
<td>$1.4mm</td>
</tr>
<tr>
<td>Completion (58 days to TIL)</td>
<td>$2.1mm</td>
</tr>
<tr>
<td>TIL</td>
<td>$0.7mm</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>$4.2mm</strong></td>
</tr>
</tbody>
</table>

### Interest / Gross Locations

<table>
<thead>
<tr>
<th>Category</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>WI / NRI(7)</td>
<td>63%/47%</td>
</tr>
<tr>
<td>Producing</td>
<td>1,580</td>
</tr>
<tr>
<td>DUCs</td>
<td>50</td>
</tr>
<tr>
<td>Undrilled(8)</td>
<td>3,200</td>
</tr>
<tr>
<td>Rig Count</td>
<td>5 – 15</td>
</tr>
</tbody>
</table>

---

(1) Applies to total asset inclusive of non-operated
(2) Compound Annual Decline from 7/2016 – 6/2020
(3) Reflects net asset level production expense including LOE, overhead and Ad Val
(4) Excludes all intercompany marketing fees
(5) 30 day average IP
(6) 13 days spud to spud
(7) Assumed until well proposed
(8) All potential locations; not necessarily all drilled by 2020; excludes Upper Eagle Ford and Austin Chalk locations
GULF COAST:
Unique Position, Extraordinary Asset

JASON PIGOTT
CHESAPEAKE OWNS THE HAYNESVILLE
GROSS PRODUCTION AND RIG COUNT

Appraisal Program
HBP Acreage
Decreased Activity
Core Development
Technological Breakthrough

Rig Count

bcf/d


0 0.2 0.4 0.6 0.8 1.0 1.2 1.4 1.6

0 5 10 15 20 25 30 35 40

2016 ANALYST DAY – GULF COAST | 2
GULF COAST – HAYNESVILLE
ASSET OVERVIEW

- Acreage position is 100% HBP, 25% developed – ideal for long lateral development
- Completions breakthrough is scalable across entire acreage position
- Greater than 200% improvement in year-over-year gas production generated per rig line in 2016
- Ample takeaway capacity to markets with favorable pricing
- Tremendous re-stimulation and Bossier upside

### Production Mix

- **Natural Gas 100%**

### Locations

- **Drilled**: 25%
- **Remaining Development**: 75%

### Play Statistics

<table>
<thead>
<tr>
<th></th>
<th>Current</th>
<th>Post Divestiture</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Producing</strong></td>
<td>810</td>
<td>610</td>
</tr>
<tr>
<td><strong>DUC Inventory</strong></td>
<td>20</td>
<td>20</td>
</tr>
<tr>
<td><strong>Undrilled</strong></td>
<td>2,070</td>
<td>1,425</td>
</tr>
<tr>
<td><strong>Acreage</strong></td>
<td>~385,000</td>
<td>~255,000</td>
</tr>
<tr>
<td><strong>Production</strong></td>
<td>1.2 bcf/d</td>
<td>1.1 bcf/d</td>
</tr>
</tbody>
</table>
OPERATIONAL PERFORMANCE
GULF COAST

• Leading drilling performance founded on a culture of continuous improvement
• Record-setting productivity delivers more reserves per dollar invested
• Ultra-high density, large volume frac jobs and XL laterals significantly improve capital efficiency
• Relentless pursuit of value drives low production costs and greater efficiency

(1) Data represents operated net lease operating expenses excluding taxes / net equivalent volume.
(2) Average cost per foot of wells drilled and/or completed within the time period.
(3) Data represents average net D&C / net EUR, grouped by TIL year.
50mm pounds
Proppant planned for the Black 2&11-15-11 1H
Completion in progress: 70 of 85 stages pumped

19 of 20 longest laterals
Drilled by Chesapeake in the Louisiana Haynesville Shale
OLD CORE VS. NEW CORE
FULL-FIELD PARADIGM SHIFT

Completion designs increase field-wide productivity to unprecedented levels

PRE 2016

TODAY

Chesapeake retained acreage after planned divestitures
DELIVERING EXCEPTIONAL PRODUCTIVITY

>200% improvement
In production delivered per rig line from 2015 to 2016

~20% improvement in ‘17
Productivity projected to increase due to faster drilling, longer laterals and next-generation completions

<table>
<thead>
<tr>
<th>Year</th>
<th>Proppant Per Lateral Foot</th>
</tr>
</thead>
<tbody>
<tr>
<td>'08</td>
<td>6</td>
</tr>
<tr>
<td>'09</td>
<td>7</td>
</tr>
<tr>
<td>'10</td>
<td>12</td>
</tr>
<tr>
<td>'11</td>
<td>21</td>
</tr>
<tr>
<td>'12</td>
<td>24</td>
</tr>
<tr>
<td>'13</td>
<td>42</td>
</tr>
<tr>
<td>'14</td>
<td>29</td>
</tr>
<tr>
<td>'15</td>
<td>44</td>
</tr>
<tr>
<td>'16E</td>
<td>140</td>
</tr>
<tr>
<td>'17E</td>
<td>170</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Year</th>
<th>Drilled Lateral Length</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>5,847</td>
</tr>
<tr>
<td>2016E</td>
<td>7,578</td>
</tr>
<tr>
<td>2017E</td>
<td>9,100</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Year</th>
<th>Drilling Days</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>36</td>
</tr>
<tr>
<td>2016E</td>
<td>33</td>
</tr>
<tr>
<td>2017E</td>
<td>30</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Year</th>
<th>Annualized Gas Rate per Rig (mmcf/d/rig)</th>
</tr>
</thead>
<tbody>
<tr>
<td>'15</td>
<td>170</td>
</tr>
<tr>
<td>'16E</td>
<td>140</td>
</tr>
<tr>
<td>'17E</td>
<td>170</td>
</tr>
</tbody>
</table>

Drilled Lateral Length
Drilling Days
Proppant Per Lateral Foot
Annualized Gas Rate per Rig (mmcf/d/rig)
GAME-CHANGING PERFORMANCE
LONGER LATERALS AND BIGGER COMPLETIONS

New CHK wells delivering monster IPs
CA 1H – 38 mmcf/d, 10,000’ lateral
PCK 1H – 31 mmcf/d, 7,000’ lateral
WILL 1H – 34 mmcf/d, 8,350’ lateral

>250% increase
In 90-day production with extended laterals, increased proppant loading and reduced cluster spacing
**DRAWDOWN MANAGEMENT**

**RECORD PRODUCTIVITY WITH RESPONSIBLE DRAWDOWN**

- **3 bcf in 90 days**
  CA 1H cumulative production – a 63% improvement over the *next-best CHK well* in the play

- **9.3 bcf in first year**
  CA 1H first year estimated cumulative production – a ~50% increase over a 10K lateral with an improved completion

- **One-year payout**
  CA 1H estimate – Haynesville wells driving short-cycle cash flow

- **Prioritizing long-term value over short-term gains**

---

**90-Day Pressure Drawdown (psi/day)**

- **‘07**
- **‘08 – ‘09**
- **‘10 – ‘13**
- **‘14 – ‘15**
- **‘16YTD**

**90-Day Cumulative Production (bcf)**

- **0.0**
- **0.5**
- **1.0**
- **1.5**
- **2.0**
- **2.5**
- **3.0**
- **3.5**

**CA 1H 10,000' lateral well**
NEW TECHNOLOGY DRIVES VALUE CREATION
LONGER LATERALS AND BIGGER COMPLETIONS

3% ROR $\rightarrow$ 47% ROR \(^{(1)}\)
Combination of extended laterals and current completions revolutionize economics

$2.30$ break-even
CA 1H PV10 break-even gas price

10,000' wells remaining
660 Haynesville locations
190 Bossier locations

(1) Assumes $3.00 flat price deck
OFFSET FRAC UPLIFT
BREATHING NEW LIFE INTO AGING WELLS

7,250 mcf/d increase
In production from the Clingman Acres 1H after the CA 1H stimulation

85% success rate
In 26 trials the existing well production uplift >1,000 mcf/d after offsetting stimulation

7,500 mcf/d

250 mcf/d

Days Before / After Re-stimulation

Clingman Acres 12-15-15 H-1
GULF COAST
WORLD-CLASS RESOURCE

• CHK Haynesville position is **100% HBP** and **only 25% developed**

• Unique opportunity to develop field with newest technology

• Industry-leading Bossier position and re-stimulation potential

Future Returns of the Gulf Coast (1)

<table>
<thead>
<tr>
<th>Year</th>
<th>2Q '16</th>
<th>10,000' Laterals w/ Modern Completion</th>
<th>10,000'+ Lateral w/ 3,000'+ lbs./ft. Completion</th>
</tr>
</thead>
<tbody>
<tr>
<td>2016E</td>
<td>27%</td>
<td>50%</td>
<td>~70%</td>
</tr>
<tr>
<td>2017+</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The Haynesville is no longer a Chesapeake obligation – it is a world-class investment opportunity

(1) Assumes $3 mcf gas price
BOSSIER SHALE
SIGNIFICANT UPSIDE POTENTIAL

• First 7,500’ lateral drilled in 2015
  > IP 17.7 mmcf/d at 7,480 psi
  > 1,900 lbs. of proppant per ft.

• Completions optimization
  > Promising results observed with vintage completions
  > **Substantial** uplift anticipated with 3,000 – 5,000 lbs./ft.

• Significant upside potential across CHK-operated acreage
  > Estimated 190 10,000’ lateral locations
  > Nearly 5 tcf of recoverable reserves

---

**The Bossier is a blank canvas upon which we can apply eight years of learnings from the Haynesville**

---

70% IP and 50% EUR improvement
Expected with 10,000' lateral and 3,000 lbs./ft.
NET EQUIVALENT PRODUCTION
GULF COAST: ~20% TOTAL PRODUCTION 2016E

Gulf Coast
**GULF COAST MODELING INPUTS**

### Base Production

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>3Q’16E Net Production</td>
<td>835 mmcf/d</td>
</tr>
<tr>
<td>4 Yr. Average Annual Decline</td>
<td>30%</td>
</tr>
</tbody>
</table>

### 2017 Expenses & Differential Estimates

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production Expense ($/mcf)</td>
<td>$0.20 - $0.26</td>
</tr>
<tr>
<td>GP&amp;T ($/mcf)</td>
<td>$0.90 – $1.00</td>
</tr>
</tbody>
</table>

### 2017 – 2020 Blended Development Program

#### Curve Parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>IP</td>
<td>24.6 mmcf/d</td>
</tr>
<tr>
<td>Decline</td>
<td>73.5%</td>
</tr>
<tr>
<td>B-factor</td>
<td>0.96</td>
</tr>
<tr>
<td>EUR</td>
<td>19.9 bcf</td>
</tr>
<tr>
<td>Lateral Length</td>
<td>9,800 ft.</td>
</tr>
</tbody>
</table>

#### Gross Capex

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Drilling (133 days to TIL)</td>
<td>$3.8mm</td>
</tr>
<tr>
<td>Completion (37 days to TIL)</td>
<td>$5.7mm</td>
</tr>
<tr>
<td>TIL</td>
<td>$0.8mm</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>$10.3mm</strong></td>
</tr>
</tbody>
</table>

#### Interest / Gross Locations

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>WI / NRI</td>
<td>80%/63%</td>
</tr>
<tr>
<td>Producing</td>
<td>810</td>
</tr>
<tr>
<td>DUCs</td>
<td>20</td>
</tr>
<tr>
<td>Undrilled</td>
<td>2,070</td>
</tr>
<tr>
<td>Rig Count</td>
<td>2 – 4</td>
</tr>
</tbody>
</table>

---

(1) Applies to total asset inclusive of non-operated
(2) Compound Annual Decline from 7/2016 – 6/2020
(3) Reflects net asset level production expense including LOE, overhead and Ad Val
(4) Excludes all intercompany marketing fees
(5) 6 month flat period
(6) 35 days spud to spud
(7) Assumed until well proposed
(8) All potential locations; not necessarily all drilled by 2020
FINANCE:
Capital Structure and Outlook

NICK DELL’OSSO
WHERE WE’VE COME FROM

Substantial progress on every front

2012 – 2016

✔ Reduced total net leverage by ~50% ($10.9 billion)
✔ Improved cash costs by ~50% per boe
✔ Reduced financial and balance sheet complexity

➤ Led to substantial reduction in financing costs
➤ Increase in margins on $/boe basis
➤ Reduction in overhead due to simpler structure
**RESTORING COST OF CAPITAL**

**Restored liquidity**
**Refinanced maturities**
**Reduced total leverage**

- Third amendment to RCF
- Open-market repurchases

- Second amendment to RCF
- Debt exchange

Source: Bloomberg

(1) The composite yield represents the weighted-average yield by outstanding principal for nine different bonds with maturities ranging from 2017 to 2023.
### REDUCED TOTAL LEVERAGE AND COMPLEXITY

Chesapeake continues to simplify the business:

- Eliminated finance leases, subsidiary preferred equity and seven VPPs
- Optimizing the capital structure

#### ~50% reduction

In total net leverage

= $10.9 billion

#### Reduced Total Leverage and Complexity

<table>
<thead>
<tr>
<th></th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>3Q’16</th>
<th>Pro Forma 3Q’16</th>
</tr>
</thead>
<tbody>
<tr>
<td>Credit Facility</td>
<td>$418</td>
<td>$405</td>
<td>$0</td>
<td>$0</td>
<td>$240</td>
<td>$0</td>
</tr>
<tr>
<td>Term Loan</td>
<td>$2,000</td>
<td>$2,000</td>
<td>$0</td>
<td>$0</td>
<td>$1,500</td>
<td>$1,500</td>
</tr>
<tr>
<td>Second-Lien Notes</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$2,425</td>
<td>$2,425</td>
<td>$2,425</td>
</tr>
<tr>
<td>Long-Term Bonds</td>
<td>$10,647</td>
<td>$10,825</td>
<td>$11,756</td>
<td>$7,281</td>
<td>$4,552</td>
<td>$5,697</td>
</tr>
<tr>
<td>Less: Cash</td>
<td>($287)</td>
<td>($837)</td>
<td>($4,108)</td>
<td>($825)</td>
<td>($4)</td>
<td>($900)</td>
</tr>
<tr>
<td><strong>Net Debt</strong></td>
<td>$12,778</td>
<td>$12,393</td>
<td>$7,648</td>
<td>$8,881</td>
<td>$8,713</td>
<td>$8,722</td>
</tr>
<tr>
<td>VPPs</td>
<td>$3,186</td>
<td>$2,454</td>
<td>$1,702</td>
<td>$1,289</td>
<td>$675</td>
<td>$675</td>
</tr>
<tr>
<td>Operating and Finance Leases</td>
<td>$1,255</td>
<td>$948</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>Subsidiary Preferred</td>
<td>$2,500</td>
<td>$2,310</td>
<td>$1,250</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>Corporate Preferred</td>
<td>$1,531</td>
<td>$1,531</td>
<td>$1,531</td>
<td>$1,531</td>
<td>$1,518</td>
<td>$932</td>
</tr>
<tr>
<td><strong>Total Adjusted Net Leverage</strong></td>
<td>$21,250</td>
<td>$19,636</td>
<td>$12,131</td>
<td>$11,701</td>
<td>$10,906</td>
<td>$10,329</td>
</tr>
</tbody>
</table>

(1) Pro forma convertible note offering, preferred stock for common stock exchanges and open market repurchases of outstanding long-term bonds in October
(2) 2016 security is 1.5 Lien Term Loan
(3) Assumes euro-denominated notes are converted to USD at the relevant exchange rate for each calendar period; for pro forma 3Q’16E, exchange rate as of 9/30/16
(4) Using Moody’s valuation methodology
WHERE WE ARE GOING

Strategic financial targets

- Grow production 5 – 15% annually
- Retire $2 – $3 billion of debt
- Reduce leverage to 2X net debt/ebitda
- Achieve free cash flow neutrality
- More than double ebitda by 2018

- Leads to investment grade metrics
- Allows more stable development profile through cycles
- Provides flexibility to pursue opportunities for growth
### 2016E AND 2017E OUTLOOK SUMMARY

<table>
<thead>
<tr>
<th>2016E</th>
<th>2017E</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Adjusted Production Growth</strong>&lt;sup&gt;(1)&lt;/sup&gt;</td>
<td>0% – 3%</td>
</tr>
<tr>
<td><strong>Absolute Production:</strong></td>
<td></td>
</tr>
<tr>
<td>Oil – mmbbls</td>
<td>33 – 35</td>
</tr>
<tr>
<td>NGL – mmbbls</td>
<td>23 – 25</td>
</tr>
<tr>
<td>Natural gas – bcf</td>
<td>1,020 – 1,040</td>
</tr>
<tr>
<td><strong>Total absolute production – mmboe</strong></td>
<td>226 – 233</td>
</tr>
<tr>
<td><strong>Absolute daily rate – mboe</strong></td>
<td>617 – 637</td>
</tr>
<tr>
<td><strong>Operating Costs per Boe of Projected Production:</strong>&lt;sup&gt;(2)&lt;/sup&gt;</td>
<td></td>
</tr>
<tr>
<td>Production expenses, production taxes and G&amp;A</td>
<td>$4.25 – $4.75</td>
</tr>
<tr>
<td>Gathering, processing and transportation expenses</td>
<td>$7.60 – $8.10</td>
</tr>
<tr>
<td>Capital Expenditures ($mm)&lt;sup&gt;(3)&lt;/sup&gt;</td>
<td>$1,400 – $1,500</td>
</tr>
<tr>
<td>Capitalized Interest ($mm)</td>
<td>$250</td>
</tr>
<tr>
<td><strong>Total Capital Expenditures ($mm)</strong></td>
<td>$1,650 – $1,750</td>
</tr>
</tbody>
</table>

<sup>(1)</sup> Based on 2015 production of 550 mboe per day, adjusted for 2015 and 2016 sales
<sup>(2)</sup> Includes stock-based compensation
<sup>(3)</sup> Includes capital expenditures for drilling and completion, leasehold, geological and geophysical costs, rig termination payments and other property and plant and equipment

---

<sup>(1)</sup> Based on 2016 estimated production of 548 mboe per day, adjusted for 2016 sales. Subject to future A&D activity.
<sup>(2)</sup> Includes stock-based compensation
<sup>(3)</sup> Includes capital expenditures for drilling and completion, leasehold, geological and geophysical costs, rig termination payments and other property and plant and equipment.
SIGNIFICANT REDUCTIONS IN CASH COSTS

Industry-leading cash cost structure:

> Relentless focus on cost management

> Operational leadership and technical capabilities provide industry-leading production expense

~50% reduction
In production and G&A expenses per boe since 2012

<table>
<thead>
<tr>
<th>Year</th>
<th>Production Expense and G&amp;A ($/boe)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>$7.76</td>
</tr>
<tr>
<td>2013</td>
<td>$6.60</td>
</tr>
<tr>
<td>2014</td>
<td>$5.94</td>
</tr>
<tr>
<td>2015</td>
<td>$5.17</td>
</tr>
<tr>
<td>2016E</td>
<td>$4.10</td>
</tr>
<tr>
<td>2017E</td>
<td>$3.80</td>
</tr>
</tbody>
</table>

(1) Includes production expenses and general and administrative expenses, including stock-based compensation
(2) 2016E and 2017E represents current guidance midpoints
CONTINUED IMPROVEMENT IN MIDSTREAM FEES

**Utica**
Optimized COS (Wet), Fixed (Dry) Fees
24% of GP&T Exposure

**Eagle Ford**
Optimizing Fee
25% of GP&T Exposure

**Marcellus**
Optimized COS Fee
18% of GP&T Exposure

**Haynesville**
Optimized Fixed Fee
21% of GP&T Exposure

**Mid-Continent**
Optimized Fixed Tiered Fee
8% of GP&T Exposure

**Powder River**
Optimizing to Fixed Tiered Fee
4% GP&T Exposure
OPTIMIZING COMMITMENTS TO FURTHER INCREASE EBITDA

~$59mm reduction
In natural gas transportation shortfall in 2016

~25% improvement
In natural gas transportation utilization in 2016

~$5.0 billion reduction
In midstream and marketing commitments since 2014

GP&T Commitments ($ billion)

<table>
<thead>
<tr>
<th></th>
<th>YE’14</th>
<th>YE’15</th>
<th>YE’16E (1,2)</th>
</tr>
</thead>
<tbody>
<tr>
<td>YE’14</td>
<td>$16.0</td>
<td>$14.0</td>
<td>$11.1</td>
</tr>
</tbody>
</table>

(1) 2016E excludes Barnett (divestment pending)
(2) Also have additional gas gathering agreements with cost-of-service based fees; redetermined annually or tiered fees based on volumes
~15% IMPROVEMENT IN GP&T COSTS SINCE 2015

- **Marcellus**
  - Optimized COS fee

- **Utica Dry & Haynesville**
  - Restructured COS fee to fixed fee

- **Mid-Con & Barnett**
  - Restructured fixed fee in Mid-Con and signed PSA in Barnett; Reduced several transportation commitments

- **Powder River**
  - Under binding LOI to restructure COS fee to fixed fee

- **Eagle Ford**
  - Optimizing fee
  - 80%+ of revenues driven by oil

### GP&T $/boe (1,2)

- **2014**: $8.43
- **2015**: $8.55
- **2016 Prior Estimate**: $8.58
- **2016E**: $7.60 – $8.10
- **2017E New**: $7.00 – $7.50
- **Future**: $6.00 – $7.00

2017: Expect 14% improvement in GP&T due to recent Mid-Con restructuring and Barnett divestiture (pending)

---

(1) Includes MVC shortfall

(2) Excludes all intercompany marketing fees
THE PATH TO FCF NEUTRAL

Cost structure improvements are clearing the path to FCF neutrality in 2018

~$5.50/boe reduction
In LOE, G&A and GP&T from peak rates since 2012 (1)

$10.9 billion
In total net leverage reduction since 2012

40% – 60% improvement
In capital efficiency since 2012

~$600mm reduction
In annual leverage service costs since 2012 (2)

(1) Compared to 2017 guidance midpoints
(2) Represents reductions to corporate preferred dividends, subsidiary preferred dividends and interest expense on debt instruments and financing leases
CASH FLOW NEUTRAL IN 2018

2017 vs. 2016 Adjusted Production Decline of (5%) – 0%

2017 cash flow outspend of $400mm – $600mm (1)

2018 vs. 2017 Adjusted Production Growth of 10% – 15%

CHK turns FCF neutral
In 2018 due to production growth from 2017 investment

(1) Excluding judgment for BONY litigation and debt maturities
HEDGING POSITION

### Natural Gas
- **2016**
  - 72% Swaps
  - 6% Collars
  - $3.00/$3.48/mcf NYMEX

### Oil
- **2016**
  - 75%
  - Swaps $46.84/bbl

### NGL
- **2016**
  - 17%
  - Ethane Swaps $0.17/gal
  - Propane Swaps $0.46/gal

### Natural Gas
- **2017**
  - 63%
  - 3% Collars
  - $3.00/$3.48/mcf NYMEX

### Oil
- **2017**
  - 52%
  - Swaps $49.68/bbl

---

(1) Calculated off of 4Q production forecast as of 10/10/16
(2) Using midpoints for projected 2017 total production from 8/9/2016 Outlook
REDUCTION IN 2017 MATURITIES

70% reduction
In maturities from 9/30/15 to 9/30/16

$2,214 (2)
$1,168
$660
$60
$1,384 (2)
$730
$315
$625 (2)
$275
$339
$315
$387

Sources: Company management and disclosures. Note: $ in millions.
(1) $4.0 billion credit facility plus cash pro forma the convertible note funds, less outstanding letters of credit as of 9/30/2016
(2) 6.25% 2017’s converted to USD for entire period using exchange rate of $1.1235 to €1.00 as of 9/30/2016
(3) Pro forma open market repurchases in October 2016
(4) Incremental liquidity savings includes principal savings and net interest impact

Financial Transaction | Liquidity Savings (4)
---|---
Debt Exchange | $305mm of second-lien notes | $291mm
Open Market Repurchases | $138mm of cash | $85mm
Debt for Equity Exchanges | 68.6mm shares (valued at $295mm) | $354mm
Tender Offer | $722mm of 1.5 lien term loan | $684mm

~$1.4 billion
DEBT MATURITY PROFILE

$2.1 billion
Debt principal removed from books in 2015 and 2016 as of 9/30/16

Pre-fund
Remaining 2017 – 2018 maturities with convertible note offering due 2026

(1) Recognizes earliest investor put option as maturity for the 2.75% 2035, 2.50% 2037 and 2.25% 2038 Contingent Convertible Senior Notes
(2) Pro forma convertible note offering and open market repurchases in October 2016
PREFERRED STOCK EXCHANGES

To further improve the capital structure, Chesapeake negotiated agreements to exchange shares of preferred stock for common shares:

- Issued an aggregate of 110.3 millions of shares of common stock to eliminate approximately $1.2 billion of preferred stock obligations from capital structure.
- Secured annual dividend savings of approximately $67mm.

### Exchange Transaction Summary

<table>
<thead>
<tr>
<th>Series</th>
<th>Annual Dividend ($000)</th>
<th>Preferred Shares</th>
<th>Liquidation Preference Value ($000)</th>
<th>Preferred Shares Eliminated</th>
<th>Preference Value Eliminated ($000)</th>
<th>Common Shares Issued</th>
<th>Annual Dividend ($000)</th>
<th>Preferred Shares</th>
<th>Liquidation Preference Value ($000)</th>
</tr>
</thead>
<tbody>
<tr>
<td>4.50%</td>
<td>$11,515</td>
<td>2,558,900</td>
<td>$255,890</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>$11,515</td>
<td>2,558,900</td>
<td>$255,890</td>
</tr>
<tr>
<td>5.00%</td>
<td>$10,478</td>
<td>2,095,615</td>
<td>$209,562</td>
<td>134,000</td>
<td>$13,400</td>
<td>1,012,032</td>
<td>$9,808</td>
<td>1,961,615</td>
<td>$196,162</td>
</tr>
<tr>
<td>5.75%</td>
<td>$84,663</td>
<td>1,472,399</td>
<td>$1,472,399</td>
<td>606,271</td>
<td>$606,271</td>
<td>55,083,869</td>
<td>$49,802</td>
<td>866,128</td>
<td>$866,128</td>
</tr>
<tr>
<td>5.75% (A)</td>
<td>$63,181</td>
<td>1,098,799</td>
<td>$1,098,799</td>
<td>553,007</td>
<td>$553,007</td>
<td>54,243,322</td>
<td>$31,383</td>
<td>545,792</td>
<td>$545,792</td>
</tr>
<tr>
<td></td>
<td>$169,837</td>
<td>7,225,713</td>
<td>$3,036,650</td>
<td>1,293,278</td>
<td>$1,172,678</td>
<td>110,339,223</td>
<td>$102,508</td>
<td>5,932,435</td>
<td>$1,863,972</td>
</tr>
</tbody>
</table>

- **$586mm reduction** in leverage from cap structure (1)
- **$67mm reduction** in cumulative annual dividends

(1) Using Moody’s valuation methodology
Marcellus North GP&T \(^{(1)}\)

Cost-of-service advantage
Continued fee reduction through midstream optimization
- Increase infrastructure utilization
- Decrease capex for wedge production
- 20% decrease in gathering fees since 2014

Transport optionality enables margin capture above postings

Incremental Value for the Manhattan Lateral

(1) Excludes all intercompany marketing fees
**Haynesville GP&T**

- 2014: $1.21
- 2015: $1.20
- 2016E: $1.05 – $1.15
- 2017E: $0.90 – $1.00

**Transportation portfolio**

Allows access to major market hubs, industrial market centers and export markets for LNG and Mexico

**Improved Tiger commitment by 30% – 50%**

In 2016

---

(1) Excludes all intercompany marketing fees
UTICA

Selling gas to premium out-of-basin locations with limited basis exposure

Focus on expanding margins
Significant cost savings on crude oil hauling realized over past 14 months

Negotiated Crude Oil Hauling Rate Reductions

<table>
<thead>
<tr>
<th>Month</th>
<th>Wt. Avg. Haul/bbl</th>
<th>Diesel $/gal</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aug 2015</td>
<td>$1.94</td>
<td>$2.60</td>
</tr>
<tr>
<td>Jun 2016</td>
<td>$1.58</td>
<td>$2.42</td>
</tr>
<tr>
<td>Change</td>
<td>-19%</td>
<td>-7%</td>
</tr>
</tbody>
</table>

(1) Excludes all intercompany marketing fees
Targeting downstream markets with a premium to CIG

Development of crude takeaway from basin leads to improved margins

(1) Excludes all intercompany marketing fees
Increased revenue through additional NGL recovery
Wedge production under fixed-fee contracts allow greater NGL yields from gas production (vs. historical POP contracts)

Recognizing increasing premiums for Miss Lime production

(1) Excludes all intercompany marketing fees. 2017 Mid-Con impact from NGL wedge production under fixed processing fee.
Better margins through downstream marketing

Crude market access to:
- ~2,500 mbo/d per day refinery demand in Houston
- ~700 mbo/d per day refinery demand in Corpus
- Multiple deep-water docks for potential exports

Eagle Ford GP&T, $/boe

Negotiated Crude Oil Hauling Rate Reductions

<table>
<thead>
<tr>
<th>Month</th>
<th>Wt. Avg. Haul/bbl</th>
<th>Diesel $/gal</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aug 2015</td>
<td>$1.70</td>
<td>$2.04</td>
</tr>
<tr>
<td>Jun 2016</td>
<td>$1.53</td>
<td>$1.97</td>
</tr>
<tr>
<td>Change</td>
<td>-11%</td>
<td>-3.5%</td>
</tr>
</tbody>
</table>

(1) Excludes all intercompany marketing fees
## MARKETING COMMITMENTS ESTIMATES ($MM)

### ~15% improvement in transport utilization since 2015 (1)

<table>
<thead>
<tr>
<th>Category</th>
<th>2016 (2)</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
<th>Thereafter</th>
</tr>
</thead>
<tbody>
<tr>
<td>Barnett Gathering</td>
<td>415</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Barnett Transportation</td>
<td>165</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Haynesville Gathering</td>
<td>215</td>
<td>195</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Haynesville Transportation</td>
<td>160</td>
<td>160</td>
<td>150</td>
<td>150</td>
<td>125</td>
<td>115</td>
<td>425</td>
</tr>
<tr>
<td>Northeast Gathering</td>
<td>10</td>
<td>25</td>
<td>45</td>
<td>45</td>
<td>45</td>
<td>45</td>
<td>550</td>
</tr>
<tr>
<td>Northeast Transport</td>
<td>275</td>
<td>270</td>
<td>260</td>
<td>260</td>
<td>260</td>
<td>255</td>
<td>2470</td>
</tr>
<tr>
<td>NGL Transportation</td>
<td>60</td>
<td>70</td>
<td>90</td>
<td>90</td>
<td>90</td>
<td>90</td>
<td>600</td>
</tr>
<tr>
<td>Crude Oil Transportation</td>
<td>260</td>
<td>290</td>
<td>260</td>
<td>255</td>
<td>260</td>
<td>255</td>
<td>580</td>
</tr>
<tr>
<td>Processing/Treating</td>
<td>150</td>
<td>150</td>
<td>155</td>
<td>155</td>
<td>150</td>
<td>125</td>
<td>680</td>
</tr>
<tr>
<td>Other Commitments</td>
<td>230</td>
<td>210</td>
<td>210</td>
<td>185</td>
<td>185</td>
<td>85</td>
<td>10</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>1,940</strong></td>
<td><strong>1,370</strong></td>
<td><strong>1,170</strong></td>
<td><strong>1,140</strong></td>
<td><strong>1,115</strong></td>
<td><strong>970</strong></td>
<td><strong>5,315</strong></td>
</tr>
</tbody>
</table>

1. Continuing to optimize firm transportation shortfalls through capacity releases, third-party gas purchases and asset management agreements
2. Also have additional gas gathering agreements with cost-of-service based fees; redetermined annually or tiered fees based on volumes
RECONCILIATION OF PV10 TO STANDARDIZED MEASURE

PV10 is a non-GAAP metric used by the industry, investors and analysts to estimate the present value, discounted at 10% per annum, of estimated future cash flows of the company’s estimated proved reserves before income tax and asset retirement obligations. The following table shows the reconciliation of PV10 to the company’s standardized measure of discounted future net cash flows, the most directly comparable GAAP measure, for the year ended December 31, 2015 and for the interim period ended June 30, 2016. Management believes that PV10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and natural gas companies. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, management believes the use of a pre-tax measure is valuable for evaluating the company. PV10 should not be considered as an alternative to the standardized measure of discounted future net cash flows as computed under GAAP. With respect to PV10 calculated as of an interim date, it is not practical to calculate taxes for the related interim period because GAAP does not provide for disclosure of standardized measure on an interim basis.

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>PV10 – June 30, 2016 @ NYMEX Strip</td>
<td>11,050</td>
</tr>
<tr>
<td>Less: Change in pricing assumption from NYMEX Strip to SEC</td>
<td>(7,995)</td>
</tr>
<tr>
<td>PV10 – June 30, 2016 @ SEC</td>
<td>3,055</td>
</tr>
<tr>
<td>Change in PV10 from 12/31/15 to 6/30/16</td>
<td>1,672</td>
</tr>
<tr>
<td>PV10 – December 31, 2015 @ SEC</td>
<td>4,727</td>
</tr>
<tr>
<td>Less: Present value of future income tax discounted at 10%</td>
<td>(34)</td>
</tr>
<tr>
<td>Standardized measure of discounted future cash flows – December 31, 2015</td>
<td>$ 4,693</td>
</tr>
</tbody>
</table>
Summary and Path Forward
$2–3 BILLION
in additional planned debt reduction
REDUCE LEVERAGE TO 2X Debt/EBITDA

*Assumes retirement of maturities in 2017 and 2018 as well as conversion to equity of convertible note in 2019; 5 – 15% production growth and gas and oil price assumptions range from $2.50 – $3.50 and $50 – $70.
BUSINESS DEVELOPMENT

FINANCIAL DISCIPLINE

EXPLORATION

PROFITABLE AND EFFICIENT GROWTH
Active Portfolio Management

Committed to high-grading the portfolio through value-accrative transactions
Exploration Opportunities

17

Prospects adding value to current HBP position

15

Growth opportunities in CHK-operated basins

11

New basin-entry plays

COMMITTED TO FURTHER STRENGTHEN PORTFOLIO THROUGH EXPLORATION
PROFITABLE AND EFFICIENT GROWTH
TARGETING 5–15% GROWTH THROUGH END OF DECADE

*5 – 15% represents an adjusted production growth; capital ranges dependent on anticipated pricing
MARGIN EXPECTED TO TRIPLE

*5 – 15% production growth and gas and oil price assumptions range from $2.50 – $3.50 and $50 – $70
EBITDA GROWTH MORE THAN DOUBLE BY 2018

*5 – 15% production growth and gas and oil price assumptions range from $2.50 – $3.50 and $50 – $70
Chesapeake Energy Rediscovered

Done more, doing more, more to do.