FORWARD-LOOKING STATEMENT

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, management's outlook 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, anticipated timing of wells to be placed into production, general and administrative expenses, capital expenditures, the timing of anticipated asset sales and proceeds to be received therefrom, the expected use of proceeds of anticipated asset sales, projected cash flow and liquidity, our ability to enhance our cash flow and financial flexibility, plans and objectives for future operations, 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; 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 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 cyber-attacks adversely impacting our operations; an interruption in operations at our headquarters due to a catastrophic event; 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.

We use certain terms in this presentation such as “Resource Potential,” “Net Resource,” “Net Reserves” and similar terms that the SEC’s guidelines strictly prohibit us from including in filings with the SEC. These terms include reserves with substantially less certainty, and no discount or other adjustment is included in the presentation of such reserve numbers. U.S. investors are urged to consider closely the disclosure in our Form 10-K for the year ended December 31, 2017, File No. 1-13726 and in our other filings with the SEC, available from us at 6100 North Western Avenue, Oklahoma City, Oklahoma 73118. These forms can also be obtained from the SEC by calling 1-800-SEC-0330.
BUSINESS STRATEGIES

Our strategy remains unchanged – resilient to commodity price volatility

- Financial discipline
- Profitable and efficient growth from captured resources
- Exploration
- Business development

STRATEGIC GOALS

1. Net debt to EBITDA of 2X
2. Free cash flow neutrality
3. Margin enhancement
RESTORING OUR BALANCE SHEET

Intend to apply $1.9 billion net proceeds from Utica transaction to debt reduction

- Anticipate targeting secured and near-term maturities
- Up to $150 million in cash interest savings projected for 2019

Renewed revolving credit facility in 3Q 2018

- More than $7 billion of collateral, excluding Utica assets, to support borrowing base
DIVERSE AND STRONG PORTFOLIO
CORE POSITION ACROSS FIVE BASINS

POWDER RIVER BASIN
5 Rigs, 1 Frac Crew
~$25 – 35/bbl Breakeven
~256,000 Net Acres (77% HBP)

APPALACHIA NORTH
3 Rigs, 1 Frac Crew
~$1.80 – 2.20/mcf Breakeven
~552,000 Net Acres (86% HBP)

MID-CONTINENT
2 Rigs, 1 Frac Crew
~$30 – 45/bbl Breakeven
~783,000 Net Acres (96% HBP)

GULF COAST
3 Rigs, 1 Frac Crew
~$2.00 – 2.25/mcf Breakeven
~375,000 Net Acres (90% HBP)

SOUTH TEXAS
4 Rigs, 2 Frac Crews
~$25 – 45/bbl Breakeven
~266,000 Net Acres (97% HBP)

530 mboe/d
90 mbo/d

(1) Net acreage estimates as of June 30, 2018 and pro forma for announced Utica asset divestiture. Includes acreage outside of these specific basins shown. 2018 current rig and crew count; PV10 breakeven with oil held flat at $60/bbl and gas held flat at $2.75/mcf.
(2) Average production for Q2 2018 that includes production 106 mboe/d from the Utica asset

September 2018 Update
POWDER RIVER BASIN
OIL GROWTH ENGINE

- Production Ramp Ahead of Schedule
- Turner Leads the Way
- Stacked Future, Hotspot Advantage

~2.6 bboe
Gross resource size
~1.7 bboe net

Production Mix (1)

<table>
<thead>
<tr>
<th></th>
<th>Oil</th>
<th>NGL</th>
<th>Natural Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>44%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>17%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>39%</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

(1) Represents average for 2Q 2018
PRODUCTION GROWING RAPIDLY
~90% OIL GROWTH YTD, ~100% EXPECTED IN 2019\(^{(1)}\)

32 mboe/d
Current field rate\(^{(2)}\)

---

\(1\) Projected annual growth in 2019 compared to 2018 projected annual volumes
\(2\) As of 7/24/2018, net volume
Progress to date

- De-risking acreage
- 18 Turner producers to date
- TIL pace accelerating
- Testing spacing assumptions
- ~$25/bbl breakeven\(^{(1)}\)

\(^{(1)}\) Assuming a flat $2.75/mcf gas price and a discount rate of 10%
TURNER SPACING TEST UPDATE

- 100-day production analysis yielding positive results
  - Continue monitoring for 250+ days
- Potential to expand inventory ~80 wells to ~470 Turner locations at 1,980'
IMPROVING EFFICIENCIES, ENHANCING RETURNS

Turner Well Costs

$2,500

50% reduction

Gross $ / lateral foot

Q1 2017
Q2 2017
Q3 2017
Q4 2017
Q1 2018
Q2 2018
Q3 2018E

Includes pre-drill, drilling, completion and TIL costs

September 2018 Update
STACKED FUTURE, HOTSPOT ADVANTAGE

Potential Wells Per Section

- 1 – 5
- 6 – 10
- 10 – 15
- 16 – 20
- 21 – 26
- CHK Footprint

Peer Positions

Chesapeake Core Area

- North
  - Teapot
  - Parkman BC
- South
  - Teapot
  - Parkman BC

Niobrara Source Rock

- Turner
- Frontier
- Non-Conductive Basement

Mowry Source Rock

- Heat

Northern Hot Spot

Chesapeake Hot Spot
Infrastructure enhancements
- Leveraging Bucking Horse expansion
- Building central production facilities
- Installing crude oil and water gathering systems

Environmental stewardship
- Developing multi-well pads
- Recycling water for drilling and completions
- Powering rigs with electricity

Next formations to develop
- Niobrara
- Parkman

Other potential formations include: Teckla, Surrey, Frontier, Muddy, Dakota/Lakota and Pennsylvanian
POWDER RIVER BASIN
OIL GROWTH ENGINE

- Production ramp ahead of schedule
- Turner leads the way
- Stacked future, hotspot advantage

PATH FORWARD

- 100% expected oil growth within cash flow\(^{(1)}\) in 2019
- Move to additional zone development, potential sixth rig in 2019
- Expanding marketing options

\(^{(1)}\) Defined as net revenue less all operating costs and capital expenditures. Excludes corporate overhead costs such as capitalized interest and capitalized G&A expenses.

September 2018 Update
SOUTH TEXAS
FOUNDATIONAL ASSET

- Consistent High-Margin EBITDA Delivery
- ~$475 Million FCF\(^{(1)}\) in 2018
- Multi-Zone Growth Potential

1.3 bboe
Net resource size\(^{(2)}\)

<table>
<thead>
<tr>
<th>Production Mix (^{(3)})</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil: 58%</td>
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<tr>
<td>NGL: 18%</td>
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<tr>
<td>Natural Gas: 24%</td>
</tr>
</tbody>
</table>

\(^{(1)}\) Free cash flow defined as net revenue less all operating costs and capital expenditures. Excludes corporate overhead costs such as capitalized interest and capitalized G&A expenses.

\(^{(2)}\) Includes IOR potential

\(^{(3)}\) Represents average for 2Q 2018
Increased lateral length, spacing and completions design results in:

- 45% increase in initial well performance (1)
- 140% increase in PV per well (2)

- Cumulative production to date of optimized Blakeway development program vs. historic development of the area at 330’ spacing
- $2.75 / $60 price deck
- First year average gross oil rate per day binned by turn-in-line year
FOUNDATIONAL ASSET
GENERATING SIGNIFICANT FREE CASH FLOW

~$475 million in FCF\(^{(1)}\)
Projected for 2018

(1) Free cash flow defined as net revenue less all operating costs and capital expenditures. Excludes corporate overhead costs such as capitalized interest and capitalized G&A expenses.
CONTINUOUS IMPROVEMENT IN A MATURE BASIN

Feet Drilled / Day

<table>
<thead>
<tr>
<th>Year</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018E</th>
</tr>
</thead>
<tbody>
<tr>
<td>Value</td>
<td>1,013’</td>
<td>1,147’</td>
<td>1,772’</td>
<td>1,668’</td>
<td>1,855’</td>
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</table>

Gross Well Costs / Foot\(^{(1)}\)

<table>
<thead>
<tr>
<th>Year</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018E</th>
</tr>
</thead>
<tbody>
<tr>
<td>Value</td>
<td>$1,011</td>
<td>$866</td>
<td>$463</td>
<td>$652</td>
<td>$569</td>
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</tbody>
</table>

Completed Lateral Feet / Day / Crew

<table>
<thead>
<tr>
<th>Year</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018E</th>
</tr>
</thead>
<tbody>
<tr>
<td>Value</td>
<td>785</td>
<td>699</td>
<td>711</td>
<td>660</td>
<td>1,122</td>
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</tbody>
</table>

Spud to First Sales

<table>
<thead>
<tr>
<th>Year</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018E</th>
</tr>
</thead>
<tbody>
<tr>
<td>Value</td>
<td>162</td>
<td>279</td>
<td>128</td>
<td>128</td>
<td>93</td>
</tr>
</tbody>
</table>

(1) Includes pre-drill, drilling, completion and TIL costs
FUTURE GROWTH OPPORTUNITIES

- **Austin Chalk**
  - 2017 – Initial co-development testing with encouraging results
  - 2018 – Data analysis and program design
  - 2019 – Additional co-development and repeatability testing

- **Upper Eagle Ford**
  - 2016 and 2017 – Initial infill testing and successful co-development testing
  - 2018 – Additional co-development and repeatability testing
  - 2019 – Co-development, delineation and infill testing

Cumulative Gross Production (mboe)
1.3 – 1.7x potential improvement in oil recovery

Proven technology
- Multiple in-basin pilots and up-scaled projects

Expected benefits
- Increase resource potential
- Lower capital cost per barrel recovered

Path forward
- Phase 1 implementation – 2019
SOUTH TEXAS FOUNDATIONAL ASSET

- Consistent high-margin EBITDA delivery
- ~$475 million FCF\(^{(1)}\) in 2018
- Multi-zone growth potential

PATH FORWARD

- Continue to deliver low-cost, high-margin barrels
- Generate incremental value through optimized asset development
- Build for the future through appraisal, technology and business development

\(^{(1)}\) Free cash flow defined as net revenue less all operating costs and capital expenditures. Excludes corporate overhead costs such as capitalized interest and capitalized G&A expenses.
MID-CONTINENT
REINVENTING A LEGACY ASSET

- Well-Positioned Acreage
- Appraising Liquid-Rich Opportunities
- Efficient Oil Volumes

~550 mmboe
Net resource size

<table>
<thead>
<tr>
<th>Production Mix (1)</th>
<th>38%</th>
<th>20%</th>
<th>46%</th>
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</thead>
<tbody>
<tr>
<td>Oil</td>
<td>NGL</td>
<td>Natural Gas</td>
<td></td>
</tr>
</tbody>
</table>

(1) Represents average for 2Q 2018
OSWEGO: EFFICIENT OIL VOLUMES
50% PROGRAM ROR\(^{(1)}\)

- Lateral length up ~90% and well cost per lateral foot down ~25% YOY
- $4.5 million average 2018 gross well cost
- Avg. IP30 ~900 bo/d in 2018
- +300 mboe EUR (83% liquid)
- $30/bbl breakeven\(^{(1)}\)

\(^{(1)}\) Price Deck: $2.75/mcf and $60/bbl oil flat
~783,000 (96% HBP) of multi-zone stacked potential

Targeting liquid-rich opportunities
  • Appraising six formations in 2018

Reopening mature plays through modern technology
Well-positioned acreage

Appraising liquid-rich opportunities

Efficient oil volumes

PATH FORWARD

Expand the Oswego program

Appraise the Wedge

Explore new concepts
GULF COAST
CONSISTENT PERFORMANCE, SIGNIFICANT RUNNING ROOM

- Completion and Drilling Excellence Redefines Play
- Expansive Inventory
- Access to Premium Markets

15 tcf
Net resource size

Production Mix\(^{(1)}\)

- 100%
  Natural Gas

\(^{(1)}\) Represents average for 2Q 2018
A DECADE LATER, DELIVERING MORE VALUE
MORE VALUE, FEWER RIGS

Core Development

Technological Breakthrough
Reservoir modeling, longer laterals, enhanced completions

Gross Operated Production (bcf/d)

Rig Count


September 2018 Update
Substantial portfolio of extended reach laterals\(^{(1)}\)

Driving capital efficiency by increasing lateral length

Operational advances continue to unlock value

\(^{(1)}\) Includes laterals of 10,000' or greater in lateral length
INNOVATION LEADS TO VALUE

- Strong economics and large inventory
- Fast rate of progress
  - First to use enhanced completions
  - First to drill 15k Haynesville lateral

Bossier Invest differentials ($/mcf): 2018 – 0.76, 2019 – 0.79, 2020 – 0.81, 2021 – 0.81
Haynesville Invest differentials ($/mcf): 2018 – 0.73, 2019 – 0.76, 2020 – 0.78, 2021 – 0.78

### Investment Economics

<table>
<thead>
<tr>
<th>Case</th>
<th>Lateral Length</th>
<th>EUR(bcf)</th>
<th>ROR</th>
<th>PV10($M)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Haynesville 15k</td>
<td>15,000</td>
<td>31</td>
<td>45%</td>
<td>7,890</td>
</tr>
<tr>
<td>Haynesville 10k</td>
<td>10,000</td>
<td>20</td>
<td>52%</td>
<td>4,990</td>
</tr>
<tr>
<td>Bossier 10k</td>
<td>10,000</td>
<td>16</td>
<td>20%</td>
<td>1,890</td>
</tr>
<tr>
<td>Haynesville 7.5k</td>
<td>7,500</td>
<td>15</td>
<td>44%</td>
<td>3,760</td>
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</tbody>
</table>
BOSSIER SHALE
THE NEXT HORIZON

- 5.4 tcf net recoverable resource
- 140,000 acres legacy HBP leasehold position
- ~730 locations remaining
PREMIUM ASSET, PREMIUM LOCATION

- Premium market optionality
  - Existing and future coastal LNG market

- Significant takeaway capacity
  - System capacity of 1.8 bcf/day
  - Current rates average 1.2 bcf/day
  - 1.1 bcf/day of firm transportation

- Potential to increase capacity out of basin
GULF COAST
CONSISTENT PERFORMANCE, SIGNIFICANT RUNNING ROOM

- Completion and drilling excellence redefines play
- Expansive inventory
- Access to premium markets

PATH FORWARD

- Continue to drive operational efficiency
- Improve economics through new facility design
- Begin developing Bossier and explore re-frac options
Low Cost, High Value

Premier Position

Expanding Inventory

12.6 tcf
Net resource size

Production Mix

Natural Gas

(1) Represents average for 2Q 2018
CAPITAL EFFICIENCY DEFINED

- Low maintenance capital with optionality to grow production
DOMINANT POSITION
SIGNIFICANT POTENTIAL REMAINING

- Optimum spacing driving better performance
- Existing well density primed for extended lateral development
- Co-development with stacked plays
- Opportunity to capture in-basin price increases

- Lateral Well

<table>
<thead>
<tr>
<th>Core Upper Marcellus</th>
<th>Lower Marcellus Core Expansion</th>
<th>Core Lower Marcellus</th>
</tr>
</thead>
<tbody>
<tr>
<td>~300'</td>
<td>1,200' – 1,800'</td>
<td>1,200’ – 1,800’</td>
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</tbody>
</table>

Upper Marcellus

Lower Marcellus

CHESapeake ENERGY

September 2018 Update
Production outpacing competitors

Breaking news

- 13,380' lateral successfully drilled
- 14,500' lateral currently drilling

Data pulled from IHS for wells turned in line in 2017 and Q1 of 2018. CHK data was also pulled using IHS. Peers include: Cabot, Chief, EQT, Repsol, Seneca and SWN
EXPANDING OUR CORE

- Enhanced completions and extended laterals expand core
- Four wells in expanded core planned in 2H18-1H19
- ~300 locations in Lower Marcellus core expansion opportunity
Industry established play fairway
- Collected 450' of core
- DFIT\(^{(1)}\) completed in 2Q18

Path forward
- Analyzing data and updating models to assess play potential

~240 locations
- Made up of 10,000' laterals at 1,200' spacing

\(^{(1)}\) Dynamic formation integrity test
APPALACHIA NORTH
LEADING THE INDUSTRY

- Low cost, high value
- Premier position
- Expanding inventory

PATH FORWARD

- ~$300 million in FCF\(^{(1)}\) expected in 2018
- Continue optimizing drilling, completions and spacing
- Expanding the opportunity set by redefining the core

\(^{(1)}\) Free cash flow defined as net revenue less all operating costs and capital expenditures. Excludes corporate overhead costs such as capitalized interest and capitalized G&A expenses.
HEDGING POSITION
AS OF 9/21/18

Natural Gas
2018

- 73% Swaps
- 7% Collars

$3.00/$3.25/mcf
HH

Oil
2018

- 83% Swaps
- 6% Collars

$3.00/mcf
HH

$39.15/$47/$55/bbl
WTI

$54.09/bbl
WTI

NGL
2018

- 38% Swaps

• ~88 bcf of 2019 natural gas hedged with three way collars @ $2.50/$2.80/$3.10/mcf
• ~55 bcf of 2019 natural gas hedged with two way collars @ $2.75/$3.02/mcf
• ~73 bcf of 2019 natural gas hedged with swaps @ $2.78/mcf
• ~15 mmbbls of 2019 oil hedged with swaps @ $59.44/bbl

Percentages are as of our midpoints from the Management Outlook less actuals.
BASIS HEDGES
AS OF 9/21/18

2019 CIG
10,950,000 MMBtu
($0.89) / MMBtu

2018 Marcellus Basis
Tennessee Zone 4-300 Leg
5,890,000 MMBtu
($0.77) / MMBtu

2019 HSC
22,470,000 MMBtu
$0.03 / MMBtu

2019 Tetco M3
4,631,500 MMBtu
$2.22 / MMBtu

Argus LLS vs Argus WTI
2018: 3,128,000 bbls @ $3.51 / bbl
2019: 4,015,000 bbls @ $6.20 / bbl

2018 Argus WTI Houston (MEH)
460,000 bbls
$3.57 / bbl
## CORPORATE INFORMATION

### Headquarters

6100 N. Western Avenue  
Oklahoma City, OK 73118  
WEBSITE: [www.chk.com](http://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](mailto:ir@chk.com)

### Publicly Traded Securities

<table>
<thead>
<tr>
<th>Description</th>
<th>Cusip</th>
<th>Ticker</th>
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<td>7.25% Senior Notes due 2018</td>
<td>#165167CC9</td>
<td>CHK18A</td>
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<tr>
<td>3mL + 3.25% Senior Notes due 2019</td>
<td>#165167CM7</td>
<td>CHK19</td>
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<tr>
<td>6.625% Senior Notes due 2020</td>
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<tr>
<td>6.875% Senior Notes due 2020</td>
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<tr>
<td>6.125% Senior Notes Due 2021</td>
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<td>5.375% Senior Notes Due 2021</td>
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<td>CHK21A</td>
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<td>4.875% Senior Notes Due 2022</td>
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<td>8.00% Senior Secured Second Lien Notes due 2022</td>
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<td>2.25% Contingent Convertible Senior Notes due 2038</td>
<td>#165167CB1</td>
<td>CHK38</td>
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<td>4.5% Cumulative Convertible Preferred Stock</td>
<td>#165167842</td>
<td>CHK PrD</td>
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<tr>
<td>5.0% Cumulative Convertible Preferred Stock (Series 2005B)</td>
<td>#165167834 #165167826 N/A</td>
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<td>5.75% Cumulative Convertible Preferred Stock</td>
<td>#U16450204 #165167776 #165167768</td>
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<tr>
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