Deutsche Bank
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North America
United States
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Integrated Oil

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F.I.T.T. for Investors
The "Other" 40 Million Barrels a Day
and the Call on US Crude Growth
The Coming Highs & Lows of Non-OPEC Production (and what it means for US)
While significant attention has been dedicated to the analysis of the US supply dynamics over
past 6 months, we turn our attention to the less-well understood 40 MMb/d of global crude
production (ex-OPEC, ex-US onshore, ex-NGLs), and the outlook for the coming 2-5 years. Key
takeaways: 1) Don't expect a major roll-over in Non-OPEC supply through 2017, 2) we still see a
call on US onshore growth of 500 Mb/d in 2017 with 2H16 ramp 3) we likely need $65-$70/bbl oil
to incentivize and support this growth, 4) post-2017, Non-OPEC shortages to drive rapidly
escalating call on US crude and price inflation.

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The Coming Highs & Lows of Non-OPEC Production (and what it means for US)

While significant attention has been dedicated to the analysis of the US supply dynamics over past 6 months, we turn our attention to the less-well understood 40 MMb/d of global crude production (ex-OPEC, ex-US onshore, ex-NGLs), and the outlook for the coming 2-5 years. Key takeaways: 1) Don't expect a major roll-over in Non-OPEC supply through 2017, 2) we still see a call on US onshore growth of 500 Mb/d in 2017 with 2H16 ramp 3) we likely need $65-$70/bbl oil to incentivize and support this growth, 4) post-2017, Non-OPEC shortages to drive rapidly escalating call on US crude and price inflation.

Waiting for the Non-OPEC collapse? Don’t hold your breath

Despite significant capital cuts (20% across our global coverage), and fears of massive Non-OPEC declines, our analysis suggests greater than expected resilience in global Non-OPEC production through 2017, as a slug of major projects works its way through the system. Between 2015 and 2017, we estimate annual, major project-driven growth barrels of 1380 Mb/d, vs. the historical rate of 970 Mb/d between 2004-2013, supporting annual Non-OPEC supply growth of 150-200 Mb/d through 2017.

But, there is a call on US onshore oil growth – the new swing producer

Even with moderate growth in Non-OPEC production, solid global crude demand will still result in a call on US onshore production growth, although not likely until 2H16 (+350 Mb/d by 4Q16), rising to ~500+ Mb/d in 2017. With current activity levels resulting in slightly declining US onshore production in 2H15, we see the need for increasing activity into late 2015/early 2016 to meet a rising call on US crude into 2H16. OPEC production, however, remains a looming risk, where current elevated levels of production (May 2015 estimated 31.6 MMb/d vs. our assumed 30.5 MMb/d target), a lifting of sanctions in Iran, or Saudi strategy could push the US call further into 2017.

$55/bbl oil isn’t going to suffice

Single well economics aside, corporate level cash flow suggests higher price is necessary to incentivize sufficient activity. We estimate an average oil price of $70/bbl to support moderated volume growth (ie. 35%-40% of pre-collapse peak rate) within producer cash flows. This falls to $60/bbl breakeven when

spending 120% of cash flow. In other words, we will need a higher price than where we are today to make the US onshore "machine" work.
Post-2017? Hold on to your hat…
By late 2017, rising declines and deferred FIDs will drive a rapidly escalating
call on US supply. Major oil project FIDs fell to 6 in 2014, the lowest level in 15
years, well below the average of 23/yr since 2000, with 2015 likely to be even
lower. With an average of 1.2 MMb/d of capacity sanctioned a year over the past 10 years, the hole left by deferrals will be difficult to address, sending the
call on US crude growth north of 1,000 Mb/d/yr by late this decade.
Thriving in moderation – Stocks to own; Upgrade OXY to Buy; Cut HES to Hold
Given the relatively cautious medium-term oil price outlook, our preference remains largely for names whose combination of asset quality and balance sheet allow them to support moderate, capital efficient growth within a moderate oil price environment. We upgrade OXY to BUY and downgrade HES to HOLD. Other preferred names include MRO, DVN, EOG.
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31 May 2015
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Key Changes
Company
CVX.N
HES.N
MRO.N
MUR.N
OXY.N
XOM.N
DVN.N
APA.N
APC.N
PXD.N
NBL.N
Source: Deutsche Bank
Top picks
Marathon Oil (MRO.N),USD27.19
Devon Energy (DVN.N),USD65.22

Source: Deutsche Bank
Companies Featured
Chevron (CVX.N),USD103.00
ConocoPhillips (COP.N),USD63.68
Hess Corporation (HES.N),USD67.52
Marathon Oil (MRO.N),USD27.19
Murphy Oil (MUR.N),USD43.46
Buy
Buy
Hold
Buy
Hold
Occidental Petroleum (OXY.N),USD78.19 Buy
ExxonMobil (XOM.N),USD85.20
Source: Deutsche Bank
Hold
Target Price
120.00 to
Rating
-
125.00(USD)
90.00 to
75.00(USD)
37.00 to
35.00(USD)
51.00 to
46.00(USD)
81.00 to
90.00(USD)
91.00 to
89.00(USD)
70.00 to
81.00(USD)
69.00 to
60.00(USD)
96.00 to
100.00(USD)
182.00 to
175.00(USD)
56.00 to
52.00(USD)
Buy to Hold
-
-
Hold to Buy
-
-
-
-
-
-

Buy
Buy
Occidental Petroleum (OXY.N),USD78.19 Buy
EOG Resources (EOG.N),USD88.69
Buy

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Executive Summary

Expecting a Non-OPEC collapse? Don’t hold your breath

Given the scale of cuts to global capex (20% across our global coverage universe), many in the market have speculated about the imminent decline of global Non-OPEC production. Although we see significant risk post-2017, our analysis suggests greater than expected resilience in global Non-OPEC production over the next couple of years, as a slug of major capital projects,
the fruit of 5 years of consistently high oil prices, works its way through the
system. Between 2015 and 2017, we estimate annual, major project-driven growth barrels of 1380 Mb/d, vs. the historical rate of 970 Mb/d between 20042013,
supporting annual Non-OPEC supply growth of 500 Mb/d through 2017.
Leading drivers: US GoM, Brazil, Canada, and slower declines on recent redevelopment projects in the North Sea. While project delays or poor performance could lead to disappointment (a hallmark of Non-OPEC supply), there is clearly a robust slate of projects on the horizon.

Figure 1: Since 2004, higher contributions from major
projects have driven Non-OPEC Supply growth

2000
1528
1500
1134
1000
719
500
0
<800 Mb/d
-500
Avg Growth Bbl Contribution
Source: Deutsche Bank, Wood Mackenzie, IEA
YoY Non-OPEC Supply Growth (Avg)
Source: Deutsche Bank, Wood Mackenzie, IEA

Despite the large cut to headline capex, this is largely consistent with the source of the capex cuts, with the largest share of capex reductions (outside of
the US onshore) concentrated in exploration budgets and deferrals of major project spend, with limited impact on near-term production levels.

Norway: Exhibit A

In some ways, Norway is a microcosm of the larger global picture. Largely synonymous with mature declining assets, averaging 6% YoY decline since 2002 (vs 9% for the UK), the Norwegian North Sea will actually see production flat to slightly increasing through 2017. Driving this is a significant increase in
major project growth barrels, with nearly 380 Mb/d expected online between 2015-2017, vs. an average of 35 Mb/d of annual, projected driven increase from 2009-2013.

800-1000 Mb/d
1000 - 1200 Mb/d
>1200 Mb/d
933
Figure 2: .And over the coming 5 yr outlook, major project growth is expected to reach peak levels following recent $100/bbl oil incentivized spend
200
400
600
800
1000
1200
1400
1600
1800
0
1325 Mb/d
975 Mb/d

Mb/d
YoY Crude Production Growth (Mb/d)

Figure 3: Norwegian growth barrels at recent highs
100
120
140
160
180
200
20
40
60
80
0
2009
2010
2011
2012
2013
Source: Deutsche Bank, Wood Mackenzie, IEA, includes Ekofisk II redevelopment project
2014
2015
2016

But, there is a call on US onshore oil growth – the new swing producer

Although we don't expect a rapid decline in Non-OPEC production, stronger than expected global crude demand will still result in a call on US onshore production growth, although not likely until 2H 2016 culminating in a 2017 call
of ~500 Mb/d. We decompose the call into two parts:

- We estimate that ~260 Mb/d of incremental demand is needed beyond peak (2Q15) L48 production that is not otherwise being supplied from non-OPEC producers (assuming non-growing OPEC).
- We anticipate a trough in US production in 1Q16 and estimate a gap of ~270 Mb/d vs 2Q15 production that will need to narrowed toward an estimated call on US onshore production of ~7.65 MMb/d in '17.

We anticipate demand for US onshore crude production to accelerate through 2017 and for the call on YoY crude growth to nearly 700 Mb/d in 2018 and to surpass 1,000 Mb/d in 2019/2020 as Non-OPEC production growth tapers off.

Figure 4: Incremental Demand for US Onshore Crude Expected To Emerge Late 2016 (vs. 2Q15 Production)…
1500
1000
500
0
100
200
300

400
500
600
-500
-1000
-300
-200
-100
0
-42
-230
1Q16
-1500
2Q16
3Q16
4Q16
1Q17
531
342
149
Figure 5:..Forward rolling 12 mo call on US onshore production growth (vs 1Q16 production) positive in 2H16
Source: Deutsche Bank, Wood Mackenzie, IEA
Source: Deutsche Bank, Wood Mackenzie, IEA

call on US Crude vs. 2Q15 Production (mbpd)
YoY Growth
12 Mo Rolling Call on US onshore production
(Mb/d)

And $40-55/bbl oil isn't going to suffice
Despite arguments about asset breakevens in the onshore at prices as low as $40/bbl, the number that matters for the resumption of drilling/completion activity is corporate level cash flow, not single well rates of return, in our view.
Despite the sector being fairly well capitalized at present, partially thanks to a
recent wave of equity issuance, total leverage remains quite high and companies are likely to stick relatively close to cash flow as activity picks up.
Across the E&P universe, if we assume 20% decline in well costs and spend within cash flow in 2016/2017, we estimate an average oil price of $70/bbl to support 35% of pre-collapse production growth (our estimated demand for US onshore crude by late 2016). This falls to $60/bbl breakeven when spending 120% of cash flow. In other words, we will need a materially higher price than
asset-breakeven prices to make the US onshore "machine" work.
Figure 6: Oil Price to generate 35% of prior peak growth in 2016-17
$10
$20
$30
$40
$50
$60
$70
$80
$90
$0
CLR EOG PXD CXO APC DVN WLL HES MRO Avg
CFO=Capex
CFO=120% Capex
Source: Deutsche Bank
By late 2017, hold on to your hats
By late 2017, rising declines and deferred FIDs will drive a rapidly escalating
call on US supply. Major oil project FIDs fell to 6 in 2014, the lowest level in 15
years, well below the average of 23/yr since 2000, with 2015 likely to be even
lower. With an average of 1.2 MMb/d of capacity sanctioned a year over the past 10 years, the hole left by deferrals will be difficult to address, sending the
call on US crude growth north of 1,000 Mb/d/yr by late this decade.
Figure 7: Major Oil Project Sanctions (FIDs) by year
10
15
20
25

30
35
40
0
5
Figure 8: Peak capacity of project FIDs by year (Mb/d)
500
1000
1500
2000
2500
3000
0
$72
$61
Source: Deutsche Bank, Wood Mackenzie
Source: Deutsche Bank, Wood Mackenzie

$/bbl (WTI)

What does it mean for the stocks?
For the equities, the debate centers on the pace of the recovery in crude price,
and how soon should investors pay for it. Given what we view as a rather tepid
recovery in crude over the next 18-24 months, (followed by significant longterm
strength), and relatively aggressive current implied valuations (sector discounting $75/bbl+), we remain focused on names that have the asset quality and balance sheet to grow production in a capital efficient manner (ie.
largely within cash flow) in a moderate oil price world. We upgrade OXY to Buy and downgrade HES to Hold on an improving outlook at OXY (Permian exceeding expectation + FCF generation and cash return to shareholders at the current strip). Other preferred names include: DVN, MRO, EOG.

OXY: We upgrade OXY to Buy (from Hold) on its advantaged combination of growth and free cash flow in a moderate oil price environment. We see a number of key drivers for OXY, including: 1) Permian performance continues to exceed expectations, with likely upside to conservative 2016 target of 120 Mboe/d, 2) leading FCF generation in our coverage universe at $65/bbl WTI (1.8% postdividend in 2016, or 5.8% pre-dividend, vs. peer average of a 2.4% FCF deficit in 2016), led by three primary Middle East projects which generate ~$1.0-$1.5 Bn/yr of FCF, 3) 2017 start-up of ethylene cracker driving ~$1.0 Bn/yr of FCF from the chemical business from 2017, 4) 2nd highest dividend yield in our coverage universe (3.9%), with FCF driving further growth and share buyback, 5) solid crude leverage in the case of a rebound in oil price, and 6) relatively attractive valuation at 6.7x 2017 EV/DACF (or 6.4x adjusted for Midstream/Chemicals segments).

HES: We downgrade HES to Hold (from Buy) primarily on account of the company's notable outspend (second to worst in the group based on 4Q15 annualized figures). We expect investors to continue to struggle (4%/3% underperformer since recent WTI trough/in May) with HES' relatively high spend on investments that are not expected to generate near-term cash flow (North Malay Basin, US midstream, Stampede, exploration, etc); not surprisingly, HES scores last on our defensive scorecard despite offering a healthy balance sheet (4th in the group on a '16 net debt/cap basis). While an attractive valuation (5.6x 2017 EV/DACF vs group at 6.4x) and impressive liquids leverage (highest in the group) sets up well for investors looking to play a crude price bounce, our defensive-tilted outlook suggests HES's mediumterm outspend/ FCF profile will remain in the spotlight.
Primary Risks: global demand, supply delays, decline rate and OPEC
We view the following as amongst the primary risks to our outlook:
OPEC – Outside of a change in policy by Saudi, we see two primary risks to

our
forecast in the immediate horizon (6-12 months): Iran (a potential reduction in
the call on US growth by ~450 Mb/d) and Iraq (increased export volumes out of Kurdistan an incremental ~400 Mb/d over 2014 levels presently) Longerterm growth in sustainable productive capacity from Iraq and the UAE pose
the greatest risks to an increased need for US onshore crude during the tailend
of our forecast period. As for Saudi, we sensitize our outlook to Saudi market share as a % share of global oil supply. Using a 5 year average market share of global supply, implied go-forward Saudi production results in a call on
US onshore growth of ~500 Mb/d through 2018 and increasing to 700 Mb/d by 2019. Assuming current Saudi market share levels (~15%) effectively renders the call on US onshore growth non-existent during our forecast period.

Global Oil Demand and Decline Rates – Our base case assumes 1.2 MMb/d of global product demand growth in 2016 (vs. 2015), an improvement over the current 2015 growth outlook (1.1 MMb/d). Although demand in 2015 has exceeded expectations (current estimate revised higher vs. initial 1 MMb/d), with particular strength seen in US gasoline and European product demand, increasing efficiencies in global fuel consumption, or a slowing global economy, could result in lower growth, potentially eliminating the call on US crude growth. On the flip side, demand growth approaching our bull case (1.4 MMb/d) would push the call on US crude growth towards 650 Mb/d, stressing the ability of US producers to respond, and driving much higher than expected crude prices. A change in our modeled decline rates (2015+) by 25 bps could impact the call on US crude growth by ~150 mbpd in 2017.
Inventory Overhang: At its peak (in 2Q16) we expect accumulated crude inventories post 4Q14 to reach 500 mbbls or ~17.5% of annualized 2Q15 production. While on first blush this may seemingly present a significant headwind to our outlook, we contend that a) relative to historical levels we aren’t visiting new ground, and b) strong product demand and relatively low product inventories should support an inventory shift from crude to products, somewhat mitigating the risk.

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Integrated Oil
US Integrated Oils
The Non-OPEC growth
outlook to 2017
Looking for rapid declines? Don't hold your breath
The prevailing narrative on global Non-OPEC crude production is that: 1) it always disappoints (not entirely unfair), and 2) near-term production will disappoint as decline rates accelerate from capex cuts. While there is certainly risk to the current supply outlook and decline rates may eventually tick higher, the reality is that those looking for a rapid negative response in Non-OPEC production are likely to be disappointed. The reason? 1) Despite frequent jokes to the contrary, 4+ years of ~$100/bbl crude generated significant investment that is now showing up in a relatively robust queue of growth projects that, already underway, are proceeding no matter the medium-term price of crude; and 2) Capex cuts across the globe have been disproportionately driven by major project deferral (ie. FID delays, with volume impact felt 3-5 years out), rather than cuts to brownfield/maintenance spend.
Non-OPEC growth: Late to the party
A look back at new, project-driven "growth" barrels (ie. incremental barrels associated with project starts or significant expansions) show that ex-US onshore Non-OPEC averaged annual growth of 970 Mb/d from 2004-2013, including only 700 Mb/d in 2012 and 2013. However, beginning in 2014, after multiple years of elevated investment, incremental project-driven growth was ~ 1050 Mb/d, rising to an expected 1600 Mb/d in 2015, and remaining at an elevated 1275 Mb/d per year through the rest of the decade.
Figure 9: Since 2004, higher contributions from major
projects have driven Non-OPEC Supply growth
2000
1528
1500
1134
1000
719
500
0
<800 Mb/d
-500
Avg Growth Bbl Contribution
Source: Deutsche Bank
YoY Non-OPEC Supply Growth (Avg)
Source: Deutsche Bank
800-1000 Mb/d
1000 - 1200 Mb/d
>1200 Mb/d
933
Figure 10: .And over the near-term outlook, major

project growth is expected to reach peak levels following
recent $100/bbl oil incentivized spend
200
400
600
800
1000
1200
1400
1600
1800
0
1325 Mb/d
975 Mb/d

Mb/d
YoY Crude Production Growth (Mb/d)

Despite the current speculation on the impact of potential reductions to brownfield capital spend (infill drilling, tie-backs) or other decline maintenance efforts, the reality is that large projects remain the single largest driver of incremental volume growth, and the lag in project development timelines means that many of those "$100/bbl crude" projects will start over the coming 2-3 years.

Figure 11: Non-OPEC peak spending from 2012-2014 chief driver of increase in incremental "growth" barrels anticipated on-stream between 2015-2017

100
150
200
250
300
350
400
450
500
50
0
Onshore (ex US, Canada)

Source: Deutsche Bank, Wood Mackenzie

There are clearly risks to this outlook, as Non-OPEC supply has historically disappointed (see figure below), but there is no avoiding the fact that the outlook for Non-OPEC supply is more robust than usual.

Figure 12: However, Non-OPEC Supply has often disappointed (IEA NonOPEC supply projection revisions)

(0.8)
(0.6)
(0.4)
(0.2)
0.0
0.2
0.4
0.6
0.8
1.0
1.2
2014
2010
2012
2013
2011
2015
Shallow DW UDW Canada Offshore, Oil Sands
LNG
2009

Month IEA Forecast was Made
Source: IEA, Deutsche Bank

Real Capital Spending ($2014 USD, Billions)
Forecast non-OPEC Supply ex US
(mmb/d)
Feb-08
Jul-08
Dec-08
May-09
Oct-09
Mar-10
Aug-10
Jan-11
Jun-11
Nov-11
Apr-12
Sep-12
Feb-13
Jul-13
Dec-13
May-14
Oct-14

Where is the growth coming from?

While volume growth is coming from a variety of sources, the single largest drivers outside of the US onshore are clearly Brazil and Canada. Brazil, after
years of delays and disappointment, is set to contribute ~155 Mb/d per year from 2014-2020. And while the combination of lower oil price and political scandal has certainly elevated the risk profile, particularly in the out years,
near-term schedules remain largely intact (see Brazil focus section on page 43).

Excluding Brazil, crude production from the rest (ex-OPEC, US onshore) is projected to be relatively flat through 2020.

Figure 13: 2014-2017 Cumulative Growth (Mb/d)

Non-OPEC Middle East
Mexico
North Sea
Colombia
Caspian Sea
Alaska
Other Non-OECD Asia
Europe Non-OECD
India
Other FSU
Angola
Australia
Other Non-OPEC Latin America
Other Europe OECD
Other Asia OECD
Indonesia
China
Non-OPEC Africa
Malaysia
Russia
Canada
Brazil
GoM
-400 -200 0 200 400 600 800

Source: Deutsche Bank

Source: Deutsche Bank

Figure 14: 2014-2020 Cumulative Growth (Mb/d)

Non-OPEC Middle East
Mexico
North Sea
Colombia
Non-OPEC Africa
Alaska
Indonesia

Other Non-OECD Asia
India
Other Europe OECD
Europe Non-OECD
Other FSU
Russia
Other Non-OPEC Latin
America
Other Asia OECD
Malaysia
Australia
China
Angola
Caspian Sea
GoM
Canada
Brazil
-500
0
500
1000

Figure 15: Brazil and Canada: Exclude them and Non-OPEC crude production is down ~1500 MMb/d from 2014-2020,
include them and production is up 400 Mb/d
-2000
3000
8000
13000
18000
23000
28000
33000
38000
43000
GoM
Non-OPEC Middle East
Indonesia
Caspian Sea
Other
India
Source: Deutsche Bank, Wood Mackenzie, IEA
Through 2017, the vast majority of this growth (~99%) is currently on-stream or under development, reducing the potential risk of low current oil price. Onshore projects remain the largest source of growth (36%), with deepwater projects representing an increasingly meaningful 35% of incremental barrels (vs. only 8% of current Non-OPEC production).
Figure 16: 99% of Growth from 2015-2017 of "Other Bbls" are either "Onstream" or "Under Development"…
Not Yet Developed
1%
Figure 17: …With the onshore remaining single highest source of growth
Unconventional,
Other
11%
Under
Development
33%
Onstream
66%
Deep-Water
17%
Shallow-Water
18%
Ultra Deep-Water
18%
Onshore
36%
2014

2015E
2016E
Colombia
Australia
Other Non-OECD Asia
Total North Sea
Mexico
Total Canada
2017E
2018E
2019E
Non-OPEC Africa
Malaysia
Russia
Other Non-OPEC Latin America
China
Brazil
2020E
Source: Deutsche Bank, Wood Mackenzie, IEA, adjusts for Brazil Lula/Iracema FPSOs not currently
onstream
Source: Deutsche Bank, Wood Mackenzie, IEA

Post-2017, project risk increases materially, with 25% of expected growth
from
2018-2020 not yet sanctioned (and unlikely to be sanctioned anytime soon).
The ultra-deepwater grows increasingly important during this time period,
rising to ~24% of expected growth, with another 11% from deepwater projects.
Figure 18: Post 2017, growth from “Not Yet Developed”
bbls is expected to increase to 25%...
Onstream
22%
Not Yet Developed
26%
Figure 19: With Deepwater (UDW and DW) expected to
be the single highest source of growth (~35%)
Unconventional,
Other
13%
Onshore
31%
Ultra Deep-Water
24%
Deep-Water
11%
Under
Development
52%
Source: Deutsche Bank, Wood Mackenzie, IEA
Source: Deutsche Bank, Wood Mackenzie, IEA, Unconventional includes oil
sands, bitumen
Shallow-Water
21%
Figure 20: Decomposition of YoY Growth from Major
Projects By Development Status
200
400
600
800
1000
1200
1400
1600
1800
0
2015E
Onstream
2016E
2017E
Under Development
2018E

2019E
2020E
Not Yet Developed
Source: Deutsche Bank, Wood Mackenzie, IEA, adjusts for Brazil Lula/Iracema FPSOs not currently onstream
Onshore
Figure 21: Decomposition of YoY Growth from Major Projects By Project Type
200
400
600
800
1000
1200
1400
1600
1800
0
2015E
2016E
Shallow-Water
2017E
Deep-Water
2018E
Ultra Deep-Water
2019E
2020E
Unconventional, Other
Source: Deutsche Bank, Wood Mackenzie, IEA, 2020 pick-up in shallow water growth from Johan Sverdrup ramp

In terms of the physical decomposition of the crude bbls that are to hit the global market in the coming years, the mix is weighted heavily toward heavy Canadian oil sand volumes and medium heavy Brazilian barrels (Iara and Tartaruga Verde fields)

Decomposition of YoY Growth from Major Projects (Mb/d)
Decomposition of YoY Growth from Major Projects (Mb/d)

EFTA01411453

Figure 22: While the current Non-OPEC production mix is ~2/3 medium

Light
15%
Extra Light
1%
Extra
Heavy
1% Heavy
17%

Figure 23: 2014-2020 “growth bbls” are anticipated to be heavier on increased volumes from the Canadian oil sands and from medium-heavy Brazil volumes

Extra
Heavy,
14%
Extra Light,
0%
Light, 18%
Heavy,
23%
Medium
66%
Medium,
46%

Source: Deutsche Bank, Wood Mackenzie, IEA, Heavy barrels are classified as <28 API with extra heavy barrels <11 API. Light barrels are classified as having an API of 38+ with Extra Light > 51

Source: Deutsche Bank, Wood Mackenzie, IEA, Heavy barrels are classified as <28 API with extra heavy barrels <11 API. Light barrels are classified as having an API of 38+ with Extra Light > 51

Figure 24: Top 25 Projects (2014-2017) Incremental Oil Production

Project
Region
Lula-Iracema
Sapinhoa
Kearl
SeverEnergia
Kizomba Satellites Phase2
Papa-Terra
Surmont Project
Horizon Project
Edvard Grieg
Srednebotuobinskoye
Block 15/06 NW Hub
Kashagan Contract Area

Foster Creek
Laggan & Tormore Area
Roncador
Yarudeiskoye
Delta House
Goliat Area
Lucius (KC 875)
AOSP
Ekofisk Area II
Tsimin-Xux
Mafumeira
Golden Eagle Area
Sunrise
Latin America
Latin America
North America
FSU
Africa
Latin America
North America
North America
Europe
FSU
Africa
FSU
North America
Europe
Latin America
FSU
North America
Europe
North America
North America
Europe
Latin America
Africa
Europe
North America
Source: Deutsche Bank, Wood Mackenzie
Country
Brazil
Brazil
Canada
Russia
Angola
Brazil
Canada
Canada
Norway
Russia
Angola

Kazakhstan
Canada
UK
Brazil
Russia
United States
Norway
Canada
Norway
Mexico
Angola
UK
Canada
Basin
Santos
Santos
West Canadian - Alberta
West Siberia (Central)
Lower Congo
Campos
West Canadian - Alberta
West Canadian - Alberta
Northern North Sea
Nepa - Botuoba
Lower Congo
Precaspian
West Canadian - Alberta
West Shetland
Campos
West Siberia (Central)
East Gulf Coast Tertiary
West Barents Sea
United States West Gulf Coast Tertiary
West Canadian - Alberta
Central Graben
Salinas-Suerte
Lower Congo
Moray Firth
West Canadian - Alberta
Operator
Petrobras
Petrobras
Imperial Oil
SeverEnergia
ExxonMobil
Petrobras
ConocoPhillips
Canadian Natural Resources
Lundin Petroleum
Taas-Yuryakh
Eni

North Caspian Operating Co
Cenovus Energy
Total
Petrobras
Yargeo
LLOG Exploration
Eni
Anadarko
Shell
ConocoPhillips
Pemex
Chevron
Nexen
Husky Energy
Project Type
Dev Status
UDW
UDW
Onshore
Onshore
DW
DW
Onshore
Onshore
Shallow
Onshore
DW
Shallow
Onshore
DW
UDW
Onshore
UDW
DW
UDW
Onshore
Shallow
Shallow
Shallow
Shallow
Onshore
Onstream
Onstream
Onstream
Onstream
Under Development
Onstream
Onstream
Onstream
Under Development
Onstream

Onstream
Onstream
Onstream
Under Development
Onstream
Under Development
Under Development
Under Development
Onstream
Onstream
Onstream
Onstream
Onstream
Onstream
Onstream
API
27
30
8
43
28
14
8
34
35
32
24
45
11
40
24
42
36
37
29
34
40
38
36
38
8
Production
Start Up Yr
2009
2010
2013
2012
2015
2013
2007
2008

2015
2013
2014
2013
2001
2015
1999
2015
2015
2015
2015
2003
1999
2012
2009
2014
2015
Peak Prod
Yr
2022
2016
2030
2018
2020
2017
2018
2019
2016
2023
2016
2029
2029
2018
2018
2016
2017
2016
2017
2021
2002
2017
2018
2017
2025
Incremental
Production
381
171
138
120
108

96
95
89
89
85
83
83
81
81
79
79
75
72
69
68
68
64
62
60
60
2014-2017

Figure 25: Top 25 Projects (2017-2020) Incremental Oil Production
Project
IEA Region
Lula-Iracema
Johan Sverdrup
Buzios
Kashagan Contract Area
Block 32 Kaombo
Fort Hills Mine
Hebron/Ben Nevis
Novoportovskoye
Tengizchevroil Area
Block 21
Ayatsil-Tekel
Block 16
Messoyakhaneftegaz Fields
Horizon Project
Christina Lake Project
Clair
Kizomba Satellites Phase2
Appomattox (MC 392)
Vladimir Filanovski
Schiehallion
Lapa
Stampede
Bream Area
Iara
Prirazlomnoye (TP)
Latin America
Europe
Latin America
FSU
Africa
North America
North America
FSU
FSU
Africa
Country
Brazil
Norway
Brazil
Kazakhstan
Angola
Canada
Canada
Russia
Kazakhstan

Angola
North America Mexico
Africa
FSU
Angola
Russia
North America
North America
Europe
Africa
FSU
Canada
Canada
UK
Angola
North America United States
Russia
UK
Europe
Latin America
Europe
Brazil
North America United States
Norway
Latin America
FSU
Source: Deutsche Bank, Wood Mackenzie
Brazil
Russia
Basin
Santos
Central North Sea
Rio de Janeiro
Offshore
Ultra Deepwater
Athabasca
Newfoundland
West Siberia
Precaspian Basin
Deepwater
Salinas-Sureste
Deepwater
West Siberia
Athabasca
Athabasca
Atlantic Margin
Deepwater
Central Gulf
North Caucasus
Atlantic Margin
Sao Paulo

Central Gulf
Central North Sea
Rio de Janeiro
Timan-Pechora
Operator
Petrobras
Statoil
Petrobras
North Caspian Operating Co
Total
Suncor Energy
ExxonMobil
Gazpromneft Novi Port
Tengizchevroil
Cobalt International Energy
Pemex
Maersk Oil & Gas
Messoyakhaneftegaz
Canadian Natural Resources
ConocoPhillips
BP
ExxonMobil
Shell
LUKOIL Nizhnevolzhskneft
BP
Petrobras
Hess Corporation
Premier
Petrobras
Gazprom neft shelf
Project Type
Dev Status
UDW
Shallow
UDW
Shallow
UDW
Onshore
Shallow
Onshore
Onshore
UDW
Offshore
DW
Onshore
Onshore
Onshore
DW
DW
UDW
Shallow

DW
UDW
DW
Shallow
UDW
Shallow
Onstream
Probable Development
Under Development
Onstream
Under Development
Under Development
Under Development
Onstream
Onstream
Under Development
Probable Development
Probable Development
Under Development
Onstream
Onstream
Onstream
Under Development
Probable Development
Under Development
Onstream
Onstream
Under Development
Probable Development
Under Development
Onstream
API
27
28
28
45
32
10
27
32
47
44
11
36
31
34
9
24
28
38
44

26
26
32
32
26
24
Production
Start Up Yr
2009
2020
2016
2013
2017
2017
2017
2011
1991
2017
2017
2019
2017
2008
2002
2005
2015
2019
2016
1998
2011
2018
2020
2018
2013
Peak Prod
Yr
2022
2024
2023
2029
2020
2020
2023
2022
2023
2024
2021
2021
2023
2019
2025
2021

2020
2025
2022
2003
2020
2022
2020
2026
2021
Incremental
Production
397
311
300
246
174
170
120
111
91
90
88
88
86
76
75
70
69
69
67
64
57
56
54
50
47
2017-2020

Capex Reductions
Show me the money (or lack thereof)
In addition to the relatively robust queue of project starts, the production outlook is largely supported by what we have seen in global capex trends, where cuts have been disproportionately driven by major project deferral (ie. FID delays, with volume impact felt 3-5 years out), rather than cuts to brownfield/maintenance spend. In other words, the nature of the capex cuts are likely to have a significant impact on production growth in the latter part of
this decade, but a far lesser impact on near-term production (2015-2016) and/or decline rates.
A brief survey of capex trends across ~50 global oil and gas producers shows an average cut of 20% in 2015 vs. 2014 ($300Bn to $375Bn in 2014). However, drilling down a bit reveals a number of important details. 1) Capex cuts tend to
be largest in the US and amongst independent E&Ps (35%), a reflection of both relatively high financial leverage, short cycle nature of US onshore spend and
concentrated business models; 2) average capex cut across global IOCs is more moderate on average (13%), with the largest portion of cuts a result of: a)
FID deferrals and delays to large-project spend, b) exploration spend, or c) downstream investment, none of which have any impact on crude production in the next 2-3 years. Further, dollar strength has offset, or partially offset the
fall in crude prices in many parts of the world, none more evident than in Russia, where YoY activity levels are nearly flat in Roubles, despite the fall in
crude.
While certainly a limited cross section of global supply, these trends are largely
validated by corporate level guidance across the largest global IOCs (XOM, CVX, COP, BP, RDS, TOT, ENI, STO), where a 13% reduction to 2015 capital spend was accompanied by a negligible reduction to 2017 production forecasts. Spending by Petrobras (PBR, covered by DB analyst Alexander Burgansky) will also be closely monitored given Brazil’s role in driving nonOPEC
production growth. During their late April presentation, PBR noted that they would be reducing 2016 capex spend by ~40% from prior guidance and with speculation that long-term spend may also be slashed, the June budget presentation will have implications on the Call on US onshore growth.
While this cycle clearly has differences, the trends to capital are consistent
with those seen during 2008-2009, where brownfield capex as a share of total budgets increased materially as capital budgets were reduced.

Figure 26: Greenfield spending will undoubtedly be challenged through 2015; however, offshore short-cycle brownfield spending is expected to be curtailed far less
100
120
140
160
180
20
40
60
80
0
Greenfield CAPEX
Brownfield CAPEX
2014 offshore upstream CAPEX
Exploration CAPEX
153
Figure 27: While a new deeper trough in Greenfield spending is expected this time around, it's worth noting that prior cycle's SUBSEA demand fell only ~7% as brownfield activity replaced greenfield
77
63
10
15
20
25
30
35
40
0
5
2006
Engineering
2007
Equipment
2008
Services
2009
2010
SURF
2011
Share of brownfield
In 2009/10 subsea
demand only fell ~7%
as the share of
brownfield picked up

30%
32%
34%
36%
38%
40%
42%
44%
Source: Re-printed from our European Oil Service counterparts April 9 publication
th
Source: Re-printed from our European Oil Service counterparts April 9 publication
th
In our view, brownfield spend is likely to benefit from local currency devaluations. If we look at Norway as a example, our FX team forecasts a NOK to USD exchange rate of 8.2 for 2015 a drop of ~25% in the value of the Krone YoY.
If we assume that 20% of spend in the NCS is denominated in local currency (a rough estimate used by Wood Mackenzie for offshore fields driven chiefly by labor costs) the FX tailwinds from the devalued NOK will contribute
~4% of a targeted 20% (as an example) reduction in capital spend. For illustrative purposes if the NOK comprised ~80% of NCS spend then the devaluation would contribute ~15% of the targeted 20% reduction. For onshore fields with material local content requirements (i.e. Russia), Wood Mackenzie places the % of spend denominated in local currency closer to 80%.
Figure 28: Stronger dollar to soften spending declines – An illustrative example using the NOK (assumes target 20% $USD capex cut from 2014)
Spend reduction required (excl FX effects)
20%
15%
10%
5%
5%
0%
0%
10%
20%
30%
40%
% of Spend Denominated in Local Currency
Source: Deutsche Bank, Wood Mackenzie, Above Analysis Assumes Target 20% YoY Capex Cut to NCS Spend
80%
20%
18%
16%
14%
13%
Reduction in Spend from FX Tailwind

% Change in spend YoY ($USD)
$ billions

Figure 29: Aggregate DB Global Coverage Universe Company Capital Spend
YoY %
Chief Operating
Region
US Based
PDC
Continental
Concho
Range
Bonanza Creek
RSP Permian
Hess
Freeport-McMoRan
Murphy
ConocoPhillips
Occidental
Chevron
Pioneer
Apache
WPX
Devon
Magnum Hunter
EOG
Marathon
Noble Energy
Cabot
Newfield
SM Energy
Antero
Bill Barrett
ExxonMobil
Oasis
Southwestern
Anadarko
Canada
Encana
Europe
2511
2100
The following estimates only include upstream operations
2020
Tullow
Total
OMV
Shell
BG
BP
Statoil

Eni
Latin-America
1900
26200
4680
33280
8500
23100
19200
€12600
23400
3300
32520
6500
19900
17900
€11900
The following estimates only include upstream operations
5700
Ecopetrol
Petrobras
Pacific Rubiales
Asia, ex China
Santos
Woodside
Oil Search
BHP Billiton
Russia
Gazprom
Lukoil
Rosneft
Surgutneftegaz
Tatneft
Bashneft
West Africa
Cobalt
Kosmos
829
531
850
800
3%
51%
23-Feb-15
23-Feb-15
Todd
Todd
While headline capital budget remains roughly unchanged from 2014; appraisal and development make up a larger portion with
Cameia (Angola) expected to be sanctioned by YE15 and first oil in 2018
Over 60% of 2015 spend mix toward Ghana (Jubilee, TEN)

Source: Deutsche Bank, Wood Mackenzie, Total company spend unless otherwise stated, spend is expressed in $USDMM unless otherwise specified
7013
13974
14337
4474
1613
1282
5400
10900
11900
3400
1000
1000
-23%
-22%
-17%
-24%
-38%
-22%
Kushnir
Kushnir
Kushnir
Kushnir
Kushnir
Kushnir
3067
971
1869
4000
1786
1160
620
2000
-72%
16%
-201%
-100%
11-Dec-14
18-Feb-15
24-Feb-15
19-Jan-15
Hirjee
Hirjee
Hirjee
Young
2015 capex declines primarily due to up-coming start-up of flagship GLNG project (90% complete end 2014), after
commissioning of PNG LNG in 2014, FID deferrals, and slower ramp-up of growth projects under development
2015 capex increase due to Wheatstone LNG capex commitments

2015 capex declines following commissioning of flagship project PNG LNG in 2014
Company has guided to a reduction in US onshore spend from $3.4Bn in FY15 to $2.2Bn in FY16
While no formal announcements have yet been made with regard to capex cuts as a result of the oil price decline, DB expects that
many companies will either keep spending levels unchanged in RUB terms or modestly increase them. On a USD-denominated
basis, spending is anticipated to be ~20-25% lower.
4700
24500
2000
22300
900
-16%
25-Feb-15
Silverstein
In the Permian expecting to operate 4-6 horizontals and 4-6 verticals and 2-3 rigs in the Eagle Ford and 3 and 2.5 in the Montney
and Duvernay
Exploration likely falling by 20-30% with few material greenfield projects being sanctioned from this year outside of Appomatox
and the recently sanctioned Johan Sverdrup.
-6%
-12%
-42%
-2%
-31%
-16%
-7%
-6%
-21%
-10%
-122%
15-Jan-15
20-Jan-15
29-Jan-15
30-Jan-15
3-Feb-15
3-Feb-15
6-Feb-15
18-Feb-15
Robinson Capex guidance for year at $1.9Bn
Herrmann
Bloomfield
Herrmann
Herrmann
Herrmann
Bloomfield
Bloomfield
Confirmed 2015 capital spend of ~ $20bn with an investment decision on Mad

Dog II cloe to year-end. Signed deal with Egypt to
develop the West Nile Delta gas fields in March.
$5-$7Bn of flexibility by 2017/2018 from pre-FID projects. 2015 capital
guidance intact at $18Bn (inclusive of exploration) following
1Q15 results.
Guidance of Capex of €12Bn Euro. Cape Three Points was sanctioned in
January. Coral LNG (Mozambique) investment
decision likely by year-end
15-Dec-14
28-Jan-15
14-Jan-15
Burgansky
Largely exploration-driven
Burgansky Upstream capex
Burgansky
Largely exploration and some production facilities
Delaying FID on the Majnoon field in Iraq and with a 20% reduction in
unconventional spend and a re-phasing of Cardmon Creek
(Canadian Oil Sands) upstream spend to trend lower per 1Q15 guidance. Key
investment decisions to look out for in 2015/2016
include: Appomattox, Vito, Bonga SW, and Libra.
Shell is targeting a 6% reduction in organic capital spend (pro-forma BG) in
2016, from US$42-US$43 billion to below US$40 billion on pre-tax synergies.
2015 capital spend cut to $23-$24 with reductions to brownfield spend
representing a material impact.
647
4050
2300
1190
667
400
5600
3200
3433
16700
8657
37115
3200
5300
1450
5200
400
6600
5536
4880
1480
2000
1707
2500
520
38537

1430
2141
8700
473
2373
1800
722
420
400
4400
2300
2300
11500
5800
31600
1600
2200
725
4250
200
4000
3521
2900
900
1200
1045
1600
260
34000
705
1889
5650
-37%
-71%
-28%
-65%
-59%
0%
-27%
-39%
-49%
-45%
-49%
-17%
-100%
-141%
-100%
-22%
-100%
-65%
-57%

-68%
-64%
-67%
-63%
-56%
-100%
-13%
-103%
-13%
-54%
8-Dec-14
22-Dec-14
5-Jan-15
15-Jan-15
19-Jan-15
20-Jan-15
26-Jan-15
27-Jan-15
28-Jan-15
29-Jan-15
29-Jan-15
30-Jan-15
11-Feb-15
12-Feb-15
12-Feb-15
17-Feb-15
17-Feb-15
18-Feb-15
18-Feb-15
19-Feb-15
20-Feb-15
24-Feb-15
24-Feb-15
25-Feb-15
25-Feb-15
25-Feb-15
25-Feb-15
27-Feb-15
3-Mar-15
Silverstein
Expects to drill 90% of wells in the Inner/Middle Core areas, up from 67% in 2014; a 6th rig will not be added to the Wattenberg
program
Silverstein Decreasing op rig count from 50 to 31 by Q1 (31 2015 avg); taking 8 rigs out of Bakken, 10 out of SCOOP, 1 out of other
Silverstein
Silverstein
Silverstein
Silverstein
Todd
Beristain

Todd
Todd
Todd
Todd
Todd
Todd
To operate avg of 26 drilling rigs in 2015 (vs. prior 39); allocating $1.3bn D&C to DE Basin, $300mm in Texas Permian, $200mm
in New Mexico Shelf
Lowered 2015 budget from initial Dec; Marcellus is 95% of budget vs. 87% last year and 92% prior; cut prod to 20% vs prior 2025%
Plans
to complete 45-50 gross op hz wells, 30 gross op vert wells; 6 operated rigs in 2014, planning for 3.5 hz rigs and 1 vert rig
in 2015
Bakken production for 2015 expected between 95 and 105; plan to run 8 rigs for the remainder of year in Bakken. Annual run-rate
in capex expected to be ~$3.8Bn in 2H15
Plans to run only 4 rigs in the Eagle Ford for the remaining year in 2015
Rig Count in Lower 48 dropped 60% from 2014; 6 in EF, 3 in Bakken and 4 in Permian (2 unconventional)
25 horizontal rigs (4 vertical rigs) in 1Q15; 19 in Q2 and 15 in 3Q and 4Q . Total Permian production expected at 100 mboe/d in
2015 and 120 mboe/d in 2016. They had 61 uncompleted wells at year-end (exp to drill 85 and place 108 on production including
63). Could accelerate at $70/WTI
Pick-up in spend YoY in US onshore
Reducing hz drilling in Spraberry/Wolfcamp and EF to 16 by end of Feb (50% decline from YE14)
Reducing NA rig count from 91 in Q3 to 27 by end of Feb, reduced frac crews by 50%; avg 2015 NA rig count will be 17
Silverstein Aligned capital plan to spend within cash flow; Bakken rig count to decline from 5 to 1, from 3 to 2 in SJ, from 8 to 3 in Piceance
Todd
Silverstein
Todd
Todd
Todd
Silverstein
Silverstein
Silverstein
Silverstein
Silverstein
Todd
Silverstein
Silverstein
Todd
Plan for 0 operated rigs in Wolfcamp, 11-12 rigs in EF, will participate in 20 STACK wells; expect Canadian Oil Sands prod of 100105
mbo/d
Announced a preliminary budget on 3Q14 earnings call assuming Eureka Hunter

goes public (source: Magnum Hunter) and
MHR will no longer have to fund its capex needs
Expects to complete ~45% fewer wells; reducing investment in natural gas drilling, utilizing rigs under existing commitments
Plans to run 10 rigs in EF from 2Q-4Q15 and 2 rigs each in the Bakken and SCOOP/STACK through 2015
Plan for 4 rigs in the DJ, 2 rigs in the Marcellus (4 non-op rigs), and $600mm inevsted in GoM; Asdod planned for 2H15
Assumes 5 op rigs in the Marcellus (Q3 6 rigs), 4 in EF; will drill 180-190 net wells, incl 95-100 in Marcellus, 80-85 in EF ($88/bbl
and $2.80/mcf)
Newfield operated wells drilled in Anadarko Basin expected at 94 with production of 61 mboepd. 2015 domestic oil production
~20.75 mmbls
Increasing well deferrals from ~45 at YE14 to ~95 at YE15, completion cost reduction driven. 2015e oil production (annual) is
expeted at 18.6 mmbbls vs. 16.53 mmbbls in 2014.
completions.
In Eagle Ford, expecting to operate 4 to 5 rigs in 2015 and make 75
In Bakken, expecting to average 3.5 rigs and make 40 gross operated completions.
Revised capex down from initial budget per Q3 call; operating 14 rigs in 2015 down from 21 at YE; production growth fell 5-10%
on a 33% D&C cut
Laid out bull scenario of 3 rigs in DJ, 1 in UOP, capital of $475mm (expect double digit PF prod growth in 2015 from 2014 exit rate
prod)
Running just under 40 rigs in the US onshore exiting 1Q15. Investment spend is expected to remain less than $34Bn through
2016 and 2017 on lower oil sand investments and re-sequencing of FID decisions.
Expected to complete 79 gross (63.3 net) and 2.6 net non-op wells in 2015 in the Bakken; 2015 production expected at 45-49
mboepd
Planning gross well count of 540-560 (net 435-460 net) vs 2014 525 (net 412)
Excludes WES. Reducing onshore rig count by 40% from 2014; deferring 125 completion until costs align with commodity prices.
Liquids growth at DJ, EF, and Wolfcamp expected at 154.5, 77, and 14 mbpd at 2015 guidance
Company
2014 Capex
(US$M)*
2015 Capex
(US$M)*
Date of
Change
Disclosure
DB Analyst
DB Commentary

Setting the stage for the next oil price spike?
While current reductions to budgets may have limited impact to near-term production across much of the sector, it will certainly have a dramatic impact
on long-term crude supply, with a crunch likely later this decade (2018-2020) as the impact of project deferrals takes a bite out of incremental crude supply.
A quick look at global project FIDs helps put the matter into perspective. Between 2002 and 2013, the industry averaged 21 oil-targeted project sanctions a year (>5 mbpd of peak production). However, this fell to only 6 such projects sanctioned in 2014, with 2015 likely to remain in single digits. In
terms of productive capacity, each year of "lost" FIDs represents an average 830Mb/d of new, annual productive capacity.
Figure 30: Global project FIDs by year
10
15
20
25
30
35
40
0
5
Figure 31: Total "peak" production of FIDs by year
(Mb/d)
500
1000
1500
2000
2500
3000
0
Source: Deutsche Bank, Wood Mackenzie
Source: Deutsche Bank, Wood Mackenzie

Figure 32: Near-Term FID Tracker
Project
Country
Johan Sverdrup
(Phase I)
Maria
Vette (ex Bream)
Rosebank
Cameia
Norway
Norway
Norway
UK
Angola
Project Type
Shallow
DW
Shallow
DW
UDW
Operator
Statoil
Wintershall
Premier
Chevron
Cobalt
Participants
Prod Start
Yr
(Statoil 40%, Lundin 22%, Norway
State 18%, Det Norske 12%, Maersk
Oil and Gas 8%)
(Wintershall 50%, Norway State 30%,
Centrica 20%)
Premier 50%, KUFPEC 30%, Tullow
20%)
OMV (50%, CVX 40%, DONG 10%)
(Sonangola 60%, Cobalt 40%)
Bonga SW
Nigeria
DW
Shell
(CVX 20%, XOM 20%, Oando 20%,
Svenska 20%, NPDC 15%, Sasol 5%)
OPL 245-Etan
Bosi
Uge
Mad Dog 2

Appomatox
Shenandoah
Vito
Kaskida
Buzios V
Parque das Baleias
Nigeria
Nigeria
Nigeria
US
United States
United States
United States
United States
Brazil
Brazil
UDW
DW
DW
DW
UDW
UDW
DW
UDW
UDW
DW
Eni
ExxonMobil
ExxonMobil
BP
Shell
Anadarko
Shell
BPP
Petrobras
Petrobras
(Eni 50%, Shell 50%)
(XOM 56.25%, Shell 43.75%)
(CVX 20%, XOM 20%, Oando 20%,
Svenska 20%, NPDC 15%, Sasol 5%)
BP (60.5%, BHP Billiton 24%, CVX
15.5%)
(Shell 80%, Nexen 20%)
(APC 30%, COP 30%, Cobalt 20%,
MRO 10%, Venari 10%)
(Shell 51%, Statoil 30%, Freeport
19%)
BP (100%)
Petrobras (100%)
Various
2020

2018
2020
2020
2018
2024
2019
2020
2022
2025
315-380 Mb/d
50
50
80
76
Peak Prod
Yr
Production
Commentary
Plan for Development and Operation (PDO) was submitted for Phase 1 (capacity of
between 315-380 Mb/d) in February. Will consist of 4 bridge-linked platforms and subsea
water injection templates
Concept is to connect to use subsea tieback to connect to current infrastructure. Plan for
Development and Operation was submitted in May 2015
Had initially expected to FID in early 2015, now postponed so as to capture lower contracting
costs
Likely delayed for some time. The project had been delayed previously in 2013 by Chevron
because of rising costs though the company has pointed to recent changes to the project to
reduce costs.
Cobalt guide is for YE15 project sanction with development drilling likely to continue until
early 2016 with first oil in 2018
2020
2024
170
Shell as confirmed progress toward FID in the late 2015/early 2016 timeframe for the Bongo
SW/Aparo project. The project would include the construction of a new FPSO with expected
peak capacity of 225 Mb/d. WM estimates ~135 Mb/d in oil production by 2022 (2 years after
first oil).
2019
2024
2023
2021

2019
2020
2021
2022
2021
2018+
2028
2025+
2025
2023
2025
2026
2023
2027
2023
2020+
90
>60
75
75
119
60
47
66
FPSO capacity
of 150 Mb/d
100
WM assumes a start-up date of 2019. Production estimate includes Etan and nearby
Zabazaba.
Initially conceived as a tieback to the Erha FPSO but with successful appraisal, size of the
field has increased. Exxon likely to develop in phases with a dedicated FPSO.
Woodmac assumes Uge to be a standalone development with a leased 100 Mb/d FPSO
BP guidance is for likely sanctioning by YE15
Shell has noted that Appomattox remains the most attractive candidate for FID in 2015
4th appraisal well being planned. 3rd appraisal well expected to spud before end of 2Q.
WoodMac assumes first production will be achieved in 2021 via a dry-tree TLP with capacity
of 80 Mb/d of oil. WoodMac doesn't assume FID until 2017.
WM assumes field will start production in 2022 with a stand-alone spar.
Currently, Petrobras has not contracted for the envisioned 5th and last FPSO for the Buzios
development.
Includes Baleia Ana,Itaipu, Pirambu in total WoodMac estimates that ~ 100 Mb/-d of
production capacity to be needed with production starting in 2018 with the small Baleia Ana

field; however, we note risk to a near-term production production outlook as high local
requirements for these projects further cloud issues around Brazilian production.
Iara
Brazil
UDW
Petrobras
Petrobras (100%)
2021
2024
135
Declaration of Commerciality filed on Dec 30, 2014; however, not yet moved towards FID
(originally targeted mid-2015). Petrobras targeting first oil in 2018 vs. Woodmac in 2021 on
delays associated with construction of FPSO
Tengiz Projects
(FGP, WPMP)
Kazakhstan
Onshore
Tengizchevroil
(CVX 50%, XOM 25%, KazMunaiGas
20%, Lukoil 5%)
2021
2024
300
TCO is expected to sanction the FGP and WPMP projects by YE2015. Woodmac expects first
production in 2021:
FGP will consist of two main elements: drilling more wells to raise oil production and
increasing sour gas injection. Expected to lift nameplate capacity by another 260 Mb/d
WPMP will serve entire field and is expected to increase long-term recovery from fields by
lower pressure. Expected to contribute 50 Mb/d of oil production at peak.
Pearls
Kazakhstan
Shallow
Caspi Meruerty
(Shell 55%, Kaz MunaiGas 25%, Oman
Oil (20%)
Source: Deutsche Bank, Wood Mackenzie, IEA, Company Reports
2020
2024
70
Wood Mackenzie estimates first production in 2020

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Integrated Oil
US Integrated Oils
The North Sea: A Case Study On Spend and Decline Rates
In some ways, the Norwegian North Sea is representative on a small scale of larger trends across the industry over the next couple of years. After steadily
declining for nearly 14 years, the combination of high oil prices, a ramp in reinvestment
and a string of large development projects will see the basin hold production flat to showing slight growth through 2017.
The long and winding road down…
The North Sea has been synonymous in recent years with mature, Non-OPEC decline, and for good reason. Since its peak production in 2000, North Sea production has steadily declined from ~6 MMboe/d to current production levels of 2.5 MMboe/d, or an average decline rate of 6%/yr. This happened despite steadily increasing capex levels.
Figure 33: North Sea Oil Production
7000
6000
50000
5000
40000
4000
30000
3000
20000
2000
10000
1000
0
2000
UKCS
Source: Deutsche Bank, IEA
2002
NCS
2004
2006
Other
2008
2010
North Sea Capex
2012
2014
2016E
0
60000
Despite multi-year trends, two important things are driving a dramatically different outlook over the next 2-3 years: 1) elevated level of growth barrels
due to start from major projects, and 2) moderation in underlying decline

rate.

Here come the projects

After years of inconsistent development, aggressive spend on the back of 4-5 years of elevated crude price is now bearing fruit, with ~650 mbpd of incremental crude expected from 2015 through 2017. This is compared to 35 mbpd of average annual “new project” production between 2009-2013. While reduced capital budgets may provide a moderate haircut to base production over the next couple of years, this is more than offset by the scale of new projects starts.

Oil Production (mboe/d)
- in 2014 $USD

Figure 34: Norwegian North Sea – Incremental Project Growth Barrels

100
120
140
160
180
200
20
40
60
80
0
2009
2010
2011

Source: Deutsche Bank, Wood Mackenzie, includes Ekofisk II

2012
2013
2014
2015
2016

Taking a closer look at decline

While current reductions to capital budgets will eventually show up in underlying decline of mature assets (ie. reductions to infill drilling, workovers, and other decline mitigation expenditure), significant re-development spending in 2013/2014 will soften the decline of several key fields in the nearer-term.

Adjusting for growth projects (ex redevelopment activity) and after normalizing for maintenance impacts over the last few years, we estimate that decline rates on mature assets have decreased from a 5 year peak of ~12% in 2011 to ~6.5% in 2014. The peaking of decline rates in 2011 followed a cut of 17% in YoY dollar-adjusted investment spending in 2010 vs. 2008. However, in our view, the sudden V-shaped recovery in crude prices during the last cycle likely placed a floor on spending cuts that would have otherwise resulted in a higher decline rate in 2011.

In 2014 we estimate that decline rates on producing fields (ex-Ekofisk) reached a five-year low following an increase of ~50% in development spending in 2013/2014 over the prior 4-yr average (producing fields representing ~60% of this spend in 2013/2014). We forecast a normalized decline rate of 12% in the period's forecast (ex redevelopment activity which is modeled separately) during out forecast period. For every change to decline rates of 1% we estimate a production impact of 3% to our 2017 oil production estimate. In

our
view, the impact of project delays is mostly muted as growth projects are
currently either on-stream or under development. In the following analysis,
we
detail our assumptions and identify the key growth drivers as well as
present a
framework from which to think about decline rates on the base assets.

YoY Growth

North Sea Decline Rate Framework: We construct our decline rate analysis for the underlying asset base by adjusting the actual reported monthly production numbers for growth and maintenance outliers. Specifically, we extract production contributions from growth projects and normalize maintenance outages on a monthly basis over the examined time window (we use a normalized 3% of prior year adjusted production as a normal run-rate). We then calculate the resulting annual decline and find that over the last five years
decline rates peaked in 2011 at 12% following the drop-off in investment in 2010. In our view, the 12% decline in 2012 is likely understated given the Vshaped
recovery in the commodity. The UK Oil and Gas industry mentions a normalized decline rate of 10% in the UKCS with moderate levels of brownfield investing, though decline-rates on mature assets could be expected to reach declines of 15%+ with minimal capital influx.
In our base case we assume a gradual reversion to a more normalized declinerate
of 12%. We estimate that a 1% change to our base case decline rates would impact 2017 production by 3%. In our view, a further devaluation of local currencies in the near-term, alongside capital reallocation tail-winds would present upside to brown-field investments.
Figure 35: Brownfield spending has kept declines (ex new growth projects) at ~10% YoY over the last 5 yrs, peaking in 2011 following a drop in prior year spending and dropping to 6.5% in 2014 on increased redeveloped activities.
2000
2200
2400
2600
2800
3000
3200
3400
3600
3800
2009
Adj Base
2010
2011
Decline
Source: Deutsche Bank, Bloomberg, UK Oil and Gas, Norwegian Petroleum Directorate, Wood Mackenzie
From 2010-2013 we estimate that oil decline rates (adjusting for outages and growth projects) averaged ~10%; however 2014 saw a reduced decline rate of ~6.5% as re-developed projects in Norway began ramping
2012
2013

Actual
2014
Page 22
Deutsche Bank Securities Inc.
mboe/d

Why the UK isn't a good proxy for Norwegian (or global Non-OPEC) production
While some have looked at the UK as a cautionary tale for both the North Sea and as an example for global Non-OPEC production, we see limited read through. Like its neighbor, the UK has seen steadily declining production despite a significant increase in capital spent. However, we see a few meaningful differences: 1) fiscal policy (including the most recent tax change)
has done little to encourage exploration in the region (unlike Norway), resulting
in far fewer meaningful growth projects in the development queue (check the data on this), 2) aging infrastructure has become increasingly problematic (and in many cases borderline non-functioning), driving rapid increases in operating expenses and decreases in production efficiency, with increasing amounts of capital used for maintenance and asset retirement. In contrast, Norway has seen relatively limited operating cost inflation (declined in 2014),
with nearly 50% of spend on producing fields free to support development drilling.
Figure 36: Cost inflation and poor production efficiency
have remained key themes in the UKCS…
£10
£12
£14
£16
£18
£20
£0
£2
£4
£6
£8
2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014
Average Operating Cost per Bbl
Source: DECC, UK Oil and Gas, Deutsche Bank
Production Efficiency
40%
45%
50%
55%
60%
65%
70%
75%
80%
85%
90%
Figure 37: …Leading to reductions in near-term
production estimates amidst the fall in crude prices

100
200
300
400
500
600
700
800
900
0
2015
2016
2017
UKCS Oil (UK Oil and Gas) - March 2014
Source: DECC, UK Oil and Gas, Deutsche Bank
2018
2019
2020
UKCS Oil (UK Oil and Gas) - March 2015
Figure 38: However, in Norway Opex ($USD/boe)
inflation has been modest and declined in 2014 on
exchange rate tailwinds.
Figure 39: And non-development spending on currently
producing fields represents ~50% of current field capex
0.0
1.0
2.0
3.0
4.0
5.0
6.0
7.0
8.0
9.0
2009
Ordinary operating costs
Modifications
Maint Spend as a % of Total Opex
Source: Deutsche Bank, Norwegian Petroleum Directorate
Source: Deutsche Bank, Norwegian Petroleum Directorate
2010
2011
2012
Maintenance (ex wells)
Other operational support
2013
Well maintenance
Logistics costs
2014
38%
39%

40%
41%
42%
43%
44%
45%
46%
Pipelines and
terminals
8%
Other facilities
investments
23%
Development wells
49%
Modifications
20%

$USD/boe - 2014 USD Pricing
£/boe using 2014 Pricing
mboe/d

Implied Call on the US
The new, “price driven” swing producer
As we stated earlier, in our view, the three most important questions in the price of crude over the next two years is: 1) Do we need US Lower 48 production to grow?, 2) How much?, and 3) what is the oil price necessary to incentivize that level of growth? Despite our view that global Non-OPEC production is not on the verge of a dramatic, capex driven decline (at least through 2017), we still see insufficient growth outside of the US to fully supply
global demand growth. In short, there is a call on US Lower 48 production toward late 2016.
Figure 40: The Long and Winding Road: Normalizing US Onshore Crude Supply Growth
12000
The 2-Year Path To Normalized US Onshore Crude Supply Growth...
11000
...With ~Estimated Growth of ~800 Mb/d
Annually In Subsequent Phase
10000
9000
8000
7000
6000
5000
4000
Modeled risks include a swing of ~+/- 400 Mb/d
based on +/-15% revisions to YoY IEA annual
product demand growth and a 1/2% adjustment
to modeled non-OPEC decline rates.
3000
For 2016, modeled downside risk includes ~450
Mb/d of incremental production from Iran
2000
1000
0
2014
Year 0
2014 Onshore Production
Excess Global Oil Supply
Source: Deutsche Bank, IEA, Wood Mackenzie
Looking for a 500 Mb/d Call on US growth starting late 2016
We define the timing around the call on US onshore growth as the point at which a sustainable need/demand for US onshore production growth is visible
We anticipate material production growth from onshore producers starting late 2016 toward a 2017 call on US onshore growth of ~500 Mb/d rapidly escalating toward late 2017/early 2018. We estimate the YoY demand for US onshore production to increase by ~700 Mb/d in 2018 prior and to average over 1MMb/d in 2019 and 2020 as non-OPEC major project growth tapers off

on anticipated spending reductions over the next 2-3 years.
Year 1
YoY Demand Growth
Base Decline
2015E
Year 2
Growth From "Other Bbls"
2016E
2017E
2018E
Years 3-6
Call on US Onshore Crude Production (Base)
2019E
2020E

Implied Call on US Onshore Crude Supply (mboe/d)

Figure 41: Incremental Demand for US Onshore Crude
Expected To Emerge Late 2016 (vs. 2Q15 Production)…
1500
1000
500
0
100
200
300
400
500
600
-500
-1000
-300
-200
-100
0
-42
-230
1Q16
-1500
2Q16
3Q16
4Q16
1Q17
531
342
149
Figure 42:..Forward rolling 12 mo call on US onshore
production growth (vs 1Q16 production) positive in 2H16
Source: Deutsche Bank, Wood Mackenzie, IEA
Source: Deutsche Bank, Wood Mackenzie, IEA
The call on US crude production growth (~500 Mb/d) is decomposed as follows:

- We estimate that ~260 Mb/d of incremental demand is needed beyond peak (2Q15) L48 production that is not otherwise being supplied from non-OPEC producers (assuming non-growing OPEC).
- We anticipate a trough in US production in 1Q16 and estimate a gap of ~270 Mb/d vs 2Q15 production that will need to narrowed toward an estimated call on US onshore production of ~7.65 MMb/d in '17.

Figure 43: We estimate the call on annual US onshore crude growth at ~500 Mb/d in 2017 and increasing to ~1MMb/d by 2019/2020
200
400
600

800
1000
1200
0
2017E
Source: Deutsche Bank
2018E
2019E
2020E
1045
1031
723
531

Annual Change/Growth (Mb/d)
call on US Crude vs. 2Q15 Production (mbpd)
12 Mo Rolling Call on US onshore production
(Mb/d)

Methodology: Our implied call on US onshore crude growth (in the base case) builds on two critical macro assumptions:

- Global product demand is assumed to grow ~1.15 MMb/d in 2015 and 1.2 MMb/d in 2016 with average annual growth of ~1.15 MMb/d from 2017-2020. Our demand growth assumptions are based on IEA estimates and compare to ~650 Mb/d of demand growth in 2014.
- OPEC production (ex Angola) is assumed flat to 2014 levels in our forecast. This assumption is admittedly 'rosier' than would otherwise be implied from recent production levels (~31.6 MMb/d or +1100 Mb/d higher than our assumed base case vs. May 2015 levels) or from a qualitative weighting of both upside and downside risks (with Iran the most visible/pronounced risk). Please see section on OPEC risks on page 33 of the note for brief commentary around OPEC.

Guided by the highlighted assumptions above, our call on US onshore crude growth starts by removing non-crude growth contributions (NGLs, Biofuels, etc.) from assumed global demand growth to obtain a proxy for global crude demand that is then analyzed against our global crude supply build up. In our base case, we assume no pick-up in rig activity in the US L48 in 2016.

Figure 44: Deconstructing the 500 Mb/d Call on US onshore growth in 2017
NGL Demand
2016 Supply
Overhang
1200
Product Demand
Growth, net of
overhang
1000
967
800
24
600
175
531
400
Crude Demand
Growth (in excess
of Prod)
96
29
119
Biofuel, Processing
Gains
Global NGL Prod
growth
OPEC Crude Prod
Growth

Non-OPEC Crude
Prod Growth
Growth (in excess
of Prod)
200
0
-200
-235
-400
Source: Deutsche Bank, Wood Mackenzie, IEA, OPEC crude production growth is from Angola which we model out separately unlike the rest of OPEC

Annual Change in Mb/d (except for Supply Overhang)

Incentivizing the US producer

As mentioned previously, the 500 Mb/d call on US onshore growth in 2017 will begin to ramp in the 2H16. We estimate that as early as late 2016 ~350 Mb/d of US onshore crude production will be needed vs. 1Q16 production levels. Assuming the need for an incremental 350 Mb/d of YoY growth in US Lower 48 oil production starting in the 2H of 2016 there is a clear need for WTI price to incentivize incremental activity. While US onshore production has continued to climb in the first half of 2015 as producers have decelerated from high 2014 exit rates, we expect that production will peak in 2Q15, with 2H15 trending slightly lower. In the absence of incremental activity, we anticipate that 2016 crude production growth in the Lower 48 would be down 200 Mb/d YoY.

In order to incentivize a resumption in drilling activity sufficient to generate this level of growth, we estimate the need for WTI at $65-$70/bbl. While some have pointed to single well economics as a justification for why growth/-returns could work at $50 or $55/bbl, we believe corporate level cash flow will be the determining factor for go forward activity levels.

Figure 45: Oil price to generate 35% of prior peak growth in 2016-17
$10
$20
$30
$40
$50
$60
$70
$80
$90
$0
CLR EOG PXD CXO APC DVN WLL HES MRO Avg
CFO=Capex
CFO=120% Capex
Source: Deutsche Bank

In order to estimate the oil price necessary to support the proper level of corporate cash flow, we made the following assumptions: 1) well costs 20% lower than late-2014 vintage cost estimates, 2) 1Q15 operating cost assumptions, 3) base case assumes capex in line with 2016 operating cash flow (CFO), 4) 2016 volume growth at 35% of pre-collapse growth rate (ie. price necessary to support ~350 Mb/d in the US vs. the prior pace of ~1,000 Mb/d). Within these constraints, companies in our coverage universe averaged an average need of $60 - $85/bbl to restart and maintain the onshore “growth machine”. There is clearly a large degree of uncertainty surrounding this number, driven both by varied preferences of individual companies and

significant uncertainty around the eventual scale and pace of efficiency and productivity gains.
From a matter of timing, we see the need for a moderate increase in activity levels beginning in the third quarter of 2015. Given the general preference for

$72
$61
$/bbl (WTI)

pad drilling and the inherent lag in bringing pad-drilled wells onstream, we estimate that the initial signs of a production impact of rigs added in 3Q15 will
most likely not show up until early 2016. In other words, if we are to generate
a meaningful level of growth by 2H16, rigs need to be added in 3Q or 4Q 2015.
Amongst large producers, Pioneer Natural Resources (PXD) has been most
vocal about plans to add rigs mid-2015, but various other large operators,
including EOG, OXY, NBL, etc. have suggested as much by late 3Q, early 4Q.
Figure 46: Breakeven oil price by play, including sensitivity to decline
from late-2014 well costs
100
10
20
30
40
50
60
70
80
90
0
-25%
-10%
Base Case
Source: Deutsche Bank, *breakeven assumes at a 10% cost of capital
While the amount of rigs necessary to support this level of growth is highly
dependent on the level of efficiency gains that we see across the sector, we
estimate that would argue for an incremental 75 to 100 rigs, or an 20%
increase from mid-2015 trough level of ~450 for unconventional oil-directed
horizontals. We expect that the outlook is likely to remain volatile, with prices
likely to overshoot to the upside, and with the potential for producers to
accelerate too soon and further oversupply the market.

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Integrated Oil
US Integrated Oils
Updated Equities Outlook

Getting a Bit Defensive

Given the relatively cautious medium-term oil price outlook, our preference remains largely for names whose combination of asset quality and balance sheet allow them to support moderate, capital efficient growth within a moderate oil price environment. We upgrade OXY to BUY and downgrade HES to HOLD (additional color within). Other preferred names include MRO, DVN, EOG.

Figure 47: Key metrics for the group
4Q15E Annualized spend
APA
APC
COP
DVN
EOG
HES
MRO
MUR
NBL
OXY
PXD
($mm)
160
(622)
(1,840)
248
(368)
(958)
(487)
(880)
(189)
114
(59)
Source: Deutsche Bank

We provide two scorecards (Figure 48) for the two types of investors – ones favoring a relatively defensive positioning (which we favor) and ones playing an oil price bounce. Although several key investment attributes, such as select qualitative drivers (e.g. near-term catalysts), NAV-based valuations, etc fall outside of the scope of this exercise, we use the scorecards to help frame our view on stock-specific calls.

When stacking up the names by focusing mostly on key metrics for a defensive positioning – 4Q15 annualized outspend (% of market cap), net debt/total cap, div yield, FCF yield, EV/DACF multiple, CF/DAS growth, and liquids leverage (the lower the better) – we find that OXY, MRO, APA, COP and DVN round out the top five. Interestingly, we find that MRO and OXY both

stack up well (1st and 5th, respectively) in the "oil bounce" scorecard, one in
which four key metrics are taking into consideration – EV/DACF multiple,
headline production growth CAGR (2015-2017), CF/DAS growth (2015-2017)
and liquids leverage (the higher the better).
4Q15E Annualized spend
(% of mkt cap)
-0.7%
1%
2.3%
-1%
1%
5.0%
2.6%
11.5%
1%
-0.2%
0%
Net Debt/TC
2016E
20%
50%
31%
34%
25%
23%
23%
26%
34%
7%
15%
Div Yield
(Curr)
1.6%
1.3%
4.5%
1.4%
0.7%
1.4%
3.0%
3.2%
1.6%
3.9%
0.1%
FCF Yield
2015E
-5.7%
-4.4%
-6.6%
-1.2%
-3.1%

-10.9%
-7.8%
-11.9%
-7.9%
-3.3%
-1.0%
2016E
-0.7%
-0.9%
-1.3%
-1.8%
-1.0%
-2.8%
-0.6%
-9.6%
-3.3%
1.8%
-1.5%
EV/DACF
2016E
5.5x
8.1x
7.0x
6.8x
9.8x
6.6x
6.6x
5.4x
8.3x
7.1x
13.8x
2017E CF/DAS (2015-2017) Prod'n growth ('17/'15 CAGR)
19%
5.0x
6.3x
5.8x
5.5x
7.6x
5.6x
5.5x
4.8x
7.1x
6.3x
10.2x
26%
30%
26%
41%
27%
35%
21%

30%
30%
45%
2%
2%
3%
3%
7%
3%
6%
2%
15%
3%
11%
Liquids Leverage
(Global Oil + US NGLs)
66%
52%
57%
62%
66%
73%
69%
68%
46%
73%
73%

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Figure 48: Scorecards (Defensive and Oil Bounce)
Tkr Outpsend (4Q15 annualized)
OXY
APA
MRO
COP
DVN
EOG
PXD
NBL
APC
MUR
HES
MRO
PXD
OXY
EOG
HES
DVN
MUR
COP
NBL
APA
APC
3
2
9
8
1
5
4
6
7
11
10
Tkr Outpsend (4Q15 annualized)
9
4
3
5
10
1
11
8
6
2
7
Net Debt/TC

1
3
4
8
9
6
2
10
11
7
5
Net Debt/TC
4
2
1
6
5
9
7
8
10
3
11
Div Yield FCF Yield EV/DACF
2
6
4
1
8
10
11
5
9
3
7
4
11
2
10
7
8
3
1
5
6
9
1
3
2
6
8

5
7
10
4
11
9
7
2
4
6
3
10
11
9
8
1
5
Div Yield FCF Yield EV/DACF
2
7
1
5
9
8
4
11
7
11
6
10
3
4
10
5
3
1
6
9
2
8
CF/DAS
6
11
3
4
9
2
1
5
8
10

7
CF/DAS
3
1
6
2
7
9
10
4
5
11
8
Prod'n CAGR Liquids leverage Defensive Oil Bounce
6
10
4
7
5
3
2
1
11
9
8
4
2
6
3
8
5
9
7
1
2
7
4
9
8
6
3
11
10
5
1
4
3
2
6
1
8

5
9
18
20
22
24
30
32
33
34
37
38
42
10
11
11
7
10
33
18
32
42
30
38
24
34
20
37
21
30
15
26
25
21
17
26
37
25
21
Prod'n CAGR Liquids leverage Defensive Oil Bounce
22
15
17
21
21
21
25
25
26
26
30

37
Source: Deutsche Bank. Notes: Defensive score is calculated using the summation (equal weighting) of the following ranks (Outspend, Net Debt/TC, Div Yield, FCF Yield, EV/DACF, CF/DAS) minus the Liquids Leverage ranking (the lower the ranking, the higher the leverage). Oil Bounce score calculated based on the summation (equal weighting) of the following ranks (EV/DACF, Production CAGR, Liquids Leverage,CF/DAS). Liquids leverage represent total company oil production (global) plus US NGL production divided over worldwide production. EV/DACF, FCF yield, Net debt/-TC all based on 2016E (DBe). Production CAGR based on 2015-2017 headline growth.

On a 2017 EV/DACF (APC and DVN, ex-MLP value) vs CF/DAS growth (20152017, ex hedging) basis, we find that MRO and COP look particularly cheap, with most of the other names hovering in the expected relative value territories.

Figure 49: CF/DAS growth (ex hedging) vs. 2016
EV/DACF multiple
10.0x
12.0x
14.0x
16.0x
2.0x
4.0x
6.0x
8.0x
APC
APA
MUR
DVN
OXY
HES
NBL
COP
MRO
4.0x
2.0x
15.00% 20.00% 25.00% 30.00% 35.00% 40.00% 45.00% 50.00%
CF (ex hedges)/DAS Growth ('15-'17)
Source: Deutsche Bank. Note: CF calculation strips out impact from hedging
15.00% 20.00% 25.00% 30.00% 35.00% 40.00% 45.00% 50.00%
CF (ex hedges)/DAS Growth ('15-'17)
Source: Deutsche Bank. Note: CF calculation strips out impact from hedging

We also take a look at the ratio of forecasted exit 2015 outspend (4Q15 annualized, both excluding and including dividend obligations) relative to their 2015-2017 production CAGR (with outspend/growth as the numerator/denominator, the lower the ratio, the better). While using 4Q15 outspend levels as a rough proxy for medium-term outspend has its drawbacks (also not accounting for players with high DUC counts), we believe that in a relatively defensive oil price-minded world, this may be a ratio to consider.

PXD
Figure 50: CF/DAS growth (ex hedging) vs. 2017
EV/DACF multiple
12.0x
10.0x
8.0x
EOG
OXY
6.0x
APA
MUR
APC
DVN
HES
NBL
COP
MRO
EOG
PXD
2017 EV/DACF
2017 EV/DACF

Overall, we find the likes of MRO, COP, DVN, OXY, and APA screening relatively well.

Figure 51: Outspend and Production Growth (DBe) Summary

Tkr CFO (ex WC) Capex Dividend Outspend (ann) as % of mkt cap CFO (ex WC) Capex Dividend Outspend (ann) as % of mkt cap
1Q15A
APA
APC
COP
DVN
EOG
HES
MRO
MUR
NBL
OXY
PXD
900
1,464
2,123
1,433
1,058
482
412
275
523
1,121
334
1,407
1,666
3,332
1,593
1,546
1,237
1,151
613
919
1,675
541
94
139
910
99
92
72
142
62
64

557
6
(2,404)
(1,364)
(8,476)
(1,036)
(2,317)
(3,308)
(3,524)
(1,601)
(1,840)
(4,444)
(852)
10.4%
3.2%
10.8%
3.8%
4.7%
17.1%
18.8%
20.9%
10.8%
7.5%
3.7%
1,176
1,083
3,025
1,201
1,000
782
726
398
648
1,591
419
1,042
1,100
2,575
1,040
1,004
950
706
556
632
1,005
428
94
139
910
99
92

72
142
62
64
557
6
4Q15E
160
(622)
(1,840)
248
(385)
(958)
(487)
(880)
(189)
114
(59)
-0.7%
1.5%
2.3%
-0.9%
0.8%
5.0%
2.6%
11.5%
1.1%
-0.2%
0.3%
Prod'n (DBe)
2015 2016 2017
485
840
487
806
576
357
439
200
332
668
201
689
608
358
456
204
402
690
219
508

872
1,582 1,644 1,670
673
720
653
377
497
209
439
712
249
Prod'n (Cons)
547 517
839 825
668 677
578 614
358 362
431 445
203 198
326 386
654 682
202 222
DBe vs Cons
Growth (DBe, %)
2015 2016 2017 2015 2016 2017 16/'15 17/'16
495 -11% -6% 3% 0.4% 4.4%
894 0% -2% -2% -4.0% 8.1%
1,582 1,633 1,687 0% 1% -1% 3.9% 1.6%
701 1% 2% 3% 2.3% 4.5%
671 0% -1% -3% 5.6% 7.4%
377 0% -1% 0% 0.3% 5.2%
484 2% 2% 3% 3.9% 9.0%
202 -2% 3% 4% 2.2% 2.7%
417 2% 4% 5% 21.0% 9.1%
708 2% 1% 1% 3.2% 3.2%
238 -1% -1% 5% 9.2% 13.6%
Source: Deutsche Bank. Notes: APA 2015 production adjusted for Australia, NBL figures are pro-forma for ROSE acquisition, APC and DVN capex figures are ex WES/ENLK spend respectively.
Figure 52: Outspend (including div)/Prod’n CAGR ratio
10.0x
12.0x
14.0x
2.0x
4.0x
6.0x
8.0x
-1.0x
Figure 53: Outspend (excluding div)/Prod’n CAGR ratio
10.0x
12.0x

14.0x
PXD
EOG
APADVN
OXY NBL COP
APC
MRO
HES
MUR
2.0x
4.0x
6.0x
8.0x
0.0x
1.0x
2.0x
3.0x
4.0x
5.0x
4Q15 Ann Outspend (incl div)/ (% of Mkt Cap)'/15-'17 CAGR
Source: Deutsche Bank
6.0x
-2.0x
OXY COP
APA
PXD
NBL
DVN
MRO
APC
EOG
HES
MUR
-1.0x
0.0x
1.0x
2.0x
3.0x
4Q15 Ann Outspend (ex div)/ % of Mkt Cap)'/15-'17 CAGR
Source: Deutsche Bank
4.0x
Figure 54: 2017 Cash Outspend By Company
225%
181%
175%
134%
125%
125%
118%
119%
112%

120%
124%
116%
110%
92%
75%
108%
122%
25%
-25%
APA
APC
DVN
EOG
NBL
Strip -$10/bbl
th
PXD
COP
HES
Strip Pricing
MRO
MUR
Strip + $10/bbl
Source: Deutsche Bank, uses May 27 strip pricing of ~$69/bbl Brent and $63/-bbl WTI, includes dividends (Cash outspend defined as CFO ex WC divided by the sum of capital spend and dividend payments)
OXY
XOM
CVX

2016 EV/DACF
2016 EV/DACF

Upgrading OXY to Buy from Hold
OXY: We upgrade OXY to Buy (from Hold) on its advantaged combination of growth and free cash flow in a moderate oil price environment. We see a number of key drivers for OXY, including: 1) Permian performance continues to exceed expectations, with likely upside to conservative 2016 target of 120 Mboe/d, 2) leading FCF generation in our coverage universe at $65/bbl WTI (1.8% post-dividend in 2016, or 5.8% pre-dividend, vs. peer average of a 2.4% FCF deficit in 2016), led by three primary Middle East projects which generate
~$1.0-$1.5 Bn/yr of FCF, 3) 2017 start-up of ethylene cracker driving ~$1.0 Bn/yr of FCF from the chemical business from 2017, 4) 2nd highest dividend yield in our coverage universe (3.9%), with FCF driving further growth and share buyback, 5) solid crude leverage in the case of a rebound in oil price, and
6) relatively attractive valuation at 6.7x 2017 EV/DACF (or 6.4x adjusted for Midstream/Chemicals segments).
Downgrading HES to Hold from Buy
We downgrade HES to Hold (from Buy) primarily on account of the company's notable outspend (second to worst in the group based on 4Q15 annualized figures). We expect investors to continue to struggle (4%/3% underperformer since recent WTI trough/in May) with HES' relatively high spend on investments that are not expected to generate near-term cash flow (North Malay Basin, US midstream, Stampede, exploration, etc); not surprisingly, HES scores last on our defensive scorecard despite offering a healthy balance sheet
(4th in the group on a '16 net debt/cap basis). While an attractive valuation (5.6x 2017 EV/DACF vs group at 6.4x) and impressive liquids leverage (highest in the group) sets up well for investors looking to play a crude price bounce,
our defensive-tilted outlook suggests HES's medium-term outspend/ FCF profile will remain in the spotlight.

Risks to the Outlook
Iran and the Rest of OPEC
The above analysis rests upon the premise that OPEC (led by Saudi Arabia) will
largely keep production flat with current levels. In summary, outside of a change in policy by Saudi, we see two primary risks to our near-term forecast:
Iran (a potential reduction in the call on US growth by ~450 Mb/d) and Iraq (risks likely weighted toward a reduction in current Iraq production levels). Longer-term growth in sustainable productive capacity from Iraq and the UAE pose the greatest risks to an increased need for US onshore crude during the tail-end of our forecast period.
Iran: Holding the fate of US growth:
For all of the uncertainty on both sides of the Iranian debate, the stakes are
potentially enormous for US producers. An increase of even 400 Mb/d by the middle of 2016 from Iran would effectively cancel out any call on US growth in
2016 (pushing it to 2017), and with it, eliminating the need for a crude price
high enough to incentivize US growth.
Iran remains the main wildcard as it relates to the global 2H15/2016 oil supply
picture. The recently-struck (April 2) framework agreement between Iran and the P5+1 countries was the initial key milestone before any potential final deal
on Iran's nuclear program. While recent rhetoric among Iranian hardliners (Khomeini has plenty to say) and select US participants/GOP congressional members remains polarizing (parties remain wide on details such as the pace of the removal of sanctions, etc) causing some doubt, the recent letter of strong support shown by US House Democrats (150 on paper/145 voting members, just enough to sustain a presidential veto of a Congress disapproval of any final deal) have certainly increased the odds of reaching a final deal by
June 30 (deadline could be moved). While the risk of a final agreement (and the resultant addition of Iranian crude barrels into the global market) is real, the
key question remains
Figure 55: Historical Iranian crude prod'n, 2010-April 2015
Figure 56: Iranian liquids prod'n forecast, 2011-2020E
Source: Deutsche Bank, IEA. Note: crude-only production shown
Source: Wood Mackenzie, Deutsche Bank. Note: Wood Mackenzie's forecast includes
NGl/Condensate

The key uncertainties around the global oil supply impact of any final agreement stem from question marks around 1) the agreed upon pace of the removal of sanctions (John Kerry suggesting 4 months to one year while the Iranians are calling for an immediately removal), 2) the actual amount of floating storage holding Iranian barrels (IEA references reports suggesting ~30 mmbbl's, or 180kb/d for 6 months, Wood Mackenzie offers a smaller estimate), 3) the amount of reservoir and facility degradation in the key mature oil fields (main source of Iranian crude production) post years of underinvestment and need for secondary and EOR to boost production, and 4) the pace of IOCs involvement (list of priority 49 upstream/28 oil field projects released with formal details and the new Iran Petroleum Contract (IPC) (with much better fiscal terms than its predecessor) expected in September). While Bijan Zanganeh's (Iranian oil minister) promise of output levels of 3.8 Mb/d within 6 months of the deal (implying an increase in exports of ~1 Mb/d) is on the optimistic side of forecasts (Wood Mackenzie at +450kb/d in exports in mid-2016, assuming sanctions fully lifted in mid-'16, IEA suggesting sustainable production capacity at ~700kb/d above April 2015's production levels), the risk of a notable amount of Iranian crude hitting the market by end of '15/mid-'16 remains the key wildcard to our outlook.

A Random Walk Through The Rest of OPEC:

While this publication is not meant to address OPEC production growth in great detail, we attempt to present context around current trends and the potential risks to our outlook. Below we highlight several of the key questions (in addition to the previously discussed impact from finalizing an Iran deal) we entertained in "stress-testing" our outlook from an admittedly more abstract/qualitative angle (what else is there?).

What is the potential upside to OPEC production from a return of a normalized (or should we say abnormal?). Libya devoid of conflict? While many point to 2012 production of nearly ~1400 Mb/d as a starting point for quantifying a potential 'blue sky' outlook for Libya production, the country has changed significantly since the conflict first erupted in 2013. Infrastructure damage and potential degradation to field reservoir quality has resulted in a cut to the IEA estimated sustainable crude production to only 500 Mb/d for 2015. The IEA anticipates a gradual capacity creep with levels expected to reach ~980 Mb/d 2020 - still short of previous levels. While not as conservative, (productive capacity estimated at ~800 Mb/d for 2015) Wood Mackenzie estimates are also consistent with a view of limited upside to recent production trends out of Libya (~500 Mb/d in March and April). In our outlook we assume Libya

production flat to 2014 levels of ~460 Mb/d.
Is the recent production burst from OPEC likely to last? During the month of May, OPEC crude production is estimated to have averaged 31.6 MMb/d (vs. 31.5 MMb/d in April) averaged or 1.5 MMb/d higher than in February. Production growth from Saudi Arabia and Iraq accounts for ~ 75% of the increase (~ 550 Mb/d in incremental production each). The original question can be translated into: how to assess from sustained production levels from both Iraq and Saudi going forward.
a) Iraq Near-Term Production Outlook Risk Likely Upper Bound:
Iraq
production (inclusive of exports from the Kurdish Regional Government) ramped up to an estimated 3.9 MMb/d in May, ~550 Mb/d higher than 2014 levels amid strong production from Northern Iraq following the December agreement with the Kurdish Regional

Government (KRG). As a result of the damage to pipeline infrastructure in the early part of 2014 from repeated ISIS attacks, pipeline exports from Northern Iraq averaged ~185 Mb/d in 2014. Increased production from the Tawke and Taq Taq fields in Kurdistan amid the proposed financing backing from Baghdad and alongside rebuilt infrastructure, the KRG has announced a targeted pipeline export capacity/volumes of 800 Mb/d. However with current Northern Iraq export levels in excess of 600 Mb/d upside to Iraq production from the North is limited while contributions from the South remain more longterm in nature (see below section). The key driver for driving sustainability in the near-term (6-12 months) will be the extent to which Baghdad can continue to fund payments to the KRG – funds needed to pay the region's crude producers, if sustained our call on US onshore crude growth would be reduced by over 400 Mb/d.

b) Saudi Production Outlook? Who knows…but our outlook looks reasonable assuming Saudi market share of global supply remains consistent with 5 year averages. With much speculation around what production level is consistent with forward Saudi strategy; our aim is not to identify a specific production level but rather to sensitize our outlook around Saudi's market share of global oil supply (a reasonable driver for Saudi production going forward). Assuming a 5 year average for Saudi market share of global oil, our call on US onshore growth remains ~500 Mb/d through 2017. The US call on shore crude growth dips 200 Mb/d annually if we instead assume a forward market share similar to that in the 1H of 2014 for Saudi, and is effectively non-existent if Saudi were to maintain its current share.

Figure 57: YoY Call on US Crude Growth (Mb/d) Vs. Assumed Saudi Market Share of Global Crude (%)
100
200
300
400
500
600
700
800
900
1000
-100
0
2017
2018
Base (Holds Saudi Prod Flat to 2014 Levels)
w/ Saudi Supply at 1H14 Global Market Share
Source: Deutsche Bank, IEA
2019
w/ Saudi Supply at 5 Yr Avg Global Market Share
w/ Saudi Supply at Current Global Market Share

Call on US Onshore Growth (Mb/d)

What is expected long-term from OPEC? Outside of Iran and volatility around Saudi, the longer-term environment will be dictated chiefly by anticipated production capacity increases by both the UAE and Iraq. The UAE has set a target of 3.5 MMb/d by 2020 or ~600 Mb/d above current estimated capacity levels. Adnoc has mentioned in the press that it would invest ~$25Bn to develop some of its offshore fields and seems driven to meet its target production goal. In Iraq, the IEA estimates that production capacity is to increase ~1000 Mb/d by 2020 from currently estimated capacity levels. However, commentary from companies like Lukoil and BP suggest that there may be downside risk to the estimate as significant investment is required in Iraq's southern oil fields particularly with regard to water injection and gas
infrastructure projects. While IOCs have invested heavily in the country over the last couple of years, the extent to which they will continue to sustain investment will (at least theoretically) be linked to Baghdad to re-pay producers
for work done (while simultaneously maintaining the country's security against
threats from ISIS and other militant groups)

Figure 58: Longer-term, Iraq and UAE are expected to drive OPEC capacity increases

500
1000
1500
2000
-1000
-500
0
Iraq
2015
2016
2017
2018
2019
2020
Libya
Source: Deutsche Bank, IEA
UAE
Other
Net OPEC Growth in Production Capacity

Mb/d

Other Risks to the Outlook
Global oil demand and Decline Rates
Our base case assumes global product demand growth of 1.2 Mb/d in 2016 and 2017. To date in 2015, demand has generally surprised to the upside, with gasoline demand growth in the US (+2% YoY) stronger than anticipated, while Europe and Asia have also shown surprisingly robust growth. 10%+ incremental upside to YoY product demand growth results in a ~+100 mbpd increase in the 2017 implied call on US onshore crude growth. On decline rates,
we assume an average global decline rate of 1/4%/yr. We estimate a swing of 150 mbpd in the 2017 implied call on US onshore crude growth call for each 1/4% change in modeled decline rates (ex-US onshore and OPEC and compounded from 2015+).
Figure 59: 2017 Call on US Crude Onshore Growth (YoY)
834
100
200
300
400
500
600
700
800
900
0
Bear
1/4% Rev to Modeled Decline Rates
Base
Bull
15% Adj to YoY Demand Growth
Source: Deutsche Bank, Wood Mackenzie, IEA, EIA, YoY Growth is calculated as the implied 2017 Call
on US Onshore Production – Dbe 2016 US Onshore production. Revisions to modeled decline rates
only applies to those regions we have specifically modeled out in this note and excludes US onshore,
and OPEC production aside from Angola.
Figure 61: A +5% premium to ’17 demand growth
increases implied onshore crude growth by ~50 mbpd
100
200
300
400
500
600
700
800
900

0
-30%
-10%
10%
30%
Source: Deutsche Bank, Wood Mackenzie, IEA, EIA, YoY Growth is calculated as the implied 2017 Call
on US Onshore Production – Dbe 2016 US Onshore production. Revisions to modeled decline rates
only applies to those regions we have specifically modeled out in this note and excludes US onshore,
and OPEC production aside from Angola.
-1.0%
-0.5%
Figure 60: 2020 Call on US Crude Onshore Growth (YoY)
531
228
200
400
600
800
1000
1200
1400
1600
0
Bear
1/4% Rev to Modeled Decline Rates
Base
Bull
15% Adj to YoY Demand Growth
Source: Deutsche Bank, Wood Mackenzie, IEA, EIA, YoY Growth is calculated as the implied 2020 Call
on US Onshore Production – 2019 Call on US Onshore Production. Revisions to modeled decline rates
only applies to those regions we have specifically modeled out in this note and excludes US onshore,
and OPEC production aside from Angola.
Figure 62: A +1/4% revision to modeled Non-OPEC
decline rates increases implied onshore crude growth by
~150 mbpd in 2017 over our base case
200
400
600
800
1000
1200
1400
-200
0
0.0%

0.5%
1.0%
Source: Deutsche Bank, Wood Mackenzie, IEA, EIA, YoY Growth is calculated as the implied 2017 Call
on US Onshore Production – Dbe 2016 US Onshore production. Revisions to modeled decline rates
only applies to those regions we have specifically modeled out in this note and excludes US onshore,
and OPEC production aside from Angola.
1428
1031
630

Call on US Onshore CrudeGrowth (mboe/d)
Implied Call on Onshore Growth
(YoY, Mb/d)
Call on US Onshore CrudeGrowth (mboe/d)
Implied Call on Onshore Growth
(YoY, Mb/d)

Crude inventory overhang
One of the lingering challenges in tightening global crude balances, and thus pricing, is the significant crude inventory overhang, with estimated OECD crude inventories currently at 1030 MMbbls (excluding gov't stocks), or 45% above the 5 year average. We anticipate crude inventory levels to increase though mid 2016 as increasing non-OPEC supply is brought on-stream and as US onshore production gradually adjusts to a new 'normal'. The pace of inventory builds is anticipated to peak in 2Q15 with inventory levels anticipated
to dip modestly in 4Q15 prior to heading into weaker seasonal demand in the 1st half of 2016. At its peak (in 2Q16) we expect accumulated crude inventories post 4Q14 to reach 500 mbbls or ~17.5% of annualized 2Q15 production. While on first blush this may seemingly present a significant headwind to our outlook, we contend that a) relative to historical levels we aren't visiting new ground, and b) low commodity driven demand growth and lower product inventory levels will largely mitigate against the risk.
Figure 63: Though global crude inventory levels are
expected to increase during the correction, we aren't
headed anywhere we haven't already been…
2000
-16000
-14000
-12000
-10000
-8000
-6000
-4000
-2000
0
Source: Deutsche Bank, IEA, Implied global crude stock builds
Figure 64: OECD total products days forward metrics
reveal historically low inventory levels/ability to absorb
excess crude
27.5
28.0
28.5
29.0
29.5
30.0
30.5
31.0
31.5
32.0
1Q
5 Yr Range
2Q
3Q
2014

4Q
Source: Deutsche Bank, Wood Mackenzie, IEA
While current OECD crude inventories are ~45% of 5 yr averages, product inventories are essentially flattish to historicals offering some potential relief to
the crude overhang. Further we would note that looking at absolute inventory levels without regard to the role of demand trends as incomplete. Looking historically at incremental QoQ global product demand growth vs. implied crude inventory builds, we find that movements in global crude stocks closely led those in product demand (by a quarter) in the data set we looked at. Further, when adjusting for demand, OECD product inventories look more poised to potentially absorb increasing crude stocks as the IEA estimates product growing annually by ~1200 mbpd.

Cumulative Change in Implied Global Crude Stocks
since 2Q06 (mbpd)

Figure 65: Correlation of QoQ Changes in Product Demand and Implied Crude Inventory Builds
1,000
1,500
2,000
2,500
500
-3,000
-2,500
-2,000
-1,500
-1,000
-500
0
Change in Demand
Change in Stocks -1Qtr Lagged
Source: Deutsche Bank, IEA
Non-OPEC Supply Disappointment
There are clearly risks to this outlook, as Non-OPEC supply has historically disappointed (see figure below), but there is no avoiding the fact that the outlook for Non-OPEC supply is more robust than usual. The most visible risk surrounds Brazilian production. While the pre-salt basin resource is excellent,
the ability to exploit it will be challenged amid the fall-out from the "Lava Jato"
scandal and from significant local content requirements for key projects. With
2016 capital spend already reduced by 40% from prior guidance (and estimated delivered FPSOs in 2016 reduced to 3 from7) on the company's latest presentation there is significant risk to the growth story. Please see page 43 for more details on Brazil.
Figure 66: IEA Non-OPEC supply projections
(0.8)
(0.6)
(0.4)
(0.2)
0.0
0.2
0.4
0.6
0.8
1.0
1.2
2014
2010
2012
2013
2011

2015
2009
Month IEA Forecast was Made
Source: IEA, Deutsche Bank

mboepd
Forecast non-OPEC Supply ex US
(mmb/d)
Feb-08
Jul-08
Dec-08
May-09
Oct-09
Mar-10
Aug-10
Jan-11
Jun-11
Nov-11
Apr-12
Sep-12
Feb-13
Jul-13
Dec-13
May-14
Oct-14

31 May 2015
Integrated Oil
US Integrated Oils
A Country by Country
Outlook on Key Players
Angola
Recent pre-salt drilling activity withstanding, exploration spend in Angola over
the last 15 years has been largely concentrated in the Lower Congo Basin. As a result, production growth in our forecast period is chiefly driven by project
start-ups in the Lower Congo. However, longer-term production growth will likely shift towards the pre-salt Kwanza Basin (Cameia. Orca, Bicuar, etc). In
our view, the key near-term risk to production is a delay in the start-up of complex projects (Kaombo Block 32) while the key long-term risk is a delay in project FIDs in the Kwanza Basin (~250 mbpd of ’17-20 incremental growth is from unsanctioned projects)
Figure 67: Angola Production Outlook, 2014-2020e
(Mb/d)
500
1000
1500
2000
0
2014
2015
Base
Source: Deutsche Bank, Wood Mackenzie, IEA
2016
2017
2018
2019
Growth Bbls
2020
Figure 68: Production by type (area chart of onshore vs.
shallow vs. deepwater (Mb/d)
500
1000
1500
2000
0
2014
2015
2016
Onshore (Conv)
Deepwater (Conv)
Source: Deutsche Bank, Wood Mackenzie, IEA
2017
2018
2019

2020
Shallow water (Conv)
Ultra-deepwater (Conv)
Figure 69: Crude volume growth outlook by project
status (Mb/d)
500
1000
1500
2000
2500
0
2014
Base
Under Development
DB Base Case
Source: Deutsche Bank, Wood Mackenzie, IEA
2015
2016
2017
2018
2019
Growth at Onstream Assets
Probable Development
2020
Figure 70: 2017 Production Swing (Bear vs. Bull) of ~235
Mb/d
1000
1100
1200
1300
1400
1500
1600
1700
1800
1900
1771
1641
1536
Bear
Base
6mo timing shift in growth projects
Source: Deutsche Bank, Wood Mackenzie, IEA
1% adj in decline rates
Bull

mboe/d

Primary Growth Drivers

Near-term production growth will be supported by several project start-ups. The recent (and worth noting 'on schedule') starts of the Kizomba Satellites Phase 2 and Block 15/06 West Hub Development projects in 2Q15 are the chief drivers of 300 mbpd of crude growth through 2017. The long-term production outlook will be driven by the ramp from fields in the Kaombo Block 32, and contributions from currently unsanctioned projects (Cameia).

Primary Risks

Geopolitical risks withstanding, the key risks to production in our forecast window include a delay to project start-ups particularly the ramp from the Block 32 fields (projected on stream in 2017), and the delayed sanctioning of several projects including the high profile Cameia project (anticipated late 2015
FID with peak oil production by 2018 of 80 mbpd).

- Project Delays: Through 2017, primary risk is in delays to the starts of two
key projects: Block 15 NE Hub and the Kaombo Block 32. Although largely in process, there could be limited risk of delays associated with cost reduction efforts in the current environment. Incremental production from the Kaombo fields in Block 32 (2017 target project start) is expected to reach a peak capacity of ~230 mbpd by 2020. Deep water depths, dispersion of fields, and high presence of salt imaging has the potential for increased technical risks.

- Sanction Delays: Including Cameia unsanctioned projects represent nearly all the incremental crude production from 2017 to 2020. Cost reduction will be a significant driver of accelerated FID activity; Cobalt is currently estimated Cameia YE15 sanction on estimated development costs of <$20/bbl and assumed $2Bn in estimated cost savings.

Figure 71: Key Growth Projects, 2014-2020

Project
IEA Region
Kizomba Satellites Phase2
Block 15/06 NW Hub
Mafumeira
Block 32 Kaombo
Block 15/06 NE Hub
Block 21
Block 18 West
Block 31 Southeast
Block 32 Central NE
Orca
Africa
Africa
Africa
Africa
Africa

Africa
Africa
Africa
Africa
Africa
Sector
Deepwater
Deepwater
Offshore Cabinda
Ultra Deepwater
Deepwater
Deepwater
Deepwater
Ultra Deepwater
Ultra Deepwater
Deepwater
Basin
Lower Congo
Lower Congo
Lower Congo
Lower Congo
Lower Congo
Kwanza
Lower Congo
Lower Congo
Lower Congo
Kwanza
Operator
ExxonMobil
Eni
Chevron
Total
Eni
Cobalt International Energy
BP
BP
Total
Cobalt International Energy
Project Type
DW
DW
Shallow
UDW
DW
UDW
UDW
UDW
UDW
DW
Dev Status
Under Development

Onstream
Onstream
Under Development
Under Development
Under Development
Probable Development
Probable Development
Probable Development
Probable Development
API
27.5
23.6
36
32
34
44
32
32.5
33
36
Prod Start Up Yr Peak Prod Yr 2014-2017 Prod
2015
2014
2009
2017
2016
2017
2019
2020
2020
2020
2020
2016
2018
2020
2018
2024
2025
2022
2022
2022
108
83
62
40
39
10
0
0
0
0

2014-2020 Prod
177
52
64
214
67
100
45
41
28
22
Source: Deutsche Bank, Wood Mackenzie

31 May 2015
Integrated Oil
US Integrated Oils
Brazil
Through 2017, no country has a greater ability to impact the outlook on
NonOPEC
production growth than Brazil, which after years of delays, has begun
generating meaningful growth from the Pre-Salt. Although we have haircut our
outlook significantly, given the upheaval caused by the combination of lower
oil price and political/corporate scandal, Brazil still represents nearly
400 Mb/d
of production growth by 2017 (vs. 2014). See outlook and risks below.
Figure 72: Brazil Production Outlook, 2014-2020e (Mb/d)
500
1000
1500
2000
2500
3000
3500
0
2014
2015
Base
Source: Deutsche Bank, Wood Mackenzie, IEA
2016
2017
2018
2019
Growth Bbls
Source: Deutsche Bank, Wood Mackenzie, IEA
2020
Figure 73: Production by type (area chart of onshore vs.
shallow vs. deepwater (Mb/d)
500
1000
1500
2000
2500
3000
3500
0
2014
Onshore
2015
2016
Shallow
2017
2018
Deepwater
2019

2020
Ultra-deepwater
Figure 74: Crude volume growth outlook by project status (Mb/d)
500
1000
1500
2000
2500
3000
3500
4000
4500
0
2014
Base
Under Development
DB Base Case
Source: Deutsche Bank, Wood Mackenzie, IEA
2015
2016
2017
2018
2019
Growth at Onstream Assets
Probable Development
2020
Figure 75: 2017 Production Swing (Bear vs. Bull) of ~300 Mb/d
1500
1700
1900
2100
2300
2500
2700
2900
2830
2678
2550
Bear
Base
6mo timing shift in growth projects
Source: Deutsche Bank, Wood Mackenzie, IEA
1% adj in decline rates
Bull

mboe/d

Primary Growth Drivers

Volume growth from 2015-2020 is primarily driven by the continued development of Pre-Salt resource in the deepwater Santos and Campos Basins. In particular, near-term volume growth is expected to come from the start of FPSOs in the Buzios and Lula/Iracema development. Development at LulaIracema (the largest driver of growth through 2017) entails a total of 10 FPSOs (8 in Lula, 2 in Iracema). 3 FPSOs are currently in operation and 7 additional
FPSOs will be required for development (150 Mb/d of capacity each), 4 of which are replicant FPSOs being constructed in Brazil.

Primary Risks

Project execution, already problematic in recent years given the combination of
technical challenges and local content requirements, have become particularly acute given the collapse in oil price and corruption scandal affecting both Petrobras and the Brazilian government. We see two primary risks:

1. Weak oil price and uncertain investment environment could impact investment in the base (ie. maintenance capital), increasing the underlying decline at the 2.4 MMb/d of current production. We see this risk as slightly less acute than some basins heavily dependent on maintenance/infill capital spend (ie. UK North Sea/Norway), however every 1% increase in underlying decline above our 8%/yr base case would reduce 2017 production by 40 Mb/d.
2. Delays to FPSO start-ups. We see a high likelihood of material delays in the start-ups of future FPSOs, particularly the 4 replicant FPSOs being constructed in Brazil with targeted start-ups in 2017-2018 (Lula South, Lula North, Lula Extension, and Lula West — P-66, P-67, P-68, P-69). We have risked project starts in proportion to local content requirements (Buzios, Taratuga Verde), assuming an average 2-year delay in targeted first oil. We model an estimated ~225 Mb/d of incremental production through 2017 from the arrival of 4 FPSOs through (2 in each 2016 and 2017); the modeled production contribution increases to over 900 Mb/d by 2020.

Figure 76: Key Growth Projects, 2014-2020

Project
IEA Region
Lula-Iracema Latin America
Sapinhoa
Papa-Terra
Roncador
Frade
Cachalote
BS-4
Lapa
Buzios
Iara
Latin America
Latin America

Latin America
Latin America
Latin America
Latin America
Latin America
Latin America
Latin America
Country
Brazil
Brazil
Brazil
Brazil
Brazil
Brazil
Brazil
Brazil
Brazil
Brazil
Source: Deutsche Bank, Wood Mackenzie
Sector
Santos
Santos
Campos
Campos
Campos
Campos
Santos
Santos
Santos
Santos
Operator
Petrobras
Petrobras
Petrobras
Petrobras
Chevron
Petrobras
Queiroz Galvao
Petrobras
Petrobras
Petrobras
Project Type
UDW
UDW
DW
UDW
DW
DW
UDW
UDW
UDW

UDW
Dev Status
Onstream
Onstream
Onstream
Onstream
Onstream
Onstream
Probable
Development
Onstream
Under Development
Under Development
API
27
30
14
24
20
24
14
26
28
26
Prod Start Up
Yr
2009
2010
2013
1999
2009
2008
2016
2011
2016
2018
Peak Prod Yr 2014-2017 Prod 2014-2020 Prod
2022
2016
2017
2018
2017
2018
2019
2020
2023
2026
381
171
96
79

54
32
30
28
0
0
777
171
55
55
15
12
63
85
300
50

Canada
Volume growth will be primarily driven by expansions to existing oil sands projects with a handful of projects (Kearl, Surmont, Horizon, Foster Creek, AOSP, Sunrise) accounting for ~60% of the estimated 2014-2017 production growth.
With falling oil prices accelerating a decline in capital spending (with some operators announcing reductions in excess of 75% to their budgets from 2014); the longer-term (2017+) production impact resulting from subsequent project delays represents in our view the primary risk. However, we would not want to underscore the risk to production that stems from a regulatory/-political
environment in which efforts to resolve infrastructure bottlenecks have been challenged. We view the near-term risk to production from the commodity to be mostly contained as US production-roll off in 2H15 alongside seasonal demand uplift to support a moderately constructive view on crude prices.
Figure 77: Canada Production Outlook, 2014-2020e
(Mb/d)
1000
2000
3000
4000
5000
0
2014
2015
Base
Source: Deutsche Bank, Wood Mackenzie, IEA
2016
2017
2018
2019
Growth Bbls
2020
Figure 78: Production by type (area chart of onshore vs.
shallow vs. deepwater (Mb/d)
1000
2000
3000
4000
5000
6000
0
2014
2015
2016
2017
2018
2019

2020
Unconventional Onshore (Conv) Shallow water (Conv)
Source: Deutsche Bank, Wood Mackenzie, IEA
Figure 79: Crude volume growth outlook by project
status (Mb/d)
1000
2000
3000
4000
5000
6000
0
2014
Base
Under Development
DB Base Case
Source: Deutsche Bank, Wood Mackenzie, IEA
2015
2016
2017
2018
2019
Growth at Onstream Assets
Probable Development
2020
Figure 80: 2017 Production Swing (Bear vs. Bull) of ~190
Mb/d (Mb/d)
3000
3200
3400
3600
3800
4000
4200
4400
4319
4201
4128
Bear
Base
6mo timing shift in growth projects
1% adj in decline rates
Bull
Source: Deutsche Bank, Wood Mackenzie, IEA

mboe/d

31 May 2015
Integrated Oil
US Integrated Oils
Primary Growth Drivers
Volume growth will be primarily driven by expansions to existing oil sands projects with a handful of projects (Kearl, Surmont, Horizon, Foster Creek, AOSP, Sunrise) accounting for ~60% of the estimated 2014-2017 production growth. While mining techniques account for ~20% of recoverable oil sands in Alberta, the near-term production growth profile is well-represented as Kearl,
Horizon, and AOSP represent 3 of the 5 largest production contributing projects through 2017. Longer-term growth (2017+) will be driven by end of decade projects like Fort Hills and Hebron/Ben Davis.
Primary Risks
With falling oil prices accelerating a decline in capital spending (with some operators announcing reductions in excess of 75% to their budgets from 2014); the longer-term (2017+) production impact resulting from subsequent project delays represents in our view the primary risk. However, we would not want to underscore the risk to production that stems from a regulatory/-political
environment in which efforts to resolve infrastructure bottlenecks have been challenged. We view the near-term risk to production from the commodity to be mostly contained as US production-roll off in 2H15 alongside seasonal demand uplift to support a moderately constructive view on crude prices.
1. Near-term risks to production are likely contained as US production rolls-off and seasonal demand improvements are expected to support a moderately constructive view on crude prices. At current prices/differentials rail economics remain challenged to the Gulf Coast (the most visible remaining demand market for oil sands growth) affecting smaller oil sands producers that are mostly levered toward manifest rail. However, production shut-ins are unlikely. During the previous cycle the reservoir integrity at the Great Divide project was significantly damaged as a result of operator shut-in amid low crude prices.
2. Long-term risks to production delays are likely. Intuitively, the most likely candidates for a reduction are those for which not a significant amount of capital has been invested. Companies have announced expansion delays to many of such projects including CNRL's Kirby North, MEG's Christina Lake, Husky's Sunrise and Suncor's Mackay River. Of remaining potential project delays we see greatest downside risk to project expansions at Cenovus' Christina Lake, Narrows Lake and PetroChina's MacKay River.
3. Long-term, the infrastructure bottleneck needs to be addressed. As mentioned previously, the Gulf Coast represents the last remaining market (as Western Canadian crude is for the most land-locked) that is capable of absorbing heavy crude. While recent pipeline start-ups (Marketlink and Flanagan South) have increased capacity to transport WCS bbls into the Eastern Gulf Coast, the Western Gulf Coast is not readily accessible via pipeline while rail and Jones-Act compliant vessels remain expensive particularly at a lower commodity. The Western Gulf Coast contains ~60% of the entire Gulf Coast coking

capacity, a lucrative reward no doubt. In fact, TransCanada has recently announced plans to investigate the economic viability of building pipe from Houston to Louisiana, we can only hope that they will have more success than they've had with a certain other proposed pipeline

Figure 81: Though the recent recovery and narrowing of WTI-WCS has increased rail netbacks for Canadian heavies to
the Gulf Coast, rail economics remain ‘heavily’ challenged
10.0
20.0
30.0
40.0
50.0
60.0
70.0
-40.0
-30.0
-20.0
-10.0
0.0
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15 Mar-15
Apr-15
Price Diff to Implied Bitumen Price ($/bbl)
Opex
Sustaining Capex
Source: Deutsche Bank, Wood Mackenzie, Bloomberg, assumes 20% diluents penalty, costs shown represent an average of major SAGD projects/fields
Net Back to GC No 6. (3% Sulfur) Fuel Oil
Figure 82: Key Growth Projects, 2014-2020
Project
IEA Region
Kearl
Surmont Project
Horizon Project
Foster Creek
AOSP
Sunrise
Christina Lake Project
Hibernia S subsea PL1001
MEG Christina Lake
Jackfish
Source: Deutsche Bank, Wood Mackenzie
North America
North America
North America

North America
North America
North America
North America
North America
North America
North America
Country
Canada
Canada
Canada
Canada
Canada
Canada
Canada
Canada
Canada
Canada
Sector
Operator
Athabasca
Athabasca
Athabasca
Athabasca
Athabasca
Athabasca
Athabasca
Newfoundland
Athabasca
Athabasca
Imperial Oil
ConocoPhillips
Canadian Natural
Resources
Cenovus Energy
Shell
Husky Energy
ConocoPhillips
HMDC
MEG Energy
Devon Energy
Project Type Dev Status
Onshore
Onshore
Onshore
Onshore
Onshore
Onshore
Onshore
Shallow
Onshore

Onshore
Onstream
API
8
Onstream N/A
Onstream
Onstream
Onstream
Onstream
Onstream
Onstream
Onstream
Onstream
34
11
34
8
9
36
9
8
Prod Start
Up Yr
2013
2007
2008
2001
2003
2015
2002
2011
2008
2007
Peak Prod
Yr
2030
2018
2019
2029
2021
2025
2025
2017
2026
2029
2014-2017
Prod
138
95
89
81

68
60
51
51
47
41
2014-2020
Prod
148
109
165
121
98
60
126
28
69
41

$/bbl of Bitumen

Caspian Sea, ex Russia
Production from the Caspian Sea is largely concentrated around a few mega projects in Kazakhstan and Azerbaijan (with smaller contributions from Turkmenistan and Uzbekistan). The recent reduction (25%) in the Kazakhstan oil export duty this past March was not much of a surprise as the government had announced its intention to reduce rates in response to the lower oil price
environment earlier this year. With the drop in export duty rates, the government aims to sustain longer-term production by bridging the near-term incremental production (weighted toward recovery projects) with the restart of
Kashagan Phase One and ultimately growth from the currently unsanctioned Tengiz and Kashagan Phase Two projects. In Azerbaijan, the focus will be on maintaining production at the ACG contract area (~75% of 2014 country production) through the recently on-stream through the Chirag Oil Project and a renewal of the underlying PSC that is set to expire in 2024.
Figure 83: Caspian Production Outlook, 2014-2020e
(Mb/d)
500
1000
1500
2000
2500
3000
3500
0
2014
2015
Base
Source: Deutsche Bank, Wood Mackenzie, IEA
2016
2017
2018
2019
Growth Bbls
Source: Deutsche Bank, Wood Mackenzie, IEA
2020
Figure 84: Production by type (area chart of onshore vs.
shallow vs. deepwater (Mb/d)
500
1000
1500
2000
2500
3000
3500
0
2014

2015
2016
Onshore (Conv)
2017
2018
2019
Shallow water (Conv)
2020
Figure 85: Crude volume growth outlook by project status (Mb/d)
500
1000
1500
2000
2500
3000
3500
0
2014
Base
Under Development
DB Base Case
Source: Deutsche Bank, Wood Mackenzie, IEA
2015
2016
2017
2018
2019
Growth at Onstream Assets
Probable Development
2020
Figure 86: 2017 Production Swing (Bear vs. Bull) of ~120 Mb/d
1500
1700
1900
2100
2300
2500
2700
2900
2699
2583
2641
Bear
Base
6mo timing shift in growth projects
Source: Deutsche Bank, Wood Mackenzie, IEA
1% adj in decline rates
Bull

mboe/d

Primary Growth Drivers

Near-term oil production growth will be challenged as most mega project starts and expansions (Kashagan restart expected mid 2017 with Tengiz and Pearl contributions anticipated post 2020) are anticipated later this decade. We model a 2.5% decline rate for the base assets; as recent investment in recovery methods in ACG (Chirag Oil Project) and in Tengiz (Capacity and Reliability project) are expected to partially offset declines.

Primary Risks

In our view, the primary risks to the 2015-2020 production outlook for the Caspian Sea include delays to unsanctioned projects amid lower crude prices as well as increased operational delays associated with the restart of the Kashagan oil field.

1. Delays to Unsanctioned Projects: The region's most capital-intensive project is Tengiz (Wood Mackenzie estimated peak production of ~240 mbpd aggregate for the WPMP and FGP projects) at ~$37 Billion. Local content requirements and high export taxes delayed the scheduled FID from 2014 to 1H2015 yet with only 10% of the project's required capital invested as of YE14, there is significant risk to further project slippage. Woodmac anticipates a further delay in FID to 4Q15 with first oil production at FGP not expected until 2021 vs. the initial 2017 target date. FID decisions surrounding Kashagan Phase II (est peak production of 630 mbpd in 2030) and Pearls (est peak production of 50 mbpd in 2024) do not impact our forecast window but will have an impact on production sustainability in the country.

2. Operational Delays to the Restart of Kashagan: Operational-related delays to the restart of the Kashagan oil field) would represent another material risk in the outlook (with ~$50Bn in sunk costs, the project is not materially levered to lower crude prices). Following the start of Phase One in September of 2013, the field was soon shut-in following leaks in the gas pipelines that carried sour gas onshore. Following a full replacement of the oil and gas pipelines production is expected to ramp to ~400 mboe/d. Completion of pipeline replacement work is targeted for 2H2016 with Wood Mackenzie anticipated first oil production by mid-2017, reaching ~ 300 mboe/d by 2019.

Figure 87: Key Growth Projects, 2014-2020

Project
IEA Region
Kashagan Contract Area
Cheleken Contract Area
Gum Deniz-Bahar
Umid
Shah Deniz
Tengizchevroil Area
Emba Area (Post contract)
FSU
FSU
FSU
FSU

FSU
FSU
FSU
Source: Deutsche Bank, Wood Mackenzie
Country
Kazakhstan
Turkmenistan
Azerbaijan
Azerbaijan
Azerbaijan
Kazakhstan
Kazakhstan
Sector
Offshore
South Caspian Basin
Azerbaijan Offshore
Azerbaijan Offshore
Azerbaijan Offshore
Precaspian Basin
Precaspian Basin
Operator
Project Type
North Caspian Operating Co
Dragon Oil
Bahar Energy Operating Company
SOCAR
BP
Tengizchevroil
Government of Kazakhstan
Shallow
Shallow
Shallow
Shallow
Shallow
Onshore
Onshore
Dev Status
Onstream
Onstream
Onstream
Onstream
Onstream
Onstream
Onstream
API
45
34
38
40
42
47

31
Prod Start Up Yr Peak Prod Yr
2013
1972
1965
2012
2006
1991
1911
2029
2021
2021
2022
2022
2023
2022
2014-2017 Prod 2014-2020 Prod
83
17
7
3
2
2
0
329
35
11
7
32
94
28

Colombia
In our view, Colombia’s upstream sector is significantly challenged amidst a backdrop of low oil prices, a low reserve life at existing fields, high field operating costs, transportation bottlenecks, security concerns, and corruption
charges involving Colombia’s largest oil producer. From 2004 through 2008, oil production hovered around a stable 550 mboe/d before ramping aggressively in 2009 and peaking in 2013 at over 1,000 mboe/d; chiefly driven by production from the heavy oil fields of the Llanos basin. The majority of the
remaining commercial oil reserves in Colombia is in the Llanos Basin where three fields in particular (Castilla, Rubiales, and Quifa) represented ~40% of
2014 oil production. However, with the fields in decline, and production growth having largely outpaced needed infrastructure re-investment, we expect Colombia oil production to decline in our forecast period. We model a long-term decline rate of ~5% (assumed upside from EOR projects) resulting in a decline in production of ~200 mboe/d from 2013 peak levels by 2020.
Figure 88: Colombia Production Outlook, 2014-2020e
(Mb/d)
200
400
600
800
1000
1200
0
2014
2015
Base
Source: Deutsche Bank, Wood Mackenzie, IEA
2016
2017
2018
2019
Growth Bbls
Source: Deutsche Bank, Wood Mackenzie, IEA
2020
Figure 89: Production by type (area chart of onshore vs.
shallow vs. deepwater (Mb/d)
200
400
600
800
1000
1200
0
2014

2015
2016
2017
2018
Onshore (Conv)
2019
2020
Figure 90: Crude volume growth outlook by project status (Mb/d)
200
400
600
800
1000
1200
0
2014
2015
Base
Under Development
DB Base Case
Source: Deutsche Bank, Wood Mackenzie, IEA
2016
2017
2018
2019
Growth at Onstream Assets
Probable Development
2020
Figure 91: 2017 Production Swing (Bear vs. Bull) of ~40 Mb/d (Mb/d)
100
200
300
400
500
600
700
800
900
0
Bear
Base
6mo timing shift in growth projects
Source: Deutsche Bank, Wood Mackenzie, IEA
Bull
1% adj in decline rates
852
875
895

mboe/d

31 May 2015
Integrated Oil
US Integrated Oils
Primary Risks
In the near-term, we anticipate accelerated declines in mature fields as the chief risk for sustained production. Gross oil production from the Rubiales Field – one of the largest producing onshore oil fields in South America - is expected be roughly halved by mid 2016 from ~200 mboe/d in 2013 at which point Pacific Rubiales' contract will not be renewed. In our view, longer-term
production growth will suffer from a decline in near-term exploration spend particularly in offshore/unconventional, further pushing out the timeline for the
potential of frontier plays. Upside to our production estimates would likely entail a faster than anticipated adoption/execution of EOR techniques and infrastructure build-out in the Llanos Basin.
a) In the near-term, accelerated declines from major plays represents the primary risk. Gross oil production from the Rubiales Field – the largest producing onshore oil field in South America - is expected be roughly halved by mid 2016 from ~200 mboe/d in 2013 at which point Pacific Rubiales' contract will not be renewed. While a potential agreement is still possible between Ecopetrol and Pacific Rubiales or another third-party entity, a significant amount of capital investment is still required to build/re-build infrastructure around the play. In our view, the required levels of capital investment and broader security concerns represent headwinds to a more aggressive adoption of EOR techniques in the play.
b) Long-term production growth challenged from a decline in near-term exploration spend particularly in offshore and unconventional plays.
DB estimates Ecopetrol upstream capex lower ~17.5% YoY in 2015 (largely exploration-driven) while Pacific Rubiales upstream spend is expected lower 55% (largely exploration and some production facilities-driven). A further delay in the addressing the county's reserve life through the drill-bit, will place the focus back on mitigating against field declines.
c) Sustaining production levels longer-term will be challenged by infrastructure/logistical bottlenecks persist: The 'heaviness' of the oil fields of the Llanos Basin present significant strains on the current infrastructure build-out in Colombia. Not only is pipeline takeaway capacity necessary to transport the crude to coastal export terminals, but facilities are required to blend the crude (API of ~12.5 for the Rubiales field) to a level acceptable for pipeline flow. Identification and integration of diluent and light oil sources for blending is also required. While the recent integration of light oil producing fields has provided a fairly economical solution to the blending challenge, the scalability of the solution is unclear and the alternative (importing of naptha for use as diluent) likely too expensive particularly at lower commodity prices. Further, in the Rubiales field (and exhibited at Quifa as well) delays surrounding water disposal licensing has also significantly curtailed growth (4Q14 production for Rubiales was ~170 mboe/d, a 15% drop from 2013 levels) as production was capped until

licensing was obtained.

U.S. Gulf of Mexico
Near-term production in the GoM is expected to be supported by the ramp of YE14 start-ups (Tubular Bells, Jack/St Malo) and the 2015/2016 (6 and 4 projects respectively) start-up of several key deepwater projects. While the projects are expected to add an incremental 350 mbpd of crude (2016 vs. 2014), the longer-term outlook (2018+) has less visibility beyond the contribution from a few (Appomattox) deep-water projects anticipated to be sanctioned this year. Sanctioning activity, lease sales, rig rates and announcements of early rig terminations will be monitored moving forward to assess incremental shifts in industry appetite for deepwater investment. In the
shelf, we assume a 5% annual decline in the central gulf through 2020 with declines likely to accelerate toward the latter part of the forecast period resulting from decreased demand for acreage. Since 2006, average acreage value has declined from $300/acre to ~$100/acre and declining further to $50/acre in the most recent bidding in March.
Figure 92: GoM Production Outlook, 2014-2020e (Mb/d)
200
400
600
800
1000
1200
1400
1600
0
2014
2015
Base
Source: Deutsche Bank, Wood Mackenzie, IEA
2016
2017
2018
2019
Growth Bbls
2020
Figure 93: Production by type (area chart of onshore vs.
shallow vs. deepwater (Mb/d)
500
1000
1500
2000
0
2014
2015
2016
Onshore (Conv)
Deepwater (Conv)

Source: Deutsche Bank, Wood Mackenzie, IEA
2017
2018
2019
2020
Shallow water (Conv)
Ultra-deepwater (Conv)
Figure 94: Crude volume growth outlook by project
status (Mb/d)
200
400
600
800
1000
1200
1400
1600
0
0
Base
Under Development
DB Base Case
Source: Deutsche Bank, Wood Mackenzie, IEA
0
0
0
5
14
Growth at Onstream Assets
Probable Development
14
Figure 95: 2017 Production Swing (Bear vs. Bull) of ~120
Mb/d
600
700
800
900
1000
1100
1200
1300
1400
1500
1384
1310
1429
Bear
Base
6mo timing shift in growth projects
Source: Deutsche Bank, Wood Mackenzie, IEA
1% adj in decline rates

Primary Growth Drivers
Near-term production is expected to be supported by the ramp of YE14 startups (Tubular Bells, Jack/St Malo) and the 2015/2016 (6 and 4 projects respectively) start-up of several key deepwater projects. While the projects are
expected to add an incremental 350 mbpd of crude (2016 vs. 2014), the longer-term outlook (2018+) has less visibility beyond the contribution from a
few (Appomattox) deep-water projects that are largely anticipated to be sanctioned this year.
Primary Risks
The near-term risk to production is largely synonymous with a risk to project start-ups which we regard as generally modest relative to projects with exposure to broader geopolitical turmoil and/or a dependence on cooperation with state owned national oil companies. However, the longer–term sustainability of production from the GoM will be largely dictated by the pace
of improvements in the underlying economics for deepwater projects driven by a recovery in crude prices and from significant cost concessions.
In our view, tracking the progress towards improvement long-term industry sentiment toward GoM Deepwater involves

- A pick-up in FID activity. Aside from Appomattox, few unsanctioned projects are considered 'locks' to proceed through to FID this year. The sanctioning (and timing of) of Shenandoah and Mad Dog Phase II will speak to progress on the lowering of the cost curve and a higher level of conviction in the sustainability of higher crude prices.

- Extension of Rig Contracts: Wood Mackenzie estimates that ~28 DW GoM rig contracts are set to expire over the next 3 years. About 1/3 of the rigs to expire in 2015 have already been released/cold-stacked while the nearly 20 rigs set to expire in 2016/2017 have as of yet not been released.

- A uptick in M&A activity: Since 2012, GoM-focused deals have declined to 8% of US deal flow in 2014 from 13% in 2012. With the short-cycle nature of the US onshore offering accelerated cost corrections and a widening valuation gap between 'haves' & 'have nots' at what point do discounted offshore valuations incentivize a pick-up in M&A activity?

Figure 96: Production outlook robust for sanctioned projects and for unsanctioned projects high in sunk costs
2000
4000
6000
8000
-4000
-2000
0
Pre-FID projects, negative NPV at US$60 Brent

Discoverer Enterprise*
DW Champion
Ensco 8501*
Ensco 8502*
Ensco 8505
Ensco 8506
Maersk Developer
Noble Amos Runner
Remaining PV
Remaining PV at US $60 Brent planning price
Noble Danny Adkins
Source: Wood Mackenzie, Base case assumes LT (2018+) Brent of $92
Atwood Condor
Development Driller III
Discoverer Deep Seas
Ensco DS-3
Ensco DS-4
Ensco DS-5
Noble Jim Day
Noble Paul Romano
Atwood Advantage
DW Invictus
DW Nautilus
Maersk Viking
Noble Bob Douglas
Noble Sam Croft
Noble Tom Madden
Pacific Santa Ana
Rowan Relentless
Rowan Resolute
Stena IceMAX
Source: Wood Mackenzie, *Already cold/ready stacked or released, By MODU name
Figure 97: 28 DW GoM rig contracts set to expire over
next 3 years
2015
2016
2017

US$, millions
Lucius
Big Foot
St Malo
Heidelberg
Delta House
Jack
Appomattox
North Platte
Tiber
Shenandoah
Kaskida

EFTA01411573

Figure 98: Deal count in the US GoM has fallen off as a share of US Totals since 2012
250
200
150
100
50
0
20052006200720082009201020112012201320142015
Rest of US
Mixture
Source: Wood Mackenzie
D/W
S/W
0%
2%
4%
6%
8%
10%
12%
14%
16%
18%
20%
Offshore %
Source: Wood Mackenzie
Figure 99: Declining Shelf Lease Sales To Accelerate Field Declines
100
150
200
250
50
50
0
Oct-07,
Sale 205
Mar-08,
Sale 206
Mar-09,
Sale 208
Mar-10,
Sale 213
Central high bids
Jun-12,
Sale
216/222

Central US$/acre
Mar-13,
Sale 227
Mar-14,
Sale 231
Mar-15,
Sale 235
0
100
150
200
250
300
350
Figure 100: Key Growth Projects, 2014-2020
Project
IEA Region
Delta House
Lucius (KC 875)
Big Foot (WR 29)
Heidelberg (GC 859)
Jack (WR 759)
Stones (WR 508)
Gunflint (MC 948)
Julia (WR 627)
Hadrian
Dantzler (MC 782)
North America
North America
North America
North America
North America
North America
North America
North America
North America
North America
Source: Deutsche Bank, Wood Mackenzie
Sector
Central Gulf
Central Gulf
Central Gulf
Central Gulf
Central Gulf
Central Gulf
Central Gulf
Central Gulf
Central Gulf
Central Gulf
Basin
East Gulf Coast Tertiary

West Gulf Coast Tertiary
West Gulf Coast Tertiary
West Gulf Coast Tertiary
West Gulf Coast Tertiary
West Gulf Coast Tertiary
East Gulf Coast Tertiary
West Gulf Coast Tertiary
West Gulf Coast Tertiary
East Gulf Coast Tertiary
Operator
LLOG Exploration
Anadarko
Chevron
Anadarko
Chevron
Shell
Noble Energy
ExxonMobil
ExxonMobil
Noble Energy
Project Type
UDW
UDW
UDW
UDW
UDW
UDW
UDW
UDW
UDW
UDW
Dev Status
Under Development
Onstream
Under Development
Under Development
Onstream
Under Development
Under Development
Under Development
Under Development
Under Development
API
36
29
26
35
29
28.5
36
N/A

N/A
26
Prod Start Up
Yr
2015
2015
2015
2016
2014
2017
2016
2016
2015
2016
Peak Prod Yr 2014-2017 Prod 2014-2020 Prod
2017
2017
2021
2021
2020
2021
2017
2024
2025
2017
75
69
52
42
38
25
23
22
21
21
40
43
53
59
45
45
11
32
20
11

Deal Count
Number of high bids
Average acreage value (US$/acre)

Malaysia

Similar to the broader group of countries, near-term oil production growth in Malaysia will be driven by high levels of recent development activity amidst higher oil prices. Key to the near-term oil growth will be the contribution from recent deepwater discoveries off Sabah. In the longer-term we view a broadly mature exploration profile to fail to incentivize the investment level needed to sustain oil production (production from Kikeh is expected to peak in 2017). In our model, we see overall oil production in 2020 falling ~50 mboe/d from 2015 levels.

Figure 101: Malaysia Production Outlook, 2014-2020e
(Mb/d)
100
200
300
400
500
600
700
800
0
2014
2015
2016
Base
Source: Deutsche Bank, Wood Mackenzie, IEA
2017
2018
2019
Growth Bbls
2020

Figure 102: Production by type (area chart of onshore vs. shallow vs. deepwater (Mb/d)
100
200
300
400
500
600
700
800
0
2014
2015
2016
Shallow water (Conv)

Source: Deutsche Bank, Wood Mackenzie, IEA
2017
2018
2019
2020
Deepwater (Conv)
Figure 103: Crude volume growth outlook by project status (Mb/d)
100
200
300
400
500
600
700
800
0
2014
Base
Under Development
DB Base Case
Source: Deutsche Bank, Wood Mackenzie, IEA
2015
2016
2017
2018
2019
Growth at Onstream Assets
Probable Development
2020
0
Bear
6mo timing shift in growth projects
Source: Deutsche Bank, Wood Mackenzie, IEA
Base
1% adj in decline rates
Bull
Figure 104: 2017 Production Swing (Bear vs. Bull) of ~25 Mb/d
100
200
300
400
500
600
700
800
682
656
669

Deutsche Bank Securities Inc.
mboe/d

Primary Growth Drivers

Near-term volume growth will be driven by recent discoveries off Sabah which have extended the eventual drop-off from Kikeh to 2017. In the near-term (2014-2017) we anticipate oil production to increase 9% by 2017 to 670mboe/d driven exclusively by the deepwater fields off Sabah. However, with Sabah expected to peak production in 2017 and anticipated lower levels of exploration over the next several years, growth visibility in the region post 2017+ is limited.

Primary Risks

In our view, the primary risk associated to the oil production outlook is a longer-term depletion of its mature asset base. From 2010-2014 exploration activity has dropped significantly with annual exploration wells completed averaging only 11 vs. 16 during the 2003-2009 time-frame with commercial wells representing 24% and 40% of the mix respectively. While total (commercial and technical) resource discovered per well has been significant (~33 mmboe/well) over the last 5 years the commerciality of the discovered resource has fallen off. From 2000-2010 commercial reserves made up ~2/3 of the discovered resource; however, that figure has averaged ~1/3 over the last 4 years and reached an all time low in 2014 of 8%.

Figure 105: Exploration activity has dropped over the last 5 years

10
15
20
25
30
35
40
45
50
0
5
52%
38%
31%
24%
15%
5%
24%
18%
17%
13%
5%
3%
-5%
5%
15%
25%

35%
45%
55%
65%
75%
Figure 106: Even though resource per well metrics are more constructive, only 33% of the discovered reserves over the last 4 years are considered 'commercial'
200
400
600
800
1000
1200
1400
0
2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014
Appraisal
Exploration Commercial
Source: Deutsche Bank, Wood Mackenzie
Exploration Technical
Comm % of Total Exp Wells
Exploration Technical
Source: Deutsche Bank, Mackenzie
Exploration Commercial
Figure 107: Key Growth Projects, 2014-2020
Project
IEA Region Country
SB J
SB K
SB G
Wakid
Asia
Asia
Asia
Asia
Malaysia
Malaysia
Malaysia
Malaysia
Source: Deutsche Bank, Wood Mackenzie
Sector
Sabah
Sabah
Sabah
Sabah
Operator
Shell
Murphy Oil
Shell
Petronas Carigali

Project
Type
DW
DW
DW
DW
Dev Status
Onstream
Onstream
Onstream
Good Technical
API
40
37
35
35
Prod Start
Up Yr
2012
2007
2014
2019
Peak
Prod Yr
2015
2021
2022
2020
2014-2017
Prod
59
33
20
0
2014-2020
Prod
40
32
50
18

# of Wells Completed
Disc Reserves (mmboe)

Mexico

The 2013 energy reform is aimed at reducing the decline in oil production (which has been fallen by 3% since 2003 to 2450 mboe/d in 2014) that has resulted from a lack of investment in frontier plays particularly in the GoM deepwater (only 26 wells have been drilled in the deepwater). The implications of the energy reform in Mexico on production generally sit outside of our forecast period; however, updates around the bidding process will likely serve as a barometer for the viability of assets – particular the deepwater for which bids are due later this year. While capital investment into mature fields may accelerate the use of secondary and tertiary recovery techniques; 2014 production for identified mature onshore and offshore assets included in Round 1 represent only ~ 12% of 2014 production. Recovery at the Samaria field (represents 60% of the available mature assets in 2014 production) has already moved past secondary techniques, limiting to recovery factors. In our view, the key risk to production in Mexico is a continued decline in the asset base particularly as exploration results over the last several years have failed to produce prospects material enough to combat the declining portfolio.

Figure 108: Mexico Production Outlook, 2014-2020e
(Mb/d)
500
1000
1500
2000
2500
3000
0
2014
2015
Base
Source: Deutsche Bank, Wood Mackenzie, IEA
2016
2017
2018
2019
Growth Bbls
Source: Deutsche Bank, Wood Mackenzie, IEA
2020

Figure 109: Production by type (area chart of onshore vs. shallow vs. deepwater (Mb/d)
500
1000
1500
2000

2500
3000
0
2014
2015
2016
Onshore (Conv)
2017
2018
2019
Shallow water (Conv)
2020
Figure 110: Crude volume growth outlook by project status (Mb/d)
500
1000
1500
2000
2500
3000
0
2014
2015
Base
Under Development
DB Base Case
Source: Deutsche Bank, Wood Mackenzie, IEA
2016
2017
2018
2019
Growth at Onstream Assets
Probable Development
2020
Figure 111: 2017 Production Swing (Bear vs. Bull) of ~140 Mb/d
1500
1600
1700
1800
1900
2000
2100
2200
2300
2246
2173
2104
Bear
Base
6mo timing shift in growth projects

Source: Deutsche Bank, Wood Mackenzie, IEA
1% adj in decline rates
Bull

mboe/d

Primary Growth Drivers

Volume growth in the forecast period (2015-2020) will be scarce. Among the most material contributions to production in the near-term are the fields from
the Litoral de Tabasco business unit in Mexico's Southeastern business unit. The crude from the fields is mostly light (~37 API on average). The continued production ramp of the Tsimin field is likely the biggest spotlight in the group
(Woodmac estimated ~50 mboe/d in production from 2014-2017). Longerterm growth will be supported mostly by the heavy crude producing KuMaloob
Zaap fields (Ayatsil and Tekel) in the Northeastern business unit.
Wood Mackenzie estimates a production start in 2017 with peak production of oil reaching ~102 mboe/d by 2021. The fields are expected to be tendered as part of Mexico's Round 1 as part of a joint venture opportunity with Pemex.

Primary Risks

We view the near-term risk to production as minimal as contributions from project startups are marginal. In our view, the longer-term (2017-2020) risk to
production in Mexico is significant and is underlined by continued decline in the asset base following a 5yr period of relatively underwhelming exploration results. While capital investment into mature fields may accelerate the use of
secondary and tertiary recovery technique; 2014 production for identified mature onshore and offshore assets included in Round 1 represent only ~ 12% of 2014 crude production. Recovery at the Samaria field (represents 60% of the available mature assets in terms of 2014 production) has already moved past secondary techniques, limiting the upside to recovery factors and potentially to capital inflow. We model a 5% decline rate on the Mexico's base
assets during the production period and estimate that a shift in the base decline rate to represent ~60 mboe/d of production in 2017.

Figure 112: Exploration activity has dipped since 2010
with only smaller onshore discoveries classified as
commercial

10
12
14
16
18
20
0
2
4
6
8
0%
10%
20%

30%
40%
50%
60%
70%
80%
90%
100%
Figure 113: In particular, exploration in the GoM shelf has been largely disappointing with recent discoveries mostly consisting of smaller fields since 2008
100
150
200
250
300
50
2005 2006 2007 2008 2009 2010 2011 2012 2013 2014
Onshore
Source: Deutsche Bank
Shelf
DW
Comm % of Total Exp Wells
0
2005
2006
2007
2008
2009
Disc Reserve per Well (mmboe)
Source: Deutsche Bank, Wood Mackenzie
2010
2011
2012
2013
% of Comm Disc Reserves
2014
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%

# of Wells Completed

Comm
Tech
Comm
Tech
Comm
Tech
Comm
Tech
Comm
Tech
Comm
Tech
Comm
Tech
Comm
Tech
Comm
Tech
Comm
Tech

Figure 114: Timeline for Mexico Energy Reform, Round 1 Roll-Out

Date
Event
Dec-13
Aug-14
Nov-14
Energy Reform Launch
Initial Round Zero Results
Secondary legislation approved
Industry feedback on assets
Jan-15
Industry feedback on contracts
Launch of Round 1
Commentary
Allows for private investment through PSCs and licenses
Round Zero determined which assets were kept by Pemex (all producing assets are kept by Pemex)
Government has adjustment Round 1 terms based on industry feedback; however finanal terms yet to be determined
Opportunities will including joint ventures with Pemex (10 joint ventures identified) as well as standalone opportunities
3Q15
Bids due for shallow-water DROs and exploration
Shallow-water projects are decomposed into mature offshore (Bolontiku, Sinan, Ek) and extra-heavy crude oil projects in development (Ayatsil, Tekel, Utsil).
Oct-Nov-15
Bids due for mature onshore
Mature Onshore include the Rodador, Ogarrio, Cardenas-Mora, and Samaria fields. With the exception of Samaria (Tertiary) recovery the rest of the assets are being offered to accelerate hydrocarbon recovery starting with secondary-recovery.
The Samaria field represents ~60% of mature assets (onshore and offshore) 2014 production being offered in Round 1.
Dec-15
Bids due for deepwater
Deepwater gas offerings in Round 1 include: Kunah and Piklis. Water depth is less than 2,000 meters.
Deepwater oil offerings in Round 1 include fields (Trion, Exploratus, Maximino) in the Perdido area of the deepwater GoM (water depth greater than 2,500 meters)

Source: Deutsche Bank, Pemex, Wood Mackenzie

North Sea
The North Sea has been synonymous in recent years with mature, Non-OPEC decline, and for good reason. Since its peak production in 2000, North Sea production has steadily declined from ~6 MMboe/d to current production levels of 2.5 MMboe/d, or an average decline rate of 6% YoY. This happened despite steadily increasing capex levels. Despite multi-year trends, we expect
North Sea production to hold broadly flat through 2016 as several growth projects are brought on-stream and significant re-development spending over the last couple of years softens the decline of several key fields. The longerterm
outlook is most strongly correlated with the successful (i.e. timely) development of the massive Johan Sverdrup field and the management of declines across the broader mature asset base. On our base case assumes declines of 12%, and estimate a 1% revision to the assumed decline to result in
a swing of ~ 125 Mb/d to our 2017 outlook.
Figure 115: North Sea Production Outlook, 2014-2020e
(Mb/d)
500
1000
1500
2000
2500
3000
0
2014
2015
Base
Source: Deutsche Bank, Wood Mackenzie, IEA
2016
2017
2018
2019
Growth Bbls
2020
Figure 116: Production by type (area chart of onshore vs.
shallow vs. deepwater (Mb/d)
500
1000
1500
2000
2500
3000
0
2014
2015
2016

Shallow water (Conv)
Source: Deutsche Bank, Wood Mackenzie, IEA
2017
2018
2019
Deepwater (Conv)
2020
Figure 117: Crude volume growth outlook by project status (Mb/d)
500
1000
1500
2000
2500
3000
3500
0
2014
2015
Base
Under Development
DB Base Case
2016
2017
2018
2019
Growth at Onstream Assets
Probable Development
2020
Figure 118: 2017 Production Swing (Bear vs. Bull) of ~240 Mb/d
1000
1200
1400
1600
1800
2000
2200
2400
2600
2800
2518
2435
2280
Bear
Base
6mo timing shift in growth projects
Source: Deutsche Bank, Wood Mackenzie, IEA
Source: Deutsche Bank, Wood Mackenzie, IEA
1% adj in decline rates
Bull

Primary Growth Drivers
Volume growth over the next two years is primarily driven from re-developed mature assets (Ekofisk II) as well as from the bringing on-line of several growth
projects in both the UK and Norway. However, the longer-term viability of North Sea production growth is most strongly correlated with the successful (i.e. timely) development of the massive Johan Sverdrup field which was recently sanctioned in February. We estimate North Sea crude production to hold broadly flat (~2.5 MMb/d) through 2016 before declining to 2.2 MMb/d in 2019 w/ recovery in 2020 as Johan Sverdrup is brought on-line.
Primary Risks
In our view, the impact of project delays is mostly muted as all growth projects
are currently either on-stream or under development with growth from the currently producing Ekofisk field alone, estimated at ~15% of 2014-2016 North Sea. Post 2016, we expect a decline in the North Sea until the end of the decade/ramp of the massive Johan Sverdrup field (+300 Mb/d of production growth in 2020). The chief risk to North Sea production on a go-forward basis will focus on managing declines. We note, however, that Statoil (covered by our European counterparts), alone, accounts for ~20% of the oil production growth from the North Sea over the next 3 years and any announcements of a change to the company’s planned activity in the region would likely have a material impact on the forecast.
Managing Declines: For a more detail look at North Sea decline, please see our case study on page 20 of this publication. In summary, we assume a decline rate (ex growth rates and redevelopment projects) of ~12% during our forecast period and assume a contribution of ~3% from prior year production in normalized outages within the forecasted 12% forecast. We see some upside to our forecasted decline rates as operators (in the Norwegian North Sea) benefit from exchange rate tail-winds that will soften cuts to brown field
spending. Assuming that ~20% of a company’s NCS spend is denominated in the local currency ($ Kroner), we estimate that a 25% YoY reduction in $USD denominated capex (proxy for an industry average) will likely result in an “actual” 10% YoY cut spend. Further, a reallocation of capital away from more costly frontier plays in the Barents Sea towards more immediate cash flow accretive brown-field projects can also provide upside to our current forecast.
On our base case assumes declines of 12%, and estimate a 1% revision to the assumed decline to result in a swing of ~ 125 Mb/d to our 2017 outlook.
Figure 119: Key Growth Projects, 2014-2020
Project
IEA Region
Edvard Grieg
Laggan & Tormore Area
Goliat Area
Ekofisk Area II
Golden Eagle Area

Mariner
Western Isles Project
Ivar Aasen Area
Knarr Area
Hejre
Europe
Europe
Europe
Europe
Europe
Europe
Europe
Europe
Europe
Europe
Source: Deutsche Bank. Wood Mackenzie
Country
Norway
UK
Norway
Norway
UK
UK
UK
Norway
Norway
Other
North Sea
Sector
Central North Sea
Atlantic Margin
Barents Sea
Central North Sea
Central North Sea
Northern North Sea
Northern North Sea
Central North Sea
Northern North Sea
Central North Sea
Operator
Lundin Petroleum
Total
Eni
ConocoPhillips
Nexen
Statoil
Dana Petroleum
Det Norske
BG
DONG Energy
Project Type

Dev Status
Shallow
DW
DW
Shallow
Shallow
Shallow
Shallow
Shallow
DW
Shallow
Under Development
Under Development
Under Development
Onstream
Onstream
Under Development
Under Development
Under Development
Under Development
Under Development
API
35
40
36.5
39.6
37.5
13
34.5
37
45
43
Prod Start Up Yr Peak Prod Yr 2014-2017 Prod 2014-2020 Prod
2015
2015
2015
1999
2014
2017
2016
2016
2015
2017
2016
2018
2016
2002
2017
2019
2017
2020

2015
2017
89
81
72
68
60
52
33
32
27
27
34
91
35
37
24
58
11
62
13
27

Russia
At 10.5 mmbpd of crude production in 2014, Russia represents ~25% of NonOPEC production; recent production growth has been driven chiefly by contributions from the conventional West Siberia basin and in our view likely to continue to be the case moving forward. While growth from green field projects is modest when compared to the country's base production, declines in mature fields will be the key driver of the forward-looking production profile.
DB's house view is that Russia production will be broadly flat through 2020 with a slight ramp in the near-term as companies are expected to maintain robust activity levels. DB's Russian energy team broadly expects investment spend in Russia to track broadly flat/modestly higher in 2015 vs. 2014 (in RUB).
We view impacts from current sanctions as minimal as there is no sense of urgency in developing the unconventional and Artic fields so far as it relates to
sustaining the production base. Given the large size of base production, a shift
of 1% in the forecasted decline rate for Russia results in a significant ~300 Mb/d adjustment to our 2017 call on US onshore growth.
Figure 120: Russia Production Outlook, 2014-2020e
(Mb/d)
2000
4000
6000
8000
10000
12000
0
2014
2015
Base
Source: Deutsche Bank, Wood Mackenzie, IEA
2016
2017
2018
2019
Growth Bbls
Source: Deutsche Bank, Wood Mackenzie, IEA
2020
Figure 121: Production by type (area chart of onshore vs.
shallow vs. deepwater (Mb/d)
9600
9800
10000
10200
10400
10600

10800
2014
2015
2016
Onshore (Conv)
2017
2018
2019
Shallow water (Conv)
2020
Figure 122: Crude volume growth outlook by project status (Mb/d)
8500
9000
9500
10000
10500
11000
2014
2015
Base
Under Development
DB Base Case
2016
2017
2018
2019
Growth at Onstream Assets
Probable Development
2020
Figure 123: 2017 Production Swing (Bear vs. Bull) of ~600 Mb/d
8500
9000
9500
10000
10500
11000
11500
10986
10688
10411
Bear
Base
6mo timing shift in growth projects
Source: Deutsche Bank, Wood Mackenzie, IEA
Source: Deutsche Bank, Wood Mackenzie, IEA
1% adj in decline rates
Bull

EFTA01411599

mboe/d

31 May 2015
Integrated Oil
US Integrated Oils
Primary Growth Drivers
Volume growth will be chiefly driven by managing declines at various mature fields in West Siberia and a handful of moderately-sized project start-ups in the
Timan-Pechora (Trebs and Titov), Sakhalin (Arkutun-Dagi), and North Caucasus (Vladimir Filanovski) basins. In total we estimate growth projects to grow-term
near-term production of ~120 Mb/d (2016 vs. 2014)
Primary Risks
In our view, the key risk to near-term production growth/sustainment involves mitigating against declines in West Siberia. In our view, improvements in operator execution as well as cheap funding from a weakened Ruble will broadly keep production flat through 2020.
Decline Mitigation: Exiting 1Q15 development drilling was up 17.5% YoY and the well count increased by 17%, despite the bottoming of the commodity on better execution from operators and tail-winds from cheaper Rubledenominated spend. Russian oil companies have broadly spoken to flat or
modestly higher capital spending in 2015 (in RUB). The Russian government recently granted a Mineral Extraction Tax (MET) break and a reduced Export Duty rate which may ultimately further costs for operators (and incentivize drilling activity). Given the large size of the production base, a shift of 1% in
the forecasted decline rate for Russia results in a significant adjustment to our
call on US onshore growth (~300 Mb/d in our 2017 call on US onshore growth.)
Figure 124: Key Growth Projects, 2014-2020
Project
IEA
SeverEnergia
Srednebotuobinskoye
Yarudeiskoye
Talakan Fields
Yaregskoye (LUKOIL)
Suzunskoye
Trebs and Titov
Prirazlomnoye (TP)
Novoportovskoye
Sakhalin-1 Area
Region
FSU
FSU
FSU
FSU
FSU
FSU
FSU
FSU

FSU
FSU
Source: Deutsche Bank. Wood Mackenzie
Country
Russia
Russia
Russia
Russia
Russia
Russia
Russia
Russia
Russia
Russia
Sector
West Siberia
East Siberia
West Siberia
East Siberia
Timan-Pechora
East Siberia
Timan-Pechora
Timan-Pechora
West Siberia
Far East
Operator
SeverEnergia
Taas-Yuryakh
Yargeo
Talakanneft
LUKOIL-Komi (Yareganeft)
Vankorneft
Bashneft-Polus
Gazprom neft shelf
Gazpromneft Novi Port
ExxonMobil
Project Type
Onshore
Onshore
Onshore
Shallow
Onshore
Shallow
Dev Status
Onstream
Onstream
Onshore Under Development
Onshore
Onstream
Onstream
Onshore Under Development

Onshore
Onstream
Onstream
Onstream
Onstream
API
43
32
42
35
21
41
26
24
32
32
Production
Start Up Yr
2012
2013
2015
1989
1939
2016
2013
2013
2011
2005
Peak Prod Yr
2018
2023
2016
2017
2017
2018
2021
2021
2022
2025
2014-2017
Prod
120
85
79
40
36
30
29
28
28
28

2014-2020
Prod
122
112
63
22
36
60
64
75
139
8

Appendix
Figure 125: Crude Supply Model
2013
North America
United States
L48 (2017+ replaced with "The Call")
GoM
DW
SW
Alaska
Total US
Total Canada
Mexico
Chile
Total North America
Total North America, ex Onshore
Europe
Total North Sea
Other Europe OECD
Europe Non-OECD
Total Europe
Latin America
Brazil
Colombia
Venezuela
Ecuador
Other Non-OPEC Latin America
Total Latin America
Africa
Angola
Libya
Nigeria
Algeria
Non-OPEC Africa
Total Africa
Middle East
Saudi Arabia
Iran
Iraq
UAE
Kuwait
Qatar
Neutral Zone
Non-OPEC Middle East
Total Middle East
Asia
Australia
Other Asia OECD

China
India
Malaysia
Indonesia
Other Non-OECD Asia
Total Asia
Russia
Caspian Sea
Other FSU
Total FSU
"Other Bbls" ex OPEC
"Other Bbls" with Angola
5895
1254
975
279
515
7664
3333
2532
7
13537
7642
2509
430
129
3068
2030
1008
2497
517
814
6866
1718
898
1953
1148
2171
7888
9487
2682
3080
2762
2549
881
520
1305
23266
335
60
4173

769
586
732
836
7491
10506
2727
105
13339
38868
40586
2014
6946
1395
1120
275
497
8838
3612
2440
7
14897
7951
2518
412
130
3059
2260
990
2462
551
808
7072
1661
460
1915
1121
2198
7355
9611
2812
3332
2759
2608
861
383
1276
23642
354
64
4216

766
612
700
818
7529
10576
2689
99
13364
39437
41098
2015E
7351
1493
1234
259
472
9316
3756
2346
6
15424
8073
2509
395
130
3034
2427
956
2462
551
800
7196
1617
460
1915
1121
2184
7297
9611
2812
3332
2759
2608
861
383
1218
23583
357
57
4216

778
691
653
800
7551
10659
2672
93
13424
39668
41285
2016E
7293
1583
1340
243
449
9325
3964
2248
5
15542
8249
2491
391
108
2990
2563
907
2462
551
800
7283
1617
460
1915
1121
2177
7289
9611
2812
3332
2759
2608
861
383
1146
23512
322
68
4216

761
674
711
795
7546
10699
2655
87
13441
39820
41437
2017E
7674
1610
1382
228
426
9710
4157
2173
5
16045
8371
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12

79
-47
-18
22
83
-18
-6
60
231
187
Source: Deutsche Bank, Wood Mackenzie, IEA, EIA, L48 Crude “Implied Call on US Crude Growth” from 2017+ and DBe from 2015-2016, includes crude oil, condensate, bitumen
14-17
Growth
728
215
262
-47
-71
545
-267
278
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-83
-6
-31
-120
417
-116
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-8
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-20
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-158
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112
-48
-18
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538
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52
138
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-132
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308
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-42
-58
-443
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-176
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159
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-126
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-93
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-97
-68
-217
-10
240
-36
194
161
320
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31 May 2015
Integrated Oil
US Integrated Oils
Appendix 1
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share price from current price to projected target price
plus pro-jected dividend yield) , we recommend that
investors buy the stock.
Sell: Based on a current 12-month view of total shareholder
return, we recommend that investors sell the
stock
Hold: We take a neutral view on the stock 12-months
out and, based on this time horizon, do not
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Hold: Expected total return (including
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period
Sell: Expected total return (including dividends)
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Deutsche Bank Securities Inc.

Equity rating dispersion and banking relationships

100
200
300
400
500
600
0
Buy
Hold
Sell
Companies Covered Cos. w/ Banking Relationship
North American Universe
50 %
59 %
43 %
2 %37 %
48 %

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movements.
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