Company Overview
Cautionary Statement

The following presentation includes forward-looking statements. These statements relate to future events, such as anticipated revenues, earnings, business strategies, competitive position or other aspects of our operations or operating results. Actual outcomes and results may differ materially from what is expressed or forecast in such forward-looking statements. These statements are not guarantees of future performance and involve certain risks, uncertainties and assumptions that are difficult to predict such as oil and gas prices; operational hazards and drilling risks; potential failure to achieve, and potential delays in achieving expected reserves or production levels from existing and future oil and gas development projects; unsuccessful exploratory activities; unexpected cost increases or technical difficulties in constructing, maintaining or modifying company facilities; international monetary conditions and exchange controls; potential liability for remedial actions under existing or future environmental regulations or from pending or future litigation; limited access to capital or significantly higher cost of capital related to illiquidity or uncertainty in the domestic or international financial markets; general domestic and international economic and political conditions, as well as changes in tax, environmental and other laws applicable to ConocoPhillips’ business and other economic, business, competitive and/or regulatory factors affecting ConocoPhillips’ business generally as set forth in ConocoPhillips’ filings with the Securities and Exchange Commission (SEC).

Use of non-GAAP financial information – This presentation includes non-GAAP financial measures, which are included to help facilitate comparison of company operating performance across periods and with peer companies. A reconciliation of these non-GAAP measures to the nearest corresponding GAAP measure is available at www.conocophillips.com/nongaap.

Cautionary Note to U.S. Investors – The SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserves. We use the term "resource" in this presentation that the SEC’s guidelines prohibit us from including in filings with the SEC. U.S. investors are urged to consider closely the oil and gas disclosures in our Form 10-K and other reports and filings with the SEC. Copies are available from the SEC and from the ConocoPhillips website.
Our Objective is to Deliver Double-Digit Returns to Shareholders

We offer the marketplace an E&P investment that delivers sustainable double-digit returns annually to shareholders through cash flow growth and a compelling dividend.
Our Value Proposition is Unchanged

- 3 – 5% production growth rate
- 3 – 5% margin growth rate
- Compelling dividend
- Ongoing priority to improve financial returns
- Relentless focus on safety and execution

Production and cash margin reflect compound annual growth rates. Unless otherwise noted, this deck is based on 2014 real prices of $100 Brent / $90 WTI / $70 WCS / $4 Henry Hub.
Unmatched Position Today

1,530 MBOED Production\(^1\) – 1Q14

- 24% North American Gas
- 18% LNG + International Gas
- 58% Liquids

8.9 BBOE Reserves – YE 2013

- 83% OECD
- 17% Non-OECD

43 BBOE Resources – YE 2013

- 68% Liquids
- 27% Gas
- 5% LNG

- Diversified asset base with scope and scale
  - Multiple sources of growth
  - Massive positions in key resource trends
  - Growing portfolio with options and choices
  - Relatively low execution risk
- Ability to leverage technology
- Increasing capital flexibility
- Significant financial strength
- Culture of safety and execution excellence

\(^1\)Production represents continuing operations, excluding Libya.
Average Capital
~$16B

- Significant shift in capital toward development programs
- 2013: 1,472 MBOED\(^1\) is base for growth
- 2014: Expect 3-5% production growth
  - Range of 1,510-1,550 MBOED
  - Expect to exit 2014 at >1,600 MBOED
- 2015+ growth catalysts include APLNG, Surmont and unconventionals
- Expect 3-5% margin growth 2014-2017
- Focused on organically building portfolio to sustain growth beyond 2017

\(^1\)Production represents 2013 continuing operations, excluding Libya.
Capital Allocation Drives Profitable Growth

Average Capital
~$16B

>40/BOE Margin
45% of Capital

North American Unconventional

LNG

Oil Sands

International Oil & Gas

$30-$40/BOE Margin
50% of Capital

North American Conventional Oil

$10-$15/BOE Margin
5% of Capital

North American Gas

2014-2017

Production

3-5% CAGR

2013 2014 2015 2016 2017

### High-Margin Production Growth Drives Cash Margin Improvement

#### 2013 Production

<table>
<thead>
<tr>
<th>Category</th>
<th>Production</th>
</tr>
</thead>
<tbody>
<tr>
<td>North American Unconventional</td>
<td>☐ 3-5%</td>
</tr>
<tr>
<td>LNG</td>
<td>☐</td>
</tr>
<tr>
<td>Oil Sands</td>
<td>☐</td>
</tr>
<tr>
<td>North American Conventional Oil</td>
<td>☐</td>
</tr>
<tr>
<td>International Oil &amp; Gas</td>
<td>☐</td>
</tr>
<tr>
<td>North American Gas</td>
<td>☐</td>
</tr>
</tbody>
</table>

#### 2017 Production

<table>
<thead>
<tr>
<th>Category</th>
<th>Production</th>
<th>Cash Margin $/BOE</th>
<th>Production CAGR 2013-2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>North American Unconventional</td>
<td>&gt;40</td>
<td>~22%</td>
<td></td>
</tr>
<tr>
<td>LNG</td>
<td>&gt;40</td>
<td>~10%</td>
<td></td>
</tr>
<tr>
<td>Oil Sands</td>
<td>30-40</td>
<td>~21%</td>
<td></td>
</tr>
<tr>
<td>North American Conventional Oil</td>
<td>30-40</td>
<td>~1%</td>
<td></td>
</tr>
<tr>
<td>International Oil &amp; Gas</td>
<td>30-40</td>
<td>~4%</td>
<td></td>
</tr>
<tr>
<td>North American Gas</td>
<td>10-15</td>
<td>~(6)%</td>
<td></td>
</tr>
</tbody>
</table>

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1. Excludes Libya.
High-Margin Growth Generates Long-Term Cash Flow Improvements

- Continued cash margin growth in 2014+
  - Ongoing production mix shift
  - Increased production in areas with more favorable fiscal regimes
  - Declining production in North American natural gas fields

- 3-5% production and 3-5% cash margin growth generates 6-10% cash flow growth
  - $20 billion - $23 billion of cash flow in 2017 at 2013 price levels

1 Excludes working capital; 2017 range based on 6 – 10% CAGR off 2013 actuals.
Committed to Shareholder Returns

**Dividend Yield**

- Compelling dividend remains key to our value proposition
- Highest priority use of cash
- Enhances capital discipline
- Predictable portion of shareholder returns
- Differential to independent peers
- Dividends expected to increase over time

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Dividend yield as of April 30, 2014.

*Companies include: APA, APC, BG, BP, CVX, DVN, OXY, RDS, TOT, XOM.*
The Power of Portfolio: Margins, Decline Rates and Returns

- Short-cycle cash flow
- Avoid over capitalizing
- Increases capital intensity of portfolio
- Medium-cycle cash flow
- Differing spend characteristics
- Conventional decline rates
- Front-end loaded capital
- Robust free cash flow once producing
- Lowers capital intensity of portfolio

Size of the bubble represents 2014-2017 average capital.
North American Unconventionals: Unmatched Portfolio and Capabilities

- Great positions in proven and emerging plays
- Eagle Ford and Bakken sweet spots
- Exceptional growth in high-margin resource base
- Decades of drilling inventory with upside
- Leveraging scale and technology

Average Capital

Average MBOED

Average Wellhead Breakeven Price

Eagle Ford: Significant Resource Increase

- 221 M net acres; acreage capture complete
- 96% average operated working interest
- 1.8 BBOE to 2.5 BBOE net EUR increase
- >3,000 identified drilling locations
- Outlook based on 12-rig program
- $20-25/BOE full-cycle F&D cost

Average Capital

<table>
<thead>
<tr>
<th>Year</th>
<th>Capital</th>
</tr>
</thead>
<tbody>
<tr>
<td>2014-2017</td>
<td>~$3B</td>
</tr>
</tbody>
</table>

Production

<table>
<thead>
<tr>
<th>Year</th>
<th>MBOED</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>100</td>
</tr>
<tr>
<td>2017</td>
<td>250</td>
</tr>
</tbody>
</table>

-20% CAGR

Product Mix

- Oil: 59%
- NGL: 20%
- Gas: 21%

12014-2017 average.
Eagle Ford: Premium Value from Best Wells in the Play

Highest Oil Rates per Well

<table>
<thead>
<tr>
<th>Gross Operated Production (BPD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ConocoPhillips</td>
</tr>
<tr>
<td>250</td>
</tr>
<tr>
<td>200</td>
</tr>
<tr>
<td>150</td>
</tr>
<tr>
<td>100</td>
</tr>
<tr>
<td>50</td>
</tr>
<tr>
<td>0</td>
</tr>
</tbody>
</table>

Industry-Leading Value

<table>
<thead>
<tr>
<th>NPV, 20 per Acre ($M)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ConocoPhillips</td>
</tr>
<tr>
<td>60</td>
</tr>
<tr>
<td>40</td>
</tr>
<tr>
<td>30</td>
</tr>
<tr>
<td>20</td>
</tr>
<tr>
<td>10</td>
</tr>
<tr>
<td>0</td>
</tr>
</tbody>
</table>

1Texas Railroad Commission, 2013.

2Wood Mackenzie.
Bakken: High-Margin Growth

- 620 M net acres; mostly HBP or mineral fee
- 45% average operated working interest
- 600 MMBOE net EUR
- >1,800 identified gross drilling locations
- Outlook based on average 10-rig program
- $20-25/BOE full-cycle F&D cost

**Average Capital**

~$1B

**Production**

2014-2017

- 2013
- 2017

- ~20% CAGR

**Product Mix**

- Oil 83%
- Gas 11%
- NGL 6%

12014-2017 average.
Bakken: Advantaged Position in the Heart of the Trend

Bakken Acreage Values by Area (NPV_{10} per Acre)\textsuperscript{1}

<table>
<thead>
<tr>
<th>Area</th>
<th>Bakken</th>
<th>Three Forks</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nesson Anticline</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Parshall-Sanish</td>
<td></td>
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</tr>
<tr>
<td>Fort Berthold</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Williams Core</td>
<td></td>
<td></td>
</tr>
<tr>
<td>West Nesson</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Northern Mountrail</td>
<td></td>
<td></td>
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<tr>
<td>Elm Coulee</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Dunn County</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Williams Perimeter</td>
<td></td>
<td></td>
</tr>
<tr>
<td>West McKenzie</td>
<td></td>
<td></td>
</tr>
<tr>
<td>North Williston</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Southern Fringe</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Lowest Cost of Supply\textsuperscript{1}

Nesson Anticline: 2013 Top Oil Producers\textsuperscript{1}

\textsuperscript{1}Wood Mackenzie.
Permian Unconventional: Early Appraisal Results Encouraging

- 150 M net acres in Delaware Basin; 90 M net acres in Midland Basin
- Thick column of both shale and tight rock intervals
- Four rigs running in Delaware Basin
- 24 horizontal wells planned for 2014
- Average early rates >1,000 BOED

Permian Basin Stratigraphy\(^1\)

Permian Appraisal Strategy

\(^1\)West Texas Geological Society.
Niobrara: Early Appraisal Results Encouraging

- 130 M net acres in the DJ Basin
- Appraisal program ongoing; 2 rigs running
- 18 horizontal wells planned for 2014
- Optimization of drilling and completions design
- Average early rates from new design >600 BOED
LNG: Positioned in High-Margin Markets

- Oil-linked contracts; robust cash flows
- Darwin and Qatar: High-liquids yield; premium markets
- Kenai: Restarting for seasonal exports
- AKLNG: Studying feasibility of North Slope gas
- APLNG: Project on schedule

Average Capital

~$1.5B

Production

>40/BOE
AVERAGE MARGIN
2014-2017

2014-2017

2013
2017

MBOED

10% CAGR

2017+
Oil Sands: Significant Growth from World Class SAGD Portfolio

- Second largest net SAGD producer
- Top quartile steam-to-oil ratio
- Executing 7 major projects and 2 optimization projects
- 2017+ net cash flow >$1 billion per year
- Upside from 15 BBOE resource

$30-40/BOE\textsuperscript{1}
AVERAGE MARGIN
2014-2017

\textasciitilde$0.8B

\textsuperscript{1}PC basis for cash margin.

First Production Dates

<table>
<thead>
<tr>
<th>Year</th>
<th>Projects</th>
</tr>
</thead>
<tbody>
<tr>
<td>2014</td>
<td>Surmont 1 Optimization, Surmont 2, FC Phase G, CL Phase CDE Optimization</td>
</tr>
<tr>
<td>2015</td>
<td>FC Phase F</td>
</tr>
<tr>
<td>2016</td>
<td>CL Phase F, FC Phase H</td>
</tr>
<tr>
<td>2017</td>
<td></td>
</tr>
</tbody>
</table>
International Oil & Gas: Major Projects Driving Growth

- Strong legacy positions
- 130 MBOED major projects growth expected by 2017
- 2013: Ekofisk South and Jasmine started on schedule
- 2014: 5 projects in Europe and Malaysia
- 2015-2017: 7 projects expected to come online
- $20-25/BOE full-cycle F&D cost

Average Capital
$30-40/BOE
AVERAGE MARGIN
2014-2017

~$4B

Average Production
MBOED
2014-2017

~4% CAGR

2013
2017

Product Mix
1

Gas 1
45%

Oil 52%

NGL 3%

Libya volumes excluded; ~50 MBOED upon resumption.
North American Conventional Oil: Protecting and Growing the Base

- Development drilling and major projects in Alaska
- Infill drilling and waterflood expansion in the Permian
- Drilling and expanded waterflood recovery at Ursa
- Liquids-focused drilling in the Anadarko Basin
- Technology and EOR mitigate base decline

$30-40/BOE
AVERAGE MARGIN
2014-2017

Average Capital

~$3.5B

Production

~1% CAGR

Product Mix

Gas 20%
NGL 8%
Oil 72%

¹2014-2017 average.
North American Gas: Low-Cost Option on Significant Resource Base

- Capital program focused on liquids-rich gas
- ~$1.10/MCF lifting cost
- 6.5 BBOE total resource
- >15,000 identified well locations
- ~$1.5 billion annual cash from operations at $4/MCF gas

Average Capital

$10-15/BOE
AVERAGE MARGIN
2014-2017

~$0.8B

2014-2017

Production

400
300
200
100
0

6% CAGR

2013
2017

Product Mix

- Gas 78%
- NGL 18%
- Oil 4%

1 2014-2017 average.
2014: Testing Global Portfolio

2014 Drilling Activity
- Unconventional
- Deepwater
- Other Conventional

1 Based on high bid award on Block AD-10.
Gila
- 20% working interest in discovery well
- Lower Tertiary oil discovery in 2013
- Testing deeper, unpenetrated zones in 2014
- Adjacent to ConocoPhillips 100% working interest acreage

Tiber
- 18% working interest
- Lower Tertiary oil discovery in 2009
- Multiple reservoir intervals
- Appraisal commenced in 2013; continues in 2014

Shenandoah
- 30% working interest
- Lower Tertiary oil discovery in 2009
- First appraisal well in 2013; >1,000 feet net pay
- Next appraisal well planned for 2014

Coronado
- 35% working interest
- Lower Tertiary oil discovery in 2013
- Encountered >400 feet net pay
- Appraisal commenced in 2013; continues in 2014
Angola: Deepwater Exploration

- Block 36: 50% working interest; operator
- Block 37: 30% working interest; operator
- Pre-salt lacustrine carbonate play in Kwanza Basin
- Analogous to Brazilian Santos/Campos Basins and recent discoveries on adjacent blocks
- Kamoxi-1 well planned for Block 36 in 2Q 2014
- First of four-well continuous program
Key Messages

- Value proposition unchanged

- Growth underway in 2014

- Significant identified resource upside in unconventionals

- Visible options and choices for organic growth beyond 2017

- Strategic linkage between capex, volume growth and margin expansion

- Cash flow is growing, financial position is strong and dividend is top priority

- On track to deliver annual double-digit returns to shareholders
Supplemental Slides
Our Strategy Achieves Value Proposition

Average Capital
~$16B

15%
Exploration & Appraisal
Delivers 2017+
growth

30%
Major Projects
Generates strong production
growth

45%
Development Programs
Mitigates base
decline

10%
Base Maintenance
Protects the base

2014-2017

Production¹

3-5% CAGR

²Production excludes Libya.
2012 – 2013: Delivered on Milestones and Achieved Peer-Leading TSR

• Proceeds of $12.4 billion from sale of non-core assets

• Met production targets and advanced growth projects

• Achieved 11% cash margin growth\(^1\)

• Positioned in four deepwater Gulf of Mexico discoveries

• Achieved 167% organic reserve replacement ratio\(^2\)

• Increased dividend by 4.5% in 2013

• Delivered peer-leading shareholder returns

\(^1\) Change from 2012 to 2013 on actual prices.
\(^2\) Represents two-year average.

**Total Shareholder Return Since April 30, 2012**

- ConocoPhillips: 22.6%
- Integrated Peer Average: 13.0%
- Independent Peer Average: 21.3%
- S&P 500: -0.8%

Current Status of Unconventional Plays

**EXPLORATION**
- ACREAGE CAPTURE
- BASIN MODEL CALIBRATION

**APPRaisal**
- HORIZONTAL WELL TESTS
- PILOT TESTS

**DEVELOPMENT**
- EARLY DEVELOPMENT
- OPTIMIZATION
- FULL-FIELD DEVELOPMENT

- Sweet Spots in the Best Plays
- Optimal Fracture Stimulation Design
- Scientific Pilot Design
- Delivering Capital Efficiencies
- Optimal Well Spacing & Placement
- Operations Excellence

- EAGLE FORD
- BAKKEN
- PERMIAN
- NIOBRARA
- CANADIAN PLAYS
- NEW OPPORTUNITIES
Disciplined Pace of Development Maximizes Value

Reasons to Accelerate
- Acreage Retention
- Driven by Growth
- Faster Cash from Operations

Reasons to Optimize
- Cost Learning Curve Benefits
- Technology Learning Curve Benefits
- Infrastructure Efficiency
- Higher Ultimate Recovery
Eagle Ford: Acreage in Heart of the Sweet Spot

Sweet Spot Identification – Critical Success Factors

Pressure  Maturity  Thickness

Sweet Spot  Geology

Pressure & Thickness

ConocoPhillips Acreage

Upper Eagle Ford

Lower Eagle Ford

Maturity Sweet Spot

Geology

Clay Rich Poor Fracability Less Organics

Good Quality Organics

Best Organic Quality

COP Acreage
Eagle Ford: Value-Driven Approach to Well Density

2013
Lower Eagle Ford 80-acre\(^1\) Single Layer
1.8 BBOE EUR

2014 Transition to High/Low
Lower Eagle Ford 80-acre\(^2\) High/Low
2.5 BBOE EUR

Evaluating Further Upside
Lower Eagle Ford 40-acre\(^2\)
Upper Eagle Ford/Austin Chalk

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\(^1\) 660’ between 1-mile long wells is equivalent to 80-acre spacing.
\(^2\) 330’ between 1-mile long wells is equivalent to 40-acre spacing.
Eagle Ford: Value-Driven Approach to Fracture Stimulation Design

- Extensive pilot testing to verify stimulation models
- Constantly enhancing fracture stimulation design
- 30% increase in EUR per well from increased proppant
- >100% production increase with current design
- Additional testing and analysis underway
Eagle Ford: Delivering Capital Efficiencies

- ~40% reduction in drilling days
- ~40% reduction in completion cost per unit of proppant
- 75% of 2014 wells benefit from multi-well pad drilling
- Leveraging size to realize contract savings
- Testing additional drilling and completion technologies

Drilling Cost Efficiency\(^1\)

Completion Cost Efficiency\(^2\)

\(^1\)Comparison to 2010 average days spud to spud.
\(^2\)Comparison to 2010 average completion cost per unit of proppant.
Drilling Execution Efficiency Platform (DEEP)

- Optimizes drilling performance in real time
- Currently being field piloted in Eagle Ford and Permian
- Demonstrated >20% increase in drilling rate in the build and lateral section of horizontal wells
- Applicable across portfolio
- Potential savings of ~$250 million per year globally
Bakken: Optimal Well Spacing and Placement

Current
320-acre\(^2\) in Bakken/
Upper Three Forks

Testing Tighter Spacing
160-acre\(^2\) in Bakken/
Upper Three Forks

Evaluating Further Upside
Additional Wells in
Middle Three Forks

\(^1\)320' between 2-mile long wells is equivalent to 320-acre spacing. \(^2\)660' between 2-mile long wells is equivalent to 160-acre spacing.
Bakken: Delivering Capital Efficiencies

Drilling Cost Efficiency\(^1\)

- ~30% reduction in drilling days
- ~50% reduction in completion cost per unit of proppant
- 90% of 2014 wells to benefit from multi-well pad drilling
- Leveraging size to realize contract savings
- Testing additional drilling and completion technologies

Completion Cost Efficiency\(^2\)

\(^1\)Comparison to 2010 average days spud to spud.
\(^2\)Comparison to 2010 average completion cost per unit of proppant.
Other N.A. Unconventionals: Strong Position in Emerging Plays

- Focused on high-margin, liquids-rich opportunities
- >500 M net acres under appraisal
- Key programs in Permian, Niobrara and Canada
- Leveraging Eagle Ford and Bakken learnings
- Potential for significant additional growth beyond 2017

Average Capital:

~$1.5B

Production:

~3% CAGR

Play Status Summary:

<table>
<thead>
<tr>
<th>EXPLORATION</th>
<th>APPRAISAL</th>
<th>DEVELOPMENT</th>
</tr>
</thead>
<tbody>
<tr>
<td>ACREAGE CAPTURE</td>
<td>BUDGET MODEL CALIBRATION</td>
<td>HORIZONTAL WELL TESTS</td>
</tr>
<tr>
<td>PILOT TESTS</td>
<td>EIGHTY TWO DEVELOPMENT</td>
<td>OPTIMIZATION</td>
</tr>
<tr>
<td>FULL FIELD DEVELOPMENT</td>
<td>NEW OPPORTUNITIES</td>
<td></td>
</tr>
</tbody>
</table>

- Permian
- Niobrara
- Canadian Plays

Graphs showing production and capital investments over the years 2013 to 2017.
Canada: Appraising Montney and Duvernay

Montney

• 230 M net acres
• 90% average working Interest
• Focused on 135 M net acres with 30-40% liquid yield
• 14 horizontal wells planned for 2014
• Access to existing infrastructure

Duvernay

• 118 M net acres
• 100% working interest
• Focused on 107 M net acres with 25-90% liquid yield
• 3 horizontal wells planned for 2014
• Access to existing infrastructure
APLNG: Long-Term Cash Flow Generation

- Two 4.5 MTPA trains with long-term sales to Asia
- Project ~67% complete at the end of 1Q14
- On schedule for first LNG in mid-2015
- ~$25/BOE full-cycle F&D cost
- 2017+ distributions ~$1 billion per year

APLNG Project Capital

Production

![Bar chart showing APLNG Project Capital from 2013 to 2017]

![Bar chart showing Production from 2013 to 2017 with a CAGR of ~55%]

2030+
Surmont 2: Progressing Toward Startup

- Construction 68% complete at the end of 1Q14
- First steam expected in mid-2015
- Surmont 2 increases gross capacity to 150 MBOED
- Optimization and debottlenecking studies underway
- ~$20/BOE full-cycle F&D cost
- Significant remaining development potential

Total Surmont Capital

<table>
<thead>
<tr>
<th>Year</th>
<th>Capital (B)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>1.5</td>
</tr>
<tr>
<td>2014</td>
<td>1.0</td>
</tr>
<tr>
<td>2015</td>
<td>0.8</td>
</tr>
<tr>
<td>2016</td>
<td>0.5</td>
</tr>
<tr>
<td>2017</td>
<td>0</td>
</tr>
</tbody>
</table>

Total Surmont Production

- Optimizing
- Surmont 2
- Surmont 1

2030+
Creating Value from Operations Excellence and Technology

- Operations Excellence
  - Surmont 1 operating >15% above design capacity
  - Reduced drilling cost by 12% in 2013
  - Longest SAGD wells in industry

- Proven Technologies
  - Flow Control Devices
  - Modularization
  - Optimized well and pad architecture
  - Vacuum Insulated Tubing

- Technologies in Development
  - e-SAGD
  - Testing 20 new drilling technologies
  - Fishbone wells
  - Solvent soak with dilation

1 McDaniel & Associates Consultants Ltd.
Robust Technology Pipeline Targeting Improved Project Returns

Flow Control Devices (FCD)
- Accelerates production and reduces SOR
- Successfully deployed and expanding application
- Pilot performance improvements
  - Production 50% higher
  - SOR and GHG emissions decreased by 15%

e-SAGD
- Accelerates production and reduces SOR
- Two-well pilot conducted in 2013
- Pilot performance improvements
  - Production 30% higher
  - SOR and GHG emissions decreased by 20%
North Sea: Revitalization from High-Margin Projects

- 2014: Jasmine and Ekofisk South ramp up; Britannia LTC startup
- 2015: Eldfisk II and Enochdhu startups
- 2016/17: Alder, Clair Ridge and Aasta Hansteen startups
- 5% production CAGR from 2013 to 2017
- Additional projects under evaluation
Malaysia: Building a Legacy Position

- 2014: Milestone year with 3 project startups expected
  - Siakap North-Petai (SNP): First production achieved
  - Gumusut FPS: 3Q14 startup targeted
  - KBB gas development: 4Q startup targeted
- Progressing exploration and development opportunities

Malaysia – Major Project Capital

![Graph showing project capital investment from 2013 to 2017](image-url)
Alaska: Increased Investment Targeting Resource Development

- Increased investments reflect better fiscal terms
- Technology mitigating decline in mature fields
- CD5 project in execution
- Drill site 2S, GMT1 and 1H NEWS projects progressing
- Prudhoe Bay pad expansions and projects

100% INCREASE IN ALASKA CAPITAL WITH IMPROVED BUSINESS CLIMATE

Capital

Kuparuk – Improving Base Recovery

- 76% EUR INCREASE SINCE FIRST OIL
• Consistently adding new, high-margin resources
• 6.7 BBOE resources discovered from 2009 to 2013
• Discovery costs of $1.3/BOE\(^1\)
• Four large Gulf of Mexico discoveries
• Leader in North American liquids-rich unconventionals

\(^1\)Based on working interest.

Australia: Appraising Discoveries at Poseidon and Barossa

Greater Poseidon Complex
- 40% working interest; operator
- Discovered in 2009
- Jurassic Plover and Montara formation reservoirs
- Six successful wells to date
- Two more wells planned for 2014

Barossa
- 37.5% working interest; operator
- Discovered in 2006
- Jurassic Plover and Elang formation reservoirs
- Two successful wells to date in Caldita/Barossa area
- Three-well appraisal program commencing in 2Q 2014
Senegal: Deepwater Exploration

- 35% working interest
- FAN-1 well planned in 2Q 2014
  - Cretaceous pinch-out play
  - Similar age as the recent Mauritanian discovery approximately 360 miles north-east
- SNE-1 well planned in 3Q 2014
  - Unconformity truncation play
- Additional stacked fan complexes on acreage provide upside potential
**Norway: Barents Sea**
- 25-30% working interest
- Two wildcats to be drilled in Barents Sea license PL615 commencing in 2Q 2014
  - One Triassic and one Jurassic target
- Awarded four more licenses in 2013

**Indonesia: Palangkaraya PSC**
- 100% working interest
- Re-examining oil seeps and stratigraphic wells drilled in the 1930s
- 1.9 MM acres in central Kalimantan
- Seismic acquisition in 2013 and 2014
- Drilling expected to commence in 4Q 2014
**Poland**
- 70% working interest; operator
- 354 M net acres in the Baltic Basin
- Drilling two vertical wells and one long lateral well in 2014
- Hydraulic stimulation planned with 90-day flow test

**Colombia**
- Santa Isabel – 70% working interest (71 M net acres)
- VMM Blocks – 30% working interest (116 M net acres)
- Targeting Upper Cretaceous La Luna Shale
- Drilling a stratigraphic well in 2014
Strength and Flexibility Throughout the E&P Value Creation Cycle

- Growing portfolio of high-return, high-margin investments
- Track record of reserve replacement at competitive F&D cost
- 3-5% production and 3-5% cash margin growth
- 6-10% cash flow growth
- Strong credit rating and cash balance
- Competitive and growing dividend

Production and cash margin reflect compound annual growth rates.
Shifting Portfolio Driving Peer-Leading Cash Margin Growth

- Visible margin growth in 2013
- 9% price normalized cash margin growth
- Liquids growth in Lower 48, Canada and APME
- Shift to more favorable fiscal regimes
- Reduced North American natural gas volumes

2013 vs. 2012 Cash Margin/BOE Relative Improvement

�Companies include: APA, APC, BG, BP, CVX, DVN, OXY, RDS, TOT, XOM.
ConocoPhillips cash margin represents operating segments only, see website for reconciliation.
The peers' cash margins represent E&P adjusted income plus adjusted DD&A, divided by production.
Appendix
Annualized Net Income Sensitivities

• Crude
  • **Brent/ANS:** $80-90MM change for $1/BBL change
  • **WTI:** $35-40MM change for $1/BBL change
  • **WCS**: $30-40MM change for $1/BBL change

• North American NGL
  • **Representative blend:** $10-15MM change for $1/BBL change

• Natural Gas
  • **Henry Hub:** $100-110MM change for $0.25/MCF change
  • **International gas:** $10-15MM change for $0.25/MCF change

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1WCS price used for the sensitivity represents a volumetric weighted average of Shorcan and Net Energy indices.

The published sensitivities above reflect annual estimates and may not apply to quarterly results due to lift timing/product sales differences, significant turnaround activity or other unforeseen portfolio shifts in production. Additionally, the above sensitivities apply to the current range of commodity price fluctuations, but may not apply to significant and unexpected increases or decreases.
## 2014 Production Guidance: Continuing Operations

### Annual Planned Turnarounds

<table>
<thead>
<tr>
<th>Quarter</th>
<th>Major Turnarounds</th>
</tr>
</thead>
<tbody>
<tr>
<td>1Q14</td>
<td>J-Area</td>
</tr>
<tr>
<td>2Q14</td>
<td></td>
</tr>
<tr>
<td>3Q14</td>
<td>Prudhoe Bay, Surmont, Britannia Area, East Irish Sea, Southern North Sea, Bayu-Undan</td>
</tr>
<tr>
<td>4Q14</td>
<td></td>
</tr>
<tr>
<td>FY14</td>
<td></td>
</tr>
</tbody>
</table>

### Continuing Operations (Excluding Libya)

<table>
<thead>
<tr>
<th>Quarter</th>
<th>Volume Range</th>
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</thead>
<tbody>
<tr>
<td>1Q14</td>
<td>1,530</td>
</tr>
<tr>
<td>2Q14</td>
<td>1,490 – 1,540</td>
</tr>
<tr>
<td>3Q14</td>
<td>1,435 – 1,485</td>
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<tr>
<td>4Q14</td>
<td>1,590 – 1,640</td>
</tr>
<tr>
<td>FY14</td>
<td>1,510 – 1,550</td>
</tr>
</tbody>
</table>

No Libya volumes assumed for 2014.
2014 Outlook Guidance

- 2014 DD&A of ~$8.5 B
  - Higher DD&A from Jasmine and Gumusut startup
  - Reflects reserve booking schedule in unconventionals

- Expenses from continuing operations
  - Production and SG&A expense of ~$8.5B
  - Exploration expense of ~$1.5B$^1$
  - Corporate segment costs of ~$950 MM

$^1$Includes risk weighted dry hole costs.
# Margin Class Categorization

<table>
<thead>
<tr>
<th>North American Unconventionals</th>
<th>LNG</th>
<th>Oil Sands</th>
<th>International Oil &amp; Gas</th>
<th>North American Conventional Oil</th>
<th>North American Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bakken</td>
<td>AKLNG</td>
<td>Christina Lake</td>
<td>China</td>
<td>Alaska North Slope</td>
<td>Lobo</td>
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<td>Barnett</td>
<td>APLNG</td>
<td>Foster Creek</td>
<td>Indonesia</td>
<td>Anadarko</td>
<td>San Juan</td>
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<tr>
<td>Canada Unconventional</td>
<td>Bayu Undan</td>
<td>Surmont</td>
<td>Malaysia</td>
<td>Gulf of Mexico</td>
<td>Western Canada</td>
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<td>Eagle Ford</td>
<td>Kenai</td>
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<td>Norway</td>
<td>Permian</td>
<td>Other</td>
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<tr>
<td>Niobrara</td>
<td>Poseidon</td>
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<td>U.K.</td>
<td>Other</td>
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<tr>
<td>Permian</td>
<td>Qatar</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Other</td>
<td>Other</td>
<td></td>
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</tr>
</tbody>
</table>

List is representative of assets in each margin class, not all assets are listed.
Abbreviations and Glossary

- **4-D**: four dimensional
- **ANS**: Alaska North Slope
- **Average Cash Margin (2014-2017)**: Average cash margin represents the projected cash flow from operating activities, excluding working capital, divided by estimated production. Estimated cash flow is based on $100 Brent / $90 WTI / $70 WCS / $4 Henry Hub
- **B**: billion
- **BBL**: barrel
- **BBOE**: billions of barrels of oil equivalent
- **BOE**: barrels of oil equivalent
- **CAGR**: compound annual growth rate
- **CTD**: coiled tubing drilling
- **EUR**: estimated ultimate recovery
- **DD&A**: depreciation, depletion and amortization
- **F&D**: finding and development
- **GAAP**: generally accepted accounting principles
- **GOM**: Gulf of Mexico
- **HBP**: held by production
- **HH**: Henry Hub
- **LNG**: liquefied natural gas
- **M**: thousand
- **MM**: million
- **MBOED**: thousands of barrels of oil equivalent per day
- **MMBOE**: millions of barrels of oil equivalent
- **MMBOED**: millions of barrels of oil equivalent per day
- **MTPA**: millions of tonnes per annum
- **OECD**: Organisation for Economic Co-operation and Development
- **Organic RRR**: organic reserve replacement ratio excludes the impact of purchases and sales
- **PSC**: production sharing contract
- **ROCE**: return on capital employed
- **R/P**: reserve to production ratio
- **SAGD**: steam-assisted gravity drainage
- **SG&A**: selling, general and administrative expenses
- **SOR**: steam-to-oil ratio
- **TSR**: total shareholder return
- **WCS**: Western Canada Select
- **WI**: working interest
- **WTI**: West Texas Intermediate
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