Executive Summary

In March 2014 ExxonMobil published a document entitled, “Energy and Carbon – Managing the Risks” in response to a shareholder proposal by Arjuna Capital and As You Sow. The document aimed to assure investors that the company was managing climate related risks. However in this report Carbon Tracker Initiative (CTI) explains that far from assuring investors, we believe that ExxonMobil is underestimating the risks to its business model from action on climate change.

This report looks at how Exxon’s share price performance has gone from outperformer to underperformer in recent years, arguing that its deterioration is partly due to investment in capital intensive, low return projects such as oil sands. It also raises concerns that the company is failing to consider a low carbon scenario in planning its capital allocation. This report questions the very narrow definition that Exxon uses to define ‘stranded assets’ in its ‘Managing the Risks’ report and therefore explains the wider potential for value destruction at Exxon from stranded assets as they are more broadly understood.

Diminishing returns

For 40 years, Exxon outperformed the market, however over the last five years the company has lagged the broader market and some of its peers; despite oil prices remaining high. The reduction in returns can be partially attributed to industry wide trends such as rising costs and fiscal changes, however we believe it also reflects Exxon’s choice to put increasingly more investment in to capital intensive, low return projects. These include tar sands, heavy oil, arctic developments and mega-projects such as Kashagan.

For example, in 2007, tar sands and heavy oil accounted for 7.5% of Exxon's proven oil and gas reserves and around 15% of its liquid reserves. By the end of 2013, this had risen to 17% and 32% respectively. In contrast, ‘conventional’ projects fell from 45% to 33% of total proven reserves. Looking

Responding to Exxon — A Strategic Perspective

Key takeaways and recommendations

- Exxon’s returns have fallen as it has invested in capital intensive, low return projects which include oil sands.
- Looking at Exxon’s resource estimates, the proportion of such high capital, lower return projects is likely to continue to rise potentially pressuring group returns - unless management changes course.
- A strategy focusing on lower cost projects, stricter capital discipline and increased distribution to shareholders may boost group returns and lower risk.
- Exxon’s narrow definition of stranded assets may leave it unprepared for a shift in the oil market and could risk projects delivering an unacceptably low return to shareholders.
- Exxon’s report does not seem to consider the financial risk to it and other oil producers from the potential for global oil demand to begin declining within the next 10-15 years, even without robust climate policies.
- Exxon ought to consider more seriously the likelihood of a ‘2°C climate scenario’ and the implications for its business model.

ETA
Lead Analyst- Paul Spedding
Mark Fulton

CTI
Lead Analyst - Andrew Grant
James Leaton
Reid Capalino
Mark Campanale (commissioning editor)
September 11th 2014
at Exxon’s resource estimates, the proportion of such high capital, lower return projects is likely to continue to rise, potentially lowering group returns - unless management changes course. If, as we believe, Exxon’s investment in low return, high cost projects is a factor behind its deteriorating returns, increasing investment in such projects seems at odds with Exxon’s emphasis on improving shareholder returns.

Throughout Section One of this report we offer top-down and bottom up analysis of the strategy outlined in Exxon’s “Managing the Risks” report and explain why we believe that returns could deteriorate further. We also explore how an alternative ‘shrink to grow’ strategy, focusing on per share metrics to deliver growth to shareholders and thereby favouring the highest return projects for development, may boost group returns and lower its risk profile.

---

**In 2007, tar sands and heavy oil accounted for 7.5% of Exxon's proven oil and gas reserves, by the end of 2013, this had risen to 17%**

---

**Wider context, wider concerns**

Section Two of this report looks at the wider concerns that investors may have from the manner in which Exxon’s report seems to dramatically downplay the risk of policy change in respect of carbon. We believe that Exxon’s report uses limited and highly favorable assumptions and definitions to support its conclusion that a low-carbon scenario is ‘extremely unlikely’. As a result the company may be seriously underestimating the risk to shareholder value such a scenario poses. Exxon’s assumption of continuing high growth could leave it unprepared for a shift in the oil market, much as it was unprepared for the structural change in the US gas market following the shale boom.

Firstly, when considering the proportion of reserves that are at risk of becoming ‘stranded’, Exxon use a very narrow definition of ‘stranded’ essentially taking it to mean ‘unburnable’ and referring to proven reserves only. By contrast, CTI and other actors such as the EIA use a broader definition, understanding a stranded asset as indicating the potential for investments to become uneconomic due to changing market and regulatory forces, including lower future oil prices. Any one or combination of these factors could result in previously sunk costs never being fully recovered and/or projects delivering an unacceptably low return to shareholders.

Secondly, Exxon’s assumption of increased energy use and hence increased fossil fuel use is based on continuing energy demand growth alongside population and GDP growth. However, it is by no means certain that historic trends in energy use will continue with many OECD countries seeing rising GDP but falling energy demand in recent times and some IEA Scenarios envisaging a plateau in oil demand from 2020 through to 2035, followed by decline thereafter.

Thirdly, we believe that Exxon is underestimating the risk of a low carbon scenario and the length of time that a transition to a low carbon economy might take. Exxon’s belief that it is, “difficult to envision governments opting for a low-carbon path” is at odds with the reality that global GHG emissions are increasingly subject to legislation or emission reduction strategies and that both national and sub-national governments are increasingly proposing and enacting new emission-reduction policies. Contrary to Exxon’s belief that it is difficult to envision governments opting for a
low-carbon path, the share of global GHG emissions subject to national legislation or emission-reduction strategies rose from 45% to 67% between 2007 and 2012.

Predictions that renewable energy will be limited by cost as far ahead as 2040 are also highly questionable. For example, it was recently estimated by the International Renewable Energy Agency (IRENA) that doubling global investment in renewable energy could quadruple the share of global energy generated from modern low-carbon renewable energy sources from 9% currently to 36% in 2030. We also outline potential flaws in Exxon’s analysis of carbon pricing.

Are the risks being managed?

Engaging with the requirements of a 2°C scenario does not imply an immediate need to cease investing in new fossil fuel production. It does imply, however, a need to evaluate how the demand and price conditions of such a low-carbon world will affect the profitability of future high-cost production. It should be worrying for investors that Exxon, although recognizing the need for ‘Managing the Risks’ from climate change, continues with an investment strategy that seems to assume business as usual.

---

It should be worrying for investors that Exxon, although recognising the need for ‘Managing the Risks’ from climate change, continues with an investment strategy that seems to assume business as usual.

---

Carbon Tracker Initiative and ETA are grateful for the support of Bonwood Social Investments towards the production of this report.
Contents
1. Introduction.......................................................................................................................... 5
SECTION I – Exxon’s strategic challenge .............................................................................. 7
2. Returns deteriorating?.......................................................................................................... 7
3. Falling returns behind oil sector’s underperformance? ..................................................... 10
4. Top down analysis suggest returns could deteriorate further ........................................ 16
5. Isolating high cost projects .............................................................................................. 18
6. Potential Future Production and Capex ........................................................................ 19
7. Lower returns equal lower multiples .............................................................................. 23
8. Shrink to grow. An alternative strategy .......................................................................... 25
SECTION II - Focusing on Exxon’s response: Energy and Carbon - Managing the Risks .... 28
9. The issue of “Stranded Assets” ....................................................................................... 28
10. The Relationship between Economic Growth and Fossil Fuel Demand .................. 35
11. The Energy Transition ..................................................................................................... 39
1. Introduction

On March 31\(^1\), Exxon published a report, entitled “Energy and Carbon - Managing the Risks”, following a shareholder resolution by Arjuna Capital and As You Sow (subsequently withdrawn\(^1\)) regarding potential carbon asset risk. Other responses from major oil companies followed, sparked by letters from Ceres and CTI on this topic\(^2\).

On May 15\(^3\) CTI specifically responded to Shell\(^3\). Exxon and Shell have common views on some of the more general issues regarding climate trends and policy and energy markets. These are addressed again in this response to Exxon in Section II. Crucially, we believe that Exxon, like Shell, gives far too low a probability to climate policy in the future and overestimates the likely robustness of oil demand.

Section I of this note looks more directly at the risk to investors of Exxon’s growth strategy which appears to be based on the assumptions of prolonged demand growth and high oil prices. In order to assess this we have looked at the trends in Exxon’s returns in recent years and related this to its potential growth options, with the following key findings:

a) One reason Exxon’s returns may have deteriorated is because capital investment has been directed increasingly to more capital intensive, low return projects including tar sands. A top-down assessment of its resource base suggests this trend is likely to continue.

b) A bottom up analysis of its development portfolio shows some of its projects have high break-even oil prices, potentially threatening returns and increasing operational gearing and hence risk.

c) Its management’s belief that action on climate is “extremely unlikely” means it risks being blind-sided, as was the case ahead of the collapse in US gas prices during the shale boom. It compounds this strategic blindness by assuming that even if climate policy were implemented, its business model would remain robust.

Following many years of robust performance, Exxon has underperformed the S&P 500 for the last five years despite persistently high oil prices. One possible reason for this underperformance is the deterioration in Exxon’s return on capital, which we believe has been partly driven by investments in high cost - and hence low return - projects. If so, continuing with the current growth strategy, which includes similar high cost assets, is unlikely to remedy this. It also raises operational gearing, increasing the potential risk to its portfolio should demand prove weaker than it forecasts, leading to pressure on commodity prices. Exxon’s forecasts for growth in oil demand between 2012 and 2035 are slightly higher than the IEA New Policies scenario. Such weakness could be caused by many factors, including government action to address climate issues.

Given that Exxon has sanctioned several long term projects that we believe have break-even prices of around $100/bbl, presumably it thinks that the long term price of oil will remain high. This may be

---

\(^1\) http://arjuna-capital.com/sites/default/files/Exxon%20CAR%20withdrawal%20release%202020140320%20FINAL.pdf
\(^2\) http://www.carbontracker.org/site/investors-challenge-fossil-fuel-companies
\(^3\) http://www.carbontracker.org/shell-response/
a reflection of its optimistic demand forecast. But history shows us that the real oil price rarely rises and often falls during periods of weak demand (as occurred in 1980-85, 1990-94, and late 2008/early 2009). If Exxon’s view proves wrong and oil demand does decline, as in the IEA 450 scenario for example, downward pressure on oil prices is likely in our view. History shows that oil prices can move rapidly in response to small movements in demand and well within the production time frame of Exxon’s proven reserves. The decline in demand under a 450 scenario would be long term and so pressure on prices could also be long term. A study by HSBC in 2013\(^4\) showed that lower oil prices are one of the main potential threats to shareholder returns. In very rough terms, the HSBC research showed that a $10/bbl reduction in liquids prices could result in a loss of value equivalent to around 10% of the market capitalisation of the European oil majors.

In a scenario of falling demand, it is questionable therefore whether Exxon’s growth-based strategy, which includes investing in higher cost projects, is the best option for shareholders. Perhaps, a lower risk approach with higher pay outs and greater capital discipline might add more value and lower potential risks.

An alternative to the traditional strategy of increasing top-line production is “shrink to grow”, where a company instead focuses on per share metrics to deliver growth to shareholders whilst favouring the highest return projects for development. Exxon already uses production per share in its presentations and is pursuing buybacks; emphasising this approach more heavily along with increased capital discipline may boost returns and lower its risk profile.

SECTION I – Exxon’s strategic challenge

2. Returns deteriorating?

Outperformer to underperformer

Exxon has delivered an impressive level of outperformance over the past 40 years, beating the S&P 500 index by around 4% annually. Equally impressive is that Exxon’s long term outperformance has been achieved with a sub-market beta. According to the Capital Asset Pricing Model, this should not be possible as high returns should be associated with high rather than low risk. Certainly, it is unusual to see such low-risk outperformance sustained over such a long period. Sadly for investors, in more recent times, this outperformance has turned to underperformance as Exxon’s own presentations show.

Figure 1 Exxon shareholder returns

At the end of July 2014, it had undershot the broader market by 8% over five years and by around 7% over three and one year. This means Exxon has only delivered returns equivalent to around 60% of that of the S&P 500 over the past five years, a significant deterioration.
Part of Exxon's current period of underperformance may have been driven by structural changes in the energy industry.

**Big oil losing its competitive edge**

It seems to us that the impressive returns during 1970-2010 might have been supra-normal, possibly due to the following factors.

- **OPEC:** for much of the 1970-2010 period, the cartel restrained production to keep oil prices above their natural levels. The super-majors' low cost bases meant that they earned a "windfall" margin at the expense of OPEC;

- **Technology:** From the 1970s onwards, many countries outside the US wanted to explore their continental shelves for oil and gas. But at that stage, the oil majors had a competitive advantage as they were the repositories of the knowledge needed for offshore exploration; and

- **Access to capital:** For much of the tail-end of the last century, national governments - especially those outside the OECD - sometimes found it difficult to access capital for the development of discoveries. Banks were often put off by country or project risk, leaving the oil majors as the only source of capital.

So, the industry benefited from windfall oil prices thanks to OPEC. It also had the twin competitive advantages of technology and capital which enabled it to negotiate attractive fiscal terms for development projects.
However, the importance of these factors appear to have diminished in recent years:

• OPEC: Industry cost base rises. Although OPEC has continued to keep oil prices above their natural level by constraining production, the size of the industry’s windfall may have fallen as the its cost base has risen;

• The emergence of powerful state oil companies and the outsourcing of technical skills to the oil service sector means that the majors may have less of a technical edge than in the past;

• Banks seem to have become more ready to lend to countries that would previously be seen as financially risky; and

• The increase in scale of the super-majors and the emergence of large national oil companies may have meant that the competition for access to resources has grown, making it harder to negotiate attractive fiscal terms.

Costs and taxes offset higher prices

Data from the IEA shows that industry unit net cash-flows for 2010-14 were similar in real terms to those of ten years previously despite a near $50/bbl rise in real oil prices. In contrast, the industry’s tax bill nearly doubled and costs nearly tripled.

Figure 3 Aggregate split of oil revenue for private upstream companies ($/boe)

Governments and the oil service industry have clearly become more adept at extracting a greater share of the economic rent from the oil and gas producers.
3. Falling returns behind oil sector’s underperformance?

Return on capital deteriorating

As detailed earlier, Exxon has underperformed the wider market and the oil sector over the past five years. The fiscal and cost factors in the IEA analysis above may have contributed to pressure on the industry's earnings. But there has also been pressure on the industry’s returns. Most major oil companies use return on capital employed (or more accurately “return on average capital employed”) as a performance metric. It is a measure of the profitability of a company's investment programme relative to the size of its asset base. In general, companies with a high return on capital seem to carry premium valuations relative to their peers - such as a higher price to earnings ratio (PE) or a higher price to book ratio (P/B).

Focusing on Exxon, the return on capital for its upstream business in 2013 was 17.5%, less than half the returns seen in 2007 and 2008. The US gas price deteriorated over this period but even so, Exxon’s overall realisations in 2013 were at the top end of their 7 year history. And yet, its ROACE for 2013 was the lowest for the past 7 years.

Figure 4 Exxon return on average capital employed and realisations (Upstream)

Given that Exxon’s realisations in 2013 were around $10 above the 7-year average, the deterioration in its returns is presumably due to cost effects rather than price.
Lack of capital discipline

Despite higher oil prices, Exxon's post tax profit per barrel was little different in 2013 than the 7-year average. This is because of higher production costs, depreciation and production taxes. But this deterioration in profitability is not sufficient to explain the deterioration in Exxon’s returns in our view. After all, its overall upstream earnings in 2007 were around $27bn, almost identical to those in 2013, but its upstream returns have more than halved. The lack of growth in earnings over the period is a potential concern but, on its own, is insufficient to explain the fall in Exxon’s returns. A better explanation can perhaps be found in the Group’s capital investment programme. Exxon’s capital employed has risen by around 250% over the past seven years, yet production and earnings have been broadly flat. The annual rate of growth in capital employed over the period is around 16% annually.
The reason for this ballooning in capital employed is that Exxon's capital expenditure in the upstream division has materially outpaced its depreciation charge (depreciation and exploration write-offs). Not only is Exxon's upstream capital budget significantly higher than its depreciation charge, it has been growing at twice the rate meaning the gap between the two has been rising. In 2007, capex was around 50% above depreciation; in 2013, it was more than double.
Such an acceleration in capital investment might have been justified if it had generated growth but that seems not to have been the case. The lack of growth in production over the past several years seems set to continue; Exxon’s own projections show limited growth over the next four years.

Figure 8 Exxon production profile (mboe/d)

Even using Exxon’s 'adjusted' number for 2013, the forecast annual rate of growth in production is only 1.8%. (Its 'adjusted' number excludes production from its expired UAE concession and the production from the part disposal of an Iraqi concession.) Using the reported number for 2013 leaves production little changed between 2013 and 2017.

Capital expenditure boom could be storing up more pressure

But as well as boosting the group’s capital employed, these trends in capex and depreciation may have implications for future earnings. Over the past seven years, Exxon’s upstream capex has averaged nearly 150% above its depreciation charge. It has been steadily replacing low cost production (low capital intensity) with production with high capital intensity.
In simple terms, over the past seven years, Exxon has spent an average of $17/boe of production to replace production with unit depreciation of around $8/boe. Over the long term, depreciation should rise to reflect the trend in capital expenditure. Replacing the 2013 upstream depreciation charge of $16.8bn with that year’s capex would reduce pre-tax earnings by around $21bn. Exxon’s upstream tax rate in 2013 was around 64% so the post-tax effect of such an adjustment would be $7.7bn or 24% of group adjusted net income.

At the end of July 2013, the S&P 500 traded on a trailing PE of around 19x and Exxon was on around 14x, a near 25% discount. This most likely reflects the market’s perception that Exxon’s earnings growth has been some way below that of the broader market for several years now. But, if we adjust Exxon’s earnings to reflect the cost of replacing its production at current capital costs, we would see a rise to around 17.5x in its adjusted PE, much closer to the market average PE.

The same earnings adjustment would also reduce Exxon’s return on capital. Reducing its return by $7.7bn would lower its 2013 ROACE from 17.2% to 13.2%. Deteriorating returns and rising capital costs may be a reason behind Exxon’s underperformance of the wider market over the past 5 years.

**High return/low cost projects to low return/high cost projects**

We believe that the deterioration in the return on capital for Exxon and the industry as a whole is partly because cash flow from historic high return projects is being re-invested in to lower return projects (or using the terminology of the recent CTI report, “Carbon Supply Cost Curves: Evaluating Oil Capital Expenditures”, from low break even cost projects to high break even cost projects). All companies have a range of projects in their portfolios that they can select for investment. The key to maintaining high group returns is to only invest in high return projects. But this can mean a company may see growth in its production slow if hurdle rates cannot be met. It may even fall, something that
some managers regard as anathema. When a management team targets volumes at the expense of returns, there is a risk that some projects with inferior returns may be sanctioned.

The other effect at work is scale. As the super majors have become larger, partly through investment and partly through mergers and acquisitions, potential projects also need to become larger in order to be material. But in some cases, “material” projects may prove to be low return.

Oil majors rarely give data on returns for individual projects but in a presentation from 2009, Shell showed a chart (recreated below) that indicated the range of internal rates of return for different classes of projects. (Internal rate of return or IRR is the annual discount rate needed deliver a zero net present value). It also shows a “profitability” index which is the ratio between the net present value of the projects cash flows and the net present value of the capital invested.

Figure 10 Shell: Profitability of new projects (2009 presentation)

Although out of date, the chart makes one point very clearly, a point that we believe is still true today - on average, capital intensive, long-life projects such as tar sands generate materially lower returns (IRRs) than conventional projects. Later in this report, we look at a CTI analysis of projects that may be at risk of destroying value for Exxon’s shareholders but at this stage it is worth noting the returns (IRRs) of some of its potential projects.

5 http://s00.static-shell.com/content/dam/shell/static/investor/downloads/presentations/2009/qatar-presentationspack23112009.pdf
The three oil sands projects (Kearl, Aspen and Mildred Lake) can be seen to have relatively poor IRRs, with a maximum of 18%. But oil sands investments don’t just deliver relatively low returns, they have high operational gearing due to high costs, adding greater risk to the portfolio. We believe such projects might prove value destructive should oil prices come under pressure in a weak demand scenario, perhaps caused by government action on climate change. Note that the above IRRs have been run on Rystad’s high oil-price case, where Brent is $140/bbl in 2015 and inflated by 2.5% p.a. thereafter (i.e. flat in real terms); based on the mid case of $100/bbl, Rystad’s data show returns for Aspen and Mildred Lake that we would regard as potentially sub-commercial.

4. Top down analysis suggest returns could deteriorate further

**Top-down analysis shows Exxon’s portfolio becoming lower return/more carbon intensive**

Exxon’s proven reserve base (oil and gas) stood at around 25 billion barrels of oil equivalent (“boe”) at the end of 2013. But its resource base, a better indication of its longer term potential, stands at around 90 billion barrels, over three times higher. (As discussed later, Exxon uses the narrower "proven" category to explain why its business is robust to any potential climate policy). The difference in mix between Exxon’s shorter-life proven reserves and its longer-life resources gives an indication of the potential change in the make-up of Exxon’s future production over the next decade or so.
Liquids account for around half of combined reserves and resources, and just under half (c.45%) of this is heavy oil or tar sands. As heavy oil/tar sands constitute a greater share of resources than of proven reserves, Exxon's future production is likely to see a growing weighting of potentially high cost, low return tar sands and heavy oil projects. Indeed, this is a trend that has been underway for some time.

In 2007, tar sands and heavy oil accounted for 7.5% of Exxon’s proven oil and gas reserves and around 15% of its liquid reserves. By the end of 2013, this had risen to 17% and 32%. In contrast, "conventional" projects had fallen from 45% to 33% of total proven reserves. Within resources, at the end of 2013, tar sands and heavy oil made up 23% of Exxon’s wider resource base and 45% of the liquids component therein. If sanctioned, this implies that the weighting of potentially low-return projects in its portfolio is likely to rise further.

---

Exxon's decision to invest in a rising proportion of capital intensive, low return projects such as tar sands and heavy oil since 2007 may be one reason why its returns have deteriorated. Exxon is not alone though. In general, the proportion of low return projects in the portfolios of the other majors has also appears to have been rising. It is no coincidence that high cost, low return projects are often - although not exclusively - high carbon projects. Key factors are:

a) High API (high viscosity) crudes, including heavy oil and tar sands, need large amounts of energy to extract, transport and upgrade (refining process). This means higher operating costs and more carbon emissions than conventional crudes; and

b) Harsh environment projects, such as those in arctic environments, need greater amounts of energy intensive steel and/or concrete, adding to carbon and capital intensity.

If, as we believe, Exxon's investment in low return, high cost projects is a factor behind its deteriorating returns, increasing investment in such projects is unlikely to reverse this trend. Continuing with the same strategy seems at odds with Exxon’s emphasis on improving shareholder returns, something that has not been evident over the past five years.

5. Isolating high cost projects

Bottom up approach to Exxon's projects

The Carbon Tracker Initiative research provides investors with the opportunity to focus on projects that are likely to be high cost - and hence at risk of low returns (see CTI’s recent Carbon Supply Cost Curves report\(^7\)). In common with many oil analysts (including Goldman Sachs), CTI uses the

---

\(^7\) CTI/ETA, Carbon Supply Cost Curves
breakeven oil price (BEOP) of potential projects to isolate those that are likely to be low return.\(^8\) Though other financial metrics (e.g. cash costs and return measures) are also valid and useful, BEOP provides a valuable snapshot of the per-barrel marginal cost of developing an asset.

CTI used data provided by Rystad Energy to derive project BEOPs, the Brent oil price needed to deliver an asset-level net present value (NPV) of zero assuming a 10% discount rate.\(^9\) In theory, this is the planning price at which a major such as Exxon would be comfortable sanctioning a project. But in practice, prudent oil companies require some level of "contingency" or "risk premium" to allow for the risk of cost overruns, project delays, adverse fiscal changes and weaker than projected commodity prices. In Carbon Supply Cost Curves, CTI assumed this contingency to be $15/bbl. In other words, a project with a BEOP of $80/bbl would require an expected market oil price of at least $95/bbl to be sanctioned.

### 6. Potential Future Production and Capex

CTI's analysis of Rystad's data shows that Exxon's projects have a wide range of market prices required for project sanction\(^10\), some extremely low but some above $95/bbl (ie a BEOP of $80 plus), the highest planning price assumption we would regard as prudent.

**Figure 14 Exxon potential future oil production by required $/bbl market oil price, 2014-2050 (mmbbls)**

![Graph showing potential future oil production by required market oil price](source)  

\(^8\) See Goldman Sachs, "400 projects to change the world - From revolution to dominance: shale drives M&A, deflation, capital efficiency", May 16 2014. Also Citi, “Global Oil Vision: Stand and Deliver - Global Energy Enters a New Cycle”, March 11 2014, 13. Other key metrics for financial analysts include Internal Rate of Return (IRR) and Return on Capital Employed (ROCE).

\(^9\) Rystad Energy, "Breakeven prices in UCube - breakeven price calculated at an asset level," UCube Technical Presentation 2014, 2014, 23. For more discussion, see Appendix B of this report.

Rystad Energy, Petroleum Production under the 2 degree scenario (2DS), July 2013, 26.

\(^10\) Market price required for sanction assumes a $15/bbl contingency on top of project breakeven price, i.e. a market price required for sanction of $95/bbl is equivalent to a project breakeven price of $80/bbl
Much of Exxon's potential future production is competitively positioned, with 44% requiring a market price below $75/bbl for sanction (sub $60 BEOP). However, around 24% of potential future production through 2050, amounting to 7.5 billion barrels, would require $95/bbl in order to be sanctioned for development. (This is over 9 times Exxon's 2013 oil production). It is projects in this category that could become value destroying in a low-carbon demand scenario. Moreover, over the next decade the share of production attributable to high-cost projects is likely rise. Over 2014-2025, projects needing a $95/bbl+ market price account for only 16% of potential production but from 2026 onwards this rises to 30%, exposing Exxon to a growing risk from price weakness, cost inflation or fiscal changes, such as direct taxes on the industry's carbon emissions.

**Potential upstream capex: an opportunity to prevent wasting capital**

CTI was also able to use the Rystad data to analyse Exxon's capital expenditure profile. Note that this reflects the potential capital Exxon could spend on all the development opportunities available to it. We would hope that in the future, Exxon will exercise capital discipline to avoid potential deterioration in its returns. Indeed, Exxon has announced that it expects 2014-2017 capex to fall to an average of “less than $37bn” from nearly $40bn in 2013\(^1\). This apparent commitment to capital discipline seems sensible but some of its proposed projects have high break evens and could be return dilutive in a low demand scenario.

The high operational gearing of these high-cost projects also adds greater risk to the portfolio. This is particularly true for its interests in various Canadian oil sands projects. Of Exxon's $286 billion in potential upstream oil capex from 2014-2025, $103 billion (36%) is for projects requiring a market price above $95/bbl for prudent sanctioning.

---

Figure 15 Exxon potential upstream oil capex broken down by required market price, 2014-2025 ($m)

Within this $103 billion, $56 billion (54%) is associated with undeveloped assets, i.e. fields that are currently either "in discovery" or "undiscovered." As discussed in more detail below, the additional time required to monetise such fields increases the vulnerability to changing demand trajectories. These projects could be sub-economic in a low-price scenario. To avoid such a risk, we believe Exxon management should consider deferring or cancelling such investments.

Exxon’s potential capex on high-cost (>$95/bbl required market price for sanction), undeveloped assets is spread across its entire portfolio: over half in aggregate relates to deep water (45%) and ultra-deep water (17%) projects, 14% relates to oil sands projects and 5% to arctic developments. The majority of the balance relates to conventional onshore and offshore continental shelf projects (13%).

Source: Rystad Energy, CTI analysis 2014
Figure 16 Exxon potential capex on high-cost ($95/bbl+ market price) undeveloped projects by category, 2014-2025 ($m)

Deep water projects account for 45% of potential capex on new developments requiring $95/bbl+ market price in the medium term

Note: Data shown only for undeveloped projects requiring $95/bbl or more
Source: Rystad Energy, CTI analysis 2014

Around half of the $56bn potential capex on higher-cost new development is attributable to the 10 largest development projects currently at the “discovery stage”. These have individual capex budgets ranging from c.$1.5bn to c.$7.9bn. The breakeven levels of these projects are shown below.

Table 2 Exxon’s 10 largest high-cost ($95/bbl+ market price) development projects - oil sands and deep water dominate

<table>
<thead>
<tr>
<th>Rank</th>
<th>Project name</th>
<th>Expansion (where relevant)</th>
<th>Country</th>
<th>Region</th>
<th>Category</th>
<th>2014-2025 capex* ($bn)</th>
<th>% of total 2014-2025 capex (% of total)</th>
<th>% of total capex on undeveloped projects requiring $95/bbl+ (% of total)</th>
<th>Required market price** ($/bbl)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Aspen, CA</td>
<td>-</td>
<td>Canada</td>
<td>Alberta</td>
<td>Oil sands (in-situ)</td>
<td>2.039</td>
<td>1%</td>
<td>4%</td>
<td>132</td>
</tr>
<tr>
<td>2</td>
<td>Rosi, NG</td>
<td>-</td>
<td>Nigeria</td>
<td>Atlantic Ocean</td>
<td>Deep water</td>
<td>7.885</td>
<td>3%</td>
<td>14%</td>
<td>126</td>
</tr>
<tr>
<td>3</td>
<td>Snorre, NO</td>
<td>Phase 3 (Dekote)</td>
<td>Norway</td>
<td>North Sea</td>
<td>Deep water</td>
<td>1.495</td>
<td>1%</td>
<td>3%</td>
<td>125 - 137</td>
</tr>
<tr>
<td>4</td>
<td>Bass, US</td>
<td>Bakken/Three Forks</td>
<td>United States</td>
<td>Midwest</td>
<td>Shale Oil</td>
<td>1.463</td>
<td>1%</td>
<td>3%</td>
<td>100</td>
</tr>
<tr>
<td>5</td>
<td>Bonga, NG</td>
<td>Bonga North</td>
<td>Nigeria</td>
<td>Atlantic Ocean</td>
<td>Deep water</td>
<td>2.032</td>
<td>1%</td>
<td>4%</td>
<td>115</td>
</tr>
<tr>
<td>6</td>
<td>Kearl, CA</td>
<td>Late life, 34/4-12A (Lower Lunde)</td>
<td>Canada</td>
<td>Alberta</td>
<td>Oil sands (in-situ)</td>
<td>4.316</td>
<td>2%</td>
<td>8%</td>
<td>119</td>
</tr>
<tr>
<td>7</td>
<td>drills</td>
<td></td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>-</td>
<td>Total Top 10 Discov.</td>
<td></td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>28.595</td>
<td>10%</td>
<td>52%</td>
<td>-</td>
</tr>
<tr>
<td>-</td>
<td>Other projects</td>
<td></td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>26.860</td>
<td>9%</td>
<td>48%</td>
<td>-</td>
</tr>
</tbody>
</table>

* 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

Source: Rystad Energy, CTI analysis 2014

*Note that, due to Methodological changes in the Rystad database adjusting more directly for transport costs, we no longer include the $15/bbl transport premium for oil sands projects that has been used in prior analyses
Some of the projects on the above table are not yet on Exxon’s list of likely developments, and so could be deferred to avoid potential value destruction due to lower oil prices. However, it is pushing ahead with two tar sands projects (Mildred Lake and Kearl) which require surprisingly high market prices. It is seeking approval for a third, Aspen. (These are the same three low-return projects mentioned in the section “High return/low cost projects to low return/high cost projects”.) Investors may wish to question whether Exxon should be pressing ahead with such relatively high-risk projects and whether its commitment to capital discipline is genuine.

7. Lower returns equal lower multiples

In theory, an oil company’s share price should rise in line with its net present value. If its capital investment is creating value, its share price should rise – all other things being equal. The group’s share price should reflect its ability to create value. So a company which has cash assets of $1 and does not invest should trade at $1, i.e. at a price to book ratio of 1x. But, if it has projects that deliver a guaranteed net present value of $2, for example, it should have a net present value of $2 and so a price to book ratio of 2x would be justified. But how do investors assess what book value a company should trade for a given level of return?

It is possible to set up hypothetical field cash flow models to assess what the NPV multiple (or “profitability index”, to use Shell’s earlier terminology) would be for fields with different IRRs. (The NPV multiple is the Net Present Value of the field cash flows divided by the NPV of the capital invested. We have assumed a cost of capital of 10%). Admittedly, this approach is simplistic but it does illustrate the key point - high returns should mean higher multiples – in theory.

Figure 11 NPV multiplier for projects with different IRRs

So, in a perfect market and using our hypothetical field models, a cash shell that is investing in projects with IRRs of 20% should trade on a price to book value of around 1.6x. But, if its returns start to deteriorate, its price to book ratio should do likewise. That doesn’t mean the share price

---

13 ExxonMobil, 2013 Financial & Operating Review, page 25
necessarily falls but it would mean that the rate of value creation and hence the rate of growth in its share price would slow. In an extreme example, a company which started investing at its cost of capital would see its share price stagnate because it would no longer be adding value - its price book ratio should in theory trend down towards 1x.

Exxon’s outperformance prior to 2010 implies that it was adding material value through its investment programme - and it was not only beating the market, it was outperforming most of its super-major peers. As discussed earlier, something has clearly changed with Exxon’s returns.

But what of the future? Total presented an interesting slide in its 2013 Analysts Meeting\(^\text{14}\) which showed the IRRs for the expected returns of projects starting-up in the period 2013-17. This used Wood Mackenzie data and assumed a Brent price of $85/bbl. The peers on the chart are Royal Dutch Shell, ExxonMobil, BP and Chevron. What is surprising is how low the IRR for each company is - around 12.5%. Another observation is how similar the IRRs are for each company, suggesting Exxon’s near term projects might not have the returns advantage of old.

**Figure 17 Total: Expected return of 2013-17 project start-ups**

Even after its five years of underperformance, Exxon still stands on a premium price to book when compared to several of its peers. This presumably reflects its ability to add value through its historically higher returns.

\(^{14}\) Slide 13: http://www.total.com/sites/default/files/atoms/file/presentationtotalinvestorsday
Figure 1812 Price to book ratios for Exxon and its peers

In 2010, Exxon had a P/B ratio of nearly 3.5x, 130% above Chevron’s. Its current multiple is only 60% above Chevron’s, a material derating but still a premium. If that premium is related to Exxon’s returns, presumably Exxon needs to ensure that its returns continue to be higher than those of its peers.

If you keep doing the same thing....

In conclusion, we believe Exxon's returns have already deteriorated partly because it has invested in projects with lower returns. The lower returns have been caused by the rising capital intensity of some projects (especially tar sands), adverse fiscal changes, and cost inflation. This has led to a derating of Exxon relative to the market and its peers. The company still basks in the glow of a premium rating but it needs to focus on higher return projects in order to differentiate itself from its peers. But at present, we see few signs that Exxon has a differentiated investment strategy, preferring instead to continue with business as usual. We believe a better strategy would be to concentrate only on lower cost projects (those needing a market price below $95/bbl for sanction) and to use the freed-up cash flow to boost shareholder pay outs through higher dividends or share buyback programmes.

8. Shrink to grow. An alternative strategy

The traditional strategy for value creation in the oil industry is to invest capital in order to grow volumes and cash flow to support dividends to shareholders. In theory, this process should lead to a rising net present value and hence share price (other things such as oil prices and currencies being equal).

But there is an alternative to the traditional business model which is commonly known as "shrink to grow". One of the best examples of this, in our view, was the transformation of ConocoPhillips in the late "noughties". Many believe that its problems began in 2006 when it spent $36bn purchasing Burlington Resources, then a major player in the US natural gas business. In the fourth quarter of 2008, Conoco took a $34bn writedown, much of it due to Burlington. In 2009, the company’s CEO, Jim Mulva, announced a shift in strategy. The two year plan envisaged selling $10 billion of peripheral or non-core assets, including tar sands and part of its stake in Lukoil. It also refocused and reduced its investment programme. Part of the proceeds from asset sales was used to reduce the
group’s heavy debt burden but it was also to fund share buybacks. The lower number of shares in issue enabled it to grow its dividend faster than its group level cash generation.

As the CEO said at the time:

“Some will say what we’re doing essentially is that we’re shrinking to grow. That would be a fair assessment.”

One shift in Conoco’s metrics at the time was to move away from top-line measures such as production towards per share measures, such as production per share. The problem with targeting top-line production is that management risk taking on lower return projects in order to meet such a target. With production per share, however, it becomes possible to select only high return projects and yet still deliver growth to shareholders by redeploying capital that would otherwise have been invested in low return projects in to buybacks or special dividends instead. At its March 2010 analysts’ meeting, Conoco forecast that top-line production would remain at or below 2008’s level through until 2014. However, as this slide from that presentation shows, growth in per share terms was projected at around 4% per annum.

Figure 20 ConocoPhillips: Forecast growth in production per share (March 2010)

As the new strategy was implemented, Conoco’s rating improved. At the end of 2009, Conoco traded on a PE around half that of Exxon. By end 2010, the PEs were very similar, an astonishing performance in such a short period of time. Over the same period, its total shareholder return outperformed Exxon’s by around 40%.
Figure 21 ConocoPhillips: total return relative to ExxonMobil

![Graph showing total return relative to ExxonMobil]

Source: Thompson Financial Datastream

To be fair, Exxon also uses per share metrics such as production per share, perhaps because its top-line production growth has been so poor. This slide from its 2014 analysts’ presentation shows this.

Figure 22 Exxon: production per share

![Graph showing production growth per share]

Source: Exxon 2014 analysts’ presentation

We note, however, that since 2010, there has been little growth even at the per share level. Perhaps focusing on more buybacks or dividends rather than investing in projects at the high end of its cost curve might help its production per share performance. The least it would do is lower the risk profile of Exxon’s business.
SECTION II - Focusing on Exxon's response: Energy and Carbon - Managing the Risks

9. The issue of “Stranded Assets”

Exxon’s report on Energy and Carbon, triggered by a submission by Arjuna Capital and As You Sow, should be of concern to investors. It seeks to dramatically downplay the risk of policy change in respect of carbon. More worryingly, we believe that it uses selective data to reach this conclusion meaning that it could be understating the risk to shareholder value such a scenario poses.

*Defining “stranded assets” – those generating poor lifetime returns*

Like Shell, Exxon claims that its proven reserves are at no risk of becoming “stranded”. However, both appear to define “stranded” as meaning “obsolescent”, “shut down” or “unburnable”. This narrow definition neatly side-steps the debate as to whether a given investment runs the risk of destroying shareholder value or depressing group returns. CTI uses the term “stranded assets” to indicate the potential for investments to become uneconomic due to changing market and regulatory forces. As financial analysts, we agree that the term “stranded assets” is at times used to denote somewhat different ideas. There is, however, a generally agreed-upon core to the idea. For example, in the context of the upstream oil sector, the IEA defines stranded assets as:

“those investments which are made but which, at some time prior to the end of their economic life (as assumed at the investment decision point), are no longer able to earn an economic return, as a result of changes in the market and regulatory environment.”\(^\text{15}\) [emphasis added]

In other words, once the capital investment is made to develop an oil project, production may continue to be cash flow positive in a low oil price environment (where the oil price is above the operational production cost per barrel). However, if the overall lifetime returns from the project, including the initial outlay and subsequent abandonment costs, are less than the cost of capital used to develop it, then the project has lost value for shareholders. *In many senses the term “stranded assets” stands for economic returns at a level that is unacceptably low to corporations and to their shareholders - in effect, “value destruction.”* In previous work CTI has focused on the possibility for weak economic returns specifically associated with the transition to a low-carbon economy.

It is also important to note that “assets” can denote current or prospective investments; the “assets” in question may or may not be held on corporate balance sheets. Past costs related to developed proven assets, for example, are likely to be on the balance sheet as fixed assets. In contrast, recent discoveries are likely to have little value accounted for in the balance sheet - and yet, as BG Group’s Brazil pre-salt discoveries showed, such discoveries can have a materially greater impact on shareholder value than on the balance sheet. Any classification of reserves or resources can lose

\(^{15}\) IEA, WEO 2013, 436 Box 13.4. “Earning an economic return” means, for example, earning a return that meets the company's target for Internal Rate of Return.
value due to a variety of possible factors - including cost overruns, delays, tax changes or price pressures. Some of these could occur should policy changes be made to tackle carbon. However, it is undeveloped reserves and resources (and related infrastructure) that have the greatest potential to become low-return and even fully “stranded”. But any changes in the external environment, including price, cost and fiscal changes, that devalue undeveloped resources can also affect producing, proven reserves. Carrying a “proven” label does not make reserves immune to market forces, as the partners in the Kashagan project can testify to.

In order to assess the risk to oil projects, CTI uses the Rystad database to analyse potential projects out till 2050, identifying those in the high-cost category (i.e. $80/bbl+ break even oil price, or “BEOP” – equivalent to $95/bbl market price including contingency). This covers average annual capital expenditure of $490 billion over the period. Current annual dividends to investors from oil and gas companies are less than $200 billion. With such large amounts of capital at potential risk on high-cost projects - $1.1 trillion over the next decade - management needs to be confident of acceptable financial returns. Investors - and management - should be scrutinising investment plans carefully to ensure returns are robust under a low-carbon world where energy efficiency, alternative sources of energy and environmental policies are all potentially lowering demand for fossil fuels. CTI’s analyses suggests that the investment plans for many projects in the private-sector do not meet this test.

The risk to Exxon goes beyond its proven reserves

“A concern expressed by some of our stakeholders is whether such a “low carbon scenario” could impact ExxonMobil’s reserves and operations – i.e., whether this would result in unburnable proved reserves of oil and natural gas.”

“... we are confident that none of our hydrocarbon reserves are now or will become “stranded.”

By defining "stranded" as "unburnable" and referring to proven reserves only, Exxon narrows the debate much as Shell did in its response19. It would need a major collapse in commodity prices to cause production from proven reserves to be shut in. But we would note that current proven reserves will not account for the entirety of Exxon’s potential production over the coming decades. Indeed, Exxon points out that:

“ExxonMobil’s proved reserves at year-end 2013 are estimated to be produced on average within sixteen years, well within the Outlook period. See Exxon Mobil Corporation 2013 Financial & Operating Review, p. 22. It is important to note that this sixteen year average reserves-to-production ratio does not mean that the company will run out of hydrocarbons in sixteen years,

17 Proven reserves are defined as “those quantities of oil and gas which can be expected, with little doubt, to be recoverable commercially at current prices and costs, under existing regulatory practices and with existing conventional equipment and operating methods.” Specifically, proven (1P) reserves are “probabilistically calculated reserves having a 90 per cent confidence level (P90); such reserves have a 90 percent likelihood of being equalled or exceeded.” Oil Search, "glossary," http://www.oilsearch.com/investor-Centre/Glossary.html.
since it continues to add proved reserves from its resource base and has successfully replaced more than 100% of production for many years."

Production from Exxon’s proven reserves will have a natural decline rate. This means that its reserves will not be produced entirely or evenly within the 16 year reserve life. For example, Exxon uses a natural decline rate of 4% for its estimate of the natural decline rate for global oil production. A simple back-of-the-envelope calculation using this decline rate can be used to derive an approximate production profile for its current proven reserves.

Figure 133 Demonstrative projection of Exxon’s current reserves production (rebased)

At the end of the “reserves life” in 16 years’ time (2030), Exxon will have produced 80% of its current reserve base, so 20% will still be at risk. This decline rate also means that, assuming Exxon achieves its objective of continuing to grow company production (shown as growing at an indicative 1.8% p.a. in the above chart), an increasing proportion of production will come from oil and gas that Exxon currently classifies as “resources”. These currently stand at around 91 billion oil-equivalent barrels (“boe”), of which around 25bn boe are proven reserves.

Risks are increased as near term cash flows are recycled into future cash flows

Defining climate risk by only referring to proven reserves only (as Exxon and Shell do) or indeed the percentage of net present value at risk over time (as IHS Cera does in its report Deflating the

---

19 Based on Exxon’s forecast production growth 2013-2017 (gas and liquids) - ExxonMobil 2014 Analyst Meeting, slide 32
"Carbon Bubble"\(^{20}\) gives an apparently reassuring picture. The issue, however, is that both approaches are looking at a static snapshot of a given company. Such a picture would be valid if cashflows from proven reserves were returned to shareholders. For example, IHS Cera comments that "90% [of the value of proven reserves] are expected to be monetized in 10 to 15 years". If this were the way oil companies were managed, they would be wasting assets. A companies' net present value would be returned to shareholders as its existing portfolio was matured. Under that scenario, it is likely that "90%" of the value of a companies' reserve base would be “monetised” leaving little of the asset base exposed to action on carbon.

But that is not the way that oil companies are run. They are dynamic entities that continuously reinvest a material proportion of cashflow back into the ground. Looking at Exxon’s capital spend over the past 7 years and comparing it to shareholder returns makes this very clear.

**Figure 24 Exxon: Capital expenditure and shareholder returns ($m)**

Exxon’s investment in developing new reserves and resources has doubled in 7 years, whereas its returns to shareholders have fallen by roughly a third. The percentage allocated to shareholders rather than capital investment has fallen from nearly 60% during 2007-9 to 42% during 2010-13. Rather than withdrawing more capital from the business, Exxon’s rate of investment has accelerated at the expense of cash returns to shareholders.

---

\(^{20}\) IHS point out (accurately) that "The intrinsic value of most publicly traded oil and gas companies is based primarily on the valuation of proved reserves", based on discounted cash flow valuation. However, we disagree with the conclusion that this means that the risk from long-term trends is minimal. IHS Cera, “Deflating the ‘Carbon Bubble’”. 
The IHS Cera "90%" argument is potentially flawed for the same reason. It assumes that capital is steadily withdrawn from the business. We can see this by looking at its hypothetical net present value profile for "company A" as shown in its report.

Figure 145 Hypothetical cumulative NPV profile (%)

It is relatively simple to deconstruct such a cumulative NPV profile (using a ruler) in order to construct the underlying cashflow profile. CTI’s estimate of the cashflow profile needed to replicate the "oil and natural gas" curve is shown below.
It shows a company with a rapidly rising net cashflow over the next two years (surprising given the heavy investment in natural gas) followed by a stable plateau through till year 8. At that stage, net cashflow declines by over two thirds in five years, a fall in excess of 20% annually. If oil majors pursued such a strategy (liquidating assets), the risk to changes in carbon policy (or indeed any other changes in the external environment) would be reduced materially. And the implication of such a strategy would be that capital employed would start to fall, probably in the first third of the period under study. But the industry’s asset base does not show that pattern. Over the past decade, most have increased capital expenditure leading to a rapid rise in capital employed - this means more not less capital is at risk. We showed the rate of increase in Exxon’s capital employed earlier. This is Shell’s. It shows a rise between 2004 and 2013 of 115% of nearly 9% annually. Neither Exxon nor Shell’s investment approach demonstrate the characteristics shown in the hypothetical IHS Cera company.
If Shell and Exxon believe that their proven reserves are safe from "stranding" but accept the need for action on climate, why do they reinvest and by definition transfer the risk to their longer life resource bases? The simple answer is that under their planning assumptions, it adds value. If a project beats a company’s hurdle rate of return for a given set of assumptions, it makes sense to go ahead with investment - in theory. But some oil projects, especially capital intensive ones, can have a lead time from first discovery to first production of 15-20 years. This means that the new capital can be at risk of a changing environment for a material length of time, during which the original planning assumptions - including those on carbon policy - may prove to be incorrect.

Therefore, while Exxon’s comment that its proven reserves are at little risk of “stranding” or becoming “unburnable” may be true, development of new resources by redeploying cash flow from these “robust” proven reserves means that investors’ capital is at a longer-term risk of sub-economic returns should action be taken on climate change. The consequences of that could include higher consumer taxes on energy leading to lower demand and lower well head prices. It is also possible that in some countries, carbon capture is mandated for oil fields, leading to higher costs or that direct emissions from oil (and gas) fields are subject to an upstream carbon tax - as was implemented (and subsequently revoked) in Australia. It should be worrying for investors that Exxon, although recognising the need for action on climate change, continues with an investment strategy that assumes business as usual. This suggests it may not be prepared for such a transition - much as it was unprepared for the collapse in US gas prices caused by the shale revolution.

We believe that Exxon would be serving its shareholders better if it discussed how best to manage this risk by, for example, curbing investment in high-cost, long-life projects and returning additional cash to investors. Under its business as normal approach, Exxon’s carbon gamble is just rolled forward.
10. The Relationship between Economic Growth and Fossil Fuel Demand

Will fossil fuel demand continue to grow inexorably?

“The universal importance of accessible and affordable energy for modern life is undeniable. Energy powers economies and enables progress throughout the world.”

Exxon’s letter contains the fairly uncontroversial forecast that world growth in population and GDP will continue. It then draws the conclusion that together these will drive increased energy use with fossil fuels continuing to dominate the energy landscape. Its projection of continued growth (2014-2040) in natural gas demand is reasonable from an environmental perspective. But its view that coal demand will merely stagnate and that oil demand will grow at 0.7% annually appears optimistic to us (for instance, the IEA’s New Policies Scenario assumes coal demand growth of 0.6% per annum).

Does economic growth require increased fossil fuel use?

It is undeniable that in the past, there has been a good correlation between economic growth and energy use. However, whilst this has been true globally, many OECD countries have seen rising GDP but falling energy demand in more recent times. For example, Germany, Japan and the US have all seen rising GDP but falling energy demand over the last decade.

Figure 28 Absolute energy use (kt of oil equivalent, rebased)

Much will depend on the trajectories of economic development of the developing nations. But they do not necessarily need to follow the “old” historic trend of increased fossil fuel consumption that

---

21 IEA, World Energy Outlook 2013, p58 table 2.1. Energy demand from coal grows from 3,773 ktoe (kilotons of oil equivalent) in 2011 to 4,428 ktoe in 2035, absolute growth of 17% over the period
characterised the OECD during the second half of the twentieth century. They have both greater choice in affordable energy solutions and greater awareness of the social costs (healthcare, subsidies, infrastructure damage, etc) of climate change.

A fixed-line telephone system is neither necessary nor appropriate for many developing countries, which is why they are going straight to mobile telecommunications. In the same way, these countries can to some extent skip straight to renewable electricity sources and electric vehicles, rather than become ever more dependent on fossil fuel imports as their economies grow. This is demonstrated by pace and scale of the development of the renewables industry in China. Moreover, with respect to oil, note that the relatively short replacement cycle for cars and trucks – roughly 10 years, as opposed to several decades for power plants, buildings, and industrial facilities – accelerates the possibilities for demand-displacement. Introduction of, for example, a new battery technology that significantly reduced the cost of electric vehicles could create a possibility for countries (particularly those in the developing world) to begin rapidly reducing the volume of oil used in transport.

In terms of improving living standards, in many developing parts of the world there are large parts of the population who do not have access to energy. Programs to provide off-grid decentralised renewables to power lights for education or charge mobile phones for money transfers are often the most appropriate affordable way of providing access to energy, rather than putting in large infrastructure projects to connect everyone to the grid.

This development pathway does not fit with Exxon’s business model. As has been shown in other sectors, however, it is often difficult for incumbents to accept that change may be possible, indeed probable, until it is too late.

**Demand for oil in the IEA New Policies Scenario**

In 2013, Exxon’s energy production mix was split 55%/45% between oil and natural gas and oil is projected to grow in importance over the next five years or so. Some of Exxon’s gas production is sold at oil-linked prices: the percentage of production which was oil-linked in 2013 was 64%. So despite a sizeable position in natural gas and natural gas infrastructure, Exxon carries a high degree of "oil risk"

---


23 The IEA, for example, notes that over 15% of the world’s population lacks access to electricity and 2.6 billion people still use biomass as the primary fuel for cooking. IEA, "Energy Poverty," http://www.iea.org/topics/energypoverty.


25 ExxonMobil, 2014 Analyst Meeting, slide 32

Exxon forecasts that in 2014, liquids production will grow by 2% while gas production falls by the same percentage, followed by 4% growth in liquids production over the period 2015-17 compared to only 1% growth in gas production.
As discussed in CTI's May 2014 report “Oil Demand: Comparing Projections and Examining Risks”\textsuperscript{26}, in the IEA New Policies Scenario global oil demand through 2035 grows at a compound annual growth rate of 0.6\% (i.e. roughly half the rate of growth in global oil demand from 2000-2012).\textsuperscript{27}

Figure 29 IEA oil demand projections – 2035 demand of 101 MBPD (New Policies Scenario) vs. 78 MBPD (450 Scenario)

![Graph showing oil demand projections](image)

*Note:* Calculations of 2012-2035 Delta (i.e. absolute change) and CAGR assume original WEO 2013 value for 2012 world oil demand of 87.4 MBPD (rather than the IEA’s more recent 2012 estimate of 90.1 MBPD)

*Source:* IEA, CTI analysis 2014

Moreover, future growth is concentrated in two regions (emerging Asia and Middle East) and two sectors (transport, particularly road transport, and petrochemicals). In the IEA New Policies Scenario, 80\% of projected gross oil demand growth through 2035 is accounted for by these two regions. Conversely, in OECD countries, a combination of slower economic growth, more efficient use of oil (particularly in transport), and displacement of oil by other fuels reduces total demand for oil. This clearly has implications for Exxon’s oil infrastructure (pipelines, refineries petrochemical plants and retail outlets) within the OECD.


Despite the slowdown in growth in demand, the IEA New Policies Scenario requires upstream investment to produce an additional 470 billion barrels of oil to meet demand out till 2035;\textsuperscript{28}

\textbf{Outlook for oil beyond 2035 shows continuation of negligible demand growth}

The IEA 4DS Scenario (where long term global temperatures rise by 4°C) is similar to the New Policies Scenario through 2035 but extended till 2050.\textsuperscript{29} Under this scenario, global oil demand in 2050 is 95 million barrels per day (MBPD). So 4DS \textit{suggests a marked slowdown in growth in global oil demand around 2020 and a gradual decline beginning after 2035}. Moreover, even a 6DS Scenario (an increase of 6°C) – which would incur significant climate-related disruptions to the planet – projects 2050 global oil demand of only 100 MBPD.

CTI believes that there are a number of reasons (other than climate policy) why future oil demand growth may fall short of the IEA’s New Policies/4DS projections.\textsuperscript{31} These included:

- Slow growth in Asian emerging economies
- Rapid increases in transport efficiency
- Local air pollution control
- Curtailment of oil consumption subsidies
- Substitution by natural gas, electricity and solar

Therefore, the key point is that - even ignoring the potential for the enactment of more robust climate policies and other sources of demand destruction - we believe demand for oil is likely to

\textsuperscript{28} At the 2013 level of global oil consumption, 470 billion barrels is equivalent to roughly 14 years’ worth of oil).
\textsuperscript{30} Through 2035 the 6DS scenario resembles the Current Policies Scenario.
\textsuperscript{31} Energy Transition Advisors and Carbon Tracker Initiative, \textit{Oil demand}, 16-30.
grow modestly until 2035 before beginning to decline thereafter. Robust climate policy or other demand-reducing trends would bring forward the tipping point when global oil demand begins to decline, perhaps as early as the 2020s. Exxon is seems to be planning for an environment of perpetual growth and appears unwilling to consider otherwise. This could leave it unprepared for a shift in the oil market, much as it was unprepared for the structural change in the US gas market following the shale boom.

**While hydrocarbons will still be needed under lower-carbon scenarios, demand will be lower**

“The IEA in its World Energy Outlook 2013 examined production of liquids from currently-producing fields, in the absence of additional investment, versus liquids demand, for both their lead “New Policies Scenario” and for a “450 Scenario.” As shown in the chart above, in both scenarios, there remains significant liquids demand through 2035, and there is a need for ongoing development and investment. Without ongoing investment, liquids demand will not be met, leaving the world short of oil.”

Most energy demand forecasts show that some level of fossil fuel production will be required in the future. The natural decline in existing fields will mean that continued reinvestment and development of new sources will be required. However, the level of investment will clearly be lower in (say) a 450 scenario when compared to Exxon’s "business-as-usual" scenario. The IEA’s 450 Scenario requires 55 MBPD of new capacity in 2035, compared to 75 MBPD under its New Policies Scenario. This represents a 27% reduction in production. Capex requirements will be similarly lower. Companies that continue to invest at the levels needed for "business-as-usual" run the risk of seeing their returns fall as prices react to weaker demand.

**11. The Energy Transition**

**Transition to low-carbon may take less time than Exxon expect**

“We believe the transition to lower carbon energy sources will also take time, despite rapid growth rates for such sources. Traditional energy sources have had many decades to scale up to meet the enormous energy needs of the world. As discussed above, renewable sources, such as solar and wind, despite very rapid growth rates, cannot scale up quickly enough to meet global demand growth while at the same time displacing more traditional sources of energy”

While renewable energy sources show the fastest rate of growth in Exxon’s Outlook for Energy 2014, they come from a low base and only represent 5% of the total energy mix by 2040. Exxon point to the slow pace of historic transition from biomass, to coal, to oil in support of its argument.

---

32 ExxonMobil, Energy and Climate – Managing the Risks, page 6
Whilst the inertia in the global energy system will certainly mean that reducing atmospheric concentrations of CO₂ emissions is indeed a long-term challenge, this comparison neglects the impact policy can have on demand. One only has to look at the difference in car efficiency in Europe relative to the US and the consequent divergence of oil demand trends in the 1980s. The Europeans ratcheted up gasoline prices to encourage efficiency whereas the US left them little changed.
If the US had followed a European policy, US gasoline demand would be nearly 20% lower - equivalent to a reduction in oil demand of nearly 2 MBPD.

Furthermore, sometimes policy is not even needed to produce a dramatic movement in energy markets; for example, in the period from 2005 to 2013, the EIA estimates that primary US energy production from coal has fallen by 14% while natural gas has risen by 34%, meaning that even in this short time frame coal’s share of energy production has fallen from 33% to 24%.

Thankfully, steps to reduce emissions and promote low-carbon energy sources are occurring, and scenarios such as the IEA 2DS show pathways to extending this effort into the future. For example, the International Renewable Energy Agency (IRENA) recently estimated that doubling global investment in renewable energy (i.e. from $224 billion in 2013 to an average of $460 billion per year) could, by 2030, quadruple the share of global energy generated from modern low-carbon renewable energy sources (a category that excludes traditional biomass) from 9% currently to 36% in 2030.

**IEA Scenarios: Selective use**

“For example, the IEA predicts that energy-related emissions will grow by 20%, on trend but slightly higher than our Outlook”

Exxon claims that the IEA predicts energy-related emissions will grow by 20%, referring (we assume) to the IEA’s modelled growth of energy-related CO₂ emissions from 31.2GtCO₂ in 2011 to 37.2GtCO₂ in 2035 under its New Policies Scenario. The New Policies Scenario is the central scenario in the World Energy Outlook, and includes “policies and measures that affect energy markets and that had been adopted as of mid-2013” and “also takes account of other relevant commitments that have been announced, even when the precise implementation measures have yet to be fully defined.”

Whilst the New Policies Scenario is the central scenario in the World Energy Outlook, it is one of three that the IEA use (the others being the Current Policies Scenario, which takes into account “only those policies and measures affecting energy markets that were formally enacted as of mid-2013”, and the 450 Scenario, which “shows what is needed to set the global energy sector on a course compatible with a near 50% chance of limiting the long-term increase in the average global temperature to two degrees Celsius”).

---

33 EIA, *Monthly Energy Review June 2014*, p5 table 1.2
http://www.eia.gov/totalenergy/data/monthly/pdf/mer.pdf
34 http://www.jeremyleggett.net/2014/06/doubling-renewables-lower-cost-than-conventional-equivalent-irena/ The IRENA projections would also require average annual subsidies for renewable energy through 2030 of $315 billion per year (versus 2012 global subsidies of $100 billion for renewable energy and $544 billion for fossil fuels).
In fact the IEA is clear that its role is purely to provide information, rather than make specific predictions:

“The objective is to provide policymakers, industry and the general public in countries all over the world with the data, analysis and insights needed to make judgements about our energy future, as a basis for sound energy decision making.”

Furthermore, by including other scenarios in its analysis, the IEA expressly considers other possible outcomes based on other sets of inputs. While the New Policies scenario is one possible case therefore, it is purely the outcome of a given set of assumptions rather than the IEA’s expectation of what will happen. It could not possibly be otherwise when it doesn’t include any provision for commitments that might be made after mid-2013, given that the direction of travel is clearly in the direction of more regulation rather than less; the US and China’s recent commitments on CO₂ emissions spring to mind as high-impact examples that have been announced since the publication of the IEA’s report. When Exxon’s Outlook is comparable to a scenario that does not include any currently unannounced action to reduce carbon output, it is unsurprising that emissions on this scale are modeled. Should Exxon’s model be realised, however, it may mean the world has failed to address climate change adequately and will have to deal with the consequences.

If we consider the 450 Scenario, rather than the New Policies Scenario, the implications for the oil industry are rather gloomier. Carbon emissions in this case are 21.6GtCO₂ in 2035, a fall of 31%, driven in part by a fall in oil demand of 13%. In its recent World Energy Investment Outlook, the IEA concludes that under the 450 Scenario, $180bn in upstream oil and gas investments could potentially be stranded37, whilst stating that this figure assumes a high degree of clarity for investors regarding the evolution climate policies, and that the actual risk of fossil fuel investments being stranded is higher than they show. To be clear, the IEA does not state that the 450 Scenario is a prediction any more than it does the New Policies Scenario, they are both model outputs from a given set of inputs, with no probability of likelihood assigned.

By claiming that the IEA predicts that actual carbon emissions will follow the pathway modelled in the theoretical New Policies Scenario, and by implication that it predicts that there will be no future policy commitments/legislation that will impact the output of greenhouse gasses, Exxon appears to be using selective elements of the IEA’s findings and misunderstanding the IEA’s role.

**Renewable energy sources are increasingly economic**

“The cost limitations of renewables are likely to persist even when higher costs of carbon are considered.”

In contrast to the increasing costs of fossil fuel development, some renewables have experienced dramatic cost deflation in recent years. For example, Citigroup analysts calculate the average cost of

---

a solar panel has come down by 75% in the last four years, and note in addition that there are then no continuing fuel costs after installation. For every doubling of installed capacity since 1972, average solar PV module costs have fallen by 22% on a $/watt basis. This trend appears to have accelerated; since 2008, for every doubling of installed capacity, solar PV module costs have fallen by 40%, although this rate is considered unlikely to be sustainable (Citi estimate the actual rate as potentially 30%).

Figure 33 Solar PV module costs since 1972

Source: Citigroup

Domestic “socket” parity has already been reached in Germany, Italy, Spain, Portugal, Australia and the Southwest states in the US, and this point will increasingly arrive in a broader range of markets as the technology continues to get less expensive.

Rather than being limited by cost as far as 2040, as Exxon predicts, renewables are economic in some areas already, and will become ever more so – regardless of the price levied on carbon. As the IEA note, “the most dynamic technologies – onshore wind and solar PV – have reached, or are approaching, competitiveness in a number of markets without generation-based incentives.”

Carbon taxes too costly?

“Non-fossil energy sources, like nuclear and renewables, along with carbon capture and sequestration, are deployed in order to transform the energy system. Costs for CO2 required to drive this transformation are modeled. In general, CO2 costs rise with more stringent stabilization targets and with time. Stabilization at 450 ppm would require CO2 prices significantly above current price levels, rising to over $200 per ton by 2050. By comparison, current EU Emissions Trading System prices are approximately $8 to $10 per ton of CO2.”

---

38 Citigroup, Energy Darwinism, p14
39 Citigroup, Energy Darwinism, p48
40 Citigroup, Energy Darwinism, p50
http://www.iea.org/Textbase/npsum/MTrenew2013SUM.pdf
In its letter, Exxon points out that carbon costs are currently $8-10/tCO₂, but would need to rise to $200/tCO₂ by 2050 in order to sufficiently influence demand to drive transformation, according to the MIT IGSM model contained in a 2007 US Climate Change Science Assessment Program report. It is then further stated that an increase to $100/tCO₂ by 2030 would cost the average American household an additional $2,350 per annum for energy, and $4,500 per annum at $200/tCO₂. The implication from Exxon’s comments is that such a level of taxation would prove too high a burden for the US consumer. But we note that the current European tax on transport fuels is around $4/US gallon. Converted to a carbon tax, this is over $400/tonne. And the trajectory of the European economies and oil demand show such a level is bearable.

But the most glaring shortcoming is that Exxon’s analysis ignores the fact that carbon pricing is a gross cost and ignores the benefits such as the savings from an improvement in energy efficiency. Also, the carbon price is a tax so the government can use the funds raised to lower other taxes for employees or employers. In purely fiscal terms, therefore, a carbon tax balanced by lower corporate/personal taxes could be tax neutral. The money is not lost, only used to incentivise behaviour and drive transformation in a beneficial way. As the so-called high cost of moving to a lower-carbon economy is central to Exxon’s argument that this transition will not happen, and accordingly feeds into the basis of Exxon’s expectations of demand for its products, to not consider the associate benefits of the change strikes us as a gross oversimplification with far-reaching implications.

**Likelihood of climate policy: costs of action vs. costs of inaction**

“Our Outlook for Energy does not envision the “low carbon scenario” advocated by some because the costs and the damaging impact to accessible, reliable and affordable energy resulting from the policy changes such a scenario would produce are beyond those that societies, especially the world’s poorest and most vulnerable, would be willing to bear, in our estimation.”

Exxon’s view on the economic costs of mitigating global climate change reflects a widely-held belief within the industry. There is a need to be similarly frank, however, in (1) estimating the actual size of the “costs”; (2) understanding that these costs are often better thought of as investments; and (3) comparing mitigation costs against the costs of inaction and resulting climate-related impacts to the economy.

The aggregate economic costs of mitigating global climate change will vary significantly depending on, among other things, when mitigation efforts start and how many countries participate in them. As a benchmark, the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC) considers a scenario where all countries immediately adopt a single global carbon price (and related mitigation efforts) and all key technologies are available. Under these conditions, a median estimate suggests that a 450 ppm scenario will reduce global GDP growth through 2100 by 0.06

---

percentage points per annum (with most of the cumulative impact occurring in the second half of the century). In other words, if in a baseline scenario through 2100 global GDP will grow at an annualised rate of 1.6-3%, a 450 ppm scenario reduces the annualised growth rate to 1.5-2.9%. The IEA recently estimated energy investment over the period to 2035 as $48tr under a business as usual scenario, compared with $53tr under a scenario where global warming is limited to 2°C (i.e. an increase of 10%)\(^3\). Such costs are highly manageable, particularly when compared with the potential benefits of reducing emissions, discussed below.

The estimated costs of mitigation do increase, however, as a result of limited availability of low-carbon technologies and/or delays in adoption of additional mitigation efforts. Even in scenarios of significant delay and limited availability of low-carbon technologies, however, median estimates of the impact of mitigation costs on annualised GDP growth through 2100 generally remain small fractions of one percentage point. Moreover, that procrastination in the transition to a low-carbon world will raise the costs of achieving such a world, however, does not excuse companies from grappling with the implications of such a transition - both in terms of current low-carbon developments and potential future developments.

Recognising that the costs of climate mitigation can be manageable, it is further worth noting that a large portion of these costs are better thought of as *investments*. Even ignoring the benefits of lower carbon pollution, investments in low-carbon technologies yield a return in the form of reduced expenditures on fossil fuels. For example, in the IEA’s 2DS scenario investments in clean energy through 2050 yield net fuel savings of $60 trillion (or an average of $1.5 trillion annually). Assuming a 10% discount rate, such savings have a net present value of $5 trillion and highlight the affordability of moving to a low-carbon energy sector.\(^4\) Investments in low-carbon technologies will also yield significant benefits in the form of, among other things, cleaner local air quality.

The costs of climate mitigation look even more affordable when compared against the costs of inaction. The 2006 Stern Review of the Economics of Climate Change observes that:

> Climate change will affect the basic elements of life for people around the world – access to water, food production, health, and the environment. Hundreds of millions of people could suffer hunger, water shortages and coastal flooding as the world warms.\(^5\)

Taking these impacts into account, the Review found that "the overall costs and risks of climate change will be equivalent to losing at least 5% of global GDP each year, now and forever."\(^6\) The Review further argued that including a "wider range of risks and impacts" could increase the costs of inaction substantially above this level (i.e. to as much as 20% of global GDP each year).\(^7\)


\(^4\) IEA, *Energy Technology Perspectives 2012*, 38.


\(^6\) Stern

\(^7\) Stern, vi.
Moreover, since publication of the Stern Review, its lead author has concluded that the Review significantly underestimated potential damages from climate change over the course of this century.\textsuperscript{48} Experts have also noted a number of reasons why economic models tend to underestimate potential damages from a warming climate, including difficulty accounting for (1) declines in labor productivity due to a warming climate (e.g. due to more frequent heat waves); (2) write-offs in the value of certain assets as a result of more extreme weather events; and (3) rising premiums attached to freshwater, dry land, and other natural resources.\textsuperscript{49}

Exxon itself states that it “engineers its facilities and operations robustly with extreme weather considerations in mind” and, in \textit{Energy and Climate}, expressly links this to climate change - “Given the spatial and temporal uncertainties of many extreme weather events, particularly with respect to future changes in climate, facilities are generally engineered to be resilient to extreme event ‘tails’.”\textsuperscript{50} Exxon is thereby demonstrating and already incurring some of the costs that are required to mitigate the effects of climate change; it would be far preferable for all if climate policy were made commensurate to the challenge of keeping greenhouse gases low, and hence these extreme weather events were avoided altogether.

Though analysts continue to extensively study the magnitude of precise impacts (as well as debate how to discount those impacts), there is broad agreement that the potential costs of inaction far exceed the costs of mitigation described above\textsuperscript{51}. Exxon’s characterisation of low carbon scenario as economically “damaging”, therefore, does not stand up to scrutiny.

\textbf{The social implications of preventing climate change}

“However, this level of GDP growth requires more accessible, reliable and affordable energy to fuel growth, and it is vulnerable populations who would suffer most should that growth be artificially constrained.”

“Increasing energy costs leads to a scarcity of affordable, reliable and accessible energy and can additionally lead to social instability”

At a macroeconomic level, historically countries have industrialised based on energy from fossil fuels. This has not necessarily prevented poverty or inequality within those countries, nor the “social

\textsuperscript{48} Heather Stewart and Larry Elliot, "Nicholas Stern: 'I got it wrong on climate change - it's far, far worse''", The Guardian, Jan 26 2013, http://www.theguardian.com/environment/2013/jan/27/nicholas-stern-climate-change-davos. In explaining the upward revision to estimates of potential damages, Lord Stern notes that “emissions are growing much faster than we'd thought, the absorptive capacity of the planet is less than we'd thought, the risks of greenhouse gases are potentially bigger than more cautious estimates and the speed of climate change seems to be faster.”


\textsuperscript{50} ExxonMobil, \textit{Energy and Climate}, p20

instability” that Exxon warns of, as can be seen in places like Nigeria or other countries that have experienced the “resource curse”. Exxon again conflates “energy” with fossil fuels; there is no reason that decentralised renewables cannot be the required “accessible, reliable and accessible energy” rather than fossil fuels, saving developing economies from relying on expensive oil imports.

Contrary to Exxon’s claims that it will be the most vulnerable that have most to lose efforts to mitigate CO₂ emissions, this again focuses purely on the economic costs, and completely ignores the benefits (economic and otherwise) from having a low carbon atmosphere. Studies have shown that, inasmuch as developing countries follow economic development pathways that contribute to high levels of future warming, the impacts of such warming will be harshest for the world’s poorest populations (i.e. those living in developing countries).  

**Climate policy not binary - regional, national, and sector-level policies**

“While the risk of regulation where GHG emissions are capped to the extent contemplated in the “low carbon scenario” during the Outlook period is always possible, it is difficult to envision governments choosing this path in light of the negative implications for economic growth and prosperity that such a course poses, especially when other avenues may be available, as discussed further below.”

In responding to investor enquiries regarding climate change, many fossil fuel companies advance a common line of argument: that (1) income and population growth necessitate an increase in energy demand; (2) barring robust climate policies, fossil fuels remain the most economical means to meet growing energy demand; and (3) within any time frame relevant to corporate decision-making, actual climate policies are likely to fall far short of those needed to substantially alter demand for fossil fuels.

Limiting future global warming to 2°C is a commitment that 193 nations pledged to pursue in the 2010 Cancun Accords. Whilst many of these nations have yet to enact policies consistent with achieving this goal, as Kepler Chevreux analyst Mark Lewis has observed, “global climate policy is as much about the direction of travel as the speed.” From 2007-2012, the share of global GHG emissions subject to national legislation or emission-reduction strategies rose from 45% to 67%. Moreover, in some cases sub-national governments are leading the way in enacting frameworks that explicitly are consistent with a 2°C scenario – for example California, whose economy-wide carbon

---

55 Mark Lewis, Kepler Chevreux, May 21 2014, http://www.jeremyleggett.net/2014/05/10840/#more-10840
56 IPCC, 28.
cap-and-trade program (begun in 2013) seeks to reduce statewide emissions 80% below 1990 levels by 2050.\(^\text{57}\)

Continuing enactment of new emission-reduction policies by the world’s major CO\(_2\) emitters highlights the need for companies to assess not just what is happening now, but what may happen in the future. To take just two significant recent examples:

- In June 2014, the US Environmental Protection Agency proposed new regulations to reduce CO\(_2\) pollution from the nation’s power plants 30% below 2005 levels by 2030.\(^\text{58}\)
- The day after the US EPA announcement, the chairman of China’s Advisory Committee on Climate Change expressed his view to a conference in Beijing that China should include an absolute cap on CO\(_2\) emissions in its 13\(^\text{th}\) five-year plan (which covers 2016-2020).\(^\text{59}\)

Concurrent action on climate by the world’s two largest CO\(_2\) emitters raises the likelihood of progress in negotiating a new global climate treaty when the current Kyoto Protocol expires at the end of 2015. Even without a new global treaty, however, countries are likely to continue taking incremental steps toward becoming at least more (if not fully) consistent with a 2°C scenario. Rather than simply note how the status quo on global climate policy falls short of ultimate goal, prudent companies will note these steps toward a low-carbon world and consider the consequences for their business models should such steps accelerate in the future.

**Real risk that Exxon is basing its investment decisions on an over-optimistic view of oil’s prospects**

“Each year, ExxonMobil analyzes trends in energy and publishes our forecast of global energy requirements in our Outlook for Energy. The Outlook provides the foundation for our business and investment planning, and is compiled from the breadth of the company’s worldwide experience in and understanding of the energy industry.

Exxon is explicit that its Outlook for Energy is the basis for its investment planning. Management evidently views long-term trends as important, and the period up to 2040 as an appropriate timescale for consideration in decision-making. In the Outlook, Exxon considers many headwinds to oil demand, for example increasing energy efficiency and declining energy intensity. We agree with this approach, and consider the use of a long-term planning horizon appropriate and prudent.

However, as we have mentioned elsewhere in this note, there are a number of points where the Outlook’s view on the future for oil demand might be seen as optimistic or with risks skewed to the downside. For example:

\(^{59}\) Kathy Chen and Stian Reklev, “China plan to cap CO2 seen as turning point in climate talks,” Jun 3 2014, http://uk.reuters.com/article/2014/06/03/china-climatechange-idUKL3N0OK1VH20140603.
• Coal use is flat in the Outlook (i.e. CAGR of 0%), compared to the IEA New Policies Scenario’s modelled 0.6%. Underestimation of coal’s growth would imply higher than expected CO₂ emissions, with most likely negative implications for oil demand (from substitution and increased likelihood of climate action);

• Exxon assumes persistent high costs for renewables, when costs are dropping rapidly and parity with electricity markets has already been realised in some areas (see “Renewable energy sources are increasingly economic” above); and

• CO₂ emissions growth is approximately equivalent to the IEA’s New Policies Scenario, which assumes no further policy action on carbon emissions in the period to 2035, when the direction of travel is clearly towards greater regulation (see “Climate policy not binary - regional, national, and sector-level policies” above).

As humans we are all subject to inherent biases, and it is no surprise for an oil company to be optimistic about its prospects. However, external investors will be concerned that Exxon is willing to “bet the farm” on its own forecasts, where detailed assumptions are not disclosed and there may be limited feedback mechanisms to ensure that a conservative view is taken. We note that view few sources are quoted in Exxon’s report; Exxon’s risk-management (and shareholders’ value at risk) may benefit from greater feedback mechanisms and the consideration of other forecasts/viewpoints.

Whilst Exxon, as would be expected of any forward-thinking company, undertakes scenario analysis in its investment planning:

“Projects are evaluated under a wide range of possible economic conditions and commodity prices that are reasonably likely to occur, and we expect them to deliver competitive returns through the cycles. We do not publish the economic bases upon which we evaluate investments due to competitive considerations.”

The possible scenarios used for evaluation are, however, not disclosed, nor their weightings in the decision-making framework. Given that Exxon discloses that it does not consider a “low carbon” scenario, there will no doubt be questions as which scenarios it does factor into its capital allocation and development plans. Investors may wish to press for further detail on Exxon’s scenarios and their use, in order to ensure that planning is prudent and that there is adequate downside protection in a possible future of lower than expected oil demand. Exxon professes that the first point in its capital allocation approach is to “invest in resilient, attractive business opportunities” – some evidence that this is the case would may reassure doubters.

**Impact of carbon price on project economics: the need to consider impacts on future oil demand and prices**

“We also address the potential for future climate-related controls, including the potential for restriction on emissions, through the use of a proxy cost of carbon…. Our proxy cost, which in

---

60 IEA, *World Energy Outlook 2013*, p58 table 2.1. Energy demand from coal grows from 3,773 ktoe (kilotons of oil equivalent) in 2011 to 4,428 ktoe in 2035, absolute growth of 17% over the period

some areas may approach $80/ton over the Outlook period, is not a suggestion that governments should apply specific taxes”

ExxonMobil disclose that they use a “proxy cost of carbon”, which “seeks to reflect all types of actions and policies that governments may take over the Outlook period relating to the exploration, development, production, transportation or use of carbon-based fuels”62. This proxy carbon cost is stated to be “embedded” in Exxon’s Outlook for Energy, where it is used to derive fossil fuel demand scenarios. Looking ahead to 2040, the projected carbon cost varies from less than $20/tCO₂ in some regions (e.g. Africa and the Middle East) to as high as $80/tCO₂ in other regions. This level of regional detail, for example, helps investors to understand how companies are integrating climate risk into their capital investment decisions.

Exxon’s consideration of a CO₂ price is proper and encouraging, but it is not transparent about how it is applied. 63 For example it is not clear whether the price is applied along the value chain of oil production, (including the largest portion of emissions which come from consumption of the products). It is understandable that Exxon do not consider consumption taxes as a direct cost, but they will have a growing impact on demand and price in the future. Commonality in internal CO₂ prices across major oil companies seems to reflect a consensus of the strong likelihood of increasing measures to reduce carbon pollution. This suggests the "direction of travel" for future climate policy – that emissions regulation will continue to squeeze the margins of fossil fuel projects.

A low carbon future may be more likely than Exxon anticipates

“In assessing the economic viability of proved reserves, we do not believe a scenario consistent with reducing GHG emissions by 80 percent by 2050, as suggested by the “low carbon scenario,” lies within the “reasonably likely to occur” range of planning assumptions, since we consider the scenario highly unlikely.”

Much of Exxon’s report implies that the IEA’s 450 Scenario (where the global increase in temperature is restricted to 2°C by the limitation of atmospheric greenhouse gas content to 450ppm of CO₂), however desirable, is incompatible with continued growth in global energy demand or a continuing major role for fossil fuels in the global energy system. In fact, in the 450 Scenario, total primary energy demand grows at a 0.6% CAGR from 2011-2035 (i.e. at the same rate of increase as global oil demand in the New Policies Scenario).64 Figure 4 below shows that in the 2DS scenario (which is consistent with the 450 Scenario through 2035 but extends out until 2050), global energy demand in 2050 is still 40% higher than in 2009; moreover, fossil fuels still account for 60% of the global energy supply. Both of these projections undermine the idea that the transition away from fossil fuels required in a 2°C scenario is radical or unreasonable or that the energy transition requires a much longer timeframe than is implied by the IEA 450/2DS scenarios. Moreover,

62 ExxonMobil, 17.
Similarly reasonable trajectories for de-carbonisation can be found in low-carbon pathways from Ecofys\(^{65}\) and the European Union.\(^{66}\)

**Figure 34 Total primary energy supply in the IEA 6DS, 4DS, and 2DS scenarios, 2009-2050 (Exajoules)**

![Graph showing energy supply](image)

**Note:** For reference, we convert from EJ to MBPD at a rate of 1 EJ = 0.48 MBPD of oil.  
**Source:** IEA

Fossil fuel consumption, however, will differ significantly depending on actions taken to prevent climate change, increase energy efficiency, deploy low-carbon energy sources, etc. In the case of oil, for example, in 2013 the world consumed 91.4 MBPD\(^{67}\). The IEA’s projected demand trajectory to 2050 varies significantly across their different temperature scenarios; demand at the end of this period is roughly 50 MBPD in the 2DS scenario, compared to 95-100 MBPD in the 4DS and 6DS scenarios.\(^{68}\) Though somewhat less pronounced, the projected level of gas consumption in 2050 also varies considerably depending on actions taken to prevent climate change.

The oil industry’s history is littered with examples where managements missed signals because they were unwilling to examine scenarios they regarded as “extremely unlikely”. The latest example of this was the industry’s dash to shale gas assets (such as Exxon’s $41bn June 2010 acquisition of XTO Energy\(^{69}\)). Simple scenario analysis would have highlighted the risk that a massive ramp-up in the number of rigs drilling for gas would increase supply thereby increasing the risk of downward pressure on US gas prices. Even when gas prices started to slide, the industry - apparently in denial - continued to spend. By viewing the "low carbon scenario" as "extremely unlikely", Exxon appears to be putting on its next set of blinkers.

\(^{66}\) http://ec.europa.eu/clima/policies/roadmap/index_en.htm  
\(^{68}\) CTI calculations based on the data in Figure 4 above assuming a conversion rate of 1 EJ = 0.48 MBPD of oil.  
Exxon acknowledges that there are risks factors relating to its expectations for the demand for its products in the disclaimer on the very first page of its report:

“Statements of future events or conditions in this report are forward-looking statements. Actual future results, including economic conditions and growth rates; energy demand and supply sources; efficiency gains; and capital expenditures, could differ materially due to factors including technological developments; changes in law or regulation; the development of new supply sources; demographic changes; and other factors discussed herein and under the heading “Factors Affecting Future Results” in the Investors section of our website at: www.exxonmobil.com.” [emphasis added]

What is more, in the aforementioned acquisition of XTO Energy, Exxon inserted a clause allowing them to walk away if environmental regulations rendered its unconventional extraction technology uneconomical, expressly acknowledging the possibility of legislation and adverse impacts in its business.70

Having recognised that there are multiple risks to its business, investors would probably find it more comforting if Exxon considered their possible impacts in its business planning. Seriously engaging with the requirements of a 2°C scenario does not imply an immediate need to cease investing in new fossil fuel production. It does imply, however, a need to evaluate how demand and price conditions of a low-carbon world will affect the profitability of future high-cost production. For a report entitled “Managing the Risks” to actually dismiss the risks out of hand, rather than consider the dangers and any steps that could be taken to mitigate them, represents a major shortcoming in our view.

---

70 http://www.ft.com/cms/s/0/ccd8412a-2a11-11df-b940-00144feabcd0.html?siteedition=uk#axzz37dV2mWW
DISCLAIMER

• CTI is a non-profit company set-up to produce new thinking on climate risk. CTI publishes its research for the public good in the furtherance of CTIs not for profit objectives. Its research is provided free of charge and CTI does not seek any direct or indirect financial compensation for its research. The organization is funded by a range of European and American foundations.

  CTI is not an investment adviser, and makes no representation regarding the advisability of investing in any particular company or investment fund or other vehicle. A decision to invest in any such investment fund or other entity should not be made in reliance on any of the statements set forth in this publication.

• CTI has commissioned Energy Transition Advisors (ETA) to carry out key aspects of this research. The research is provided exclusively for CTI to serve its not for profit objectives. ETA is not permitted to otherwise use this research to secure any direct or indirect financial compensation. The information & analysis from ETA contained in this research report does not constitute an offer to sell securities or the solicitation of an offer to buy, or recommendation for investment in, any securities within the United States or any other jurisdiction. The information is not intended as financial advice. This research report provides general information only. The information and opinions constitute a judgment as at the date indicated and are subject to change without notice. The information may therefore not be accurate or current. The information and opinions contained in this report have been compiled or arrived at from sources believed to be reliable in good faith, but no representation or warranty, express or implied, is made by CTI or ETA as to their accuracy, completeness or correctness. Neither do CTI or ETA warrant that the information is up to date.

www.et-advisors.com

www.carbontracker.org

@carbonbubble