Carbon Tracker Initiative

Carbon supply cost curves:
Evaluating financial risk to oil capital expenditures

About Carbon Tracker

The Carbon Tracker Initiative (CTI) is a team of financial specialists making climate risk real 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.

This latest research series aims to explore in more detail the capital expenditure plans of the coal, oil and gas sectors.

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Acknowledgments

This paper is a summary which draws on research conducted in partnership with Energy Transition Advisors, (ETA). The full background papers produced by ETA are available on our website. ETA is led by Mark Fulton, who was supported by analysts Reid Capalino and Mark Andrich on the analysis, advised by Paul Spedding. James Leaton, Luke Sussams and Margherita Gagliardi contributed from CTI.

The underlying analysis is based on data licensed from the UCube database of Rystad Energy. Rystad is an independent oil and gas consulting services and business intelligence data firm, who provide data to the IEA and industry. Rystad analysts reviewed ETA's data manipulation to ensure data integrity was intact after filtering it by different variables (eg price band, province, company).

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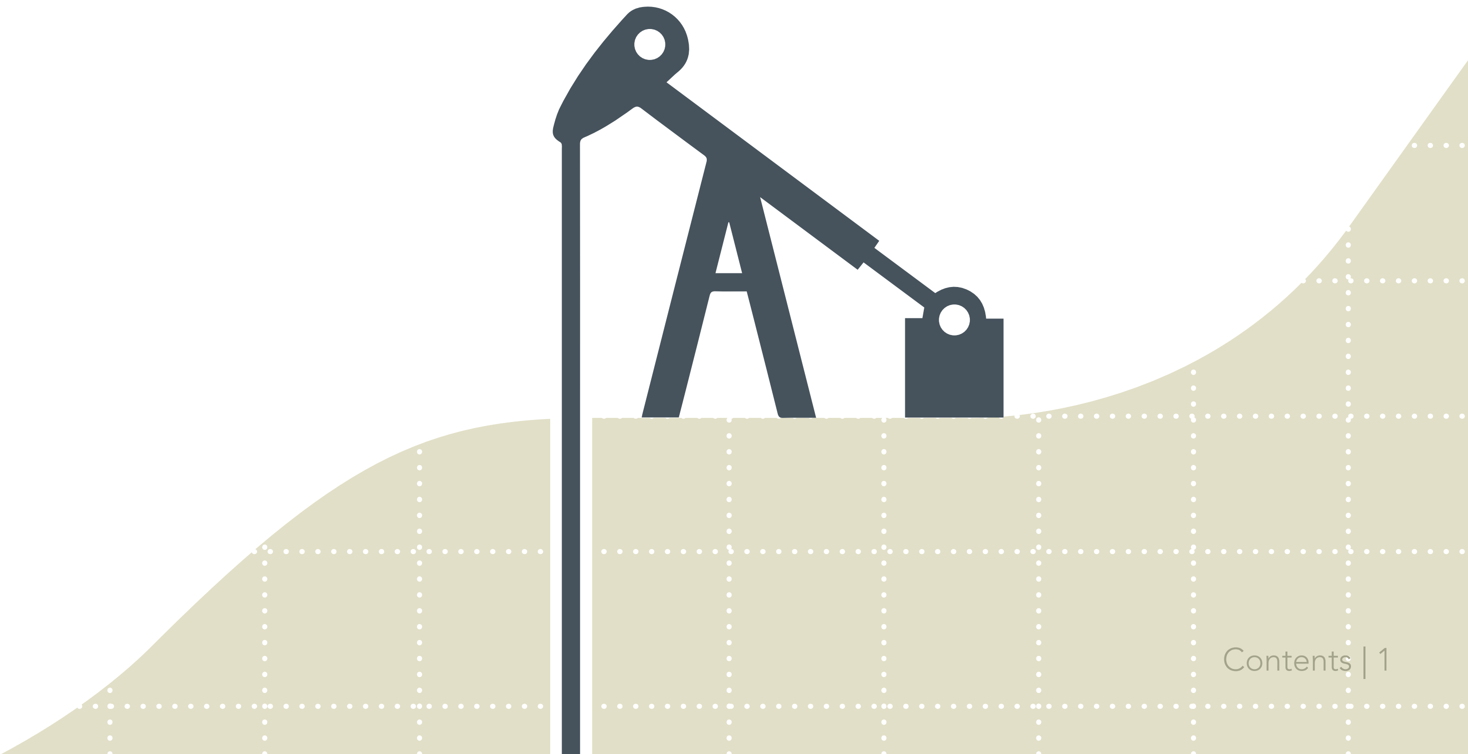


Executive Summary

Challenge demand assumptions

Conducting risk analysis to understand the implications of lower demand, price and emissions scenarios needs to be an open process. These stress tests can inform investor understanding and engagement on capex plans. Demand may be affected by a range of factors including supply costs, air quality standards, technological advances and carbon regulation.

Understand exposure on the carbon supply cost curve

Investors can consider a range of demand scenarios and then determine which price bands of production cost they think are at risk. This oil price sensitivity is an important proxy for how well a company can adapt to a low carbon future.

The private sector plays a key role

Listed companies have more exposure to potential production than national oil companies, especially as you go up the cost curve. This shows how important the private sector will be in determining how far up the cost curve we go, and what emissions we produce. Differentiating on production costs paints a very different picture to just looking at overall statistics on reserves and resources ownership.

Majors can enhance value

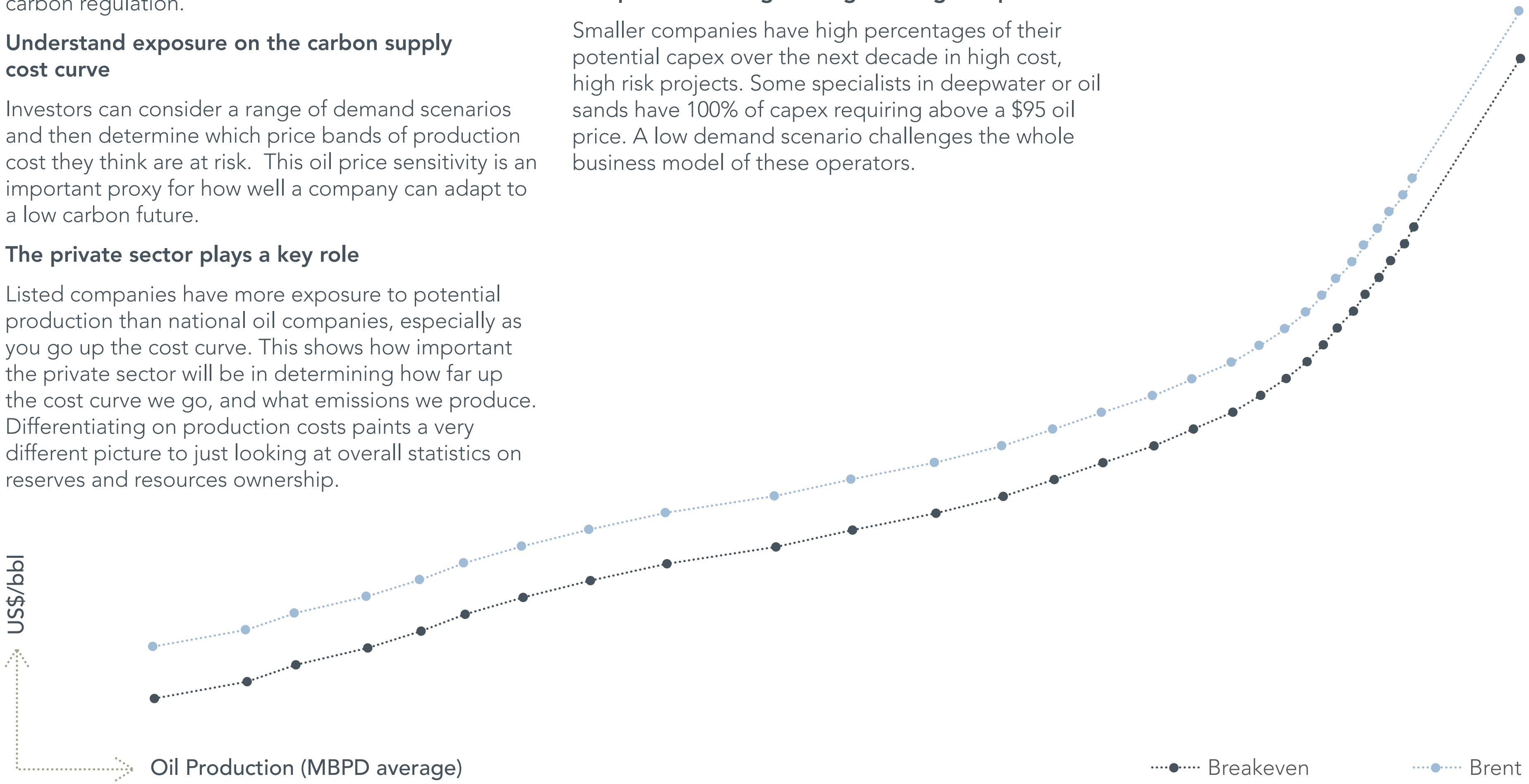
The majors have large interests across the cost curve, reflecting the sheer scale of their interests, and the desire to be involved in any large developments. Reducing high cost options may be viewed favourably by the market as a way of cutting capex and maintaining dividends.

Independents are gambling on a high oil price

Smaller companies have high percentages of their potential capex over the next decade in high cost, high risk projects. Some specialists in deepwater or oil sands have 100% of capex requiring above a $95 oil price. A low demand scenario challenges the whole business model of these operators.

Oil sands, Arctic and Deepwater

There is an estimated $1.1trillion of capex earmarked for high cost oil projects needing a market price of over $95 out to 2025. This is largely made up of Deepwater, Arctic, Oil sands and other unconventionals. This should be the start point for investors seeking to reduce their exposure to the high end of the cost curve.



Recommendations for investors

Given there is $1.1trillion of capex at stake for the private oil sector over the next decade, this needs to be a priority for stewards of capital. We would suggest the following for asset owners and managers to consider:

1. Understand the exposure of your portfolio/fund to the upper end of the carbon cost curve, and articulate how this risk is being managed.
2. Identify the companies with the majority of capex earmarked for high cost projects.
3. Focus engagement on projects requiring $95/bbl market prices as a starting point.
4. Set thresholds for exposure to projects at the high end of the cost curve for portfolio companies to adhere to.
5. Make it known to company management that you are seeking value not volume.
6. Ensure remuneration policy at companies is consistent with shareholder return objectives not just rewarding reserves replacement or spending capital.
7. Require improved disclosure of demand and price assumptions underpinning capex strategy.
8. Support transparency of company exposure to the cost curve and impairment trigger points, eg through annual publication of sensitivity analysis/ stress tests to oil price.

Foreword

CTI's research has created a new debate around climate change and investment. This report takes CTI into the territory of analytics. Numbers are the bedrock of financial markets and it is the numbers that allow you to move from the general to the specific in the investment world.

Our mission is to mobilise financial experts to make carbon investment risk visible in the capital markets today. Our work to date has started this process by translating key aspects of the climate science, the carbon budget, into the language of the financial markets. We have brought together a range of professionals from accountants to bankers to policymakers to lawyers to actuaries to understand what this means for the capital markets in the future.

CTI started this journey by considering the stocks of carbon in coal, oil and gas and comparing them to the carbon budget necessary to keep average global temperature increase below 2°C. Our earlier work in 2011 demonstrated the concept of 'unburnable carbon' and then in 2013 we highlighted the potential for wasted capital. Building on this previous work, we now take this to the granular level. We look specifically at individual projects to see if we can identify where such wasted capital is most likely to sit.

This report marks the start of a new generation of CTI research, CTI 2.0, delivering a fresh look at energy economics, starting with the oil markets. It takes a closer look into how carbon constraints intersect with the economics of fossil fuels. This report is the first of three reports where we will look in turn at oil, coal and gas. For the purposes of this report we have assumed that oil would have a 40% share of a global carbon budget. This does of course raise interesting questions around other scenarios, where oil or gas might have a larger share of the budget at the expense of coal for example.

Our analysis follows on from a first round of engagement by investors with the oil majors. The responses have made it clear that the incumbents have done the maths, but don't all believe the answer. This demonstrates progress already, in that this debate is now being had in the public domain, rather than within corporate walls.

Our analysis also shows that if demand for oil is not substantially reduced we are clearly heading for a level of warming far in excess of 2°C. Which reveals that there is no free lunch here for investors. Either policy and technological tipping points will reduce demand in line with our analysis or we will face levels of warming described as catastrophic by many.

We have developed a carbon supply cost curve and introduced a tool asset owners can use to differentiate between different oil investments within companies portfolios, identifying the most climate exposed oil. Our analysis starkly reveals those oil projects which are financially risky in any event. Were these risky and marginal projects to be subjected to other risk factors they could begin to look very unattractive to shareholders.

There is a realisation that ignoring climate risk and hoping it will go away is no longer an acceptable risk management strategy for investment institutions. Pension funds are under increasing pressure to articulate how they are addressing the need to both mitigate emissions and adapt to changing climates and markets.

This does not need to be a negative issue for investors. As active stewards of capital they can, using tools such as the carbon supply cost curve, ensure that value is maximised, either through redeployment of capital within companies, or by returning the capital to shareholders. There is clear alignment between high cost and excess carbon through the cost curve. This analysis serves as a reminder to investors to ensure company strategy is aligned with their best long-term interests.

If we are to prevent wasted capital, value needs to win over volume, which means staying at the low end of the cost curve.

Anthony Hobley

CEO, The Carbon Tracker Initiative
May 2014

1. Introduction

Investors engaging

Following our Unburnable Carbon 2013 analysis on wasted capital and stranded assets, there has been growing interest amongst investors in how to manage these risks. It led to questions from investors around which are the most likely investments to be at risk of becoming non-economic, and, who the winners and losers are likely to be as a result. This has developed into a number of engagement activities around the world to improve understanding of company exposure to higher risk fossil fuel based activities.

For example we have worked with CERES to engage 45 of the largest global companies. This has seen a high level of response, and emerging disclosures in annual reports. In order to further the debate CTI will continue to provide more information to investors. This will help the financial system understand the global picture until corporate information is more illuminating and commonplace.

A focus on capital discipline is therefore seen as prudent by many sector analysts.

To spend or not to spend

There is a strong debate in the market at present around the ability of oil companies to maintain both capital expenditure and dividends. Companies will not be able to continue increasing capital expenditure without rising oil prices. A focus on capital discipline is therefore seen as prudent by many sector analysts.

This analysis contributes further to that conversation, highlighting places where high carbon and high risk do not make economic sense. These investments would appear prime candidates for cancellation, especially given that they would also take our civilisation towards dangerous levels of climate change.

Risk factors

We see a number of risks factors which should lead shareholders to question the financial viability of projects. The starting point is pure cost - the breakeven oil price required by the project. It is standard practice for oil companies to run internal sensitivity analysis on their projects against oil prices. We believe it is time the findings of this analysis were shared and debated, before capital is deployed as a bet on future high oil prices.

Companies are also increasing their exposure to unconventional types of hydrocarbon and physically challenging environments. This includes shale oil, oil sands, ultra deepwater and the Arctic. The technical risk can increase costs, whilst the industry also faces legal and regulatory challenges as they seek to enter these frontier areas.

Creating value for shareholders

CTI is conducting this analysis to demonstrate that if oil companies are to create optimum value for shareholders they need to focus on doing lower cost, lower risk projects which give better returns. At present this approach is compromised by the drive to replace reserves at any cost, which could leave companies exposed to oil price shifts.

Some oil companies are already starting to move towards this model, and therefore will have a strong story to tell their shareholders about how they are spending capital wisely. Active shareholders need to ensure that they are redirecting companies which are not on a suitable trajectory. Capital sanctioned now will deliver production for 2020 and beyond, which could enter a very different market and operating context.

As stewards of capital, we believe shareholders should ensure that performance metrics driving company management are aligned with creating shareholder value. Our analysis demonstrates that a blind pursuit of reserves replacement at all costs, or a focus on high levels of expenditure, regardless of returns, could go against improving shareholder returns. Investors have an opportunity to vote on remuneration policy each year. The compensation incentives of oil companies should be reviewed to prevent wasted capital.

2. Demand, price and capex

Demand scenarios

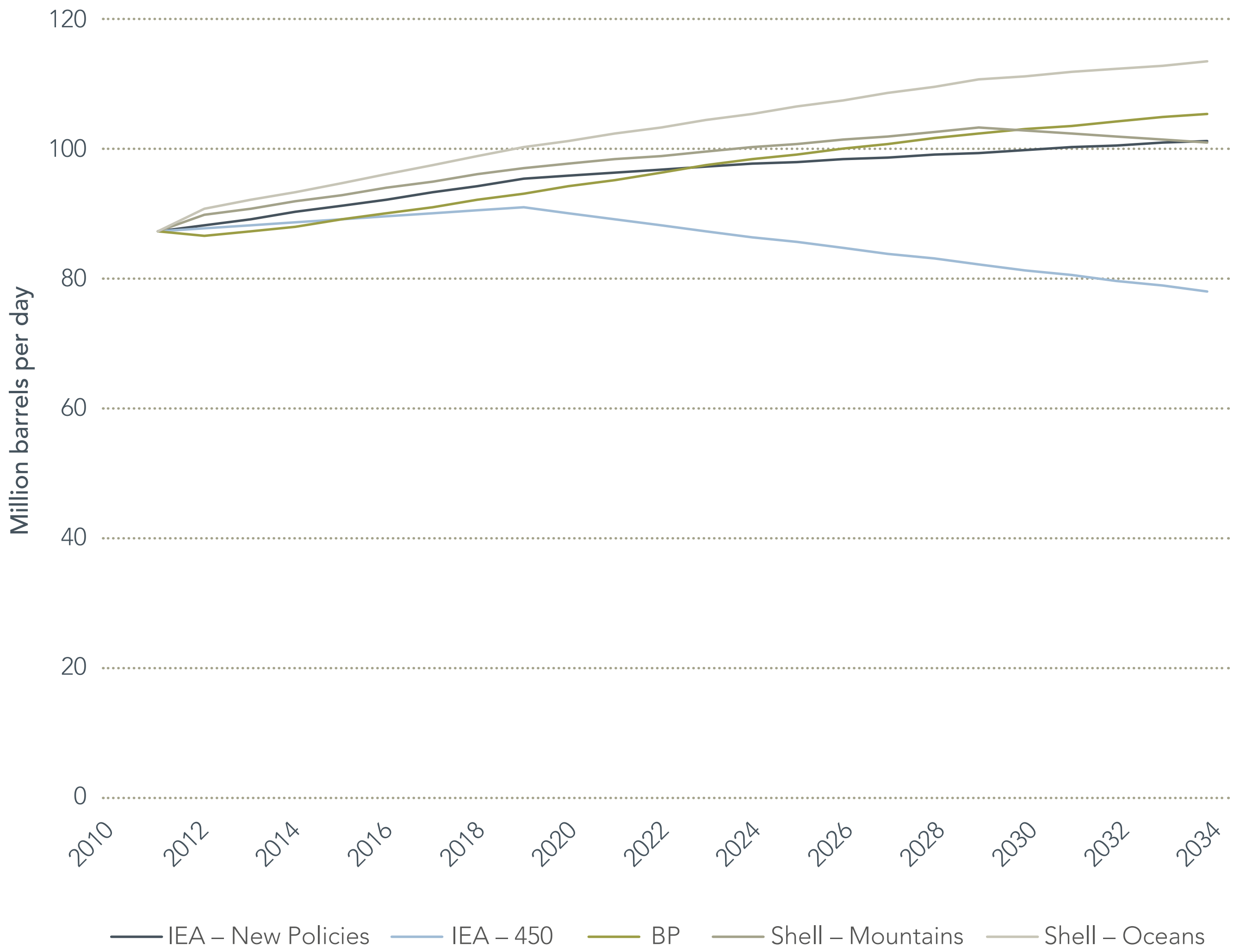
Investing in more oil production is typically justified by pointing to scenarios of demand growth. However alternative futures such as the IEA's 450ppm scenario indicate oil consumption could peak and decline.

There is a clear desire to avoid the impacts of both poor urban air quality and climate change. Regulation and technology continue to advance to deliver a future that will not replicate the past. This means avoiding ever-growing consumption of oil by the internal combustion engine for transport. However it is clear that the existing vehicle fleet will not disappear overnight, so demand will not be suddenly switched off.

Assumptions around Chinese economic growth in these scenarios need updating to reflect this has slowed below the rates included in many existing models. The growth in demand for oil is often based on increased demand in BRICS economies.

Oil companies produce scenarios as shown in the graph alongside the IEA scenarios, (which the companies qualify as not being predictions). We believe it is informative to understand what it means for the business models of these companies if demand does not keep rising, as in the IEA 450ppm scenario. Scenarios and stress tests should be used to identify potential blind spots, not merely to legitimise existing plans.

Figure 1: Oil demand scenarios



Bridging cost and carbon

Markets allocating the carbon budget

It is increasingly recognised by the energy sector and commentators – including the IEA and BP – that not all known reserves fit within a carbon budget to limit global warming below dangerous levels. The market will play a key role in allocating the carbon budget in response to technology and policy developments. The demand and supply interaction of fossil fuel markets setting commodity prices will help determine the viability of fossil fuels right down at the project or asset level.

Competition between fossil fuels

As indicated by the IPCC reports, there is a finite amount of greenhouse gases which can be emitted to have a reasonable probability of limiting global warming to 2°C. Depending on the distribution between coal, oil and gas, it is possible to derive a budget for oil emissions, using the current proportion and various scenarios. Oil currently accounts for around 40% of global energy emissions according to the IEA. As a reference point, applying this to global carbon budget of around 900GtCO_2 for 2013 – 2050 gives a budget of 360 GtCO_2 for oil. The 900GtCO_2 is the budget estimated by the Grantham Research Institute on Climate Change at LSE to give an 80% probability of limiting anthropogenic warming to 2°C.

Carbon Supply Cost Curves

This reference 360GtCO_2 budget of cumulative emissions intersects with the supply cost curve at around the $60 break even oil price. (Applying an average lifecycle emissions factor of 0.47 tonnes of CO_2 per barrel of oil to around 760billion barrels of production.) This translates to a required Brent price of $75/bbl when taking into account market contingency.

Oil price sensitivity

Given the relationship between the carbon cost curve and current oil price, we have identified two bands of high risk potential production. The $75–95 market price ($60–80 breakeven) range are the marginal barrels of oil which are just outside the carbon budget and are at risk in a low oil demand/price scenario. The $95+ market price ($80 breakeven) range is clearly excess to requirements from a 2°C carbon budget perspective and is more exposed in terms of economic viability.

There are other factors beyond the pure breakeven price which may determine which assets get developed. Political relationships and energy security concerns may see higher cost assets developed for example. Carbon capture and storage may also increase the budget slightly by 2050. On the flip side of this carbon prices may increase costs and reduce demand, and cheaper sources of oil may displace projects higher up the cost curve.

The $75–95 market price, ($60–80 breakeven) band is vulnerable in economic terms only in a future lower price environment. This level is at the lower end of that considered by oil companies in assessing project viability. For example Shell recently disclosed they consider an oil price range of $70–110.

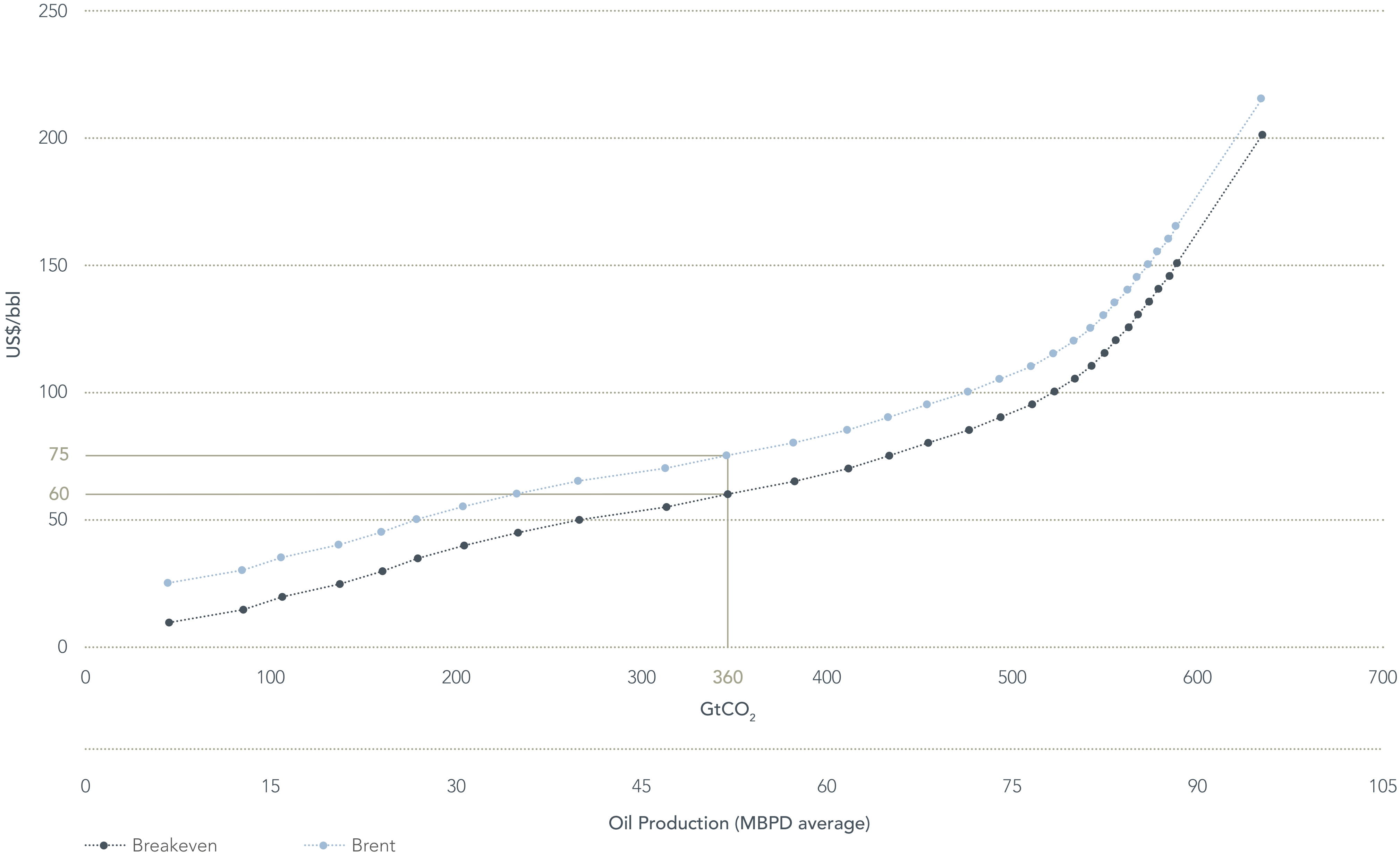
Degrees of warming

The oil price can be used as a proxy for the carbon budget as a result. This is why understanding oil price sensitivity across different companies is so important for investors. It enables them to consider a range of futures in a relatively simple way. This is also a reminder that the future is not a binary choice between 2°C or 6°C degrees of warming. There are a range of potential outcomes in-between which also impact business as usual.

Financial regulators are applying stress tests to the banking sector to understand the resilience of each organisation. This is not determined by how likely the banks or the regulators consider the scenarios to be. Predicting the oil price is a difficult exercise. In the last decade the Brent oil price has been below $50/bbl for two periods in 2008/9 and in 2004. It does not seem unreasonable to stress test against oil prices that range from this up to the current level.

This 360GtCO_2 budget of cumulative emissions intersects with the supply cost curve at around the $60 break even oil price.

Figure 2: Carbon cost curve of oil production



Risk analysis

Figure 2 is a variation on a traditional cost curve. Instead of just showing how much oil can produced at a certain price, it converts this into CO_2, to show the emissions that would result from producing and using oil up to a certain breakeven price or market price. The chart shows two curves; one for the breakeven oil price, and one for the required market price, (see adjacent box or technical analysis for more details).

Some oil companies, (eg Exxon), have indicated they do not consider a 2°C outcome likely and therefore have dismissed the need to consider exposure to a carbon budget. However even a larger carbon budget still has implications for future investment at the wrong end of the cost curve. This is why we recommended investors engage oil companies to understand where they sit on the cost curve.

The UNFCCC 2°C target was agreed internationally under the Cancun Accord and negotiations continue towards Paris 2015. In the meantime a patchwork of measures to limit emissions and improve efficiency and air quality are being brought in anyway. Many of these regional or national measures are not specifically labelled carbon or climate. So the future of the energy system is not solely dependent on the outcome of those negotiations, and the market needs to factor in a range of more complex signals.

It is unsustainable for many companies to maintain both capex and dividends unless the oil price continues to rise.

Oil price assumptions

The breakeven price includes an Internal Rate of Return (IRR) of 10%, (where NPV=0), but does not allow any room for increased costs, or a fall in oil prices. It may also be insufficient to contribute to making a company cashflow neutral once it has covered other commitments such as dividends. Rystad therefore expect that an oil company would allow another $15 when making investment decisions, depending on its portfolio of projects. This means that a $60 breakeven project would be dependent on assuming a $75 Brent oil price.

Rising costs

According to Bloomberg data, capital expenditure by the largest oil companies is now five times the level it was in 2000. Yet the production of the companies has barely increased. This continuing fall in capex productivity has been masked by the annual average Brent oil price rising to four times the level in 2000. The cost of producing the marginal barrel of oil is increasing. According to Goldman Sachs, over the past two years no major new project has come onstream below $70/bbl, with most in the $80–100/bbl range.

Free cashflow

Companies also have to maintain other expectations alongside capital expenditure. Shareholders have become used to dividends. Goldman Sachs estimated in April 2013 that over half of the listed oil companies need oil prices above $120/bbl to be cashflow neutral. In the first quarter of 2014, Brent was hovering around the $110/bbl mark. This has resulted in analysts asking whether something has to give. It is unsustainable for many companies to maintain both capex and dividends unless the oil price continues to rise.

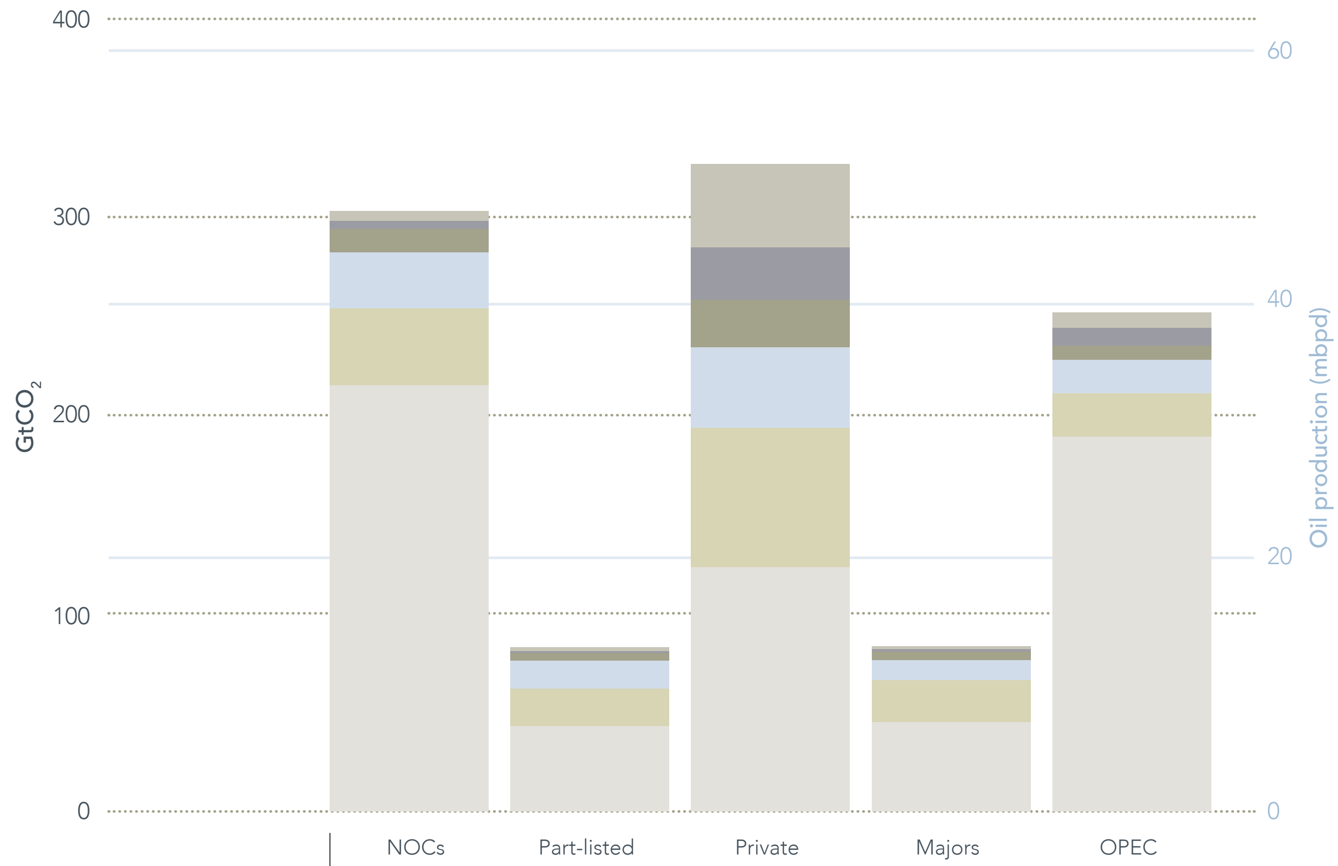
Ownership of potential production to 2050

There is a total of 635GtCO_2, (equivalent to 1350bn boe), of potential production of liquids, (oil, condensates and Natural Gas Liquids), projected to 2050, (according to the Rystad UCube database, March 2014). This potential production is displayed on the cost curve in Figure 2. Despite the majority of reserves usually being identified as owned by state entities, this indicates that private companies are responsible for over half of potential production. The private sector has a leading role in determining the future of the oil industry.

Within the state-owned companies there are a number of part-listed companies which further increases the exposure of investors. If the contribution of the 10 largest part-listed companies is subtracted from the state-owned total, it leaves less than 35% of potential production as completely state-owned. It is clear that the completely state owned entities have limited exposure to high cost operation relative to the fully privately owned entities. However the large companies which are part-state/part listed have a very similar cost profile to the majors. OPEC interests in potential production have limited high cost exposure.

Private companies are responsible for over half of potential production.

Figure 3: Breakeven price bands of production by ownership type



	NOCs	Part-listed	Private	Majors	OPEC
Above $150	5	2	42	1	8
$120–150	4	1	27	2	9
$100–120	12	4	24	4	7
$80–100	28	14	42	10	17
$60–80	39	19	70	21	22
$0–60	215	43	125	46	189

Exposure to the low end of the cost curve

The adjacent chart shows the distribution of global potential production to 2050, broken down by breakeven oil price bands, across state entities, hybrid state-listed companies, private companies, oil majors and OPEC countries.

Focusing on the projects with over $80 breakeven, the percentage of potential production above this level for each type of owner is as follows:

State-owned	16%
Part-listed	25%
Private	41%
Majors	20%
OPEC	16%
Global average	29%

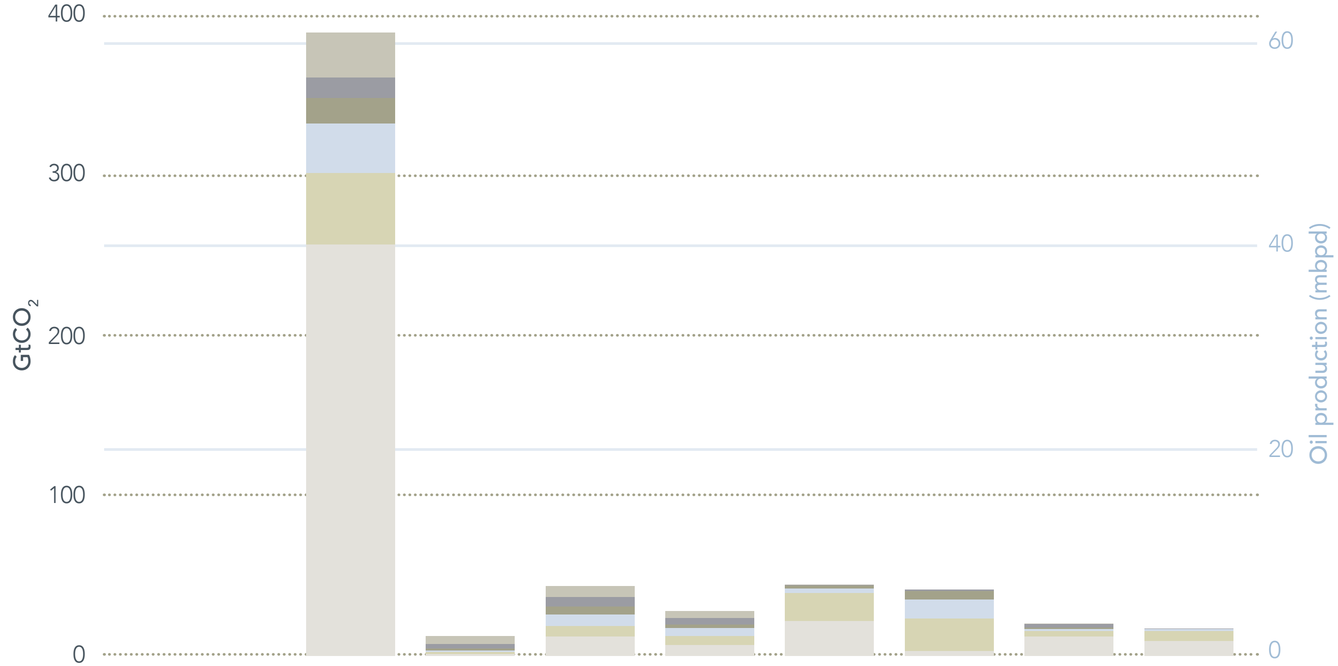
The breakdown of ownership indicates that the majors have managed to secure more of the lower cost production than smaller private companies. This means that the risk may be more concentrated in some of the independent operators who do not have the financial strength of the larger companies to ride out price shifts.

Notes

1. Part-listed companies are a subset of NOCs in this dataset.
2. Majors are a subset of Private in this dataset.
3. OPEC refers to production from OPEC member countries which overlaps with the other categories in this dataset.

3. Higher risk operations

Figure 4: Breakeven prices of carbon production by oil type 2014–2050



	Conventional	Arctic	Deep water only	Ultra deep water only	Shale oil	Oil sands	Extra heavy oil	Tight liquids
Above $150	22	5.3	6.7	4.6	0.2	0.0	0.2	0.0
$120–150	11	2.5	6.0	4.3	0.2	0.9	2.4	0.0
$100–120	14	1.4	5.2	1.9	2.0	5.5	0.7	0.2
$80–100	30	1.0	7.0	5.1	3.0	11.9	1.5	1.2
$60–80	43	1.2	6.6	5.8	17.3	20.4	3.5	6.5
$0–60	258	1.1	12.2	6.6	21.9	2.9	12.0	9.1

Different types of oil

In addition to pure cost concerns for conventional projects, we have identified the following categories to understand the higher risk areas of potential capital expenditure out to 2050:

A. Operational challenges

- Arctic
- Deepwater
- Ultra deepwater

B. Unconventional oil types

- Oil sands*
- Heavy oil
- Shale oil
- Extra heavy oil
- Tight liquids

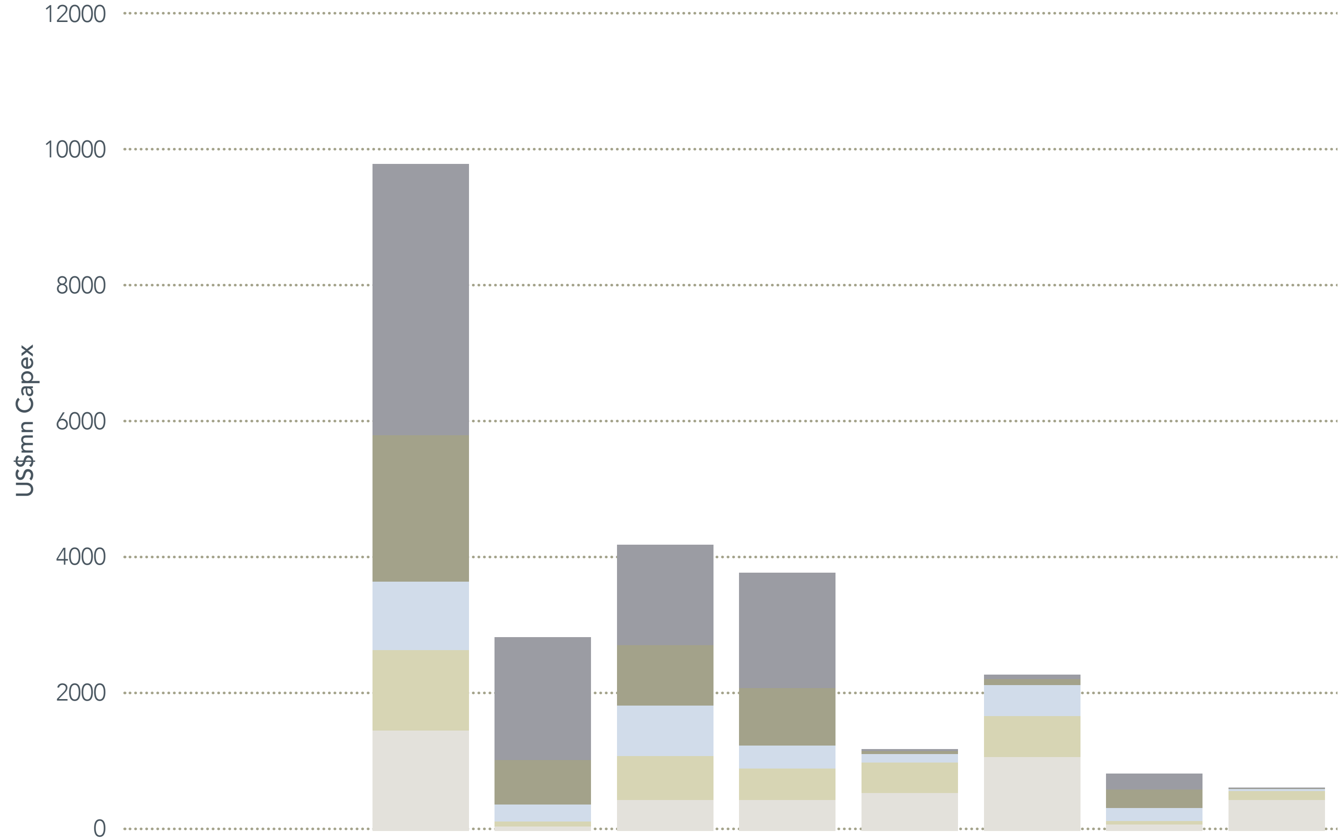
*For oil sands economics we add on a $15 cost to reflect the extra transport costs, as outlined in details in our KXL analysis.

Figure 4 shows the breakdown of global potential production to 2050 by different types of oil and location.

Notes

The conventional category displayed in this report excludes the amounts shown for other conventional subsets also provided (ie Arctic, Deepwater, Ultra deepwater).

Figure 5: Breakeven price band split by oil type 2012–2050



	Conventional	Arctic	Deep water only	Ultra deep water only	Shale oil	Oil sands	Extra heavy oil	Tight liquids
Private above $150	3970	1793	1466	1685	24	61	233	8
Private $120–150	2142	646	887	843	48	91	272	9
Private ($100–200)	1004	255	743	336	122	451	187	23
Private $80–100	1175	69	639	464	441	601	56	133
Private $60–80	1472	67	456	451	560	1084	91	456

Private sector exposure

We now focus on the potential interests of companies which are exclusively in the private sector (ie not including part-listed national oil companies). Figure 5 indicates the amount of private company capex earmarked to 2050 for the price bands in each category:

In total there is around $21trn of potential capex out to 2050 for projects which require more than a $95 oil price, including:

- $2.8trn for Arctic projects
- $3.3trn for Deepwater
- $3.7trn for Ultra-deepwater
- $1.2trn for Oil sands
- $1.1trn for Shale oil and Extra heavy oil

Apart from the conventional projects, Deepwater and Arctic regions stand out as having a significant proportion of potential capex with breakevens above $150/bbl. It would seem unlikely that projects at that cost level could be sanctioned at present.

4. Geographical distribution across provinces

Figure 6: Map of oil provinces with high cost potential production

This map depicts the oil provinces which have the largest potential developments which require above a $95 market price, including some open acreage.

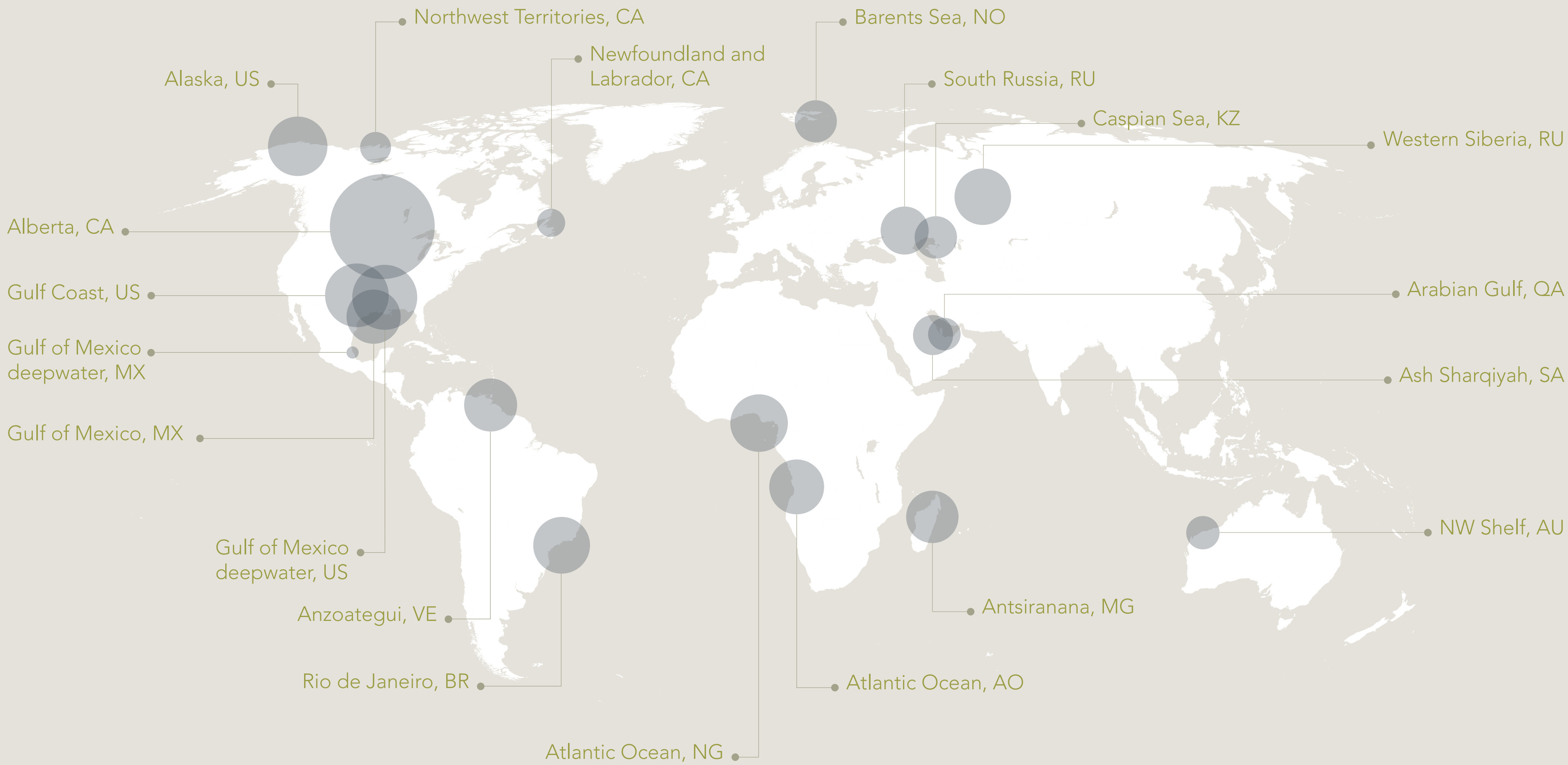
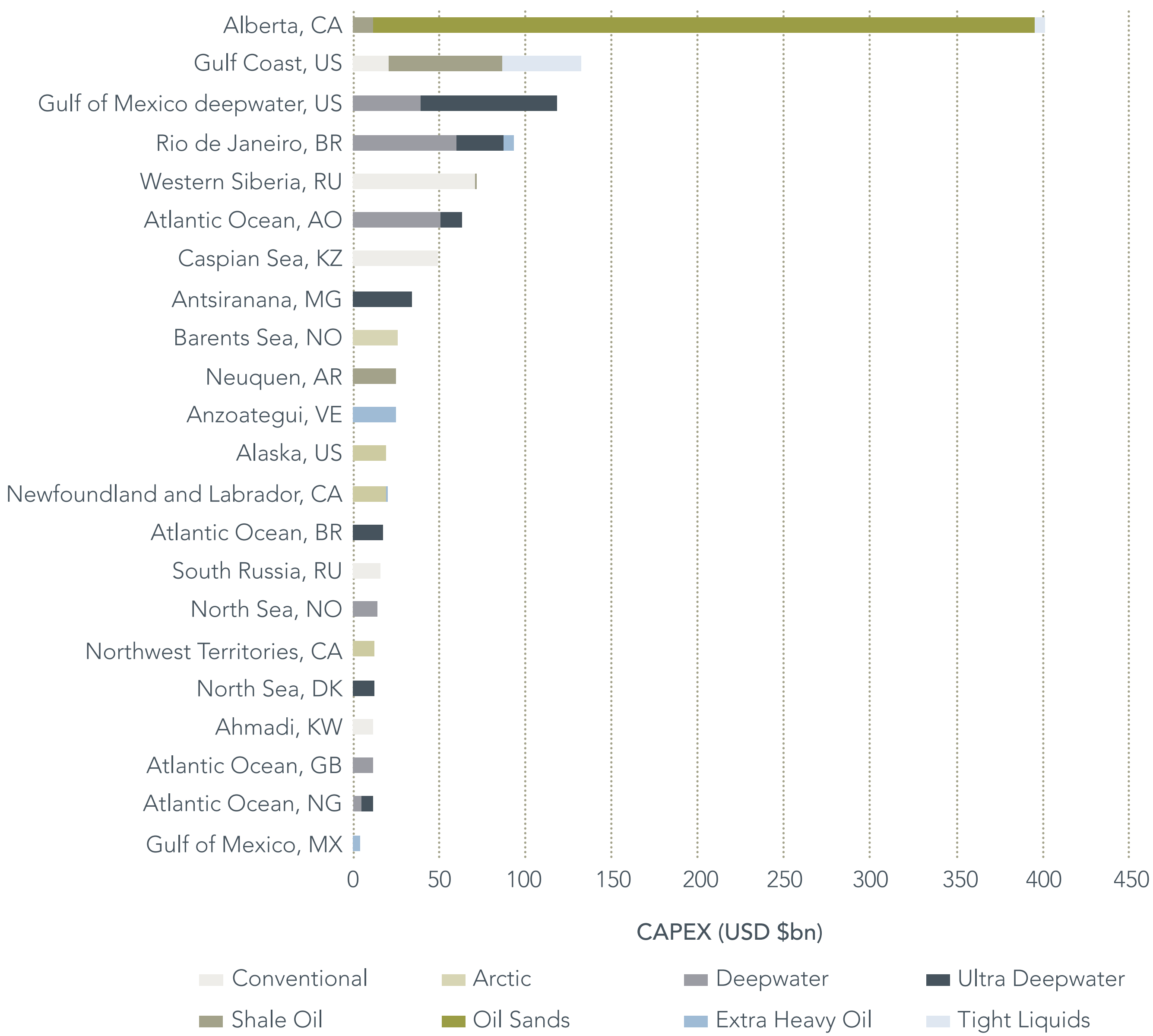


Figure 7: The most significant oil provinces capex (2014–2025) for projects above $80 breakeven



Geography of potential capex

To focus more on the capex which private sector companies are most likely to commit over the next decade, this chart shows the geography and oil type associated with potential capex in the Rystad database. This totals around $1.1trillion, focusing in on the highest cost, highest risk opportunities within a 10 year timeframe. This potential capex should be the focus of investor engagement with oil companies.

The oil sands of Alberta dominate the chart as the largest potential destination for capital, (nearly 40% of the total). This is followed by unconventionals on the US Gulf coast, and deepwater in the Gulf of Mexico and Brazilian pre-salt.

There are also some expensive conventional projects in Western Siberia and the Caspian Sea. Arctic options also make an appearance in the Barents Sea, Newfoundland and Labrador, and the Northwest Territories.

The analysis indicates that 90% of the high cost capex is concentrated in 10 provinces. These are located in Canada, US, Brazil, Russia, the Atlantic Ocean, Kazakhstan, Madagascar, Norway and Argentina.

The capex data includes projects across a range of cost bands above $95 market price ($80 breakeven). This means that the level of potential production associated with similar capex totals varies depending on the capital intensity. There are limited conventional opportunities not involving deepwater or Arctic.

5. Company exposure

The following tables indicate potential company capex 2014–2025 according the Rystad database in the Arctic, Oil sands, Ultra/Deepwater and Conventional categories above $80 BEOP/$95 Brent in the major provinces identified in Figure 6.

State-owned

To illustrate the limited role of national oil companies we have included them in these tables. The main area of exposure for this group is in the high cost conventional plays. However the contribution of companies with any state ownership (including part-listed NOCs) is not included in the figures for private sector totals.

Majors' exposure

The company level breakdown of capex in the different types of oil extraction shows the mix of companies involved. As would be expected the majors have a strong presence across most of the oil types. They all have significant ultradeepwater options. However there is still variation amongst the majors, as can be seen in terms of Arctic and Oil sands capex.

Smaller independents

There are a number of medium and small operators with significant exposure to unconventionals. This reflects the rise of companies specialising in these types of oil. In particular there are Canadian companies active in the oil sands.

Figure 8: Conventional

Company	Capex (US$m)
Rosneft	69009
Gazprom	44214
Saudi Aramco	35582
Lukoil	28997
Denbury Resources	9656
ONGC (India)	8782
Bashneft	8771
PDVSA	8596
Surgutneftegas	7440
Russneft	4485
Novatek	3499
Slavneft	3359
Chevron	3062
Megionneftegaz	1823
ExxonMobil	1736
Yargeo	1695
Gazprom Neft (Public traded part)	1648
Kurdistan Regional Government (KRG)	1647
Tatneft	1582
MOL	1565

Figure 9: Arctic

Company	Capex (US$m)
Statoil	22432
Husky Energy	9466
Devon Energy	7734
ConocoPhillips	6679
BP	6546
Chevron	4942
ExxonMobil	3944
Eni	3768
Petoro	3665
Suncor Energy	3142
OMV	1742
Tullow Oil	1415
Idemitsu	1359
Rosneft	456
Gazprom	420
ATS	384
Lundin Petroleum	269
Murphy Oil	267
Imperial Oil (Public traded part)	243
Det norske oljeselskap	177

Figure 10: Oil sands

Company	Capex (US$m)
Canadian Natural Resources (CNRL)	38507
Suncor Energy	31402
Shell	25898
Cenovus Energy	25650
Athabasca Oil Sands Corporation	23634
ExxonMobil	18075
Laricina Energy	14428
Teck Resources Limited	12502
MEG Energy	12278
Total	11987
OSUM	11755
PetroChina	11439
Eni	9448
ConocoPhillips	9054
Marathon Oil	8846
CNOOC	8723
Statoil	7848
Sunshine Oil Sands	7527
Chevron	7435
Value Creation	7308

Figure 11: Deepwater

Company	Capex (US$m)
Petrobras	79336
ExxonMobil	22307
OGX Petroleo e Gas	21117
Shell	20254
Chevron	20095
Total	17188
Pemex	13883
Eni	11481
BP	11039
Sonangol	9957
Statoil	8329
ConocoPhillips	5833
Maersk Oil	5164
Sinopec Group (parent)	4320
CNOOC	3356
Cobalt International Energy	2940
BHP Billiton	2650
SNPC (Congo)	2378
Karoon Gas Australia	2223
Repsol	2166

Figure 12: Ultradeepwater

Company	Capex (US$m)
Total	26909
BP	24223
BG	23147
ExxonMobil	20066
Shell	15869
Repsol	15601
Chevron	12857
Eni	11412
Rocksource	6902
Reliance	6700
Cobalt International Energy	5766
Barra Energia	5625
Queiroz Galvao E&P	5625
Famfa Oil	5010
BHP Billiton	4784
OGX Petroleo e Gas	4681
Noble Energy	4076
LLOG	2988
Galp Energia SA	2832
Partex (Gulbenkian Foundation)	2672

Absolute exposure

Figure 13 below shows the companies with the largest exposure to all of the geographical, cost and oil type criteria we have applied to identify higher risk projects. First this is represented in absolute terms.

As the largest companies, it is unsurprising that the majors make the list, as they have the largest capex plans. The majors have a spread along the cost curve, partly due to not wanting to be left out of any major opportunity. Investors need to monitor that this does not result in capex being sanctioning in high cost projects which don't make economic sense.

The part-listed companies such as Petrobras (through its deepwater interests) and Statoil (with Arctic, deepwater and oil sands interests) are present. The big oil sands operators also make the top 20, reflecting the capital intensity of the projects in Alberta.

Relative exposure

We also considered the level of capex identified as higher risk as a proportion of the total capex indicated in Rystad to 2025. Figure 14 shows that for some smaller companies 100% of the capex was in these categories. The second table displays the companies with the largest capex totals which represented 50% or more of their total potential capex over the period.

For the majors this percentage ranges between 18%–28%. This means they are retaining significant options at the higher end of the cost curve.

This list brings out the larger oil sands and deepwater specialists. There are also a large number of smaller companies which have the majority of their interests in projects at the upper end of the cost curve.

Company significance

In order to understand the significance for each company, the capital expenditure needs to be put in context. For example:

- What is the timing of the planned expenditure and when would production be expected to come online?
- What proportion of the next ten years of capex does this represent?
- Is the capex concentrated in a particular region or oil type, eg oil sands or deepwater?
- What other cashflow commitments do they have?

Reducing exposure to high cost, high risk projects does not mean that the oil majors will go out of business. Indeed the market has reacted positively in the past to companies which get out of expensive projects. Cutting the capex to the upper end of the cost curve could be a positive process rather than a painful one. Where majors are exiting high cost plays, it should act as a signal to investors that any smaller operators still active in these regions are betting on high prices and low costs.

Cutting the capex to the upper end of the cost curve could be a positive process rather than a painful one.

Figure 13: The companies with the highest total capex exposure to 2025 in the provinces and type of oil above $80BEOP identified in our analysis are as follows:

	Capex (2014–2025) US$million									
Company	Conventional	Arctic	Deep Water	Ultra Deep Water	Shale Oil	Oil Sands	Extra Heavy	Tight Liquids	High cost/ risk total	Total company capex
Petrobras	26		79,336				4,089		83,452	454,317
ExxonMobil	1,736	3,944	22,307	20,066	2,286	18,075	5	4,927	73,346	290,012
Rosneft	69,009	456			129			92	69,686	264,661
Shell	49	152	20,254	15,869	1,169	25,898			63,392	314,551
Total	58	50	17,188	26,909		11,987			56,193	197,674
Chevron	3,062	4,942	20,095	12,857		7,435		7,384	55,774	247,093
BP	228	6,546	11,039	24,223		3,978			46,014	253,066
Gazprom	44,214	420	9		81				44,724	111,881
Statoil	2	22,432	8,329		22	7,848			38,634	218,578
CNRL		2	1			38,507		45	38,555	74,917
Eni	48	3,768	11,481	11,412	78	9,448			36,235	173,426
Saudi Aramco	35,582								35,582	402,509
Suncor Energy	114	3,142	20			31,402	2		34,679	70,995
Lukoil	28,997	9							29,006	132,497
Cenovus Energy	244					25,650	2,961		28,855	46,805
OGX Petroleo e Gas			21,117	2,340				4,681	28,138	30,839
ConocoPhillips	6,679	1,432	5,833		9,054	939		2,212	26,150	140,085
BG	5	115	2,001					23,147	25,267	55,775
Athabasca Oil Sands					23,634		65		23,698	26,498
Repsol	90	1,223	2,166					15,601	19,079	47,030

Figure 14: The following companies have the largest exposure where 50% or over of the total capex is in these categories and provinces above $80BEOP:

Capex (2014–2025) US$million

Company	Conventional	Arctic	Deep Water	Ultra Deep Water	Shale Oil	Oil Sands	Extra Heavy	Tight Liquids	Total high cost/high risk	%age high cost/high risk capex
CNRL		2	1			38,507		45	38,555	51%
Cenovus Energy	244					25,650	2,961		28,855	62%
OGX Petroleo e Gas			21,117	4,681			2,340		28,138	91%
Athabasca Oil Sands Corp						23,634		65	23,698	89%
Laricina Energy						14,428			14,428	97%
Teck Resources Limited						12,502			12,502	100%
MEG Energy						12,278			12,278	64%
OSUM						11,755			11,755	99%
Denbury Resources	9,656								9,656	57%
Queiroz Galvao E&P			182	5,625			1,755		7,562	100%
Sunshine Oil Sands						7,527			7,527	90%
Barra Energia				5,625			1,755		7,380	100%
Value Creation						7,308			7,308	99%
Reliance			375	6,700					7,075	85%
Rocksource		15		6,902					6,917	100%
Clayton Williams Energy	105				1,096			5,473	6,674	76%
Paramount Resources	42					5,490		8	5,541	91%
Famfa Oil				5,010					5,010	100%
Partex (Gulbenkian Fdn)			54	2,672					2,726	82%
Forest Oil					691			1,951	2,642	61%

6. Conclusions and Recommendations

Demand

- Industry demand projections often assume business as usual, and do not typically allow for significant changes in costs, competition, efficiency or emissions constraints. There are a range of potential energy and emissions scenarios between two and six degrees of warming that need to be considered.
- The assumptions underlying demand futures need to be stress-tested. For example Chinese economic growth is already falling short of the rates that are built into many energy demand models. Using demand models to justify capex needs greater scrutiny and debate.
- Companies could provide stress test findings using a range of oil prices without giving specific project information. This analysis could reflect the range of oil prices experienced in the previous decade.

Bridging carbon and cost

- Fossil fuels are realising that they are increasingly competing for a finite carbon budget. We have choices about using it for burning coal, oil or gas. The total potential production in the Rystad UCube database of around 1.35trillion barrels of oil production, equivalent to 635GtCO_2.
- As a reference point, a total fossil fuels budget to give an 80% chance of the 2DS, is around 900GtCO_2 to 2050. Based on the current share of energy emissions, this translates to 40% or 360GtCO_2 for oil. The carbon supply cost curve for oil shows marginal production above $60 BEOP ($75 market price required) takes us over this 2°C scenario carbon budget.
- We have identified a marginal price band between the $60 BEOP 2DS intervention and where economic vulnerability is already visible at $80 BEOP. Some of this $60–80 may get developed even in a 2DS as political factors and energy security concerns mean that the pure cost logic of the cost curve does not play out. We therefore decided to focus on potential production above $80 breakeven where economic and climate risk clearly overlapped.

Private sector has a major role

- Completely private sector companies have 52% of the potential production to 2050, with part-state/part-listed companies owning 13%. This leaves 35% in the hands of purely state-owned entities. The private sector has a more significant role in the future of oil production than simple reserves data may suggest.
- This is especially the case when focusing at the top half of the cost curve. Wholly private sector companies have:
- 71% of the 177 GtCO_2 of production with a BEOP over $80 ($95 Brent)
- 62% of the 101GtCO_2 of production in the marginal $60-80 BEOP range ($75-95 Brent)
- 39% of the 357GtCO_2 of production with under $60 BEOP ($75 Brent)

Type of production

- There is capex of $9.8trn to 2050 earmarked for Deepwater and Arctic production requiring a BEOP above $80 (Brent $95) which will carry additional technical and reputational risk, as well as a further $8.3trn to 2050 of potential capex in other conventional projects in this cost range. These projects do not make economic sense and confirmation is needed that they will not proceed under the banner of replacing volumes.
- In terms of unconventional oil types, the largest potential production to 2050 sits in the oil sands, ($1.2trn of capex), with a further $1.6trn for extra heavy oil, shale oil and tight liquids combined.

Geographic distribution

- The analysis indicates that 90% of the potential to potential high cost capex is concentrated in 10 provinces. These are located in Canada, US, Brazil, Russia, the Atlantic Ocean, Kazakhstan, Madagascar, Norway and Argentina.
- The data reflects the trend that there are limited opportunities to discover large new conventional fields that do not involve deepwater or Arctic. Some regions have also appeared recently as further emphasis has been placed on unconventionals to maintain production.
- The oil sands of Alberta remain the prime candidate for avoiding high cost projects. The isolated nature of the market with uncertainty over export routes and cost inflation brings risk.

Company exposure

- The largest companies have large absolute exposure to high cost projects, but this is offset to varying degrees by exposure lower down the cost curve.
- There are opportunities for the majors to reduce their exposure to the upper end of the cost curve and improve value rather than chase volume.
- There are some smaller companies who appear high up the league tables relative to their size. This suggests they may have high exposure to particular high cost/risk regions or types of oil.
- Companies with a high proportion of future capex opportunities associated with potential production from the upper end of the cost curve are exposed to cost increases and price falls. Smaller operators may not have the financial strength to tolerate lower demand/price scenarios.
- Some companies may struggle to maintain capex and dividends going forward. Identifying areas of potential wasted capital now will prevent future problems.
- We have identified $1.1trillion of capex out to 2025 in higher cost projects requiring over $95 market price, which we believe should be the focus of investor engagement.

Recommendations for investors

Given there is $1.1trillion of capex at stake for the private oil sector over the next decade, this needs to be a priority for stewards of capital. We would suggest the following for asset owners and managers to consider:

1. Understand the exposure of your portfolio/fund to the upper end of the carbon cost curve, and articulate how this risk is being managed.
2. Identify the companies with the majority of capex earmarked for high cost projects.
3. Focus engagement on projects requiring $95/bbl market prices as a starting point.
4. Set thresholds for exposure to projects at the high end of the cost curve for portfolio companies to adhere to.
5. Make it known to company management that you are seeking value not volume.
6. Ensure remuneration policy at companies is consistent with shareholder return objectives not just rewarding reserves replacement or spending capital.
7. Require improved disclosure of demand and price assumptions underpinning capex strategy.
8. Support transparency of company exposure to the cost curve and impairment trigger points, eg through annual publication of sensitivity analysis/stress tests to oil price.

Technical Analysis

The underlying analysis for this paper is contained within the more detailed documents covering oil demand, oil supply and the carbon cost curve, and supporting technical appendices. These are available on the CTI and ETA websites.

Based on feedback from companies and investors we have sought to refine and improve our approach. Previous analysis has combined oil, gas and coal data, which has led to challenges in seeking universal terminology to describe reserves. We have focused purely on oil in this analysis and also switched to using Rystad potential production data, as used by the IEA. This provides us with a better indication of the amount of oil that may be produced to 2050. This suits our purposes as it enables a comparison to a carbon budget to 2050. It also goes further in giving more detailed capex and cost data, which informs a more detailed risk analysis. Using strict reserves data such as that required by the SEC would not indicate the amount of carbon emissions associated with the oil produced by companies over the next decades if they continue with business as usual. However this is still a useful indicator of the largest companies, which can inform engagement and index construction.

This analysis is based on data licensed from Rystad UCube, a database on oil project economics, which is used by the IEA. UCube (Upstream Database) is an online, complete and integrated field-by-field database, including reserves, production profiles, financial figures, ownership and other key parameters for all oil and gas fields, discoveries and exploration licenses globally. The data in UCube originates from primary sources such as company and government reports. Where information is not available Rystad does in-house estimates to ensure that UCube is complete in all dimensions. More information is available at www.rystadenergy.com. Rystad reviewed our datasets to ensure the integrity was retained after download and analysis.

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www.carbontracker.org