Oil & Gas Majors: Fact Sheets

August 2014

About Carbon Tracker

The Carbon Tracker Initiative (CTI) is a team of financial specialists making climate risk visible in today's financial markets.

Our research to date on unburnable carbon and stranded assets has started a new debate on how to align the financial system with the energy transition to a low carbon future.

Contacts

James Leaton
Research Director
jleaton@carbontracker.org
www.carbontracker.org
twitter: @carbonbubble

Andrew Grant
Financial Analyst
agrant@carbontracker.org
www.carbontracker.org
twitter: @carbonbubble

Team Members

Jeremy Leggett, Non-executive Chairman
Mark Campanale, Founder and Executive Director
Anthony Hobley, Chief Executive Officer
Jon Grayson, Chief Operating Officer
James Leaton, Research Director
Luke Sussams, Senior Researcher
Andrew Grant, Financial Analyst
John Wunderlin, North America Staff Attorney
Reid Capalino, Financial Analyst
Margherita Gagliardi, Communications Officer
Tracy Trainor, Office Manager

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Overview

Key Points

1. The oil & gas sector is currently facing pressure from investors to focus on capital discipline, and several majors have stated that their capex will either fall or stay flat over the coming years.

2. In order to sustain shareholder returns, companies should focus on low cost projects, deferring or cancelling projects with high breakeven costs. Capital could be redeployed to share buybacks or increased dividends.

3. This process has already started, particularly in the Canadian oil sands sector. The majors' portfolios include several significant arctic and deep water/ultra-deep water projects which could prove low return assets in a low-demand scenario. Deferral or cancellation of these might protect shareholder returns.

4. Collectively, the majors have a potential capital spend of $548bn over the period 2014-2025 on projects that require a market price of at least $95/bbl for sanction (34% of total capex on all their projects).

5. $357bn of this is on high cost projects that are yet to be developed. Such projects are candidates for deferral or cancellation.

6. Investors may wish to push companies for more detailed disclosure of project level economics, and challenge developments that carry an undue risk of wasting capital and destroying value.

Introduction

CTI has demonstrated in its research the mismatch between continuing growth in oil demand and reducing carbon emissions to limit global warming. Our most recent research with ETA to produce the carbon cost supply curve for oil indicates that there is significant potential production that could be considered both high cost and in excess of a carbon budget. We have focused our research on undeveloped projects that, allowing for a $15/bbl contingency, would need a $95/bbl market price or above to be sanctioned (i.e. a market price required for sanction of $95/bbl is equivalent to a project breakeven price of $80/bbl), as they are the marginal barrels that could be exposed to a lower demand and price scenario in the future.

This note examines the seven largest publicly listed oil companies' potential future project portfolios looking at production and capex using Rystad Energy's UCube Upstream database (as at July 2014). "Capex" and "production" in this note (amongst other terms) are thus based on Rystad's analysis and expectations of the company's potential projects. The companies' planned or realised capex and production may differ from these projections. Where possible we have sought to verify the status of the projects at the time of writing. A $15/bbl premium has been included in the required market prices for sanction of oil sands projects to account for additional transport costs.

Individual company portfolios and exposure to high-risk projects are contained in the individual company factsheets which accompany this summary comparison.

Projects Shelved

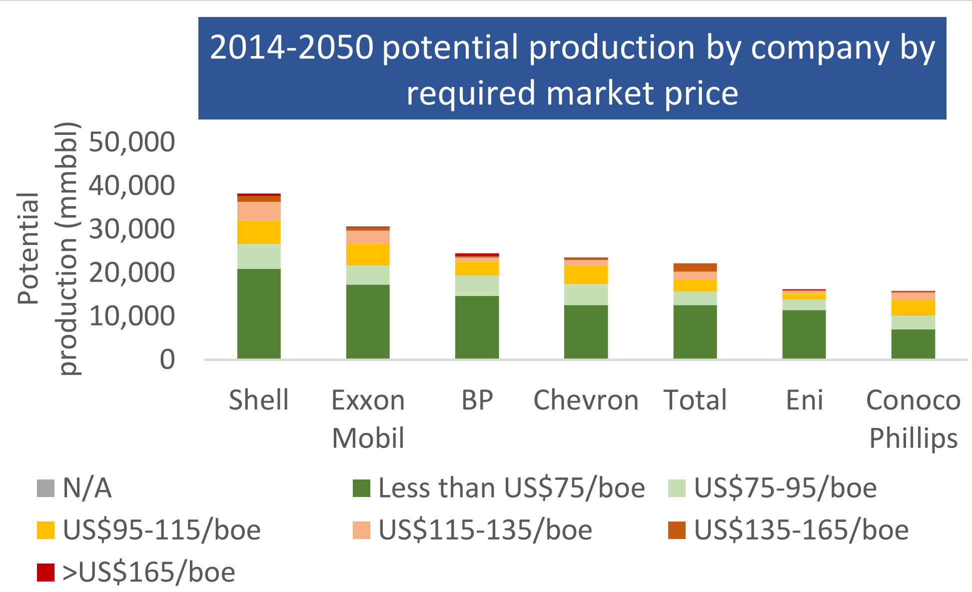
There have been some recent examples of projects being put on ice by the majors. In the oil sands in 2014, Total and Suncor have shelved the $11bn Joslyn project[1] and Shell put on hold its Pierre River project[2]. Deepwater projects have also been deferred with BP not proceeding with its Mad Dog extension in the Gulf of Mexico[3], and Chevron reviewing its $10bn Rosebank project in the North Sea[4]. In the Arctic, Statoil and Eni have deferred a decision on the $15.5bn Johan Castberg project[5].

Some companies are therefore already starting to demonstrate greater capital discipline amidst falling group returns. This is becoming increasingly necessary as near term cash flows are not sufficient to maintain both dividends and capital expenditure plans. In the short-term companies have squared the circle by selling assets or adding debt. Cutting capital spend should improve corporate cash flow statements as could new cash flow from new projects. But with some companies continuing to sanction projects at the high end of the cost curve, hence increasing operational gearing, shareholder value could be put at risk should demand and hence oil prices be lower than the majors anticipate.

1 http://www.theglobeandmail.com/report-on-business/joslyn/article18914681/
2 http://business.financialpost.com/2014/02/12/shell-halts-work-on-pierre-river-oil-sands-mine-in-northern-alberta/?__lsa=3d7c-cd43
3 http://www.reuters.com/article/2013/09/19/bp-usa-offshore-idUSL2N0HE2V520130919
4 http://www.telegraph.co.uk/finance/newsbysector/energy/oilandgas/10468111/Chevron-casts-doubt-on-10bn-North-Sea-oil-project.html
5 Statoil press release, “Need more time for Castberg”, 30 June 2014.
http://www.statoil.com/en/NewsAndMedia/News/2014/Pages/30Jun_JCmelding.aspx

Potential Production

- Shell has one of the highest proportions of high-cost potential production, with 45% requiring a market price of $75/bbl and 30% requiring at least $95/bbl, although ConocoPhillips has the highest cost production profile with 56% and 36% respectively.
- Eni and BP have the portfolios with the lowest oil market price requirements, 30% and 40% of which respectively requiring above $75/bbl and 15% and 21% of which respectively requiring at least $95/bbl.

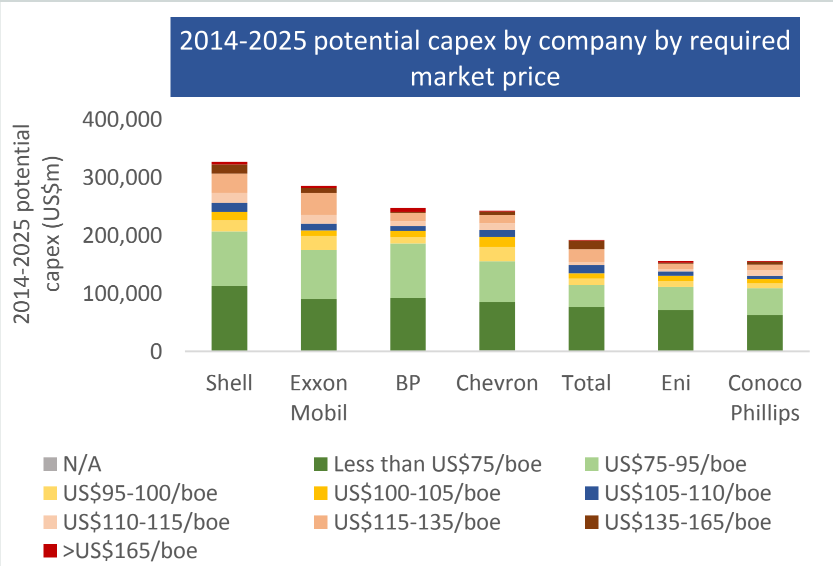


Majors ranked by highest development risk

Rank	Company	Potential 2014-2025 production (%) requiring market prices: $75/bbl+	$95/bbl+
1	Conoco Phillips	56%	36%
2	Shell	45%	30%
3	Total	44%	29%
4	Exxon Mobil	44%	29%
5	Chevron	46%	26%
6	BP	40%	21%
7	Eni	30%	15%

Potential Capex

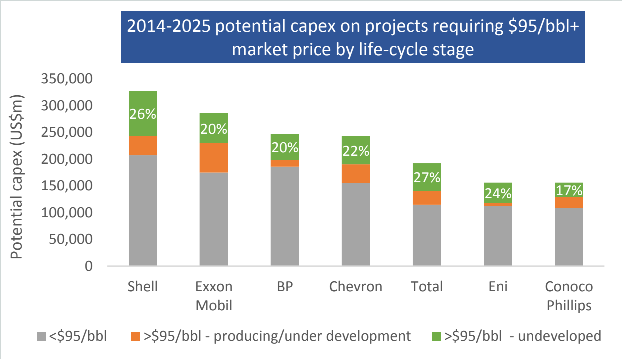
- Turning to capital spend in the nearer term (2014-2025) Total and ExxonMobil's capital budgets have some of the highest oil price requirements, with 60% and 68% respectively on potential projects requiring a market price of at least $75/bbl for sanction and 40% and 39% requiring at least $95/bbl (including a $15/bbl contingency allowance).
- Shell is not dissimilar with 65% of its potential capex requiring a market price over $75/bbl and 37% over $95/bbl.
- BP and Eni again have the lowest proportion of high-price requirements, with 25% and 28% on projects that need a market price of at least $95/bbl for sanction, although Eni and ConocoPhillips have the least exposure to projects that would be need at least $75/bbl with 54% and 59%.



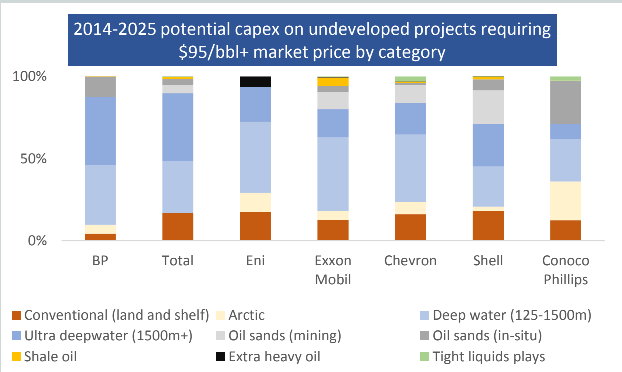
Majors ranked by highest capex risk			
		Potential 2014-2025 capex (%) requiring market prices:	
Rank	Company	$75/bbl+	$95/bbl+
1	Total	60%	40%
2	Exxon Mobil	68%	39%
3	Shell	65%	37%
4	Chevron	65%	36%
5	Conoco Phillips	59%	30%
6	Eni	54%	28%
7	BP	62%	25%

Potential Capex

- Looking at just undeveloped projects, 27% of Total's and 26% of Shell's capex in this category requires a market price of $95/bbl+.
- By contrast, only 17% of ConocoPhillips's potential capex budget is on high-cost projects that are as yet undeveloped. BP and Exxon have the second lowest exposure with with 20% of their capex in this category.
- "Undeveloped" in this sense comprises fields where a discovery has been made ("discovery") and where no discovery has been made ("undiscovered")



- Oil sands projects account for 27% and 26% of Shell and ConocoPhillips's high-cost potential development spend.
- Capital spend on undeveloped, high-break even projects is heavily biased towards the unconventional category, with just 14% of overall potential spend on conventional projects.
- BP and Total have particularly high exposure to deep water developments, with deep water and ultra-deep water in aggregate representing 78% and 73% of potential high cost spend respectively.
- ConocoPhillips is heavily biased towards arctic projects proportionately, which represent 24% of potential spend compared to an average of 5% amongst the other majors.



Potential Capex

The table below shows the companies' exposure to high cost unconventional projects in further detail.

Majors ranked by proportional potential exposure to undeveloped projects requiring $95/bbl+ oil price by category									
	% of 2014-2025 capex by category:								
Company	Conv. (land/shelf)	Oil sands	Deep water	UDW	Arctic	Shale oil	Extra heavy oil	Tight liquids	Total
BP	4% ($2 bn)	12% ($6 bn)	36% ($18 bn)	41% ($20 bn)	5% ($3 bn)	0% ($0 bn)	0% ($0 bn)	0% ($0 bn)	$49 bn
Conoco Phillips	12% ($3 bn)	26% ($7 bn)	26% ($7 bn)	9% ($2 bn)	24% ($6 bn)	0% ($0 bn)	0% ($0 bn)	2% ($1 bn)	$27 bn
Exxon Mobil	13% ($7 bn)	14% ($8 bn)	45% ($25 bn)	17% ($10 bn)	5% ($3 bn)	5% ($3 bn)	0% ($0 bn)	0% ($0 bn)	$56 bn
Chevron	16% ($8 bn)	12% ($6 bn)	41% ($21 bn)	19% ($10 bn)	8% ($4 bn)	1% ($1 bn)	0% ($0 bn)	3% ($2 bn)	$52 bn
Total	17% ($9 bn)	9% ($5 bn)	32% ($16 bn)	41% ($21 bn)	0% ($0 bn)	1% ($1 bn)	0% ($0 bn)	0% ($0 bn)	$52 bn
Eni	17% ($7 bn)	0% ($0 bn)	43% ($16 bn)	21% ($8 bn)	12% ($4 bn)	0% ($0 bn)	6% ($2 bn)	0% ($0 bn)	$38 bn
Shell	18% ($15 bn)	27% ($23 bn)	24% ($21 bn)	26% ($22 bn)	3% ($2 bn)	2% ($1 bn)	0% ($0 bn)	0% ($0 bn)	$84 bn

*Note: Categories are according to Rystad classifications. For example Shell's Chukchi Sea project is described as a gas project by the company, so is not included in the arctic total here.

Cancellation candidates

Focusing on individual projects for each company, there are a number of undeveloped, high-cost projects which are prime candidates for cancellation:

Top 20 largest undeveloped oil projects requiring $95/bbl+ market oil prices for sanction

Company	Name	Country	Region	Category	2014-2025 capex* (\$m)	Required market price** (\$/bbl)	Status***
ConocoPhillips	Foster Creek	Canada	Alberta	Oil sands (in-situ)	1,911	159	Under development/study
Shell	Carmon Creek	Canada	Alberta	Oil sands (in-situ)	3,429	157	Approved
ConocoPhillips, Total	Surmont Oil Sands project	Canada	Alberta	Oil sands (in-situ)	3,554	156	Under development
Exxon	Aspen	Canada	Alberta	Oil sands (in-situ)	2,039	147	Approval sought
Exxon	Kearl	Canada	Alberta	Oil sands (mining)	4,316	134	Ongoing
ConocoPhillips	Christina Lake	Canada	Alberta	Oil sands (in-situ)	2,185	128	Under study
Total	Block CI-514	Cote d'Ivoire	Atlantic Ocean	Ultra deepwater	2,312	127	Under study
Exxon, Shell	Bosi	Nigeria	Atlantic Ocean	Deep water	14,018	126	Under study
BP	Pitu (1-BRSA-1205-RNS)	Brazil	Rio Grande do Norte	Ultra deepwater	1,976	124	Under study
Shell	Gato do Mato	Brazil	Rio de Janeiro	Ultra deepwater	2,218	121	Under study
Chevron	Nsiko	Nigeria	Atlantic Ocean	Ultra deepwater	2,304	120	Under study
Exxon, Eni, Shell	Bonga	Nigeria	Atlantic Ocean	Deep water	8,890	115	Under development/study
Chevron	Wafra (EOR)	Neutral Zone	Ash Sharqiyah	Conventional (land/shelf)	3,081	115	Under development
BP	Sunrise	Canada	Alberta	Oil sands (in-situ)	4,343	113 - 134	Under development
Chevron, ConocoPhillips	Amauligak	Canada	Northwest Territories	Arctic	9,035	113	Under study
BP	Liberty	United States	Alaska	Arctic	2,048	109	Under study
Total	Ivoire-1X	Cote d'Ivoire	Atlantic Ocean	Ultra deepwater	2,022	109	Under study
Eni	Johan Castberg	Norway	Barents Sea	Arctic	3,028	103 - 151	Under study/deferred
Shell	Yucatan	United States	Gulf of Mexico deepwater	Ultra deepwater	3,586	99	Under study
Chevron, Shell	Athabasca Oil Sands Project	Canada	Alberta	Oil sands (mining)	14,398	96 - 118	Ongoing
Total Top 20 Discoveries					**90,693**		

** company share of capex requiring $95/bbl+ shown only. Where more than one of the companies under review has an equity stake, aggregate share of capex is shown*
*** market price required for sanction includes $15/bbl contingency on top of project breakeven price*
**** as understood based on company disclosures*

These are the top twenty largest projects which represent high-risk, high-cost options for the oil majors. They are primarily a mix of Alberta oil sands and deep water projects in the Atlantic, which would represent $91 billion of capital (over the period 2014-25). This capital could instead be returned to shareholders rather than being put at risk in projects that are already high cost and low return. Such projects have high operational gearing, putting shareholder returns at risk in a low oil price environment.

Key Questions

As well as specific questions on high cost projects and risk concentration identified for each company, investors should continue to push for disclosure on the following issues across the sector:

1. How does continuing dependence on oil fit with the imperative to tackle climate change recognised by most oil companies?

2. How would a range of oil prices impact your project economics and hence future earnings?

3. How does the current strategy of reinvesting revenues in high cost oil projects deliver shareholder value in a low demand, low price scenario?

BP

Key Points

1. BP emphasises its intended capital discipline, and expects capex to only rise marginally to 2018[1].

2. The company has further focussed on disposals, with some of the cash being returned to shareholders rather than re-invested in new projects.

3. BP's portfolio is notable amongst the majors for having relatively limited exposure to high break-even projects, and particularly a near-absence of expensive mega-projects in development.

4. This focus on quality over quantity is well-received, and we note that it has continued with the recent sale of 50% of Liberty (amongst other Alaska projects) to Hilcorp in April[2].

5. However we note BP's farm-in (announced in July 2013) to a 40% interest in the block containing Pitu[3], an ultra-deep water discovery in Brazil, which investors may want to look at given the relatively high break-even and technical risks.

6. Two oil sands projects also seem to stand out, being the Sunrise and Terre de Grace projects in Canada. They both require a market oil price in excess of $120/bbl for sanction and account for an aggregate $6.1bn in potential capex to 2025 (of which Sunrise, BP's largest high-cost project, represents $4.3bn). Although Sunrise is due to begin production later on this year, given its high-cost nature and earlier stage Terre de Glace could be a candidate to not pursue further.

Introduction

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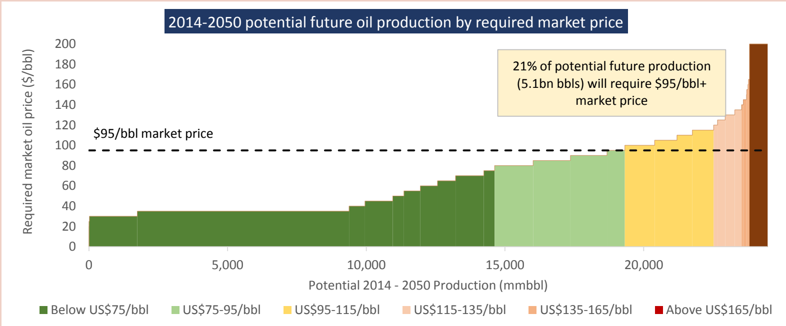
1 BP, Investor update presentation March 2014, p23. http://www.bp.com/content/dam/bp/pdf/investors/Investor_Update_script_slides_FINAL.pdf

2 BP press release, "BP Agrees to Sale of Interests in Four Alaska North Slope Assets", 22 April 2014. http://www.bp.com/en/global/corporate/press/press-releases/bp-agrees-sale-interests-alaska-north-slope.html

3 BP press release, "BP Expands Brazilian Upstream Presence, Farming-in to Five Concessions in Potiguar Basin", 15 July 2013. http://www.bp.com/en/global/corporate/press/press-releases/bp-expands-brazilian-upstream-presence.html

BP

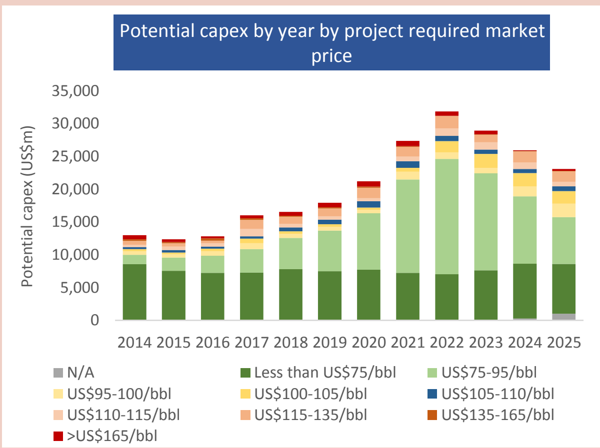
Potential future oil production



- BP's potential future project portfolio (2014-2050 production) is of an unusually low-cost nature, with 40% requiring a market oil price above $75/bbl for sanction and 21% (5.1bn bbls) above $95/bbl, the second-lowest breakeven profile amongst majors.
- BP's portfolio stands out as having a remarkable amount of very low cost potential production, with 9.4bn bbls (38% of total potential production) requiring a market price of $35/bbl or less
- In the medium term, over the next decade, only 10% of BP's production will need oil prices over $95/bbl for a commercial return (10% IRR).
- But by the end of 2025, projects requiring $95/bbl or more will have risen to 27% of the company's potential future production.

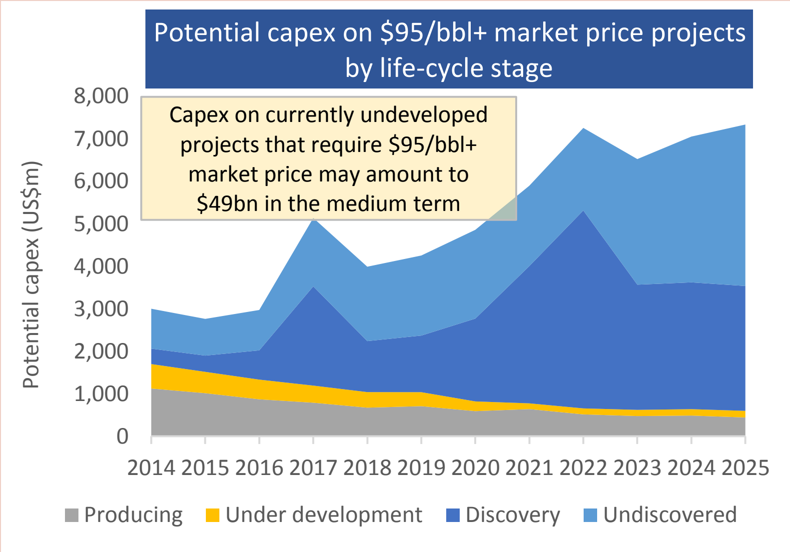
Capex

- Turning to capital spend in the nearer term, on Rystad's data, BP has potential capex of $247bn earmarked for oil projects during 2014-2025.
- Potential capex rises steadily through to 2022 at a CAGR of 11.9%, before falling off over the following years
- $61bn (25% of the total potential capital budget) is on potential projects requiring market prices of $95/bbl or more, and 62% requiring at least $75/bbl.

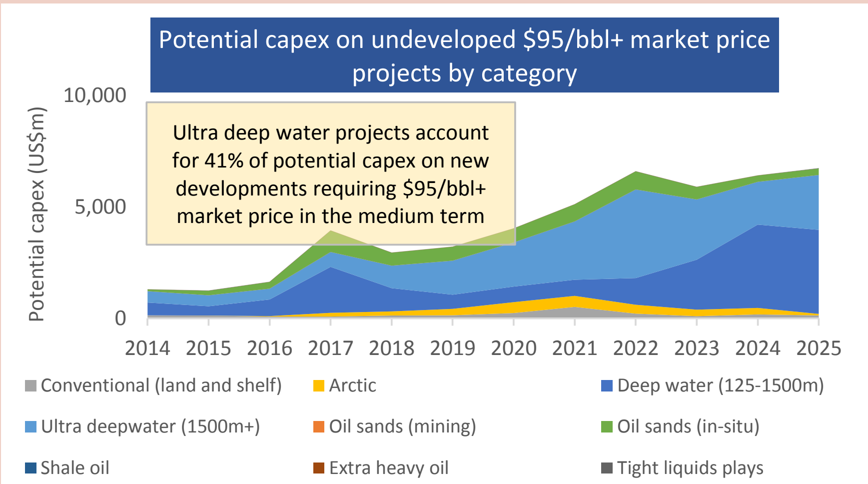


BP

- Focusing on currently undeveloped future projects, of the $61bn of capex for projects requiring a market price of $95/bbl or higher, $49bn (80%) is on projects that are yet to be developed.
- "Undeveloped" in this sense comprises fields where a discovery has been made ("discovery" in the chart opposite) and where no discovery has been made ("undiscovered")
- As high-cost, undeveloped projects, these could represent a focus for investors demanding cost savings from the company, either to be cancelled or deferred.

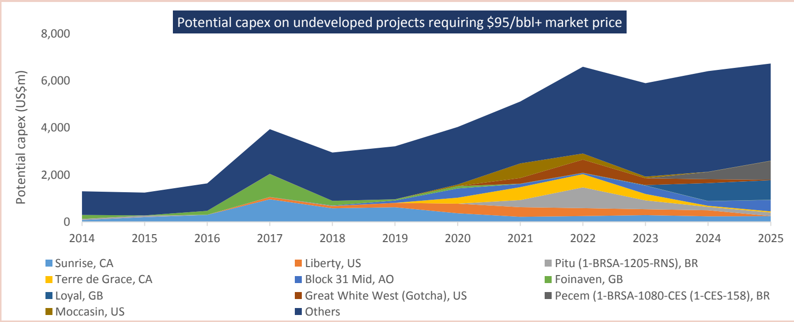


- BP's capex on high-cost projects is heavily biased towards high technical risk deep water projects; 41% of capex with market price requirements of at least $95/bbl is on ultra-deep water projects and 36% on deep water projects, in aggregate the most amongst majors.
- Just 4% of potential high-cost capex is on conventional projects (onshore and continental shelf).
- Oil sands (in-situ) and arctic projects account for 12% and 5% respectively of the potential budget.



BP

Highest risk undeveloped projects



BP's potential capex is spread over a large number of projects, with only 38% of the $49bn potential capex on higher-cost new development attributable to the 10 largest discovery stage projects. These top 10 have individual capex requirements ranging from c.$1.0bn to c.$4.3bn. The market oil prices required for sanction of these projects are shown below.

BP states that it uses a benchmark of $80/bbl in its decision making; some of the projects in the below table are presumably therefore likely to be deferred, and we would welcome declarations that this is the case.

Rank	Name	Country	Region	Category	2014-2025 capex* ($m)	% of total 2014-2025 capex (%)	% of total capex on undeveloped projects requiring $95/bbl (%)	Required market price** ($/bbl)	Status***
1	Terre de Grace, CA	Canada	Alberta, CA	Oil sands (in-situ)	1,735	1%	4%	126	Under study
2	Pitu (1-BRSA-1205-RNS), BR	Brazil	Rio Grande do Norte, BR	Ultra deepwater	1,976	1%	4%	124	Under study
3	Foinaven, GB	United Kingdom	Atlantic Ocean, GB	Deep water	1,697	1%	3%	122	Under study
4	Loyal, GB	United Kingdom	Atlantic Ocean, GB	Deep water	1,625	1%	3%	121 - 127	Ongoing
5	Sunrise, CA	Canada	Alberta, CA	Oil sands (in-situ)	4,343	2%	9%	113 - 134	Under development
6	Liberty, US	United States	Alaska, US	Arctic	2,048	1%	4%	109	Under study
7	Great White West (Gotcha), US	United States	Gulf of Mexico deepwater, US	Ultra deepwater	1,282	1%	3%	102	Not disclosed
8	Block 31 Mid, AO	Angola	Atlantic Ocean, AO	Ultra deepwater	1,729	1%	4%	101 - 128	Not disclosed
9	Pecem (1-BRSA-1080-CES (1-CES-158), BR	Brazil	Ceara, BR	Ultra deepwater	1,114	0%	2%	99	Under study
10	Moccasin, US	United States	Gulf of Mexico deepwater, US	Ultra deepwater	1,039	0%	2%	99	Under study
-	Total Top 10 Discoveries	-	-	-	18,587	8%	38%	-	-
-	Other projects	-		-	30,516	12%	62%	-	-
-	Total	-	-	-	49,103	20%	100%	-	-

** company share of capex requiring $95/bbl+ shown only*
*** market price required for sanction includes $15/bbl contingency on top of project breakeven price*
**** as understood based on company disclosures*

Questions Arising

1. What is the process for reviewing the 35% of potential production which requires more than the company's benchmark price of $80/bbl – is this the right proportion of options to have above this level?

2. How will the company ensure cost control and risk management across such a large number of projects?

3. Does the emphasis on ultra-deep water and deep water projects leave the company more exposed to technical risk and cost inflation?

Chevron Corporation

Key Points

1. Chevron has stated that 2013 will represent a peak year in capex due to volume of acquisitions, with a reduction in 2014 and flattening in 2015 and 2016[1].

2. This reflects a slight reduction in LNG spending but an increase on shale/tight liquid projects. Underlying upstream spending will actually increase from 2013 to 2014 (forecasts not disclosed for 2015-2016). Given the delays and cost increases experienced with the Gorgon LNG project[2] so far, it would not be a surprise for some capex creep to be realised compared to Chevron's projections.

3. We note that work on the Pierre River has been halted to focus on "more imminent" growth opportunities[3]. The capital intensity of Pierre River and its high break-even made it a project likely to destroy value in a low carbon environment. Expansions to the Athabasca Oil Sands project, although having a lower market oil price required for sanction, may also be considered high risk by investors.

4. The undeveloped project with the largest share of potential capex requiring $95/bbl for sanction is the offshore Amauligak project in Canada. As a deep water, arctic project, this carries significant technical and reputational risk as well as high exposure to the possibility of lower oil prices. Investors may wish to question whether this risk is desirable or appropriate to take on.

5. The Wafra EOR and Nigerian Nsiko ultra-deep water projects may also be noted by shareholders.

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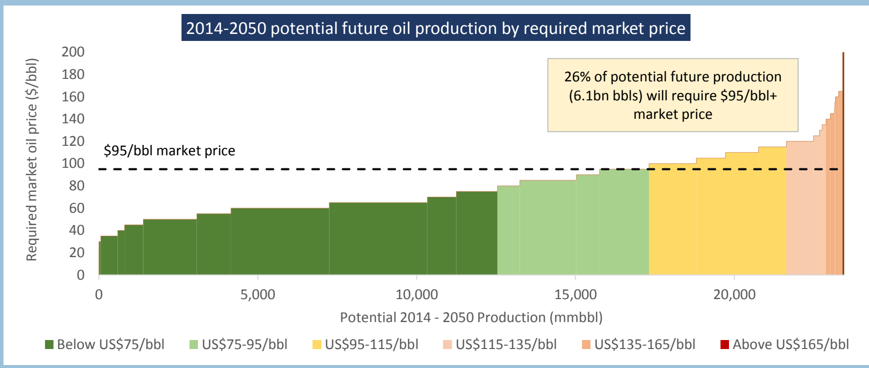
This note examines Chevron's potential future project portfolio looking at production and capex using Rystad Energy's UCube Upstream database (as at July 2014). "Capex" and "production" in this note (amongst other terms) are thus based on Rystad's analysis and expectations of the company's potential projects. Chevron's planned or realised capex and production may differ from these projections. Where possible we have sought to verify the status of the projects at the time of

1 Chevron, 2014 Security Analyst Meeting (Corporate Overview), p17
http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9MjI0MjUzfENoaWxkSUQ9LTF8VHlwZT0z&t=1
2 http://www.ft.com/cms/s/0/282d2d02-62bb-11e3-99d1-00144feabdc0.html#axzz39PgbZvdk
3 http://business.financialpost.com/2014/02/12/shell-halts-work-on-pierre-river-oil-sands-mine-in-northern-alberta/?__lsa=ab52-b2e1

Chevron Corporation

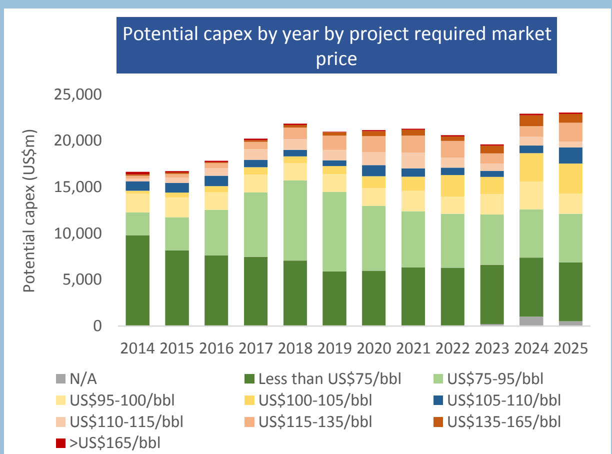
Potential future oil production



- Chevron's potential future project portfolio (2014-2050 production) is generally low cost, with 46% requiring a market price of at least $75/bbl for sanction and 26% (6.1bn barrels) at least $95/bbl.
- In the medium term, over the next decade, 14% of Chevron's production will need oil prices over $95/bbl for sanction.
- But by the end of 2025, projects requiring $95/bbl or more will have risen to 36% of the company's potential future production. This is at the upper end of the range for the majors, leaving Chevron at greater risk to its competitive position from price or cost volatility, especially in a low-carbon scenario.

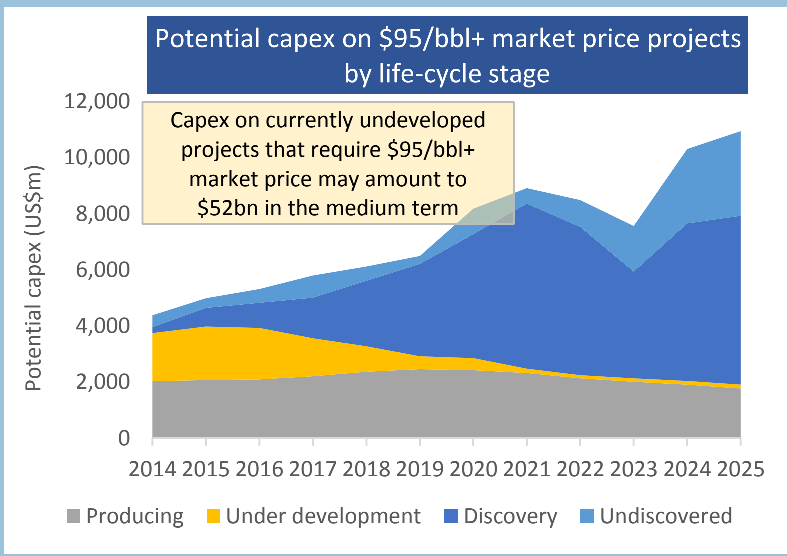
Capex

- Turning to capital spend in the nearer term, on Rystad's data, Chevron has potential capex of $242bn earmarked for oil projects during 2014-2025.
- Although it rises and falls over the period, potential capex generally trends upwards, with an overall CAGR of 3.0%
- $87bn (36% of total potential capital budget) is on potential projects requiring at least $95/bbl, and 65% requires at least $75/bbl for sanction.

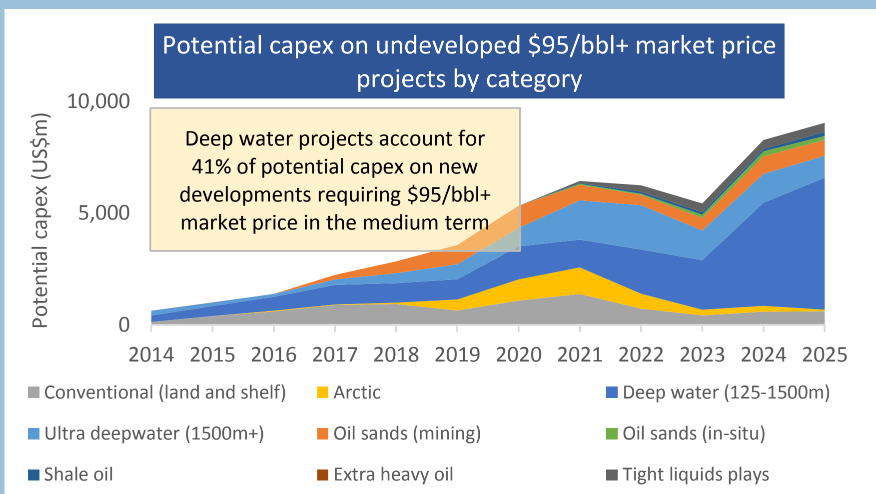


Chevron Corporation

- Focusing on currently undeveloped future projects, of the $87bn of capex for projects requiring $95/bbl or higher, $52bn (60%) is on projects that are yet to be developed.
- "Undeveloped" in this sense comprises fields where a discovery has been made ("discovery" in the chart opposite) and where no discovery has been made ("undiscovered")
- These high-cost, undeveloped projects are probably the most likely to threaten shareholder returns. Cancellation or deferral might be appropriate.

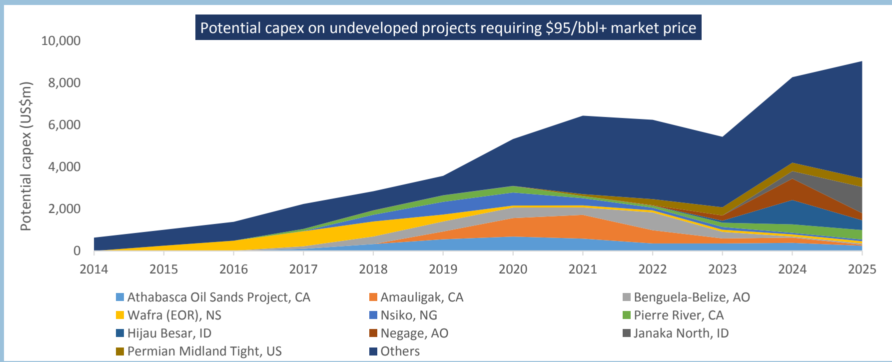


- Chevron's capex covers a fairly diverse range of potential projects, although there is a focus on deep water projects; 41% of capex for undeveloped projects requiring market prices above $95/bbl is on deep water projects, 19% on ultra-deep water projects, and 16% for conventional projects (onshore and continental shelf).
- Oil sands (mining) and Oil sands (in-situ) account for 11% and 1% respectively of the potential budget.



Chevron Corporation

Highest risk undeveloped projects



46% of the $52bn potential capex on higher-cost new development is attributable to the 10 largest discovery stage projects, which have individual capex requirements ranging from c.$1.6bn to c.$3.6bn. The market oil prices required for sanction of these projects are shown below.

Rank	Name	Country	Region	Category	2014-2025 capex* ($m)	% of total 2014-2025 capex (%)	% of total capex on undeveloped projects requiring $95/bbl (%)	Required market price** ($/bbl)	Status***
1	Pierre River, CA	Canada	Alberta, CA	Oil sands (mining)	2,181	1%	4%	158 - 162	Deferred
2	Nsiko, NG	Nigeria	Atlantic Ocean, NG	Ultra deepwater	2,304	1%	4%	120	Under study
3	Wafra (EOR), NS	Neutral Zone	Ash Sharqiyah, NS	Conventional (land/shelf)	3,081	1%	6%	115	Under development
4	Amauligak, CA	Canada	Northwest Territories, CA	Arctic	3,554	1%	7%	113	Under study
5	Hijau Besar, ID	Indonesia	Makassar Strait, ID	Deep water	1,728	1%	3%	105	Not disclosed
6	Janaka North, ID	Indonesia	Makassar Strait, ID	Deep water	1,613	1%	3%	102	Not disclosed
7	Permian Midland Tight, US	United States	Gulf Coast, US	Tight liquids plays	1,580	1%	3%	101	Ongoing
8	Benguela-Belize, AO	Angola	Atlantic Ocean, AO	Deep water	3,104	1%	6%	98 - 103	Not disclosed
9	Negage, AO	Angola	Atlantic Ocean, AO	Deep water	1,635	1%	3%	97	Not disclosed
10	Athabasca Oil Sands Project, CA	Canada	Alberta, CA	Oil sands (mining)	3,600	1%	7%	96 - 118	Ongoing
	- Total Top 10 Discoveries	-		-	24,378	10%	46%	-	-
	- Other projects	-		-	28,053	12%	54%	-	-
	- Total	-		-	52,431	22%	100%	-	-

** company share of capex requiring $95/bbl+ shown only*
*** market price required for sanction includes $15/bbl contingency on top of project breakeven price*
**** as understood based on company disclosures*

Some of the projects the above table are not yet on Chevron's list of likely developments and so may be deferred to avoid value destruction.

Questions Arising

1. What oil price does Chevron need to sustain its capex plans and dividend levels?

2. Should further oil sands/deepwater/Arctic projects from the list above be deferred?

3. Is Chevron's strategy pursuing quantity of oil rather than quality of returns?

ConocoPhillips

Key Points

1. ConocoPhillips has indicated that capex in 2017 will be approximately equal to that in 2013, although with development programme spend having increased by 60%[1] (with "major project" spend being reduced commensurately).

2. Amongst the majors, ConocoPhillips's portfolio appears to have a focus on quality over quantity; potential production is the lowest amongst the majors and the same is true of potential capex, yet amongst the majors it also has one of the lowest proportions of projects that require a market price of $95/bbl or more for sanction.

3. However, it also has the lowest proportion of projects that require below $75/bbl, meaning it has high operational gearing should prices approach the $75-95/bbl range.

4. It's portfolio of potential development projects that appear to have poor economics is dominated by the arctic Amauligak project and various Canadian in-situ oil sands projects. These increase the company's risk profile in the event that lower than anticipated demand puts pressure on prices. Deferral or cancellation might reduce the risk of poor returns threatening shareholder value.

5. Given their high breakeven levels and some of the other project deferrals in the oil sands space (such as Pierre River[2] and Joslyn).[3] Conoco's tar sand projects appear high risk, although they are at a later stage of development than some others.

Introduction

CTI has demonstrated in its research the mismatch between continuing growth in oil demand and reducing carbon emissions to limit global warming. Our most recent research with ETA to produce the carbon cost supply curve for oil indicates that there is significant potential production that could be considered both high cost and in excess of a carbon budget. We have focused our research on undeveloped projects that, allowing for a $15/bbl contingency, would need a $95/bbl market price or above to be sanctioned (i.e. a market price required for sanction of $95/bbl is equivalent to a project breakeven price of $80/bbl), as they are the marginal barrels that could be exposed to a lower demand and price scenario in the future.This note examines ConocoPhillips's potential future project portfolio looking at production and capex using Rystad Energy's UCube Upstream database (as at July 2014). "Capex" and "production" in this note (amongst other terms) are thus based on Rystad's analysis and expectations of the company's potential projects. ConocoPhillips's planned or realised capex and production may differ from these projections. Where possible we have sought to verify the status of the projects at the time of writing.

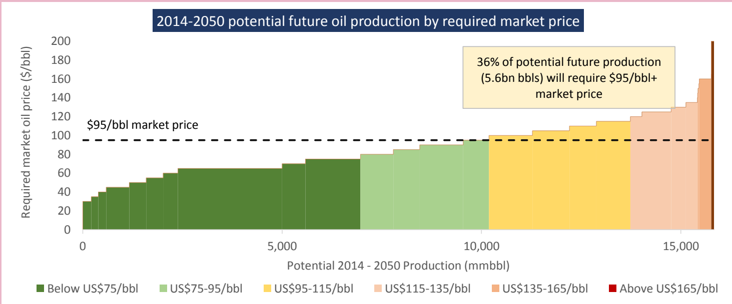
1 ConocoPhillips, Investor Update (27 May 2014), p6
http://www.conocophillips.com/investor-relations/Investor%20Presentation%20Documents/Company%20Overview%20Presentation%205-27-2014%20PDF.PDF

2 http://business.financialpost.com/2014/02/12/shell-halts-work-on-pierre-river-oil-sands-mine-in-northern-alberta/?__lsa=ab52-b2e1

3 http://business.financialpost.com/2014/05/29/total-sa-suspends-11b-joslyn-oil-sands-mine-in-alberta-lays-off-up-to-150-staff/?__lsa=ab52-b2e1

ConocoPhillips

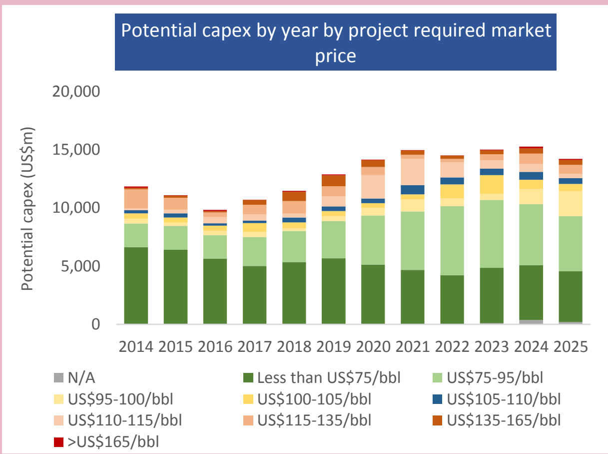
Potential future oil production



- ConocoPhillips's potential future project portfolio (2014-2050 production) has the least low-cost production, with 56% requiring a market price above $75/bbl for sanction and 36% requiring above $95/bbl. This leaves 5.6 billion barrels requiring over $95/bbl for sanction after allowing for contingencies.
- In the medium term, over the next decade, 18% of ConocoPhillips's production will need oil prices over $95/bbl for sanction.
- However, by the end of 2025, projects requiring $95/bbl or more will have risen to 45% of the company's potential future production and two-thirds will require $75/bbl. This are the highest proportions amongst majors by some margin (the next being Shell with 36% and 51% respectively), leaving ConocoPhillips at greater risk to its competitive position from price or cost volatility, especially in a low-carbon scenario.

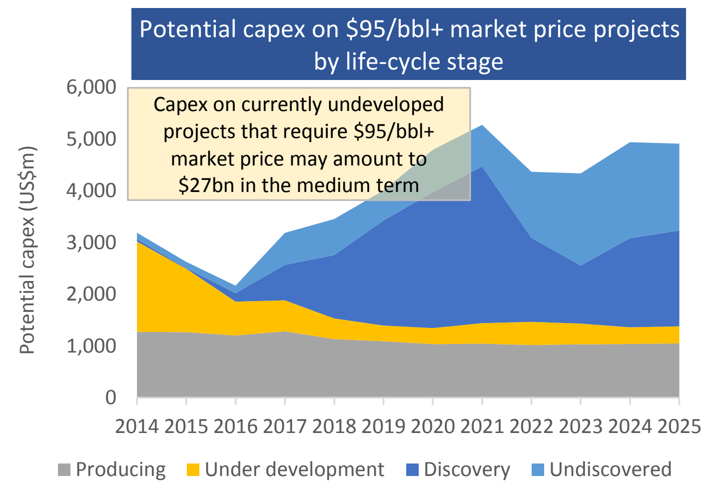
Capex

- Turning to capital spend in the nearer term, on Rystad's data, ConocoPhillips has potential capex of $156bn earmarked for oil projects during 2014-2025, the lowest of the majors.
- Potential capex falls over the coming years and remains flat through the rest of the decade, but subsequent growth results in an overall CAGR of 1.7%.
- 30% ($47bn) of ConocoPhillips's potential capital budget on projects requiring market prices of over $95/bbl, and 59% on projects requiring at least $75/bbl.

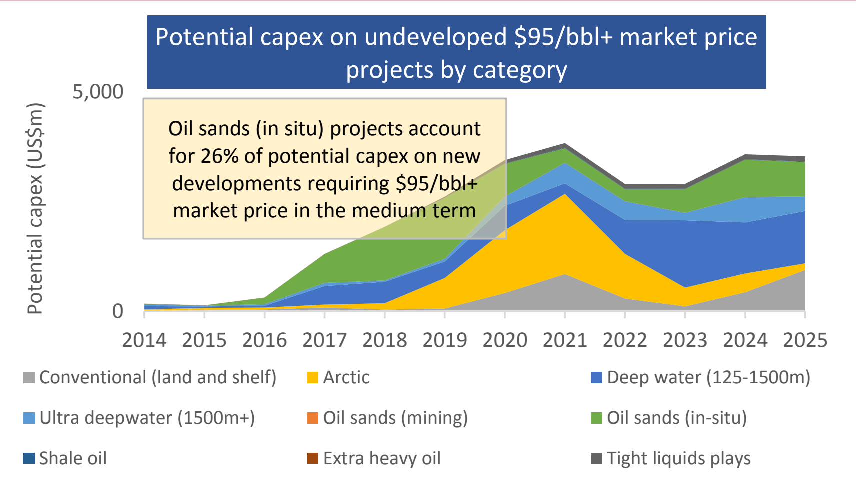


ConocoPhillips

- Focusing on currently undeveloped future projects, of the $47bn of capex for projects requiring a market price of $95/bbl or higher, $27bn (56%) is on projects that are yet to be developed.
- "Undeveloped" in this sense comprises fields where a discovery has been made ("discovery" in the chart opposite) and where no discovery has been made ("undiscovered")
- As high-cost, undeveloped projects, these could warrant attention from investors demanding cost savings from the company, either to be cancelled or deferred.

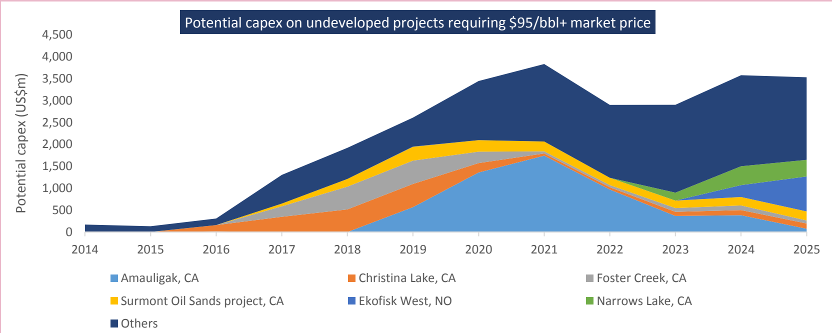


- ConocoPhillips's potential high-cost oil capex budget is unusually heavily exposed to Arctic developments which account for 24% of the budget, a significantly higher proportion than any of the other majors.
- Deep water and ultra-deep water projects account for 26% and 9% respectively.
- Oil sands (in situ) projects are also significant, accounting for 26% of the capital budget on high-breakeven new development.
- Only 12% of capital spend is on conventional (onshore and offshore continental shelf) projects.



ConocoPhillips

Highest risk undeveloped projects



ConocoPhillips has far fewer significant individual high-cost development projects than any of the other majors. 50% of the $27bn potential capex on higher-cost new development is attributable to the 6 largest discovery stage projects, which have individual capex requirements ranging from c.$1.0bn to c.$5.5bn.

Rank	Name	Country	Region	Category	2014-2025 capex* ($m)	% of total 2014-2025 capex (%)	% of total capex on undeveloped projects requiring $95/bbl (%)	Required market price** ($/bbl)	Status***
1	Foster Creek, CA	Canada	Alberta, CA	Oil sands (in-situ)	1,911	1%	7%	159	Under development/study
2	Surmont Oil Sands project, CA	Canada	Alberta, CA	Oil sands (in-situ)	1,777	1%	7%	156	Under development
3	Christina Lake, CA	Canada	Alberta, CA	Oil sands (in-situ)	2,185	1%	8%	128	Under study
4	Narrows Lake, CA	Canada	Alberta, CA	Oil sands (in-situ)	994	1%	4%	115 - 118	Approved
5	Amauligak, CA	Canada	Northwest Territories, CA	Arctic	5,481	4%	21%	113	Under study
6	Ekofisk West, NO	Norway	North Sea, NO	Conventional (land/shelf)	1,073	1%	4%	96	Not disclosed
	- Total Top 6 Discoveries	-		-	13,421	9%	50%	-	-
	- Other projects	-		-	13,216	8%	50%	-	-
	- Total	-		-	26,637	17%	100%	-	-

** company share of capex requiring $95/bbl+ shown only*
*** market price required for sanction includes $15/bbl contingency on top of project breakeven price*
**** as understood based on company disclosures*

The largest of these, Amauligak, accounts for 21% alone, which is by far the highest proportion for a single project in this category amongst the 7 majors. The market oil prices required for sanction of these projects are shown above.
Some of the projects the above table are not yet on ConocoPhillips's list of likely developments and so may be deferred to avoid value destruction.

Questions Arising

1. How will the company maintain its policy of focus on fewer projects going forward?

2. Does the company consider its oil sands interests to be economically viable without increasing oil prices?

3. Does the Amauligak Arctic project fit with ConocoPhillips's focus on shareholder value, given the likely technical risks and environmental opposition which could increase costs?

Eni

Key Points

1. Eni is currently pursuing a strategy of strict capex discipline, and its outlook assumes weak demand for oil products over 2014[1]; accordingly it plans to cut capex[2] over the next few years and has launched a buyback programme[3].

2. As its potential capex, analysed below, would rise steeply if all its projects were developed, we assume that Eni does not plan to develop many of its high cost projects. It is notable that the higher-cost projects highlighted by our analysis below are not currently on Eni's list of likely developments, and we would welcome formal declarations that they have been cancelled.

3. The investment decision on Johan Castberg (potential capex $3.0bn), an offshore project in the Norwegian Barents Sea, has been delayed to 2015[4] following adverse Norwegian tax changes, rising costs and lower resource estimates following a disappointing appraisal programme.

4. However, development or study of other high-risk projects, such as deep and ultra-deep water projects in Angola and Nigeria appears to be ongoing. These projects all have market oil price requirements we regard as high and so could be value destroying in a low demand scenario. Investors looking for capex savings may wish to question these projects in particular.

Introduction

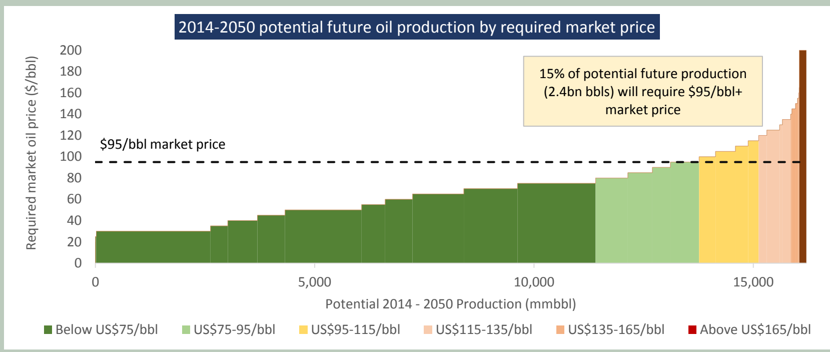
CTI has demonstrated in its research the mismatch between continuing growth in oil demand and reducing carbon emissions to limit global warming. Our most recent research with ETA to produce the carbon cost supply curve for oil indicates that there is significant potential production that could be considered both high cost and in excess of a carbon budget. We have focused our research on undeveloped projects that, allowing for a $15/bbl contingency, would need a $95/bbl market price or above to be sanctioned (i.e. a market price required for sanction of $95/bbl is equivalent to a project breakeven price of $80/bbl), as they are the marginal barrels that could be exposed to a lower demand and price scenario in the future.

This note examines Eni's potential future project portfolio looking at production and capex using Rystad Energy's UCube Upstream database (as at July 2014). "Capex" and "production" in this note (amongst other terms) are thus based on Rystad's analysis and expectations of the company's potential projects. Eni's planned or realised capex and production may differ from these projections. Where possible we have sought to verify the status of the projects at the time of writing.

1 Eni, "2013 results and 2014-2017 strategy", p4
https://www.eni.com/en_IT/attachments/investor-relations/presentation/2014/4Q-2013-strategy/2014-2017-strategy.pdf
2 Eni, "2013 results and 2014-2017 strategy", p25
https://www.eni.com/en_IT/attachments/investor-relations/presentation/2014/4Q-2013-strategy/2014-2017-strategy.pdf
3 Eni press release, "Eni starts its share buyback programme", 3 January 2014.
http://www.eni.com/en_IT/media/press-releases/2014/01/2014-01-03-eni-buyback.shtml?shortUrl=yes
4 Statoil press release, "Need more time for Castberg", 30 June 2014.
http://www.statoil.com/en/NewsAndMedia/News/2014/Pages/30Jun_JCmelding.aspx

Eni

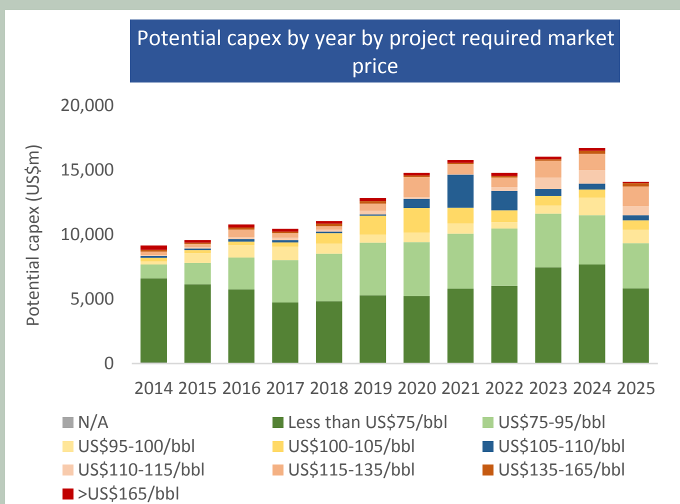
Potential future oil production



- Eni's potential future project portfolio (2014-2050 production) has the lowest-cost production profile amongst majors, with 30% requiring a market price above $75/bbl for sanction and 15% (2.4 billion barrels) requiring above $95/bbl for sanction after allowing for contingencies.
- In the medium term, over the next decade, 10% of Eni's production will need oil prices over $95/bbl for sanction.
- However, by the end of 2025, projects requiring $95/bbl or more will have risen to 18% of the company's potential future production and 34% will require $75/bbl.

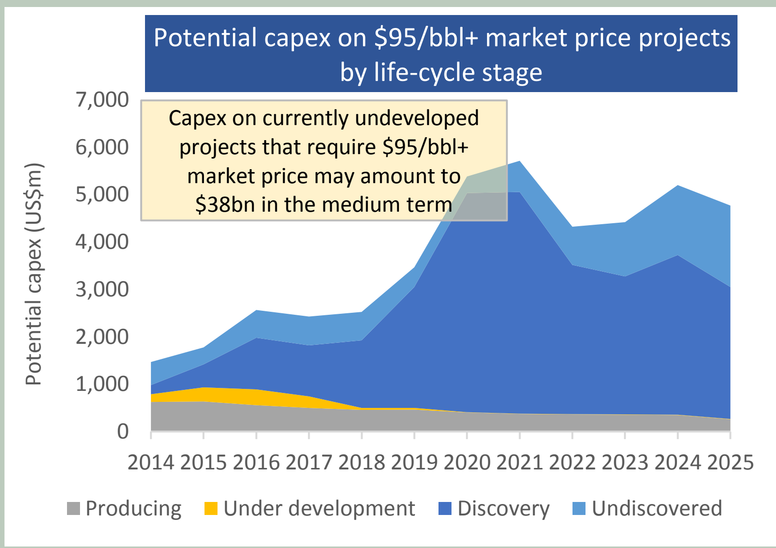
Capex

- Turning to capital spend in the nearer term, on Rystad's data, Eni has potential capex of $156bn earmarked for oil projects during 2014-2025, the lowest of the majors.
- Potential capex rises steeply into the first half of the next decade, producing an overall CAGR of 6.2% to 2024 before falling the next year.
- Projects requiring more than $95/bbl for sanction account for 28% of the potential capital budget ($44bn)

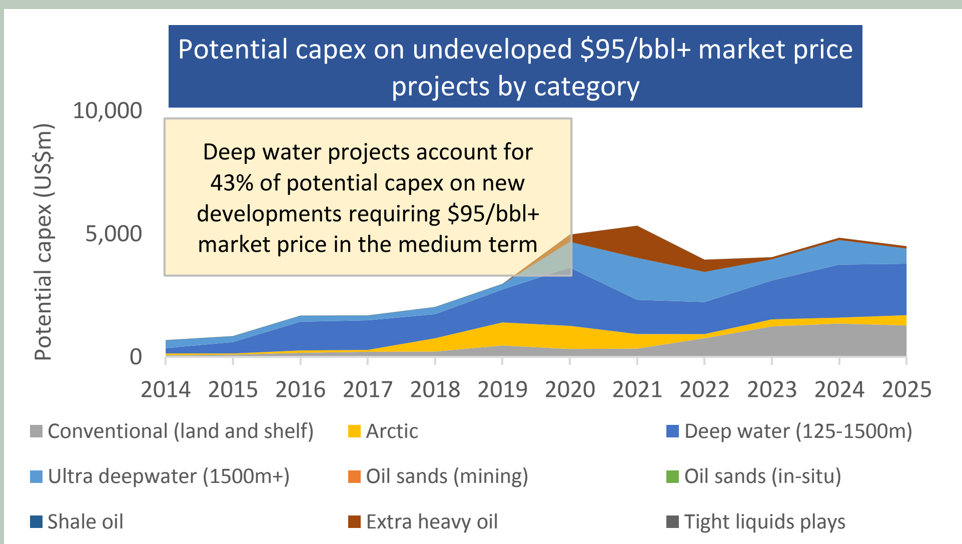


Eni

- Focusing on currently undeveloped future projects, of the $44bn of capex for projects requiring a market price of $95/bbl or higher, $38bn (85%) is on projects that are yet to be developed.
- "Undeveloped" in this sense comprises fields where a discovery has been made ("discovery" in the chart opposite) and where no discovery has been made ("undiscovered")
- As high-cost, undeveloped projects, these could represent a hit list for investors demanding cost savings from the company, either to be cancelled or deferred.

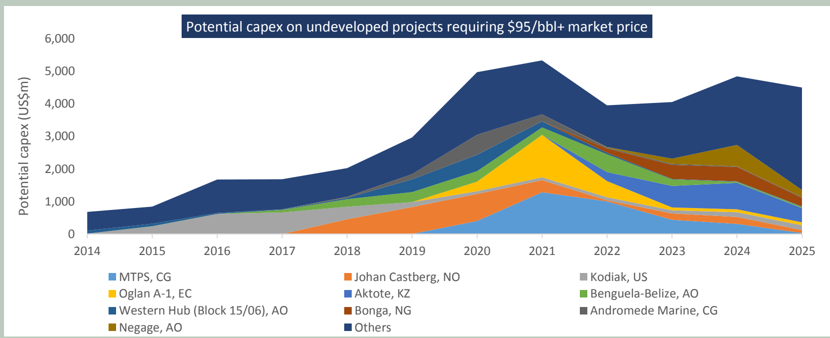


- Over half of Eni's potential capex budget on high-cost undeveloped assets is on challenging offshore projects, with deep water and ultra-deep water projects accounting for 43% and 21% respectively.
- Arctic and extra heavy oil projects are also significant, accounting for 12% and 6%.
- 17% of capital spend in this category is on conventional (onshore and offshore continental shelf) projects.



Eni

Highest risk undeveloped projects



55% of the $38bn potential capex on higher-cost new development is attributable to the 10 largest discovery stage projects, which have individual capex requirements ranging from c.$1.0bn to c.$3.5bn. The market oil prices required for sanction of these projects are shown below. Some of the projects the above table are not yet on Eni's list of likely developments and so may be deferred to avoid value destruction.

Rank	Name	Country	Region	Category	2014-2025 capex* ($m)	% of total 2014-2025 capex (%)	% of total capex on undeveloped projects requiring $95/bbl (%)	Required market price** ($/bbl)	Status***
1	Andromede Marine, CG	Congo	Atlantic Ocean, CG	Ultra deepwater	1,134	1%	3%	120	Not disclosed
2	Aktote, KZ	Kazakhstan	Atyrau, KZ	Conventional (land/shelf)	2,191	1%	6%	116	Not disclosed
3	Bonga, NG	Nigeria	Atlantic Ocean, NG	Deep water	1,270	1%	3%	115	Under developm
4	Oglan A-1, EC	Ecuador	Pastaza, EC	Extra heavy oil	2,360	2%	6%	109	Not disclosed
5	Johan Castberg, NO	Norway	Barents Sea, NO	Arctic	3,028	2%	8%	103 - 151	Under study/def
6	Benguela-Belize, AO	Angola	Atlantic Ocean, AO	Deep water	2,002	1%	5%	98 - 103	Not disclosed
7	Kodiak, US	United States	Gulf of Mexico deepwater, US	Deep water	2,695	2%	7%	97	Not disclosed
8	Western Hub (Block 15/06), AO	Angola	Atlantic Ocean, AO	Deep water	1,418	1%	4%	97 - 104	Under study
9	Negage, AO	Angola	Atlantic Ocean, AO	Deep water	1,055	1%	3%	97	Not disclosed
10	MTPS, CG	Congo	Atlantic Ocean, CG	Ultra deepwater	3,486	2%	9%	96 - 108	Not disclosed
-	Total Top 10 Discoveries	-		-	20,639	13%	55%	-	-
-	Other projects	-		-	16,911	11%	45%	-	-
-	Total	-		-	37,550	24%	100%	-	-

** company share of capex requiring $95/bbl+ shown only*
*** market price required for sanction includes $15/bbl contingency on top of project breakeven price*
**** as understood based on company disclosures*

Questions Arising

1. Why is Eni investigating such high cost projects – what are its oil price assumptions?

2. How would Eni be exposed if costs increase on its deep water projects – have they conducted a sensitivity analysis?

3. What is a sensible proportion of capex to pursue at these high breakeven levels?

ExxonMobil

Key Points

1. ExxonMobil has announced that it expects 2014-2017 capex to be significantly below that pent in 2013, on average[1]. We regard its commitment to capital discipline as sensible.

2. However, it is currently moving ahead with certain projects that could be considered to have high break evens and thus could end up wasting investment in a low demand scenario.

3. This is particularly true for its interests in various Canadian oil sands projects, which also carry additional risks relating to, for example, transport issues and their high carbon intensity.

4. Investors may wish to question whether Exxon should be pressing ahead with such relatively high-risk projects.

Introduction

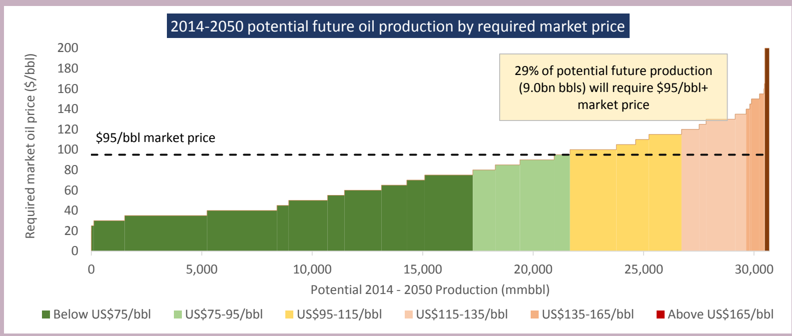
CTI has demonstrated in its research the mismatch between continuing growth in oil demand and reducing carbon emissions to limit global warming. Our most recent research with ETA to produce the carbon cost supply curve for oil indicates that there is significant potential production that could be considered both high cost and in excess of a carbon budget. We have focused our research on undeveloped projects that, allowing for a $15/bbl contingency, would need a $95/bbl market price or above to be sanctioned (i.e. a market price required for sanction of $95/bbl is equivalent to a project breakeven price of $80/bbl), as they are the marginal barrels that could be exposed to a lower demand and price scenario in the future.

This note examines ExxonMobil's potential future project portfolio looking at production and capex using Rystad Energy's UCube Upstream database (as at July 2014). "Capex" and "production" in this note (amongst other terms) are thus based on Rystad's analysis and expectations of the company's potential projects. ExxonMobil's planned or realised capex and production may differ from these projections. Where possible we have sought to verify the status of the projects at the time of writing.

1 ExxonMobil press release, "ExxonMobil to Start Production at Record Number of New Oil and Gas Projects in 2014", 5 March 2014.
http://news.exxonmobil.com/press-release/exxonmobil-start-production-record-number-new-oil-and-gas-projects-2014

ExxonMobil

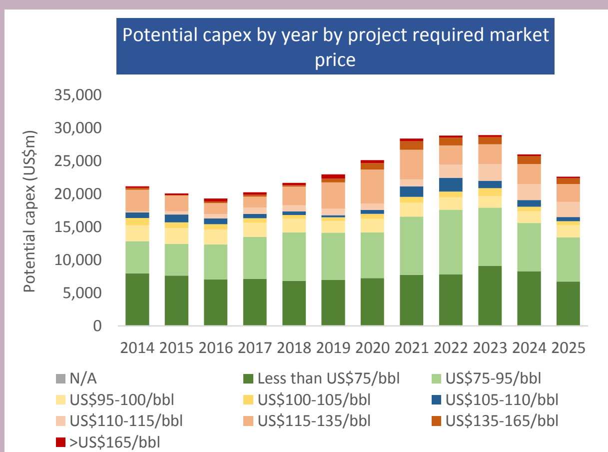
Potential future oil production



- ExxonMobil's potential future project portfolio (2014-2050 production) is mid-range compared to other majors on cost grounds, with 44% requiring a market price of at least $75/bbl for sanction including contingencies and 29% (9.0bn barrels) at least $95/bbl.
- In the medium term, over the next decade, 21% of ExxonMobil's production will need oil market prices over $95/bbl for sanction.
- But by the end of 2025, projects with a break-even price of $95/bbl or more will have risen to 35% of the company's potential future production leaving ExxonMobil at greater risk from price or cost volatility, especially in a low-carbon scenario.

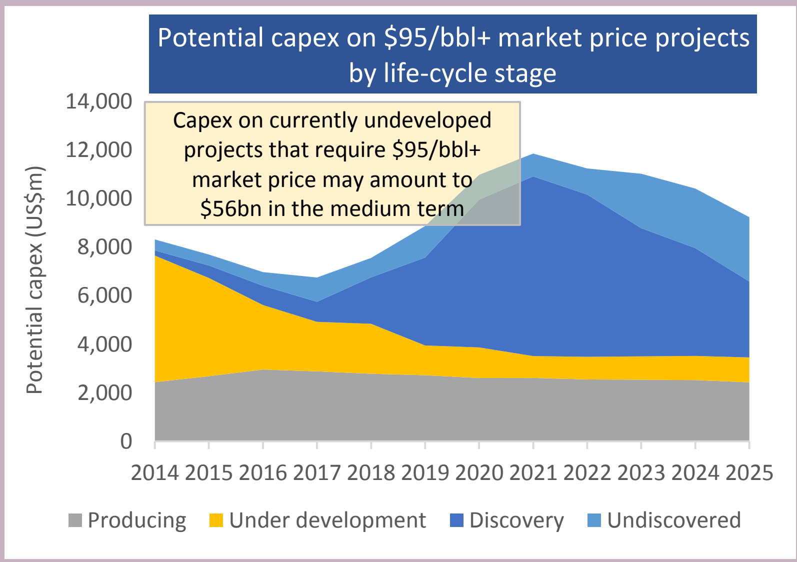
Capex

- Turning to capital spend in the nearer term, on Rystad's data, ExxonMobil has potential capex of $286bn earmarked for oil projects during 2014-2025.
- Potential capex is generally flat over the period, although with a rise in expenditure over 2021-2024 before returning to the levels seen previously
- $111bn (39%) of the potential capital budget is on projects with market price requirements over $95/bbl. 17% of capex is on projects requiring over $115/bbl for sanction.

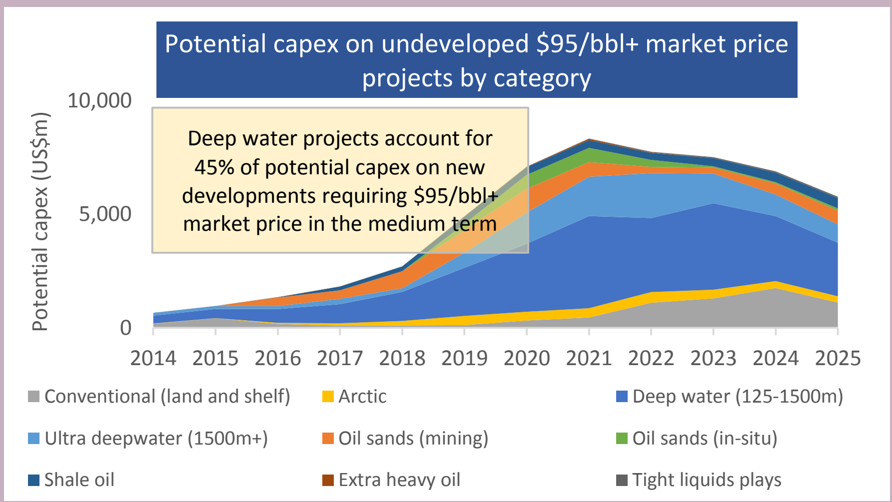


ExxonMobil

- Focusing on currently undeveloped future projects, of the $111bn of capex for projects requiring an oil price of $95/bbl or higher, $56bn (50%) is on projects that are yet to be developed.
- "Undeveloped" in this sense comprises fields where a discovery has been made ("discovery" in the chart opposite) and where no discovery has been made ("undiscovered")
- As high-cost, undeveloped projects, these could represent a hit list for investors demanding cost savings from the company, either to be cancelled or deferred.

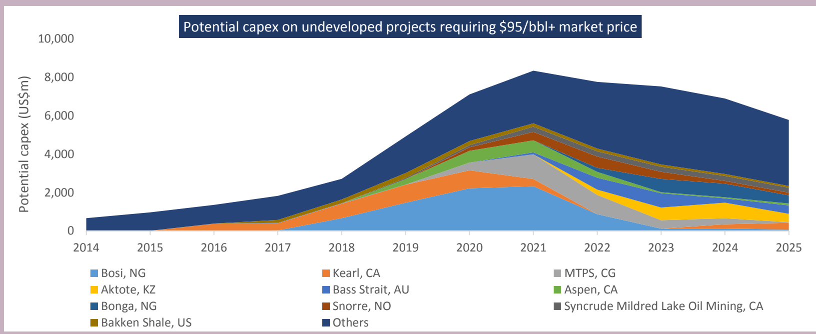


- ExxonMobil's potential capex for undeveloped projects requiring over $95/bbl covers a diverse range of potential projects, with a bias towards deep water projects; 45% of is on deep water projects and 17% on ultra-deep water projects.
- 13% is for conventional projects (onshore and continental shelf).
- Oil sands (mining) and Oil sands (in-situ) account for 10% and 4% respectively of the potential budget.



ExxonMobil

Highest risk undeveloped projects



52% of the $56bn potential capex on higher-cost new development is attributable to the 10 largest discovery stage projects, which have individual capex requirements ranging from c.$1.5bn to c.$7.9bn. The market oil prices required for sanction of these projects are shown below. Some of the projects the above table are not yet on ExxonMobil's list of likely developments and so may be deferred to avoid value destruction.

Rank	Name	Country	Region	Category	2014-2025 capex* ($m)	% of total 2014-2025 capex (%)	% of total capex on undeveloped projects requiring $95/bbl (%)	Required market price** ($/bbl)	Status***
1	Aspen, CA	Canada	Alberta, CA	Oil sands (in-situ)	2,039	1%	4%	147	Approval sought
2	Syncrude Mildred Lake Oil Mining, CA	Canada	Alberta, CA	Oil sands (mining)	1,495	1%	3%	140 - 152	Under study
3	Kearl, CA	Canada	Alberta, CA	Oil sands (mining)	4,316	2%	8%	134	Ongoing
4	Bosi, NG	Nigeria	Atlantic Ocean, NG	Deep water	7,885	3%	14%	126	Under study
5	Aktote, KZ	Kazakhstan	Atyrau, KZ	Conventional (land/shelf)	2,191	1%	4%	116	Not disclosed
6	Bonga, NG	Nigeria	Atlantic Ocean, NG	Deep water	2,032	1%	4%	115	Under development/study
7	Snorre, NO	Norway	North Sea, NO	Deep water	1,868	1%	3%	102 - 109	Under study
8	Bakken Shale, US	United States	Midwest, US	Shale Oil	1,463	1%	3%	100	Ongoing
9	Bass Strait, AU	Australia	Bass Strait, AU	Deep water	2,180	1%	4%	97 - 125	Not disclosed
10	MTPS, CG	Congo	Atlantic Ocean, CG	Ultra deepwater	3,486	1%	6%	96 - 108	Not disclosed
-	Total Top 10 Discoveries	-		-	28,956	10%	52%	-	-
-	Other projects	-		-	26,862	9%	48%	-	-
-	Total	-		-	55,818	20%	100%	-	-

** company share of capex requiring $95/bbl+ shown only*
*** market price required for sanction includes $15/bbl contingency on top of project breakeven price*
**** as understood based on company disclosures*

Questions Arising

1. Should Exxon's oil sands projects from the list above be deferred, given the high costs which are causing cancellation of other companies' projects?

2. Is the company concerned that its returns will continue to be diluted, with such a large proportion of potential capex requiring high oil prices?

3. Which projects does the company intend to delay/defer/sell in order to deliver the forecast reduction in capex?

Royal Dutch Shell

Key Points

1. Royal Dutch Shell ("Shell") has indicated that capex will fall in 2014 compared to 2013[1]. This appears sensible as its heavy spending over the past five years appears to have depressed group returns. Focusing on lower cost projects may could help reverse that deterioration.

2. We note that Shell announced in February 2014 it has decided to halt work on the Pierre River approval to focus on "more imminent" growth opportunities[2]. We believe this is sensible as the high capital intensity of Pierre River and its high break-even made it a project likely to destroy value in a low carbon environment.

3. However, several others including Carmon Creek and various deep water and ultra-deep water projects in the Atlantic are either under construction or being considered for approval. These projects all have market oil price requirements we regard as high and so could be value destroying in a low demand scenario.

4. Given that a significant proportion of Shell's potential future production requires a market price of at least $95/bbl, investors may wish to look for similar announcements on the deferral or cancellation of other projects that may be proven uneconomic in a low demand scenario.

Introduction

CTI has demonstrated in its research the mismatch between continuing growth in oil demand and reducing carbon emissions to limit global warming. Our most recent research with ETA to produce the carbon cost supply curve for oil indicates that there is significant potential production that could be considered both high cost and in excess of a carbon budget. We have focused our research on undeveloped projects that, allowing for a $15/bbl contingency, would need a $95/bbl market price or above to be sanctioned (i.e. a market price required for sanction of $95/bbl is equivalent to a project breakeven price of $80/bbl), as they are the marginal barrels that could be exposed to a lower demand and price scenario in the future.

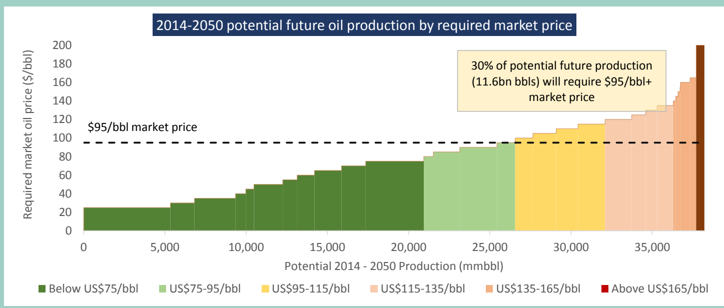
This note examines Shell's potential future project portfolio looking at production and capex using Rystad Energy's UCube Upstream database (as at July 2014). "Capex" and "production" in this note (amongst other terms) are thus based on Rystad's analysis and expectations of the company's potential projects. Shell's planned or realised capex and production may differ from these projections. Where possible we have sought to verify the status of the projects at the time of writing.

1 Shell presentation, Management Day in London, March 13, 2014, p20 http://s00.static-shell.com/content/dam/shell-new/local/corporate/corporate/downloads/pdf/investor/presentations/2014/shell-analysts-2014-management-day-london-13032014.pdf

2 http://business.financialpost.com/2014/02/12/shell-halts-work-on-pierre-river-oil-sands-mine-in-northern-alberta/?__lsa=ab52-b2e1

Royal Dutch Shell

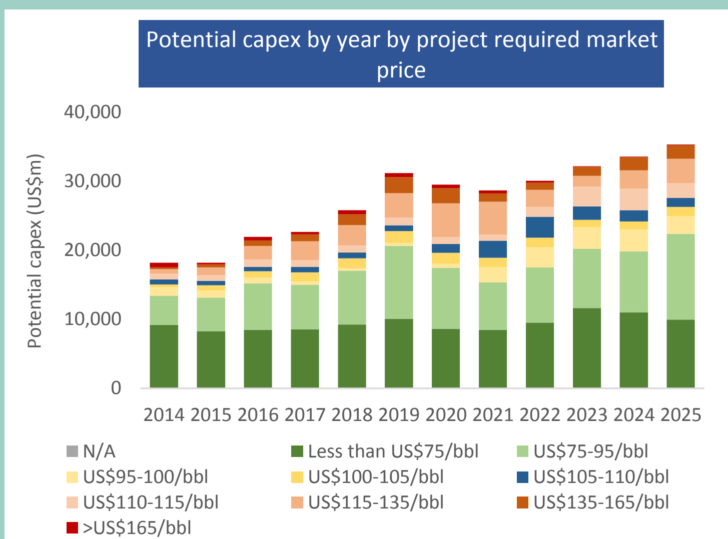
Potential future oil production



- Shell's potential future project portfolio (2014-2050 production) exposes it to material risk from lower oil prices, with 45% requiring a market oil price above $75/bbl for sanction and 30% (11.6bn barrels) above $95/bbl, one of the highest proportions amongst majors.
- In the medium term, over the next decade, 16% of Shell's production will need oil market prices over $95/bbl for a commercial return (10% IRR).
- But by the end of 2025, projects requiring a market price of $95/bbl or more will have risen to 36% of the company's potential future production leaving Shell at greater risk from price or cost volatility, especially in a low-carbon scenario.

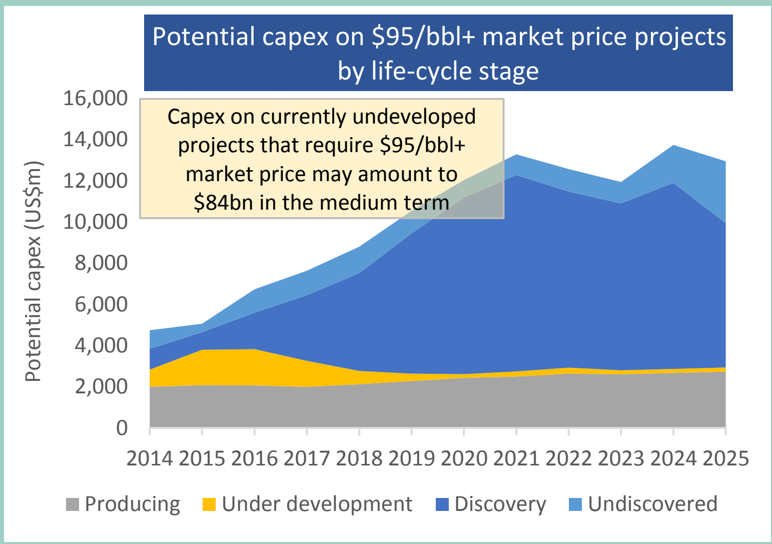
Capex

- Turning to capital spend in the nearer term, on Rystad's data, Shell has potential capex of $327bn earmarked for oil projects during 2014-2025.
- Potential capex rises fairly steadily over the period, at an overall CAGR of 6.2%, (assuming all project options are taken up). As such, Shell is likely to have to high-grade its projects to avoid a loss of capital discipline.
- $120bn (37%) of the potential capital budget is on projects requiring at least $95/bbl for sanction.

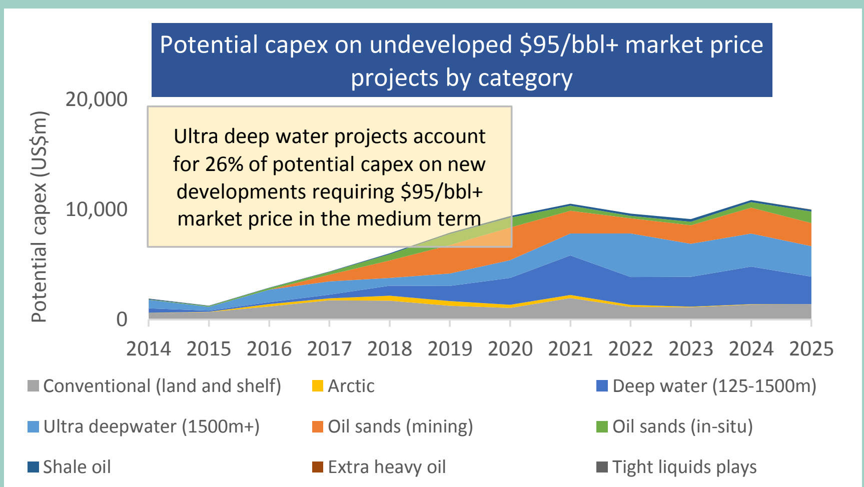


Royal Dutch Shell

- Focusing on currently undeveloped future projects, of the $120bn of capex for projects requiring a market price of $95/bbl or higher, $84bn (70%) is on projects that are yet to be developed.
- "Undeveloped" in this sense comprises fields where a discovery has been made ("discovery" in the chart opposite) and where no discovery has been made ("undiscovered")
- As high-cost, undeveloped projects, these could represent a focus for investors requiring cost savings from the company, by being either cancelled or deferred.

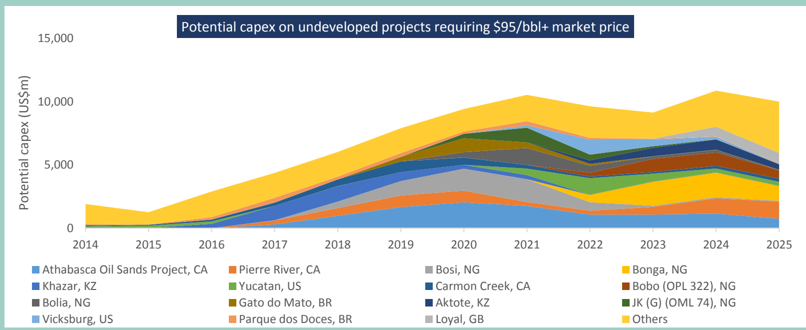


- Because of its size, Shell's capex covers a diverse range of potential projects; 24% of capex for undeveloped projects requiring at least $95/bbl is on deep water and 26% on ultra-deep water projects, with 18% for conventional projects (onshore and continental shelf).
- Oil sands (mining) and Oil sands (in-situ) account for 21% and 7% respectively of the potential budget.
- Under Rystad's classification of projects, Shell's major Arctic project – in the Chukchi Sea – is listed as a gas project by Shell, although it is likely to require oil production in order to make it economically viable. This project is not included in the Arctic numbers shown here.



Royal Dutch Shell

Highest risk undeveloped projects



69% of the $84bn potential capex on higher-cost new development attributable to the 15 largest discovery stage projects. These top 15 have individual capex requirements ranging from c.$1.9bn to c.$10.8bn. The market oil prices required for sanction of these projects are shown below.
Some of the projects the below table are not yet on Shell's list of likely developments and so may be deferred to avoid value destruction.

Rank	Name	Country	Region	Category	2014-2025 capex* ($m)	% of total 2014-2025 capex (%)	% of total capex on undeveloped projects requiring $95/bbl (%)	Required market price** ($/bbl)	Status***
1	Pierre River, CA	Canada	Alberta, CA	Oil sands (mining)	6,543	2%	8%	158 - 162	Deferred
2	Carmon Creek, CA	Canada	Alberta, CA	Oil sands (in-situ)	3,429	1%	4%	157	Approved
3	Khazar, KZ	Kazakhstan	Caspian Sea, KZ	Conventional (land/shelf)	4,142	1%	5%	129	Not disclosed
4	Bosi, NG	Nigeria	Atlantic Ocean, NG	Deep water	6,133	2%	7%	126	Under study
5	Gato do Mato, BR	Brazil	Rio de Janeiro, BR	Ultra deepwater	2,218	1%	3%	121	Under study
6	Loyal, GB	United Kingdom	Atlantic Ocean, GB	Deep water	1,625	0%	2%	121 - 127	Under study
7	Aktote, KZ	Kazakhstan	Atyrau, KZ	Conventional (land/shelf)	2,191	1%	3%	116	Not disclosed
8	Bonga, NG	Nigeria	Atlantic Ocean, NG	Deep water	5,588	2%	7%	115	Under development/study
9	Parque dos Doces, BR	Brazil	Espirito Santo, BR	Ultra deepwater	1,902	1%	2%	111 - 121	Not disclosed
10	Vicksburg, US	United States	Gulf of Mexico deepwater, US	Ultra deepwater	2,141	1%	3%	110	Under study
11	Bolia, NG	Nigeria	Atlantic Ocean, NG	Deep water	2,711	1%	3%	108	Not disclosed
12	Yucatan, US	United States	Gulf of Mexico deepwater, US	Ultra deepwater	3,586	1%	4%	99	Under study
13	Athabasca Oil Sands Project, CA	Canada	Alberta, CA	Oil sands (mining)	10,799	3%	13%	96 - 118	Ongoing
14	Bobo (OPL 322), NG	Nigeria	Atlantic Ocean, NG	Ultra deepwater	3,074	1%	4%	96	Not disclosed
15	JK (G) (OML 74), NG	Nigeria	Atlantic Ocean, NG	Conventional (land/shelf)	2,141	1%	3%	96	Not disclosed
-	Total Top 15 Discoveries	-		-	58,223	18%	69%	-	-
-	Other projects	-		-	25,798	8%	31%	-	-
-	Total	-		-	84,021	26%	100%	-	-

** company share of capex requiring $95/bbl+ shown only*
*** market price required for sanction includes $15/bbl contingency on top of project breakeven price*
**** as understood based on company disclosures*

Questions Arising

1. Should Shell further reduce its oil sands exposure, following the shelving of Pierre River?

2. Will the deep water/ultra-deep water projects being considered by Shell be good value if cost increase and oil prices don't rise –can they provide a sensitivity analysis?

3. Does it makes sense to continue to waste capital on the Chuckchi Sea interest?

Total

Key Points

1. Total has stated that 2013 should be its peak year in terms of capex, with falls from 2014[1], an approach which has been praised by equity analysts and rewarded with strong share price performance.

2. This implies that Total will defer or cancel some of the projects which form its relatively large exposure to high cost developments, which may be regarded as sensible by investors.

3. Earlier this year Total announced that the Joslyn oil sands project would be delayed[2] due to its high cost, a move which will save Total significant capex and seems to be logical given the project's high capital intensity and high break even requirements.

4. The Surmont oil sands project (operated by ConocoPhillips) is at a later stage than Joslyn, and Total is pressing ahead with phase 2 development which is scheduled for start-up in 2015. While the Surmont field is more favourable, it is still high cost, and investors should ask whether the company would now be off better cancelling the phase 2 development.

5. Investors may wish to look for signs that Total is willing to extend this discipline to other projects in its portfolio which seem to suffer from weak economics, most notably the deep water Julong East and Jagus East projects in Brunei and ultra-deep water Block CI-514 in Cote d'Ivoire.

Introduction

CTI has demonstrated in its research the mismatch between continuing growth in oil demand and reducing carbon emissions to limit global warming. Our most recent research with ETA to produce the carbon cost supply curve for oil indicates that there is significant potential production that could be considered both high cost and in excess of a carbon budget. We have focused our research on undeveloped projects that, allowing for a $15/bbl contingency, would need a $95/bbl market price or above to be sanctioned (i.e. a market price required for sanction of $95/bbl is equivalent to a project breakeven price of $80/bbl), as they are the marginal barrels that could be exposed to a lower demand and price scenario in the future.

This note examines Total's potential future project portfolio looking at production and capex using Rystad Energy's UCube Upstream database (as at May 2014). "Capex" and "production" in this note (amongst other terms) are thus based on Rystad's analysis and expectations of the company's potential projects. Total's planned or realised capex and production may differ from these projections.

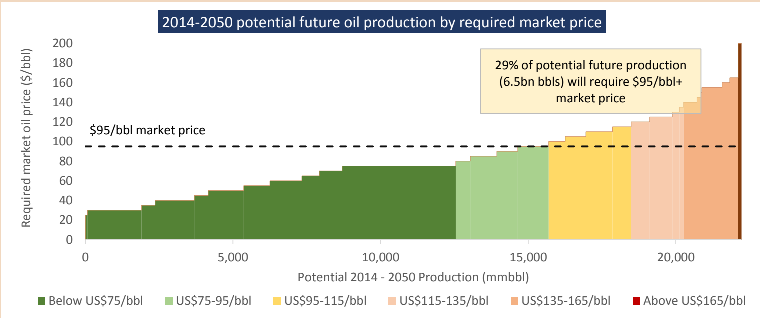
Where possible we have sought to verify the status of the projects at the time of writing.

1 http://www.ft.com/cms/s/0/d3d1c5d2-4533-11e3-b98b-00144feabdc0.html#axzz39PgbZvdk

2 http://business.financialpost.com/2014/05/29/total-sa-suspends-11b-joslyn-oil-sands-mine-in-alberta-lays-off-up-to-150-staff/?__lsa=ab52-b2e1

Total

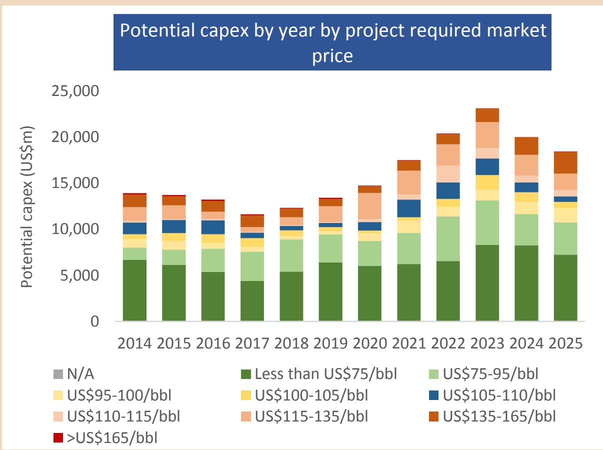
Potential future oil production



- Total's potential future project portfolio (2014-2050 production) is of a higher-cost profile than most of its peers, with 44% requiring a market oil price above $75/bbl for sanction and 29% (6.5bn barrels) above $95/bbl.
- In the nearer term, over the next decade, 20% of Total's production will need oil prices over $95/bbl for a commercial return (10% internal rate of return). As we see in the following analysis, this is equivalent to $78 billion capital investment, representing a substantial risk from lower oil prices
- By the end of 2025, projects requiring a market price of $95/bbl or more will have risen to 34% of the company's potential future production.

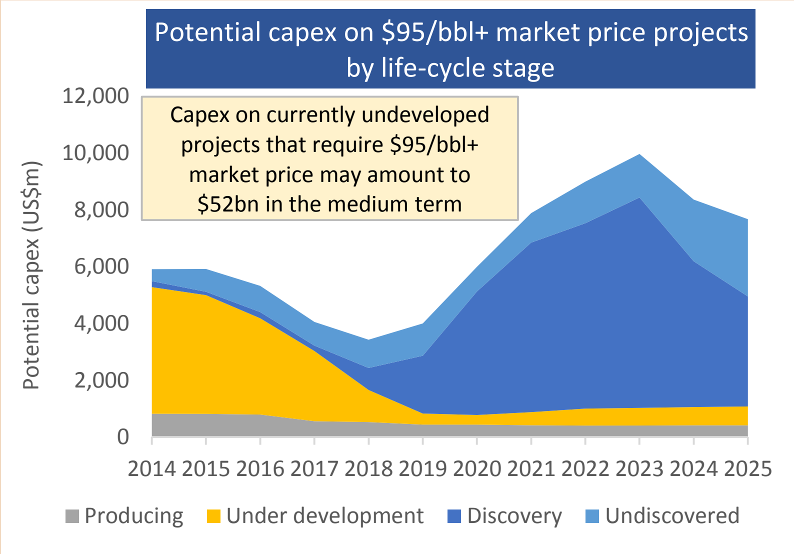
Capex

- Turning to capital spend in the nearer term, on Rystad's data, Total has potential capex of $192bn earmarked for oil projects during 2014-2025.
- Potential capex shows moderate increases through to the end of the decade, before peaking sharply in 2023 and falling off over the following years.
- $78bn (40%) of the potential capital budget is on projects requiring over $95/bbl. Again, this is high relative to competitors, and 20% of capex is on projects requiring over $115/bbl for sanction.

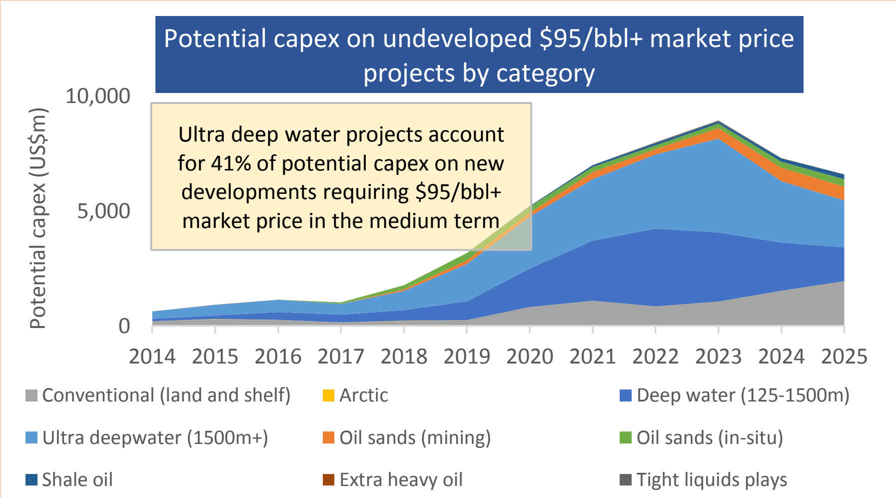


Total

•	Focusing on currently undeveloped future projects, of the $78bn of capex for projects requiring $95/bbl or higher, $52bn (67%) is on projects that are yet to be developed.
•	"Undeveloped" in this sense comprises fields where a discovery has been made ("discovery" in the chart below) and where no discovery has been made ("undiscovered")
•	As high-cost, undeveloped projects, these could represent a hit list for investors demanding cost savings from the company, either to be cancelled or deferred.

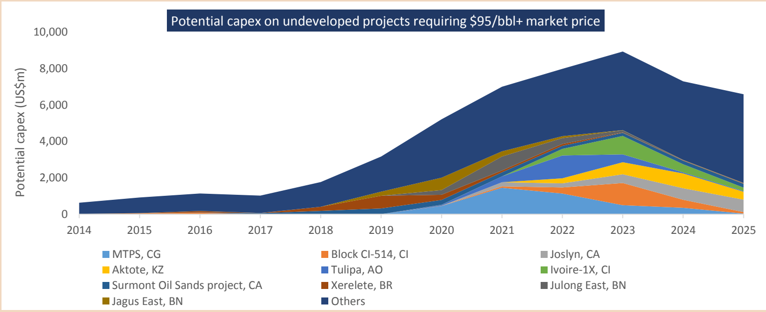


•	Total's capex on high-cost projects is heavily biased towards high technical risk deep water projects; 41% of capex for undeveloped projects requiring over $95/bbl is on ultra-deep water projects and 32% on deep water projects.
•	Just 17% of potential capex is on conventional projects (onshore and continental shelf).
•	Oil sands (mining) and oil sands (in-situ) projects account for 5% and 4% respectively of the potential budget.



Total

Highest risk undeveloped projects



41% of the $51bn potential capex on higher-cost new development is attributable to the 10 largest discovery stage projects, which have individual capex requirements ranging from c.$1.3bn to c.$4.0bn. The market oil prices required for sanction of these projects are shown below.

Rank	Name	Country	Region	Category	2014-2025 capex* ($m)	% of total 2014-2025 capex (%)	% of total capex on undeveloped projects requiring $95/bbl (%)	Required market price** ($/bbl)	Status***
1	Joslyn, CA	Canada	Alberta, CA	Oil sands (in-situ)	2,253	1%	4%	157 - 161	Deferred
2	Surmont Oil Sands project, CA	Canada	Alberta, CA	Oil sands (in-situ)	1,777	1%	3%	156	Under development
3	Block CI-514, CI	Cote d'Ivoire	Atlantic Ocean, CI	Ultra deepwater	2,312	1%	4%	127	Under study
4	Julong East, BN	Brunei	Brunei, BN	Deep water	1,500	1%	3%	124	Under study
5	Jagus East, BN	Brunei	Brunei, BN	Deep water	1,343	1%	3%	120	Under study
6	Aktote, KZ	Kazakhstan	Atyrau, KZ	Conventional (land/shelf)	2,191	1%	4%	116	Not disclosed
7	Xerelete, BR	Brazil	Rio de Janeiro, BR	Ultra deepwater	1,551	1%	3%	116	Under study
8	Tulipa, AO	Angola	Atlantic Ocean, AO	Deep water	2,161	1%	4%	111	Not disclosed
9	Ivoire-1X, CI	Cote d'Ivoire	Atlantic Ocean, CI	Ultra deepwater	2,022	1%	4%	109	Under study
10	MTPS, CG	Congo	Atlantic Ocean, CG	Ultra deepwater	3,951	2%	8%	96 - 108	Not disclosed
	- Total Top 10 Discoveries	-		-	21,061	11%	41%	-	-
	- Other projects	-		-	30,643	16%	59%	-	-
	- Total	-		-	51,704	27%	100%	-	-

** company share of capex requiring $95/bbl+ shown only*
*** market price required for sanction includes $15/bbl contingency on top of project breakeven price*
**** as understood based on company disclosures*

Some of the projects the above table are not yet on Total's list of likely developments and so may be deferred to avoid value destruction.

Questions Arising

1. Total has already reduced its exposure to oil sands – will it exit further projects, eg Surmont?

2. Total is becoming a deepwater specialist – does this expose it to cost inflation and technical risk concentration?

3. Is Total comfortable with having such a high proportion of future project options requiring oil prices above $95/bbl?

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