

RESERVES REPLACEMENT RATIO IN A MARGINAL OIL WORLD: ADEQUATE INDICATOR OR SUBPRIME STATISTIC?





Icebergs create huge logistical problems for oil companies drilling in the Arctic: they either have to be dragged out of the way of drilling areas or destroyed with hoses. ©ROSE/GREENPEACE

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Written by Lorne Stockman, Research Director, Oil Change International: [lorne \[at\] priceofoil.org](mailto:lorne@priceofoil.org)

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EXECUTIVE SUMMARY

THE RESERVES REPLACEMENT CHALLENGE

The international oil industry has entered an era in which maintaining oil production levels increasingly involves unprecedented risk, escalating costs and tighter margins. The past decade has seen a reassertion of state control over national petroleum resources, which has continued to limit international oil company (IOC) access to easy oil.¹ The bulk of the oil that remains freely accessible to IOCs is technically difficult and expensive to produce such as the Canadian tar sands, ultra-deepwater and the offshore Arctic. BP's Gulf of Mexico disaster highlights the scale of the risks involved in pursuing some of these marginal resources.

We label these resources *marginal oil* as their high cost and high risk places them at the top end of the production cost curve (see Figure 1, p8) and as such they are vulnerable to emerging trends towards efficiency and climate change regulation that may dampen demand growth and stabilise price.² We detail specific risks for each of these resource categories.

To maintain Reserves Replacement Ratio (RRR) rates above 100%, IOCs have increasingly turned to tar sands and ultra-deepwater in the face of the continuing decline in their conventional oil fields. The new exploration frontier, the offshore Arctic, is typical of the high risk, high cost resources that companies are striving to acquire in order to boost reserves in the future.

Our research found that at least four of the top six IOCs have significantly relied on tar sands reserves additions to support RRR rates in the past five years. As a percentage of total liquids additions, tar sands represents between 26% and 71% of reserves additions for these four companies (see Table 1).

However, this is a best estimate that probably understates the case for most of the companies as the publicly available data for reserves additions is highly opaque. There is no disclosure of the role of deepwater resources in reserves additions; most of the data is simply divided regionally. A look at company disclosures of

Table 1: Estimated tar sands reserves additions as a percentage of reserves additions 2005–09³

Companies	As percentage of total reserves additions	As percentage of total liquids reserves additions
ConocoPhillips ⁴	39%	71%
ExxonMobil ⁵	20%	51%
Shell ⁶	16%	34%
Total ⁷	10%	26%
Chevron ⁸	3%	7%
BP ⁹	0%	0%
Average (excl. BP) ¹⁰	19.8%	42.6%

total resources suggests that the trend towards marginal oil is only likely to intensify (see appendix).

New business models: profits without reserves

Adding to the changing risk landscape, created by the rising dominance of marginal oil resources in IOC reserves, is the emergence of new business models that do not necessarily boost reserves figures but nevertheless generate profits. The service agreement contracts signed by some IOCs in Iraq are prime examples.¹¹

The analyst community may need to modify existing valuation methods or develop new ones to assess and value companies in light of the changing landscape. Reserves replacement in particular no longer appears straightforward in its reflection of company performance and value.

It may also be the case that the existing valuation model, with its emphasis on the replacement of hydrocarbon reserves, is encouraging risk taking because it fails to assess the relative risks of accessing different hydrocarbons or, for that matter, alternative modes of profit generation. Traditional valuation models that primarily value hydrocarbon production growth and reserves replacement appear increasingly inadequate in a carbon constrained economy.

This briefing details the increasing challenges being faced by IOCs as they struggle to maintain business as usual. It highlights the changing landscape and raises difficult questions about the role investors and analysts might play in helping or hindering the transition to more flexible business models for oil companies.

ENDNOTES

- 1 Dr Vlado Vivoda, 18 August 2009. *Resource Nationalism, Bargaining and International Oil Companies: Challenges and Change in the New Millennium*. Australian Institute of Energy. http://aie.org.au/Content/NavigationMenu/OilGasSIG/InterestingUsefulArticles/ISA09_Vivoda.pdf
- 2 IEA, World Energy Outlook 2010.
- 3 2005–2009 average and excluding cost/price effects unless otherwise noted.
- 4 ConocoPhillips reserves are primarily in situ resources. Figures were primarily drawn from the company's 2010 10-K filing. Based on a sample size of only three years in the five year period.
- 5 We calculated 22% for tar sands additions 2006–09 excluding cost/price effects, and 20% for 'heavy oil/tar sands' 2005–09. Here, we present the smaller of the two values. Figures for the liquids column were primarily drawn

- from the company's 2010 and 2008 10-K filings, and the company's 2009 Financial & Operating Review.
- 6 Including cost/price effects.
- 7 Based on assuming that the total 5 year tar sands additions are covered in the single number reported by Total SA in 2009.
- 8 Based on a sample size of only two years in the five year period.
- 9 On 29 November 2010, Husky Energy announced project sanction for its joint venture with BP, the Sunrise SAGD Project. This means that BP will book its first proven tar sands reserves in 2011. The project is scheduled to produce first oil in 2014. www.huskyenergy.com/news/2010/husky-energy-announces-major-strategic-growth-initiatives.asp
- 10 Calculated using [average annual TS additions] / [average annual total additions].
- 11 Arthur D. Little, 2010. New business models for the international oil company in Prism 01/2010. Available from www.adl.com following free registration.

RESERVES REPLACEMENT RATIO IN A MARGINAL OIL WORLD: ADEQUATE INDICATOR OR SUBPRIME STATISTIC?

THE RESERVES REPLACEMENT CHALLENGE

Investors and analysts use a number of valuation indicators to assess the performance of oil companies. One such indicator, reported annually, is Reserves Replacement Ratio (RRR). RRR measures the amount of proved reserves added to a company's reserve base during the year relative to the amount of oil and gas produced.¹ Naturally, the ideal situation is one in which RRR is consistently over 100% as this would indicate that the company is replacing more oil and gas than it is producing. A company that is delivering RRR at a rate persistently below 100% is clearly running out of oil and gas.

But, as we enter the second decade of the twenty first century, the opportunities for international oil companies² (IOCs) to acquire new reserves are narrowing considerably. The past decade has seen a reassertion of state control over national petroleum resources, which has continued to limit IOC access to *easy oil*.³ The companies have met this challenge for decades with the development of technology and engineering that has enabled oil production in technically difficult locations and conditions, such as the North Sea, Alaska and in ever deeper waters around the world.

In the last decade, rising demand for oil and the associated high oil price have driven companies to increasingly produce oil from unconventional and costly sources such as the Canadian tar sands. As we look towards the coming decade, IOCs are exploring for oil in ultra-deepwater and in the oceans of the Arctic region, where climate change is rapidly thawing the ice that has hindered exploration and production in the past. Many companies are also looking at unconventional resources such as tar sands and oil shale outside of Canada in countries as diverse

as the Republic of Congo (Brazzaville), Venezuela, Jordan, China and Madagascar.⁴

As IOCs push into these frontiers, it is becoming increasingly clear that marginal resources present a range of challenges arguably greater than the industry has ever faced. Furthermore, the spoils of marginal oil are no longer the preserve of the IOCs. National Oil Companies (NOCs) are increasingly acquiring rights in international plays encroaching on the IOCs' traditional territory.

The above challenges justify examining whether RRR is actually an effective indicator of value and asking the following questions:

- ⊗ If reserve additions are made with oil that is costlier and riskier than the oil being replaced, does the RRR indicator adequately value the additions?
- ⊗ Is there enough transparency within reserves additions reporting to enable investors to judge risk?
- ⊗ Does RRR tell investors enough about the potential or otherwise of the additions made in that year?
- ⊗ Are companies taking excessive risks because of perceived pressure from investors to maintain RRR?
- ⊗ If such pressure exists, is it in the interests of investors to de-emphasise RRR and allow companies to adopt more flexible business models?
- ⊗ Would reducing emphasis on RRR render diversification into low carbon technologies more attractive?

RISING COSTS, RISING RISKS

Oil is becoming more expensive for IOCs to find and produce. While there remain very limited opportunities to gain equity production in countries belonging to the Organization of the Petroleum Exporting Countries (OPEC), the scope for reserves replacement is becoming tighter as non-OPEC conventional oil reaches its peak. The specialised equipment and skills associated with finding and developing oil reserves in ultra-deepwater and the offshore Arctic are raising exploration costs to unprecedented heights,⁵ while the extreme conditions and remote locations entail ever greater risks. Although Canadian tar sands present relatively little exploration risk as resources are shallow, high capital expenditure and operational costs squeeze profit margins considerably.

While rising oil prices reflect the increasing cost of these resources it is not clear that demand and price will always support their production. If, as many analysts are increasingly suggesting,⁶ demand were to peak and decline in the coming decade in response to the rising cost of oil and the parallel imperative of limiting carbon emissions, the costliest resources in the market clearly face the greatest threat.

There is little doubt that these marginal resources make up the majority of the remaining oil available to IOCs. The International Energy Agency (IEA) suggests that non-OPEC conventional oil production likely peaked in 2010.⁷ Unconventional oil, dominated by Canadian tar sands, is expected to counter this decline in the medium term and raise overall non-OPEC liquids production in the long term. Ultra-deepwater and possibly Arctic resources may also contribute to offsetting the decline in a business as usual demand scenario.⁸

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Demand dependent

But the circumstances under which the growth in production of these marginal resources takes place is far from assured.

Increasingly, analysts are suggesting that high oil prices, and the energy security fears they inspire, could trigger sufficient

adoption of efficiency measures to bring about a global oil demand peak before 2020.⁹ This would stabilise oil prices rendering many marginal oil sources uneconomic.

For example, Deutsche Bank produced a thought piece in October 2009 stating that *'the end is nigh for the age of oil'*.¹⁰ The basic thesis was that a return to high oil prices in the next few years would give a boost to the nascent efficiency drive already taking place primarily in the US and China. The accelerated take up of vehicle efficiency technologies such as the hybrid, plug-in hybrid and in the longer term, the electric vehicle, would bring about a peak in oil demand by 2016. As a result Deutsche Bank stated that *'The value of high capex intensity, long lead time, currently un-developed oil, such as undeveloped Canadian heavy oil sands, oil shales, and Brazilian pre-salt and other ultra-deepwater plays could be far lower than the market currently expects'*.¹¹

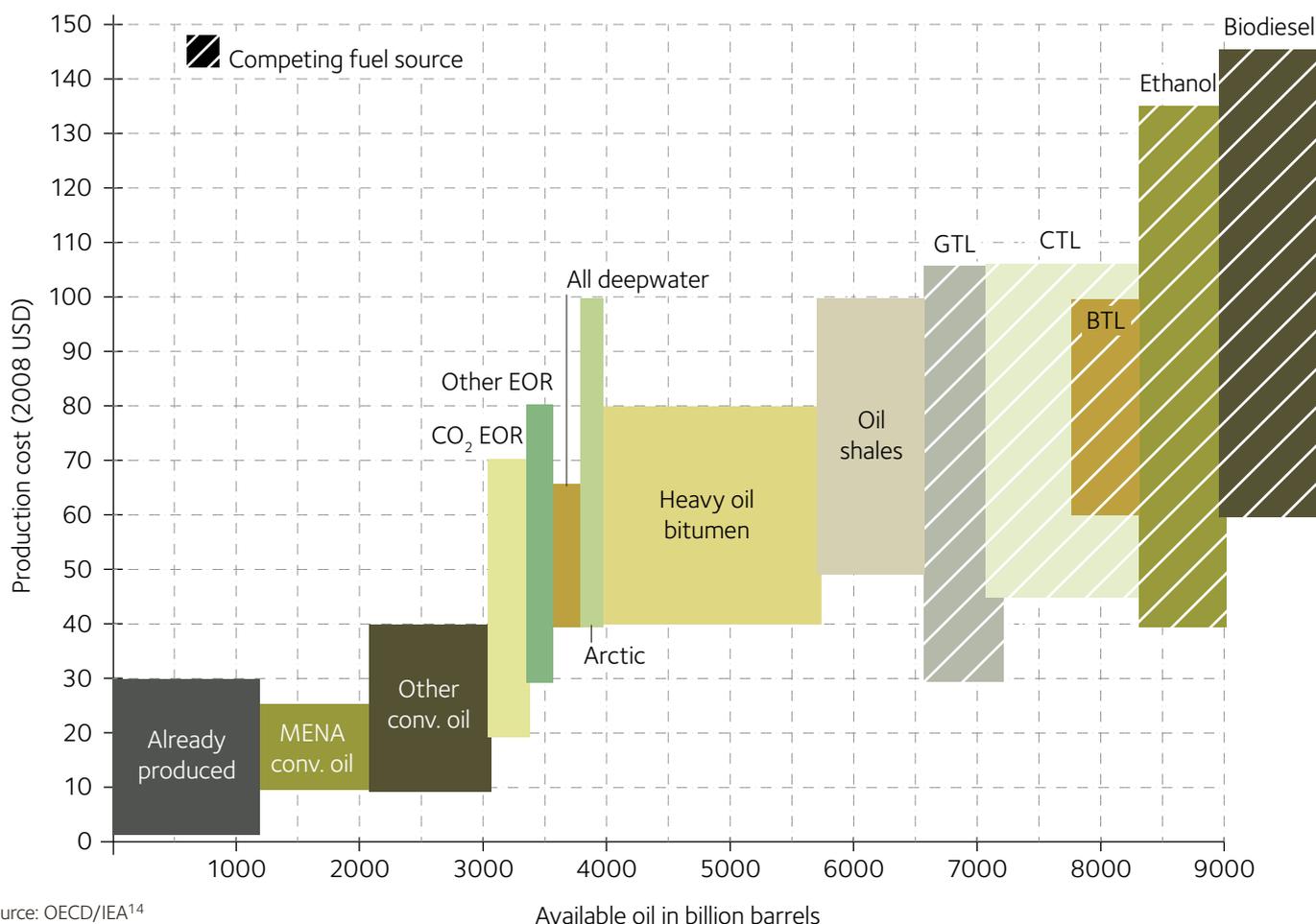
Incompatibility with climate change goals

The IEA suggests that the development of these resources, especially the offshore Arctic, Canadian tar sands and other unconventional oil such as oil shale, is significantly dependent on failure to adopt and implement effective policy to prevent climate change rising above the critical 2°C mark;¹² a stated aim of most of the world's governments. Should policies described in the IEA's 450 Scenario, which details the energy balances necessary to achieve that aim, be adopted and successfully implemented, demand for oil should peak before 2020.¹³ In this situation, the IEA suggests that the price of oil is likely to remain relatively steady in the long term and many of the more expensive and risky oil resources will stay in the ground due to lack of demand.

Deutsche Bank's analysis may be considered hasty and the idea that key governments will implement climate policy in time to prevent a 2°C rise in global temperatures may be considered optimistic. However, the trend towards greater efficiency and the increasing urgency to reduce CO₂ emissions clearly constitutes a threat to companies whose reserves are increasingly concentrated in the most expensive to produce resources.

Figure 1 shows a broad estimate of the range of costs for different categories of oil production. Given that the IOCs' opportunities for reserves growth are almost exclusively concentrated in the more expensive forms of production, the threat of demand destruction coupled with the additional operational risks described in this report, warrants a closer examination of the hazards of reserves replacement.

Figure 1: IEA oil production cost curve (not including carbon pricing)



CANADIAN TAR SANDS

While Canadian tar sands present little exploration risk, producing oil from the viscous bitumen is currently among the most expensive commercial oil production in the world. Enormous capital expenditure is required to construct a typical tar sands project. The latest tar sands mine to come on stream, Shell's Jackpine mine, cost \$14 billion (bn) to create 100,000 barrels per day (b/d) capacity and was cited by Shell's head of tar sands production as being 'some of the most expensive production that we have'.¹⁵ It will require a minimum oil price of \$70–75 a barrel to turn a profit.

In situ projects may be less capital intensive, especially if they are not integrated with upgraders, but they face high operational costs and lower returns for the un-upgraded product. Additionally, many in situ projects are facing disappointing results with recovery rates and the crucial operating cost factor of steam-to-oil ratio.^{16,17}

Analysts have expressed concern about the 'narrowing window of profitability' for tar sands production citing increasing environmental regulations and constraints on resources such as water and natural gas as adding to the already high costs.¹⁸ Costs related to land reclamation are likely to have been

underestimated raising the risk of large unplanned for expenditures in the future as it is far from certain that such costs will be borne by Albertan taxpayers.¹⁹

All the major IOCs now have significant tar sands reserves and substantial interests in a range of projects. Yet the vulnerability of tar sands production growth was demonstrated in 2008 when following the oil price crash to \$35 per barrel in the last quarter of that year, all projects that had not yet broken ground were put on hold. Of some two million barrels per day (mb/d) of non-OPEC production capacity that was shelved in this period 1.7mb/d, or 85%, was Canadian tar sands production.²⁰ While oil prices have since recovered and many projects have started to move forward, the industry remains reliant on long term oil prices not falling below \$60 a barrel and possibly requires prices over \$100 a barrel to realise the growth that companies seek.²¹

Crucially, Canadian tar sands production would be significantly curtailed if policies to address climate change are implemented, according to the IEA.²² This is not only because of the high carbon emissions of tar sands production but also because oil prices would barely support tar sands production growth in a low carbon world. As the marginal barrel on the oil market, tar sands production is a loser to any concerted efficiency drive.



Syncrude upgrader in Canada's tar sands: all tar sands bitumen has to go through an energy and cost intensive upgrader in order to produce oil. ©REZAC/GREENPEACE

ULTRA-DEEPWATER

BP's Deepwater Horizon (Macondo) tragedy that unfolded through the summer of 2010 has not only exposed the consequences of risk taking in this extreme environment but has most likely raised the cost of ultra-deepwater production forever.²³ While more stringent regulation imposed as a result of the disaster may be concentrated in North America and possibly Europe, the raised cost of insurance for ultra-deepwater production is likely to apply globally.²⁴ Additionally, finance for such projects is likely to come at a higher price as investors seek higher returns for higher risk.²⁵

Prior to the disaster, the push into ever deeper water and more complex operations was raising costs and risks to the point that it was perhaps no surprise that disaster eventually struck. Indeed, the now defunct Minerals Management Service and the deepwater industry in the Gulf of Mexico were warned of the inadequacy of blowout prevention procedures and the difficulty of controlling a blowout in the ultra-deep as far back as 2004.²⁶ It is well recognised within the industry that the operating conditions in ultra-deepwater are testing the limits of both technology and human expertise.²⁷ As one ex-industry executive commented, 'Our ability to manage risks hasn't caught up with our ability to explore and produce in deep water'.²⁸

While the complexity of operations grows with depth and remoteness from shore, so does the difficulty of addressing a leak. There is little evidence that anything less than a relief well can guarantee closure of a blowout at these depths. BP's Macondo well, at 4,993ft (1,522m), is far from being the deepest operation in the industry. Shell is operating the deepest production today with its new Perdido platform in water depths of 8,000ft (2,450m), far deeper than Macondo.²⁹ The pre-salt deposits off the Brazilian coast present further challenges as they are not only in ultra-deepwater but are also thousands of metres below the seabed under layers of rock and unstable salt.³⁰

Many IOCs are significantly invested in deepwater production particularly BP, Shell, Chevron and ExxonMobil.³¹ Indeed deepwater and, increasingly, ultra-deepwater have been the most important theme of production growth for much of the industry in the past decade. According to IHS CERA, 'from 2006 to 2009 annual world deepwater discoveries (600 feet or more) accounted for 42 to 54 percent of all discoveries – onshore and offshore. In 2008 alone, deepwater discoveries added 13.7 billion barrels of oil equivalent to global reserves'.³²

Shortly after the Horizon accident, Deutsche Bank issued a research note detailing the importance of deepwater production to the industry and speculating on the impacts of the disaster. The analysts noted that 'The Gulf of Mexico was the biggest growth-driving region of the biggest growth-driving oil supply theme: the deepwater'.³³

The report also detailed the significance of deepwater production to IOCs:

*[Deepwater] has been the source of over 60 billion barrels of 2P³⁴ reserves since the late 1990s and [...] today represents the leading single source of growth in oil production with anticipated volume growth of some 12% p.a. over the 2000–2015 period against just 2% for the market overall, directly as a result of the technological and physical push to deeper and deeper water, previously inaccessible to drilling and production.*³⁵

The report goes on to state that on average deepwater represents about 10% of the reserves and production of what Deutsche Bank refers to as *major oils*.³⁶ Further analysis from this report is presented in the appendix.

Is deepwater delivering on its promise?

While the recent growth in deepwater production is impressive, experience from some wells cast doubts on the longevity of some fields. BP's Thunder Horse project in the Gulf of Mexico is a case in point. Having been delayed by technical and engineering difficulties for four years this ultra-deepwater project started production in June 2008 following \$5 billion of investment. Its capacity was supposed to be 250,000b/d but it has never reached that level and appears to have hit a production peak within six months of coming on-stream.³⁷ By February 2010, water was making up 31% of the liquids being produced at the main well.³⁸ Observers doubt that it will reach its lifetime target production of one billion barrels.³⁹

Similar problems were experienced at BHP Billiton's Neptune project.⁴⁰ While the late Matt Simmons claimed to have tracked 25 deepwater wells that have experienced rapid decline.⁴¹

With ultra-deepwater the stakes are rising higher than ever while the margins are being squeezed by escalating costs and uncertain returns.

The oil industry is certainly no stranger to risk, but it appears that with ultra-deepwater the stakes are rising higher than ever while the margins are being squeezed by escalating costs and uncertain returns. This could be even more the case for the oil industry's final frontier, the offshore Arctic.

OFFSHORE ARCTIC

The United States Geological Survey estimates that 30% of the world's undiscovered gas and 13% of the world's undiscovered oil is to be found north of the Arctic Circle.⁴² Of this oil, 84% – approximately 90 billion barrels – is expected to be found offshore, some of it in deepwater.⁴³

The offshore Arctic presents oil companies with some of the most formidable challenges yet. Harsh conditions, low temperatures, operational windows cut short by the winter freeze-over, icebergs that threaten to collide with rigs and a delicate ecology that requires meticulous protection all conspire to make oil production here difficult, risky and expensive, possibly more so than any other region in the world.

The Arctic ecosystem is perhaps the most vulnerable to long term impacts from oil spills on earth.⁴⁴ Freezing temperatures, thick ice cover, and slow turnover of plants and animals mean that oil lingers, exposing multiple generations of organisms to contamination.⁴⁵ Weak sunlight inhibits the breakdown of spilled oil.⁴⁶ The winter freeze-over means that operations are limited to summer months, therefore a blowout has the potential to spill oil for months if it cannot be stopped before winter sets in. For these reasons, a spill in Arctic waters could be much more devastating to the local and regional ecology, and the people that depend on it, than in the warm waters of the Gulf of Mexico. Operating safely here will require rigid safety procedures with very high redundancy.

Extreme spill response logistics

The extreme conditions and the remoteness of the offshore Arctic from major population centres, push the potential costs of clearing up a major spill in the Arctic (to the extent that a clear up can be achieved) to unprecedented heights. Should a spill occur – and according to one Alaskan regulator *'there is never zero risk'*⁴⁷ – the potential impact on shareholder value adds enormously to the risk premium of companies operating there. Cairn Energy's engineering and operations director Phil Tracy, told an industry conference in Oslo recently that *'[Greenland] is unforgiving in terms of cost and consequence'*.⁴⁸

At the peak of the response effort in the Gulf of Mexico, BP was able to muster the assistance of nearly 48,000 workers, 6,000 marine vessels, 150 aircraft, six deepwater drilling rigs

and two floating production, storage and offloading units (FPSOs).⁴⁹ The cost of assembling these resources, while huge, was greatly minimised by the accident's proximity to major urban centres and centres of oil industry expertise and equipment supply.⁵⁰ Still clean up costs alone have topped \$11 billion so far. The logistical complexities and costs of delivering such a response in the remote offshore Arctic will be unlikely to prove as easy or as cheap as in the Gulf of Mexico.

High cost of minimising risk

The logistical difficulties of maintaining essential safety and disaster response capability in the offshore Arctic is exemplified by the efforts of BP and ExxonMobil owned Imperial Oil in pressuring the Canadian government to relax safety requirements for drilling in the Beaufort Sea.

In March 2010, both companies appealed to the Canadian government to withdraw a regulatory requirement to have the capability at hand to drill a relief well in the same season as drilling a main well in the Beaufort Sea.⁵¹ The companies claim that the requirement makes operating in the area unviable and that the regulation is overly prescriptive.⁵² BP argued that its safety procedures were adequate to prevent the occurrence of a blowout,⁵³ a claim that now appears impossible to support following the Macondo incident. The same season relief well hearing has since been suspended and the Canadian National Energy Board is now conducting a review of Arctic offshore drilling in light of the disaster.⁵⁴

The call for regulatory relaxation of relief well preparedness in the Beaufort Sea exemplifies the risk that companies are compelled to take in the Arctic in order to make operating there economic. Essentially the problem for the companies is that having relief well capacity brings the additional cost of maintaining a spare rig at all times and means stopping the drilling season early to allow enough time to drill a relief well should a blowout occur.⁵⁵

Relief well preparedness is a measure that can only reduce the scale of the catastrophe as even when fully prepared to begin drilling a relief well the moment a blowout occurs, oil could still spill for weeks while the drilling takes place. The purpose of the regulation was to ensure that a relief well could be drilled before the freeze-over preventing a spill from continuing for several months.

However, even this back-up measure was felt to be too onerous for companies on top of the other challenges the Arctic presents. Thus the companies are choosing to accept the risk of a prolonged spill that could be many times worse in terms of

impact and cost than the Macondo spill. It remains to be seen whether following the Macondo incident there will be sufficient public confidence in industry assurances that spills can never happen.

Most of the IOCs have some exploration ongoing or planned in the offshore Arctic and Greenpeace recently took direct action to stop Cairn Energy's exploration activities off the west coast of Greenland. BP, ExxonMobil and its 70% owned Canadian subsidiary Imperial are active in the Canadian Beaufort Sea as are Shell, Chevron, ConocoPhillips and Devon.⁵⁶ Shell is the biggest leaseholder in the Chukchi Sea off of Alaska and has already sunk \$3.5 billion into the venture since 2006 with continuous delays to drilling, which may or may not start in July 2011.⁵⁷ ConocoPhillips, BP, ENI, Total and Repsol all have interests there as well.⁵⁸

It remains to be seen whether following the Macondo incident there will be sufficient public confidence in industry assurances that spills can never happen.

RESERVES DATA OPACITY

Our research, detailed in the appendix, shows that at least four of the top six IOCs have significantly relied on tar sands reserves additions to support RRR rates in the past five years. As a percentage of total liquids additions tar sands represents between 26% and 71% of reserves additions for these four companies.⁵⁹

While it is almost common knowledge that deepwater and ultra-deepwater resources have also played a key role in reserves additions for many companies, it is currently impossible to establish from public data any company's precise exposure to the resource theme. Indeed, tar sands reserves data has only recently become more transparent through the new regulations brought into force by the US Securities and Exchange Commission (SEC) in 2010.

Even so, it is total proven reserves, not yearly reserves additions, that are detailed in the SEC data and to establish the tar sands reserves additions involves a number of calculations and inferences.⁶⁰

The current opacity of reserves additions offers insufficient insight for analysts into the relative strategies of different companies to address increasing risks in oil exploration and production. RRR would therefore appear to be a somewhat obtuse tool for valuation.

PROFITS WITHOUT RESERVES: WHAT THEN?

It is increasingly clear that huge structural shifts have taken place in the global oil industry over the past decade and many of these trends are set to intensify in the next decade. The move into riskier and more expensive resources is one such shift. Another is the changing relationship between IOCs and NOCs.

NOCs have branched out into international plays using their substantial capital and increasing technical skill base to make acquisitions and form joint ventures with IOCs or local NOCs. There is also an increasing tendency for NOCs to engage international oilfield service providers, such as Schlumberger or Halliburton, for their construction and engineering requirements leaving IOCs to opt for a role as prime contractor. In these cases there is no Production Sharing Agreement but instead a service contract, such as the fee-for-service contracts recently negotiated in Iraq, where a set fee is paid to the company for every barrel of production.

These deals are not unprofitable for the companies, albeit with significant contractual and security risk in the case of Iraq, but they do not currently provide any equity share of reserves so do nothing for key value indicators such as RRR, proven reserves or daily production.

In an analysis of these structural shifts, Arthur D. Little (ADL) suggests that companies may need to create clearly separated business divisions that give transparency to the service agreement business in order that this activity is not undervalued by investors.⁶¹ It cites the lack of reserves and equity production in these deals as the reason why investors are likely to fail to recognise the value.

If, as ADL suggests, these new ways of operating are likely to become more commonplace, there is clearly a need for analysts to re-think the emphasis on traditional top line parameters, such as production and reserves figures, in light of an increasing presence of business activities that enhance the bottom line – the main goal of doing business – but do not impact traditional top line numbers at all.

While a separation of service agreement business from the traditional production sharing business may help in assessing the relative value of business that does not deliver equity reserves and production, there remains a need for more effective ways to assess the traditional business in light of the increasing and varied risks of accessing oil and gas as previously described.

ALTERNATIVE BUSINESS MODELS FOR OIL AND GAS COMPANIES?

We have discussed throughout this report the incapacity of RRR in differentiating risk between various sources of oil that a company uses to replace its reserves. We have also mentioned the inability of the indicator to value any company activity that does not involve the acquisition of oil and gas resources for future production.

One current example of the latter is the new service agreements signed in Iraq that do not provide companies with equity reserves or production. Another example may be the alternative energy businesses that some companies are invested in, such as wind and solar generation, that also do not figure in RRR rates. Generally these have been put into separate business divisions so that they can be valued separately to the oil and gas production business. This separation of business divisions is being suggested by Arthur D. Little for the service agreement business that oil companies may increasingly find themselves engaging in.⁶²

The question of what an oil company should do to reduce its exposure to riskier sources of oil is implicit in the debate about the increasing risk of replacing oil reserves. It can be argued that it should stick with what it knows best for as long as that remains viable. After all, the oil industry has thrived on taking big gambles for over a century and has pulled through some pretty tough times. But one could also argue that the challenges ahead are unprecedented and will require unique responses. Indeed, climate change and the increasing urgency for action could take even the oil industry by surprise one day, despite all the warnings.

One industry that has gone through tremendous upheaval in recent years is the car industry, which collapsed with the financial crisis of 2008. Its recovery, albeit lavishly government assisted, emerges into an era of heightened uncertainty. In an echo of the oil industry trends discussed in this report, car manufacturers face a future of shrinking margins and weakening sales growth.⁶³ However, it is starting to demonstrate the sort of business model innovation that the oil industry should perhaps take notice of.

In addition to the demands for much greater efficiency spurred by high oil prices and climate change regulation, the car industry faces low growth projections and changing attitudes towards car ownership, particularly among younger generations and urban populations.⁶⁴ Car companies are finding that urban populations are less interested in owning a car than they are in having easy access to a diverse mix of mobility solutions. In response to this, Peugeot-Citroën has launched a product which sells subscribers 'mobility units', in exchange for use of a car, scooter or bicycle.⁶⁵ The system draws on the model of increasingly popular 'car club' businesses such as the UK's Streetcar.⁶⁶ Companies including GM, Renault, BMW and Audi are all looking at similar schemes.⁶⁷

When oil demand begins to flatten and decline, what good will reserves replacement be as an indicator of value if it does not differentiate between cheap and expensive to produce resources?

This is just an example of the kind of innovation that is taking place in the face of emerging trends and changing societal expectations. It demonstrates that to address such trends may require the innovation of new business models alongside technological advances.

While the car manufacturers will still make cars, the new business model may well require less individual vehicles, reducing the value of the traditional manufacturing business, while adding value from new sources such as service provision.

If a similar kind of innovative model of conducting business were to emerge for the international oil industry, one that did not rely on producing oil and gas but promised new sources of value with less risk, oil company value would need to be measured in correspondingly new ways.

The existing valuation model, with its emphasis on the replacement of hydrocarbon reserves, [may be] encouraging risk taking because it fails to assess the relative risks of accessing different hydrocarbons.

In particular it is the vulnerability of the marginal oil resources to a demand peak that exposes the weakness of RRR as a value indicator. When oil demand begins to flatten and decline, what good will reserves replacement be as an indicator of value if it does not differentiate between cheap and expensive to produce resources? If reserves additions were more clearly differentiated according to risk and expense, would the value of alternative investments, such as those in low carbon energy resources, also become more transparent?

SPREADSHEET MINUTIAE VERSUS THE BIG PICTURE

In 2005, a number of papers were published by researchers at Norway's Stavanger University that sought to examine how IOCs respond to analyst measurement in light of what the researchers had found to be a period of high cash flow and low investment in the international oil industry.⁶⁸

The researchers were concerned with a period from 1997 to 2001 in which they had observed an increasing tendency for oil companies to return cash to shareholders in the form of dividends and share buybacks to the detriment of investment in reserves and upstream production growth. They examined the influence of Return on Average Capital Employed (RoACE) and asserted that analysts and companies had been overly focused on this short term measure of capital return. They concluded that this was unsustainable and that investors were increasingly concerned for longer term growth prospects such as reserves replacement. Indeed, they detected in the years immediately prior to publication (2002–04) an increasing focus on reserves replacement and greater appetite for risk in upstream projects.⁶⁹

Analyst emphasis on indicators such as RoACE and RRR can perhaps stand in the way of recognising the value in emerging business models that do not conform to the standard. For example, one former senior oil and gas company executive expressed his occasional frustration with analysts' 'lack of interest in the bigger picture (...) and their preoccupation with minutiae that was destined to feed the company model in their spreadsheet'.⁷⁰

He gave the example of a company that had developed substantial new LNG infrastructure, which he felt for a long time was being consistently ignored by analysts in the valuation of the company:

...because much of the value growth in prospect was essentially option value, it did not lend itself to being factored into the analysts' models via some familiar metrics which linked volume to profit. In other words it was difficult to understand, and therefore to model, and as a result the analyst community for quite a long time simply chose to overlook it until finally, having had it explained to them time and again, they finally 'got it' and started to recognise it as a source of potentially significant profit growth (as it has turned out to be), which in turn further underpinned the strength of (the company's) share price and market valuation.⁷¹

So while key indicators of value and their use in modelling the performance of competing companies in a sector are essential tools of valuation, there may also be a need for more flexible approaches that can recognise both emerging structural risks with the traditional business model and the value in new and developing business models.

It may also be that the existing valuation model, with its emphasis on the replacement of hydrocarbon reserves, is encouraging risk taking because it fails to assess the relative risks of accessing different hydrocarbons or, for that matter, alternative modes of profit generation. Perhaps greater flexibility in the analyst model would also allow companies to consider their role in a low carbon world more broadly than they currently do.

BP's disaster leaked 4.9 million barrels of oil into the Gulf of Mexico. ©REZAC/GREENPEACE



CONCLUSION

The international oil industry has entered an era in which maintaining production numbers involves unprecedented risk, escalating costs and tighter margins. Adequate profits from equity production will increasingly depend on a high demand and high oil price environment which is not only far from assured but is also counter to the interests of energy security and climate protection.

Traditional valuation models that primarily value hydrocarbon production growth and reserves replacement appear increasingly inadequate in a carbon constrained economy. There are also emerging business models that may provide profits from oil production without providing equity reserves or production, which do not easily fit into the standard oil company valuation model.

The analyst community may need to modify existing valuation methods or develop new ones to assess and value companies in light of the changing landscape. Reserves replacement in particular no longer appears straightforward in its reflection of company performance and value.

Traditional valuation models that primarily value hydrocarbon production growth and reserves replacement appear increasingly inadequate in a carbon constrained economy.

ENDNOTES

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APPENDIX: ANALYSIS OF RESERVES ADDITIONS FOR THE TOP SIX IOCS 2005–09

INTRODUCTION

Publicly available data on the specific content of company reserves additions is opaque and inconsistent across companies. We searched annual reports and SEC filings to ascertain the proportion of marginal oil resources⁷² in the reserves additions of the top six IOCs⁷³ between 2005 and 2009. In this period RRR rates have been improving following an extended period of disappointing reserves replacement for the biggest IOCs. (See Figures 2 and 3.)

The SEC filings, annual reports and financial reviews only revealed the role of tar sands additions. Other marginal oil resources were not visible in the data. Prior to 2010, when new SEC reporting rules changed the way tar sands reserves are reported, mineable tar sands reserves were discernible as they were reported separately to oil and gas reserves. However, in situ reserves were not differentiated from conventional oil and gas reserves. Data for 2009, reported in 2010, fell under the new SEC rules, which require reporting of bitumen and synthetic oil according to the product delivered to refineries, separately from conventional crude oil. Additionally, some companies voluntarily disclosed tar sands resources in annual reports and financial reviews prior to 2010 so we have been able to compile a reasonably accurate picture.⁷⁴

No information regarding the role of deepwater and ultra-deepwater resources in reserves additions is available in the public data. We were able to discern some information on this from a Deutsche Bank research report.⁷⁵

The data presented here is therefore far from complete but does reinforce the fact that IOC oil reserves additions are increasingly reliant on marginal oil resources.

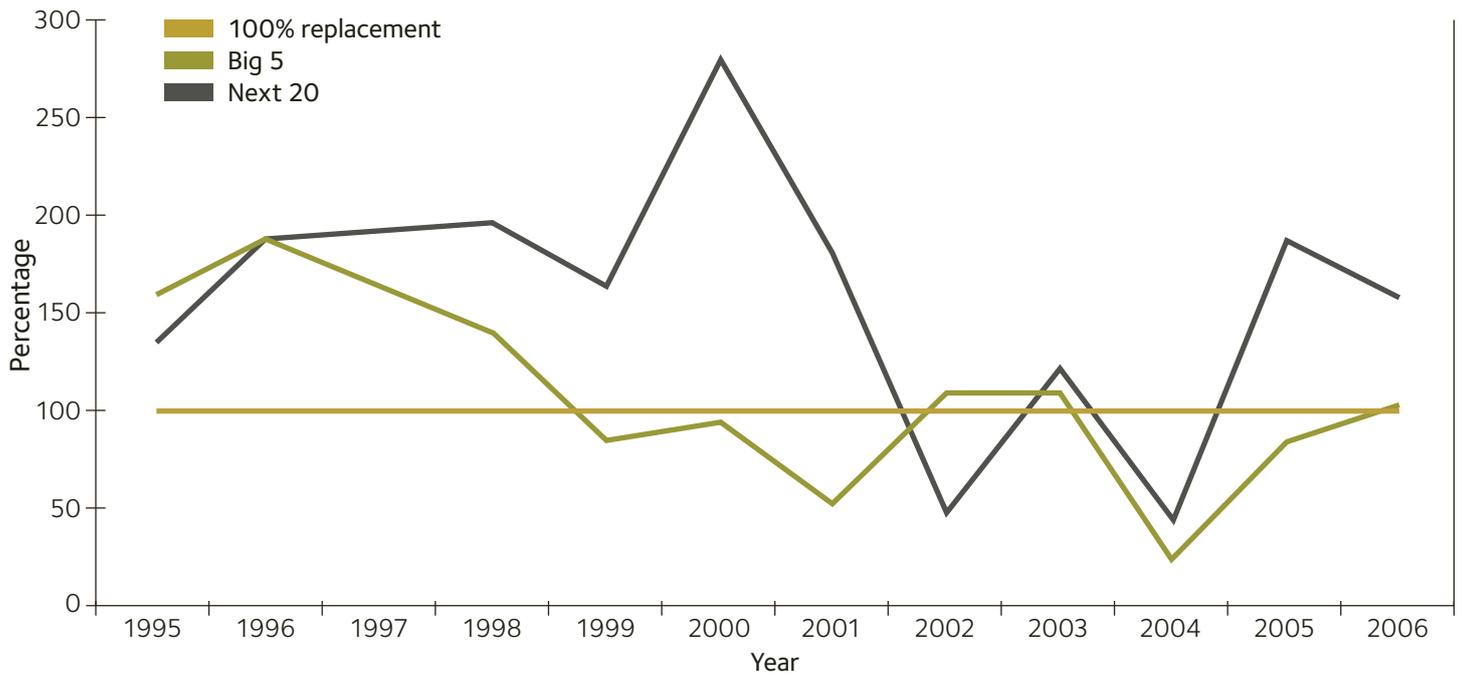
The relative exposure of individual companies to specific groups of resources can also be roughly gauged from company strategy presentations, examples of which are highlighted below. We had however sought to ascertain the role of marginal oil in reserves additions from recent years in order to gauge their importance to the high RRR rates in this period. The lack of adequate public data available to achieve this assessment highlights the weakness of current disclosure standards in enabling analysis of the relative risks of reserves additions.

DATA

Firstly it is worth looking at the general RRR rates of the companies as a group over the past 15 years. Figure 2 shows that RRR rates were disappointing for the biggest IOCs from the mid-1990s to the mid-2000s, while Figure 3 shows that rates have generally improved post 2005.

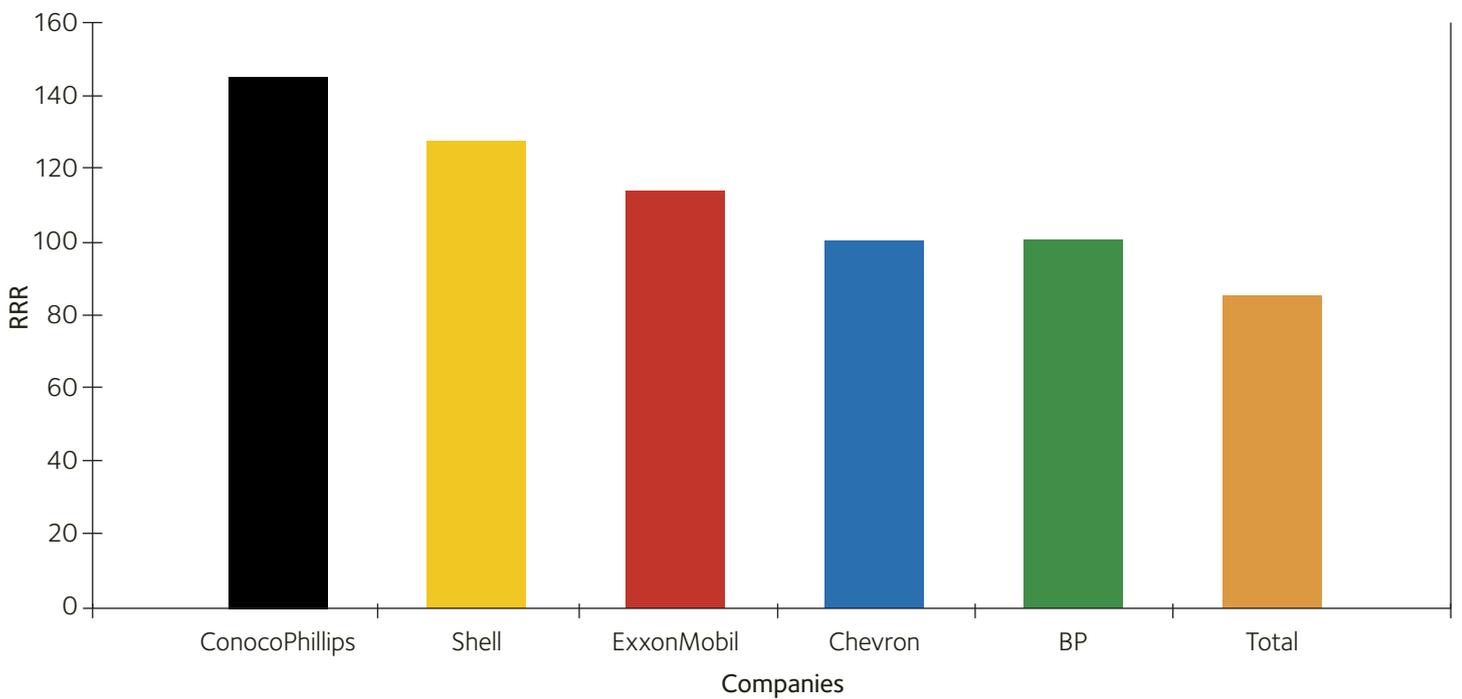
Figure 3 shows that all companies except Total kept RRR rates at 100% or over between 2005 and 2009. However, our analysis of the role of tar sands additions throughout this period suggests that the companies with the highest RRR rates also relied most heavily on tar sands reserves additions.

FIGURE 2: RRR OF TOP 25 IOCS⁷⁶ 1995–2006



Source: Amy Myers Jaffe & Ronald Soligo, 2007. IOCs: Investment and Industry Structure. James A. Baker III Institute of Policy Studies.

FIGURE 3: TOP 6 IOCS RRR 2005–09



Source: Company data compiled by the Borealis Centre.

TAR SANDS RESERVES ADDITIONS 2005–09

While companies were required to report on tar sands mining reserves separately from conventional oil and gas (based on US SEC regulations), they were not required to report on mining additions as such, nor were they required to report separately on in situ reserves.

Shell voluntarily disclosed figures for tar sands mining additions throughout the period but the other major IOCs did not.

However, tar sands mining additions can be approximately⁷⁷ inferred if a company voluntarily discloses corresponding year-end reserves and production figures. This is the case with ExxonMobil for example, where we were able to calculate the tar sands additions for each year other than 2005 and to a lesser degree for ChevronTexaco (we could only calculate it for two out of the five years) and ConocoPhillips (three out of the five years).

The data in Table 2 shows a significant role for tar sands reserves additions in the reserves replacement of major IOCs over the

past five years, especially ConocoPhillips, ExxonMobil and Shell. No data was available for BP, because its joint venture with Husky, the Sunrise Steam Assisted Gravity Drainage (SAGD) Project, has only just been sanctioned and will therefore add to the company's proven reserves base in the coming year. As we will see below in the analysis of longer term resources, BP stands poised to develop two more in situ projects. It remains to be seen whether these survive the asset sale the company is executing to pay for the Macondo disaster. So far, these projects have not been offered for sale.

Excluding BP, tar sands mining additions make up almost 20% of total reserves additions and over 42% of liquids additions on average for five of the top IOCs.

By extension, while the average Reserves Replacement Ratio (RRR) for these six companies over the period 2005–2009 is 112%, the figure becomes 92% if tar sands additions are excluded (see Table 3).

TABLE 2: ESTIMATED TAR SANDS RESERVES ADDITIONS AS A PERCENTAGE OF RESERVES ADDITIONS 2005–09⁷⁸

Company	As percentage of total reserves additions	As percentage of total liquids reserves additions
ConocoPhillips ⁷⁹	39%	71%
ExxonMobil ⁸⁰	20%	51%
Shell ⁸¹	16%	34%
Total ⁸²	10%	26%
Chevron ⁸³	3%	7%
BP	0%	0%
Average (excl. BP) ⁸⁴	19.8%	42.6%

TABLE 3: RESERVES REPLACEMENT RATIO (RRR) FOR THE PERIOD 2005–2009⁸⁵

Company	RRR	RRR excluding tar sands ⁸⁶
ConocoPhillips	145%	88%
ExxonMobil	114%	89%
Shell ⁸⁷	127%	106%
Total	85%	76%
Chevron	101%	98%
BP	100%	n/a
Average ⁸⁸	112%	92%

TABLE 4: GLOBAL DEEPWATER RESERVES AS A PERCENTAGE OF TOTAL 2P RESERVES

Company	Percentage
Total	16.2
BP	12.1
Chevron	11.1
Shell	7.3
ExxonMobil	7.2
ConocoPhillips	1.6
Average	9.25

Source: Deutsche Bank Global Markets Research, June 2010. Macondo and the Global Deepwater.

TABLE 5: FORECAST GROWTH IN DEEPWATER PRODUCTION 2009–15 EXXONMOBIL AND CHEVRON

Company	Deepwater production as percentage of total: 2009	Deepwater production as percentage of total: 2015	Compound annual growth rate: Deepwater production	Compound annual growth rate: Total production
Chevron	7.1	17.0	17.8	1.9
ExxonMobil	10.3	12.7	6.1	2.5

Source: Deutsche Bank Global Markets Research, June 2010. Macondo and the Global Deepwater.

We expect that these calculations may underestimate these additions to some extent, as the data is insufficient for some companies, particularly Chevron and Total, and it is also unclear whether in situ reserves are included in the figures of some of the companies.

When we take away tar sands additions from the companies' total RRR, we find that for all except Shell (and BP obviously) RRR rates fall below 100%.

New SEC reporting rules should improve the transparency of tar sands reserves in company reporting from 2009 onwards. This is important as the disclosure of longer term reserves, known as *total resources* and discussed further below, shows that for many of these companies the proportion of tar sands reserves that will move from probable to proven reserves, and therefore will be counted as reserves replacement, is likely to grow substantially over the next ten years.

DEEPWATER

The importance of deepwater resources to these companies cannot be gleaned from the publically available reserves additions data. We have therefore provided data from a June 2010 Deutsche Bank research report.⁸⁹

The report states that for the *major oils*, which includes a wider range of companies than discussed here, global deepwater resources account for about 10% of proven and probable reserves.⁹⁰ Our selection from the data shows that this is roughly the same for the six companies (see Table 4).

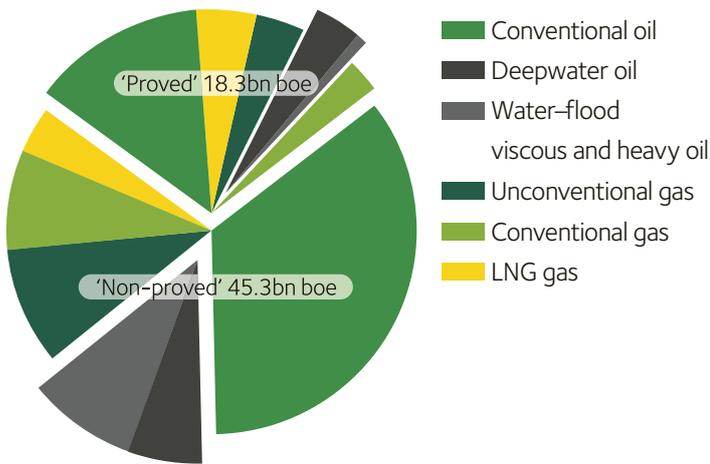
Another way to discern the role of deepwater resources in these companies' recent activities is to look at forecast production growth. Here we present the data for ExxonMobil and Chevron from the Deutsche Bank report.

The increasing role of deepwater production in Chevron's portfolio could hardly be clearer. Its growth rate will be some 800% greater than the overall growth rate of its production. In ExxonMobil's case it is a more modest 144%.

TOTAL RESOURCES

Another way to examine the role of marginal oil in the future production of IOCs is to look at their disclosure of total resources. The term total resources generally refers to all the oil and gas a company expects to extract in the future from its current resource base. These disclosures are not guided by SEC regulations and are inconsistent between the companies. Nevertheless, their graphic representation does demonstrate the growing role of marginal resources in the companies' long term resources. Here we present a selection of graphs from recent company presentations with a brief analysis.

BP: proved and non-proved reserves 2009



Source: BP 2010 Strategy Update.⁹¹

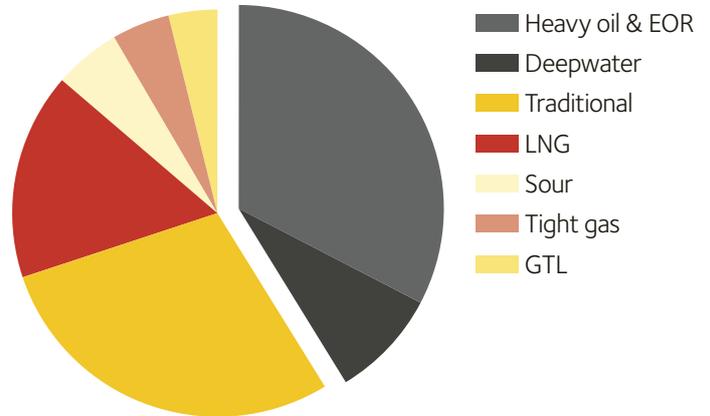
BP conveniently separates proven reserves from the rest of the resource base enabling some insight into the changes in its production base that may take place in the future. This graph precedes the Macondo disaster and so does not reflect the asset sales that BP has had to make as a result.

In the proven reserves, 'water-flood, viscous and heavy oil' is the smallest slice and this reflects BP's lack of tar sands projects currently producing or under construction. These proven reserves are most likely primarily related to equity shares in heavy oil projects in Venezuela.

In the non-proved reserves section this heavy oil category grows enormously. This reflects the tar sands resources in the company's equity share in the Sunrise SAGD project, which will move into the proven category in next year's accounts following project sanction on 29 November 2010.⁹² It also reflects resources in the Kirby region of Alberta that BP has held for some time and may be brought into production in collaboration with Devon Energy following deals made in early 2010.⁹³ Shortly before publishing this graph BP also acquired a stake in Value Creation's Canadian tar sands resource.⁹⁴ It seems unlikely that these resources are accounted for in the graph. We

therefore expect this category to substantially grow in subsequent reports. BP's concentration in deepwater production appears strong in both sections of the graph. BP is also actively exploring for new resources in the offshore Arctic.

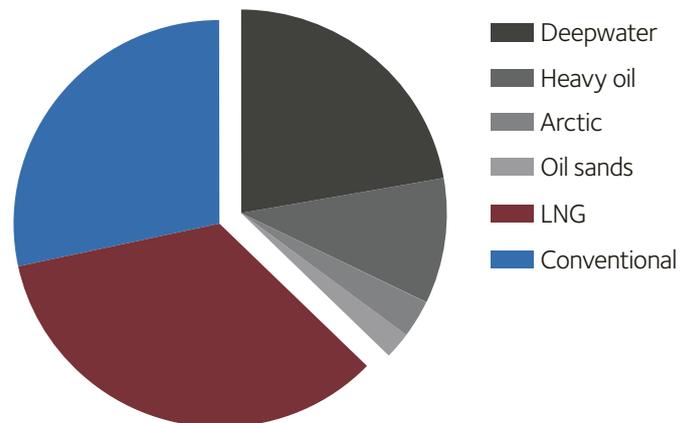
Shell: total resources 2008



Source: Shell 2008 Strategy Update.⁹⁵

Shell has one of the highest concentrations of Canadian tar sands in its total resources of all six companies. In 2008 it stated that this graph represented 66 billion barrels of oil equivalent (BBOE) of which 20 billion barrels, 30%, were Canadian tar sands.⁹⁶ In subsequent publications Shell has claimed that of its proven reserves, only 8.4% is tar sands while the resource will represent 4% of its production in 2011 when its latest tar sands mining expansion comes fully on stream.⁹⁷ The heavy weighting of tar sands resources in its unproven reserves suggests that at some point these figures will rise sharply. Shell also has significant deepwater resources and is actively exploring for oil in the offshore Arctic and for oil shale in Jordan.

Chevron: total resources 2010

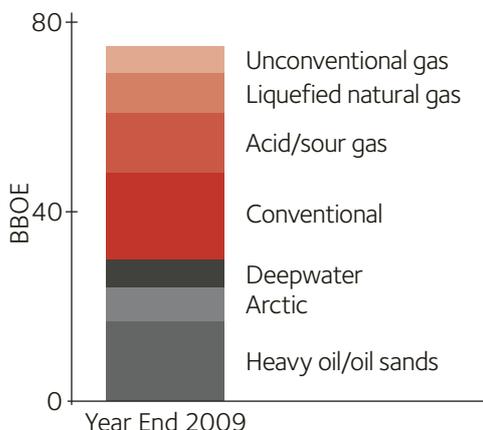


Source: Chevron 2010 Upstream Strategy Update.⁹⁸

Chevron has a very large percentage of its resources in deepwater. It also has significant heavy oil resources concentrated in California, Indonesia and the Partitioned Neutral Zone in Saudi Arabia. Heavy oil is generally produced using

steam-flooding similar to the SAGD method used in tar sands production. Chevron also has significant Canadian tar sands and Arctic resources.

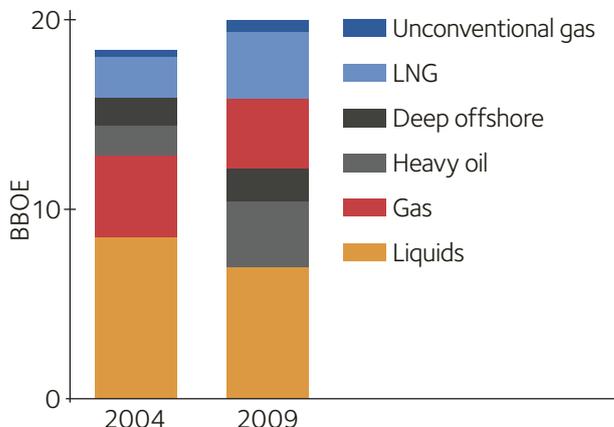
ExxonMobil: resource base 2010



Source: ExxonMobil analysts presentation 2010.⁹⁹

The heavy oil category in ExxonMobil's graph is very large and probably represents its Canadian tar sands reserves, a lot of which is being developed by its 70% owned Canadian subsidiary, Imperial Oil. ExxonMobil is less concentrated in deepwater but has significant resources in the Arctic.

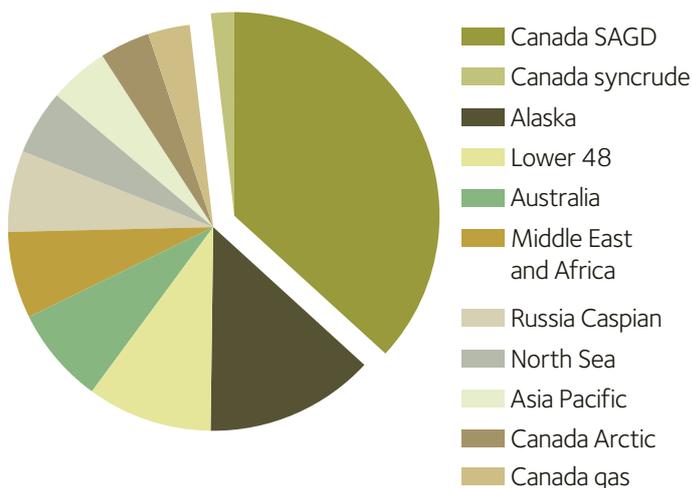
Total: proved and probable reserves growth 2004–09



Source: Total 2009 results and outlook.¹⁰⁰

Total's report, rather than showing total resources as the others do, illustrates the growth in proved and probable reserves between 2004 and 2009, which gives a reasonable idea of reserves addition in the period. We can see that while the reserves base has grown between 2004 and 2009, conventional liquids have shrunk substantially and deep offshore, heavy oil (including tar sands) and LNG have grown significantly.

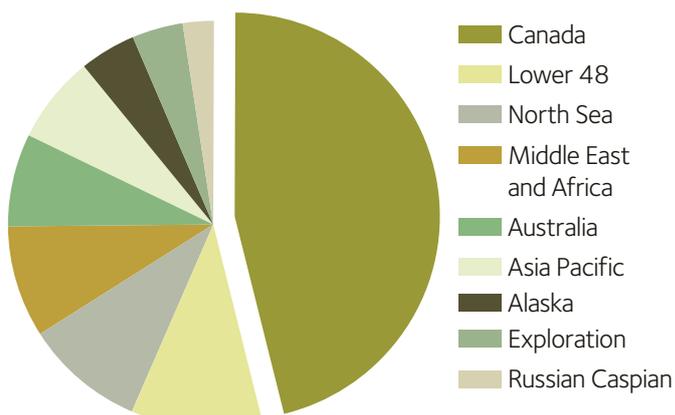
ConocoPhillips: total resources by region 2009



Source: ConocoPhillips March 2010 analyst meeting, New York.¹⁰¹

ConocoPhillips' Canadian tar sands resources, primarily in situ resources that will be produced through the SAGD method, are its biggest single resource. Our analysis of its reserves additions in the past five years shows that these resources made up 39% of its total reserves additions and a staggering 71% of its total liquids additions, far greater than any of its competitors. The second chart here also shows that the company expects to make a lot more additions from these resources in the coming five years. In its presentation the company shows that it expects to see a compound annual growth rate of 20% in SAGD production through to 2019.¹⁰² The company also holds substantial resources in the Canadian and Alaskan Arctic, some of which is offshore.

ConocoPhillips: 2010–14 reserve additions



Source: ConocoPhillips March 2010 analyst meeting, New York.¹⁰¹



ENDNOTES

- 72 Because of their high cost and high risk and their potential vulnerability to global demand decline, we consider marginal oil resources to be tar sands and other unconventional oil (mainly oil shale and coal-to-liquids, neither of which are in actual production yet so do not figure here), deepwater, ultra-deepwater and offshore Arctic.
- 73 These are: ExxonMobil, ChevronTexaco, BP, Royal Dutch Shell, ConocoPhillips, Total SA.
- 74 Reserves additions are not generally broken down in the data beyond region. Where companies have not voluntarily disclosed tar sands additions our data is calculated from the difference between reported tar sands production and reserves in a given year, which is an approximate calculation as it does not necessarily factor in cost/price effects according to SEC rules.
- 75 Deutsche Bank Global Markets Research, June 2010. Macondo and the Global Deepwater.
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- 77 Reserves replacement is normally calculated including cost/price effects, but this is not possible given the limited amount of data disclosed by the companies. Nevertheless, cost/price effects have comparatively little to no effect on five-year averages.
- 78 2005–2009 average and excluding cost/price effects unless otherwise noted.
- 79 ConocoPhillips reserves are primarily in situ resources. Figures were primarily drawn from the company's 2010 10-K filing. Based on a sample size of only three years in the five year period.
- 80 We calculated 22% for tar sands additions 2006–09 excluding cost/price effects, and 20% for 'heavy oil/tar sands' 2005–09. Here, we present the smaller of the two values. Figures for the liquids column were primarily drawn from the company's 2010 and 2008 10-K filings, and the company's 2009 Financial & Operating Review.
- 81 Including cost/price effects.
- 82 Based on assuming that the total five year tar sands additions are covered in the single number reported by Total SA in 2009.
- 83 Based on a sample size of only two years in the five year period.
- 84 Calculated using [average annual TS additions] / [average annual total additions].
- 85 Excluding cost/price effects unless otherwise noted.
- 86 Calculated based on the percentages from Table 2, using the formula $RRR * (1 - [\text{tar sands as a percentage of total reserves additions}])$.
- 87 Including cost/price effects.
- 88 Average 'RRR' column includes BP; average of 'RRR excluding tar sands' column excludes BP. RRR excluding tar sands is calculated using $[\text{sum of total additions for each company}] * (1 - 19.5\%) / (\text{sum of total production for each company})$.
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Oil Change International
236 Massachusetts Ave NE #203
Washington, DC
20002
www.priceofoil.org
info@priceofoil.org
+1-202-518-9029

Greenpeace
Canonbury Villas
London
N1 2PN
www.greenpeace.org.uk
tarsands@uk.greenpeace.org
+44 (0)20 7865 8100

Platform
7 Horselydown Lane
London
SE1 2LN
www.platformlondon.org
+44 (0)20 7403 3738