HEINRICH BÖLL STIFTUNG

OILCHANGE INTERNATIONAL

Friends of the Earth Europe

Marginal Oil

What is driving oil companies dirtier and deeper?

Aerial view of the oil on the sea surface, originating from the leaking of the Deepwater Horizon wellhead disaster, slowly approaching the coast of Louisiana East of the mouth of the Mississippi river. The BP leased oil platform exploded April 20, 2010 and sank after burning, leaking an estimate of more than 200,000 gallons of crude oil per day from the broken pipeline into the sea. © Daniel Beltrá / Greenpeace

Front cover:
Left: Fen and the Boreal Forest near McClelland Lake , north of Fort McMurray, Alberta, Canada. This area has been leased for future oil sands development. Right: Syncrude Aurora Oil Sands Mine, north of Fort McMurray, Canada. © Peter Essick 2009. All rights reserved

Preface

Boreal forest of spruce, poplar and aspen, east of Peace River in northern Alberta, Canada. © Jiri Rezac / Greenpeace

With conventional oil production in decline, the global oil industry is investing heavily in dirtier and riskier forms of unconventional oil such as heavy crude, tar sands, and oil shale. These investments pose a challenge to the climate, the environment, and local communities. One new frontier for tar sands development is sub-Sahara Africa, a region that is highly dependent on the export of raw materials, but at the same time is highly vulnerable to the impacts of climate change and the subsequent suffering due to the effects of extractive industries' projects. Other affected regions include the Orinoco Belt in Venezuela and the Western Amazon in Brazil – biodiversity hot spots and home to a number of indigenous peoples.

Apart from making a mockery of climate protection, experience shows that tar sands production in Canada – currently the biggest producer of tar sands globally – has resulted in serious damage to local communities and the environment, including destruction of the boreal forest and increased pollution, which has impacted the health and livelihoods of indigenous peoples. In countries with weaker political and environmental governance frameworks – such as Congo Brazzaville, Nigeria, and Madagascar – the consequences of its expansion are likely to be even more devastating.

Having worked with partners around the world on climate, energy, and resource issues for years, the Heinrich Böll Foundation and Friends of the Earth Europe are very concerned about the increasing investments into "marginal oil". We see it as one major wrong "solution" to the energy crisis the world is facing and we are concerned about the challenges and risks it poses for local communities as well as the climate.

In November 2010 we therefore jointly organised a networking and strategy meeting for civil society activists from North America, Europe, Africa, and Latin America. The aim was to share information and experiences and better coordinate global efforts to fight marginal oil investments and promote a clean and sustainable energy future globally.

To this end we will also work with decision makers both in the European Union and globally to ensure that the right policies are in place and that the voices of the communities are respected.

This paper was prepared as a background document for the strategy meeting. It describes the drivers behind marginal oil investments and gives an overview of existing and potential projects across the globe. Since it contains important analysis that we believe should be public knowledge, we have decided to publish it and hope it will productively feed into the ongoing debate, from Cancun to Durban to Rio and beyond.

We would like to thank the two authors of this study, Sarah Wykes and Lorne Stockman, for their excellent work and unfailing commitment, but we also want to thank all participants of the strategy meeting for their important input and feedback. A special thanks goes to Alex Quero for making this exciting but rather dry topic look nice.

Lili Fuhr, **Heinrich Böll Foundation**

Darek Urbaniak, **Friends of the Earth Europe**

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Executive Summary

This paper was written for a workshop on the expansion of investment in tar sands, in their current centre of production in Canada and beyond, and particularly the prospect of investments in developing countries. Tar sands development in Canada has had serious negative impacts on local communities and ecosystems. Current and new developments pose a significant threat to global climate protection efforts, given the highly carbon-intensive nature of the production process and the fact that protecting Alberta's tar sands industry is feeding the Canadian government's opposition to national and international mitigation efforts.

However, tar sands development is both a symptom and manifestation of a broader underlying trend: a drive to exploit *unconventional* oil resources that are more difficult and costly to produce – and usually more carbon-intensive – than conventional oil. Oil companies are increasingly bent on accessing the world's remaining *conventional* oil resources found in "frontier" locations, where their development often involves a high risk of irreversible damage to local ecologies and communities. Current exploration projects include bitumen-type resources in Venezuela and in Africa, deep offshore oil in Africa and Brazil, and heavy oil in the remote Western Amazon.

Both these trends represent an ongoing drive towards what can be called "marginal oil" with potentially devastating implications: for global and local efforts to curtail carbon emissions by transitioning away from a fossil fuel-based energy model; for the energy security of importing countries; and ultimately for sustainable growth in developed, emerging, and developing countries.

The paper begins by exploring the "macro" forces driving the search for marginal oil. Fundamentally, oil exploration is driven by the economics of global supply and demand. Global oil demand is on an upward path, mainly due to increasing demand from emerging economies such as China, according to the International Energy Agency (IEA). However, concerns about China's rapid demand growth may be overblown and need to be balanced with an awareness of the country's efforts to curtail domestic demand in the longer term.

However, while concerns about peaking oil supply are a factor, it is in fact lack of access by international oil companies (IOCs) to the remaining "easy-to-produce" oil that is driving them in search of the "marginal barrel." In the 1960s, IOCs had access to around 85 percent of global oil reserves: today that has shrunk to only 6 percent.[1] OPEC controls the vast majority of the world's remaining "easy" oil, which means the majority of future non-OPEC production growth will be in unconventional oil.[2]

The IOCs' decreasing access is mainly due to geopolitical factors such as the continued rise of resource nationalism in key producer countries, as well as rising oil prices. In addition, what little remaining access IOCs enjoy comes with much less favorable terms attached. They also face increasing competition from national oil companies (NOCs) that are becoming more technically competent or business savvy and are cash rich. This insecurity of access has been further exacerbated by the accelerating depletion of oil fields located in politically stable and "friendly" territories.

IOCs also face pressure from investors to keep adding new oil reserves to replace existing production. In some cases, the deals now available to IOCs fail to deliver new reserves, as ownership of the reserves tends to remain with the producer state or NOC.

The IOCs response has been to develop technologies to access "difficult oil." The past decade has seen increasing involvement of IOCs in offshore production at ever-greater depths, Canadian tar sands production, the development of gas-to-liquids (GTL), and technologies to produce oil shale. Analysis of the top six IOCs' reserves profile reveals that they all increasingly rely on such marginal resources.

However, the push into the margin means spiralling costs for the IOCs as, almost without exception, these resources are more expensive to develop and produce than conventional oil and thus rely on a high oil price to be profitable. Marginal oil is a symptom of *high prices and excessive demand* rather than a means of combating either.

This is why the arguments deployed by the oil industry and its supporters that increasing development of marginal resources is the key to improving the energy security of major importing states such as the United States are fundamentally flawed. Development of expensive-to-produce and limited supplies of non-OPEC marginal oil will not reduce OPEC's hold on the market. Unlike marginal resources, OPEC oil is relatively cheap and easy to bring onstream, and its market share will grow even if marginal oil is developed.

For the same reasons, more marginal oil will not mean less money for unsavoury regimes, so long as overall demand increases. The supply and demand balance that supports marginal oil is also a boon for OPEC producers, because it supports high oil prices. Finally, marginal oil production will not protect oil importers from a supply crisis because of the global nature of the oil market. No marginal oil sources (such as Canadian tar sands) have significant spare capacity to address a supply crisis.

The only sure answer to improving energy security is cutting oil demand. Otherwise, the "business as usual" energy scenario will see marginal oil development inevitably expand beyond its current centre in North America, with companies pushing to open up ever more risky and challenging resources with potentially devastating consequences for the climate, as well as local ecosystems and communities in producer countries.

Arguably, the United States is still the pivotal market in terms of its impact on global oil demand. Roll-out of existing technologies combined with robust government interventions across the board could potentially cut US oil consumption by 40 to 50 percent by 2030, setting it on a downward trajectory thereafter and more than counteracting growth in demand from China.

However, even if successful, reducing demand for oil in the medium term must be combined with a coherent supply-side approach. Governments cannot cut demand while also putting into place policies aimed at maximizing supply of oil and other fossil fuels, undercutting the political and economic case for clean energy. In addition, reducing oil demand alone will not resolve the fundamental environmental and social justice issues facing local communities at the frontline of oil development.

For climate protection and for environmental and social justice reasons, further oil investments must be monitored and challenged to prevent the ongoing environmental and social damage they entail and also to prevent states and other actors from getting "locked in" to a resource extraction model that makes the transition to a truly sustainable development path more remote.

Introduction

The Syncrude tar sands mine, Alberta, Canada. The mining operations strip away boreal forest and mine up to 100 metres into the earth. © Chris Evans / The Pembina Institute

This paper was designed as input for a workshop convened by the Heinrich Böll Foundation and Friends of the Earth Europe in Berlin from November 15–16, 2010.[3] Participants comprised activists and researchers working mainly on tar sands development in Canada and energy issues at the European level. Several Southern activists whose countries could soon face new tar sands or extra-heavy oil investment also participated in the discussion (for a definition of terms such as *tar sands* and other terms, as used in this paper, see Box 1).

Both the decision to hold the workshop and the paper's production were initially triggered by specific concerns among activists and researchers over the threat of expansion of tar sands within and beyond their current centre of production in Canada – particularly into developing countries such as Madagascar and the Republic of Congo (RoC) – and over potential imports of tar sands-derived fuel into the EU. Concerns centred on the impacts of such developments on the livelihoods and health of local communities and local ecosystems – impacts already being felt by First Nations communities and on the Athabasca River and the Canadian boreal forest in the case of Canadian tar sands.

In addition to their potentially disastrous local social and environmental impacts, ongoing tar sands development has serious implications for the global climate crisis – and for long-term energy security of oil-importing countries, including the United States and the EU. Such resources are highly carbon-intensive to produce, involving emissions per barrel that are three to five times higher than with conventional oil. Such developments also incur high costs and continuing investment in tar sands is therefore dependent on a "business as usual" energy scenario where fossil fuels, especially oil, remain the primary source of power and transport fuel, and where demand for oil – and the oil price – remains high.

This paper has now been revised for publication in the hope that it will be of interest to a wider audience interested in the energy dimensions of the climate crisis and in the social, environmental, and developmental impacts of continued investment in fossil fuel extraction.

However, it inevitably still bears the limitations of its original conception. One is that it was primarily conceived as a tool to assist advocacy groups in their strategic planning and coordination. As such, it does not offer a comprehensive overview or discussion either of current/potential developments in the oil sector or of advocacy and campaigns research in the field, but rather presents a particular argument with supporting evidence aimed at a specialist audience.

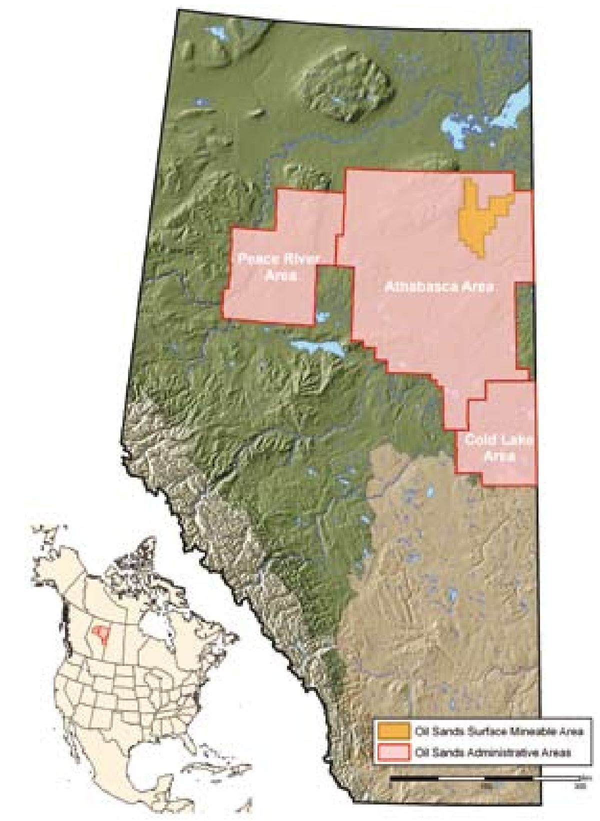
Furthermore, it also assumes a working knowledge of the climate, energy security, and local environmental and social impacts associated with tar sands development in Canada. Research and advocacy groups, including the Pembina Institute, the National Resources Defence Council, Greenpeace, Friends of the Earth, and Platform, have discussed such issues in detail in previous briefings, and any reader wishing to find out more about tar sands development in Canada and its critiques should consult this rich vein of material.

Box 1 Definitions

Tar sands (or **oil sands** as they are called in the oil industry) are deposits of sand and clay saturated with bitumen. The tar sands in Alberta, Northern Canada, are the second largest oil deposits in the world and extend over an area the size of England that includes 4.3 million hectares of boreal forest. They are now producing over a million barrels of oil per day and the number one export destination is the United States.

Bitumen is oil in a solid or semi-solid state that requires unconventional extraction methods (either mining or, in the case of the deeper deposits, steam injection to get it to flow to the surface) and then processing or "upgrading" to convert it into synthetic crude. Large amounts of fossil fuels are burned and large amounts of water used in these processes. NGOs, scientists, and local residents have expressed serious concerns about the irreparable environmental and social damage tar sands projects have caused, including serious health impacts from contamination of the Athabasca watershed.

In addition, production of a barrel of Canadian tar sands emits on average between three to five times more carbon than production of a barrel of conventional oil. The clearance of enormous areas of boreal forests is also having a huge impact on the sequestration of carbon emissions from greenhouse gases.



Location of Alberta's bituminous sands. Source: Global Forest Watch Canada

Unconventional oil

According to the International Energy Agency (IEA): "There is no universally agreed definition of unconventional oil, as opposed to conventional oil. Roughly speaking, any source of oil is described as unconventional if it requires production technologies significantly different from those used in the mainstream reservoirs exploited today."[4] The IEA's definition of unconventional oil includes extra-heavy oil (with that from Canada and from Venezuela's Orinoco Belt seen as the resources currently viable), natural bitumen (oil sands) from Canada, chemical additives, gas-to-liquids, coal-to-liquids, and oil shales.[5]

The US Energy Information Administration (EIA) notes that: "What has qualified as 'unconventional' at any particular time is a complex interactive function of resource characteristics, the available exploration and production technologies, the current economic environment, and the scale, frequency, and duration of production from the resource. Perceptions of these factors inevitably change over time and they often differ among users of the term."[6] In the 1960s and 70s, "unconventional" referred to the deepwater resources being accessed by, at the time, new technology.

Thus, the definition of "unconventional" is mutable: Other bodies may classify resources as unconventional according to the density or *gravity* of the hydrocarbon resource or the location of the reservoir – excluding the technology used to access it. In this paper, "unconventional" is an umbrella term referring to lower-grade and more technically difficult to access and produce resources requiring processing that usually involves higher levels of carbon emissions.

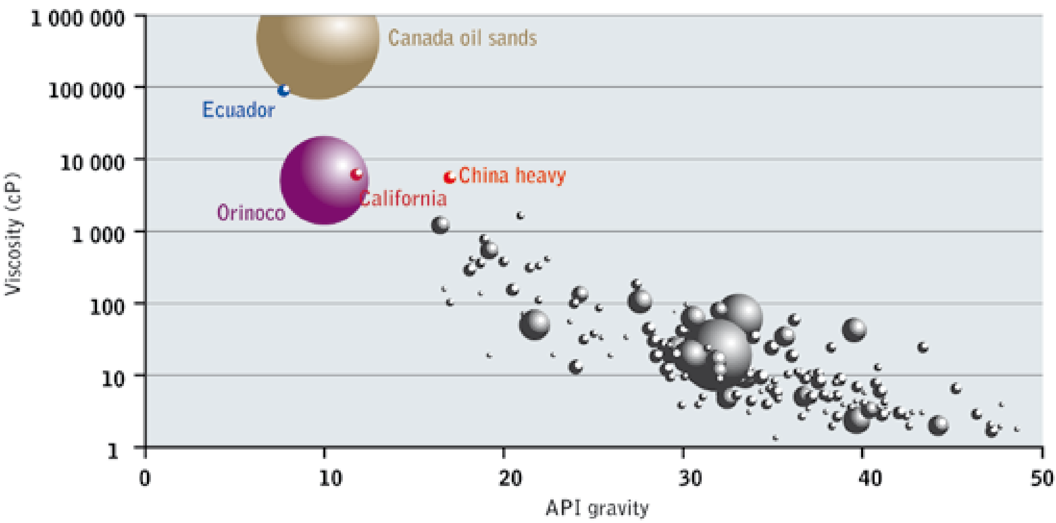
High carbon oil

When discussing unconventional oil, we have substituted the term "high carbon" oil – as shorthand for "high carbon-intensity oil" (i.e., oil that involves carbon-intensive production processes). This is on the grounds that this term best sums up the key problem with the drive to develop these more difficult-to-access resources: They represent a "recarbonization" or intensification of the carbon content of our energy supplies at a time when we need to be moving in the opposite direction to protect the climate.

Frontier oil

Frontier oil means exploring for resources in new geological areas where costs and risks (technical and financial, although it can also mean political) are high. For instance, a recent report named the following as being the next "new oil frontiers": West Africa (Sierra Leone, Liberia, Sao Tomé and Principe), ultra-deepwater in the Gulf of Mexico, Western Sahara, the Falkland Islands, Uganda, the Bahamas, and the Arctic.[7] The term "frontier oil" is usually used to cover exploration for conventional rather than unconventional resources, whether onshore or offshore.

Figure 1: Continuum from conventional to unconventional oil resources



Note: The size of the bubbles indicates recoverable resources. Reservoirs with similar properties in each geographical area have been grouped; the smallest bubbles each represent approximately 1 billion barrels of recoverable resources.

Source: World Energy Outlook 2010[8]

Overall, the argument of this paper is that tar sands development in Canada is both a symptom and manifestation of a broader, underlying trend: increasing investment by oil companies in what is termed *unconventional* oil. The latter term is applied, simply put, to oil resources that are (currently) more technically difficult and costly for companies – and usually more carbon-intensive – to access and exploit than conventional crude oil (see Box 1 for further information).

Such resources are also often (but not always) located in remote areas of high biodiversity or ecological sensitivity and/or have potentially serious effects on local communities and their livelihoods. This is the case with tar sands in Madagascar or the RoC.

In tandem, the race is on to exploit the world's remaining conventional oil resources. While these may not be so carbon-intensive to produce, they are located in "frontier" regions and are more remote or technologically difficult to access and/or more environmentally/socially high-risk than current fields. Examples are the deep offshore fields extending from the Arctic to Brazil and Africa, and the Western Amazon.

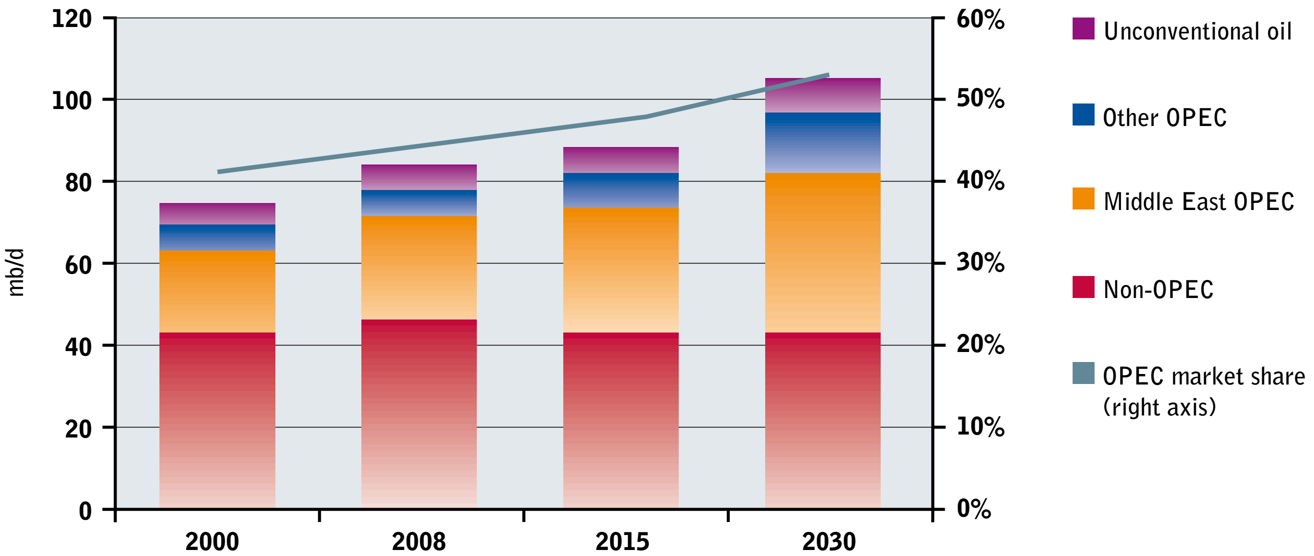
For this reason, the authors have opted to use the term "marginal oil" to refer to resources that are both at the margins of profitability in financial terms (what is sometimes referred to by the industry as the "marginal barrel") but also high-risk in terms of their potential impacts on local ecosystems and communities as well as their implications for global climate protection efforts.

Section One explores the key underlying causes – or "macro" forces – that are driving this push by oil companies to develop resources "at the margins" of the industry's current technical or financial capabilities. It argues that, fundamentally, this trend assumes a "business as usual" scenario of ever-increasing oil demand and high oil prices. Such a scenario will take us inexorably toward a potentially unmanageable rise in global temperature,[9] as well as exacerbate energy insecurity in importing countries.

Section Two surveys some key current and potential marginal oil investments outside Canada, using specific criteria raised by the issues outlined in this paper. These include: the likelihood of project development; its potential impacts on vulnerable communities and ecologies; the attitude of host communities to the investment; the openness of political space in the host country; and the involvement of European/US-listed companies.

1 **Driving over the cliff:** What's behind the increasing exploitation of marginal oil?

Figure 2: Oil production by source



Note: Excludes processing gains. Conventional oil includes crude oil, natural gas liquids (NGLs), extra heavy oil from Venezuela and chemical additives.

Source: World Energy Outlook 2009[13]

In 2011, the IEA forecast that of the 69 million barrels per day (Mbpd) of conventional oil in production in 2010, 47 Mbpd would not be available in 2035.[10] In order to meet rising demand, in a policy environment that is little changed from today's (what the IEA calls the "Current Policies Scenario") around 67 Mbpd of new capacity will have to be brought on stream by 2035.[11]

Much of this demand is likely to be met by OPEC, which retains control of the vast majority of the world's remaining "easy-to-produce" oil (see Figure 2). The IEA suggests that non-OPEC conventional oil production will peak around 2010 and that the majority of future non-OPEC production growth will be in unconventional oil.[12]

In line with these trends, for the last 10 years the oil industry has been moving increasingly toward the production of unconventional oil such as tar sands and pushing into "frontier" zones, such as ultra-deepwater and the offshore Arctic. These oil resources share in common their tendency to intensify the already high social and environmental impacts of current oil production and their high financial costs. For this reason, we have labelled them "marginal oil."

What are the economic and political factors driving this push into marginal oil? This section will not discuss the specific drivers of every marginal oil project but outline the macro-forces that underpin the general trend.

The main factor behind the push into marginal oil is generally thought to be the depletion of "easier-to-produce" oil and that is certainly important. But it is mostly political factors that restrict access to the remaining easy-to-produce oil and therefore, the drive into the margins is primarily driven by the major international oil companies. In some cases, such as the pre-salt ultra-deepwater resources of Brazil or extra-heavy oil in Venezuela, national oil companies are playing a leading role, but it is IOCs that have generally developed the technology to enable them to do so.

The actions of both types of companies are driven by the economics of global supply and demand, and by concerns about future energy security. However, given the ever-increasing costs of exploiting these resources – financial, social, and environmental – the question of limits arises. In other words, is the status quo in terms of energy policy being maintained to the point where the costs to society outweigh the benefits? To what extent does this inertia undermine the transition to cleaner and more efficient energy systems?

In addition, are oil company statements about the dynamics of supply and demand accurate or are they self-serving and designed to maintain the status quo? Arguably, to date the public debate on energy security, particularly in the United States, has focused largely on supply-side issues rather than demand-side solutions.

This section will begin by looking at IOCs and the difficulties they face accessing the world's "easier" oil resources, their struggle to replace reserves, and their increasing reliance on marginal resources. It will also discuss energy security, its misconceptions, and the inadequacy of supply-side solutions. Finally, demand scenarios will be considered, as well as the extent to which policies aimed at demand reduction can undermine the economics of marginal oil.

1.1 International oil companies: The problem of diminishing "easy oil"

In 2008, Shell's (then) CEO, Jeroen van de Veer, announced that the era of "easy-to-find" oil was coming to an end.[14] It would perhaps have been more accurate to say that *for IOCs such as Shell* the era of "easy-to-produce" oil is well and truly over.[15]

There is certainly truth to the proposition that the easy oil is running out. While there are 70,000 known oil fields in the world, around 100 "giant" fields account for roughly half of global production.[16] Many of these fields are past their peak or expected to reach their peak in the near future.[17] In some places, such as Iraq, easy oil exists but political and security concerns are likely to constrain production for the foreseeable future.[18]

Awareness of the accelerating depletion of conventional oil fields and scepticism about the industry's ability to bring sufficient new capacity on stream has triggered concerns about "peak oil" – the idea that the world has either reached, or will soon reach, the limits of its capacity to increase oil production.

However, there is much debate about the peak oil proposition, primarily because the oil industry has consistently learned to stretch oil resources further through technological breakthroughs that enable access to oil previously considered inaccessible or uneconomic to produce. This technological development has primarily been driven by the IOCs because for many years they have been excluded from, or given only very limited access to, the easy-to-produce oil.

1.2 Decreasing access for IOCs

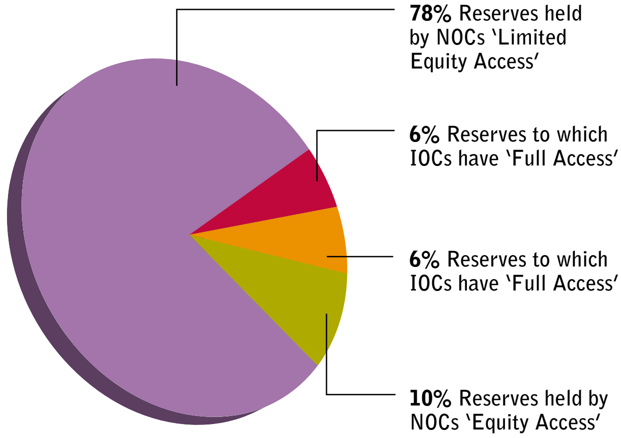
In the 1960s, IOCs had unlimited access to around 85 percent of global oil reserves. Today that access has declined to around 6 percent.[19] The decrease in access primarily stems from rising resource nationalism in oil-producing countries, which restricts and denies the IOCs access to the world's most prolific resources. The exhaustion of oil fields, primarily located in the North Sea and the United States, which were mainstays for IOCs from the 1970s to 90s, has also diminished their reserves in recent years.[20]

1.3 Continuing resource nationalism: An increasingly harder bargain for IOCs

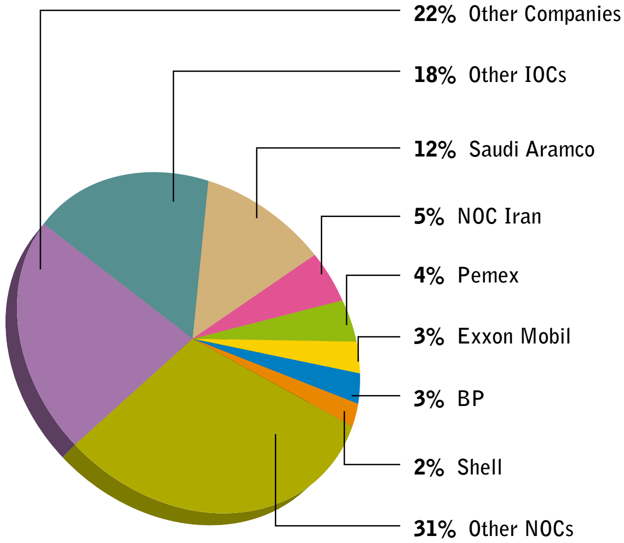
Resource nationalism – defined here as the tendency of oil-exporting states to limit access to IOCs and to assert state control over the development of oil resources – is nothing new.[22] Up until the 1960s, much of the Middle East's oil was still being produced by British, French, and American oil companies, which had unlimited access through the power of the colonial governments they represented – a fact that may explain the enduring attraction of resource nationalism in the region.

Figure 3: IOCs and NOCs access to reserves and share of production

Access to reserves:



Share of production:



Source: Arthur D. Little, January 2010[21]

However, one of the first attempts at wholesale nationalization in the Middle East ended so calamitously for its proponents that it served as a cautionary tale for other countries, explaining the slow pace of nationalization in the decades that immediately followed.[23] In 1951, the democratically elected Prime Minister of Iran, Mohammad Mossadegh, attempted to wrest control of the nation's oil resources from the Anglo Iranian Oil Company (later to become BP). This resulted in two years of economic and political turmoil in the country, as the oil industry ground to a halt and Britain, with some assistance from the United States, sponsored various opposition factions, eventually leading to a coup in 1953.[24] Mossadegh lived the rest of his life under house arrest and Iran's oil reverted to the hands of a consortium of foreign-owned companies.

While the 1960s saw some renegotiation of terms, as Middle Eastern states struggled to capture more of the revenues issuing from oil production, it was only in the 1970s that these states finally wrested back full control of their oil reserves from the IOCs.[25] Low oil prices from the mid-1980s onwards, however, caused oil-producing states to seek ways to increase revenues through increasing production. With more difficult-to-produce reservoirs a challenge for the NOCs, some states in the region (excluding Saudi Arabia) invited back the IOCs.[26]

When the Soviet Union collapsed in 1989, a whole new region of potential resources opened up for the IOCs. Newly independent states such as Kazakhstan and Azerbaijan invited IOCs to help them access resources that the Soviet state had failed to exploit. Russia signed deals that were, in some cases, so favourable to the IOCs that they became "part of corporate lore […] analysed in business school textbooks for years to come."[27] Although many of these projects were more difficult to develop than the Middle Eastern oil that was lost to resource nationalism in the 1970s, the IOCs enjoyed a resurgence and many grew exponentially in this period, on the back of a wave of mergers and acquisitions.

But the resurgence did not last long. In the early and mid-2000s, Russia, Kazakhstan, Venezuela, Ecuador, and Bolivia either took back into state control entire fields from the IOCs, or renegotiated agreements that favoured the state.[28] A new wave of resource nationalism was clearly underway.

Rising oil prices in this period are thought to have been a major driver behind these compulsory renegotiations. When prices are low, available capital is reduced and states are in a weaker position, as competition for resources among oil companies is limited. States tend to agree to easier terms to encourage inward investment. As prices rise, states begin to covet the revenues being generated and seek to rake back a larger proportion of the wealth they consider rightfully theirs.[29]

The rising oil prices in the 2000s also helped fuel civil unrest and conflict in poorly governed oil-exporting states in Africa. Conflicts in Nigeria, Chad, and Sudan disrupted oil production and jeopardized new projects, undermining the hopes of some IOCs that Africa could become a major new source of production.[30] These conflicts, while not completely closing these countries to IOC access (except for Sudan), have severely hampered the prospects for production growth.

A more recent example is the way Exxon was forced to retreat from buying a $4 billion stake in Ghana's huge new offshore Jubilee field. As one source put it: "The oil giant was compelled to cancel the deal due to extreme pressure from Ghana government and strong resistance from the state oil company, Ghana National Petroleum Corporation (GNPC)."[31] Reportedly, GNPC wanted the final say on which companies form the joint venture operating what is a key economic element for the country. This included the option of the state company bidding itself for a stake, financed with Chinese money, and potentially bringing in Chinese company CNOOC plus another oil major to the deal.[32]

The resurgence of resource nationalism in the 2000s is thought by some commentators to be a particularly potent and durable phenomenon.[33] Not only because oil prices are expected to remain high for some time, but also because of other factors supporting the view that resource nationalism in the oil-producing states will endure. The emerging role of NOCs as partners in overseas oil production is one factor (see Figure 3). Another is the huge political fallout from the Iraq war, as well as the growing backlash against globalization. In many of these states, particularly in the Middle East, the presence of IOCs is especially unpopular at present, further buoying their underlying and enduring ideological support for resource nationalism.

Therefore, the oil boom of the first decade of the new millennium did not leave the IOCs more secure in terms of access to the world's reserves. This insecurity of access has been further exacerbated by the accelerating depletion of oil fields located in politically stable and friendly territories that, over the past three decades, have been the mainstay for the oil companies. These areas are primarily the North Sea, including Norway, the United States and conventional resources in Canada.

1.4 Friendly, stable fields in decline

While the IOCs were losing access to resources in the Middle East in the 1960s, their losses were to some extent compensated by the emergence of offshore oil in politically stable and friendly countries. The North Sea, in the heart of northern Europe, became the most significant new oil province for the IOCs from the early 1970s onwards. North Sea oil boomed during the 1970s and 80s but production peaked between 1999 and 2001. It now has one of the fastest rates of decline in the world.[34] While exploration continues and some progress has been made on extending the life of North Sea oil fields, there is only hope of slowing, not reversing, the decline. The North Sea oil boom is well and truly over.

In the most mature oil province in the world, the onshore "lower 48 USA",[35] oil production has been in decline since the 1970s. In the 1970s and 80s, onshore production in Prudhoe Bay, Alaska, was a major source of growth for IOCs. However, this area now has the steepest decline of all major production zones in the United States.[36] In Canada, where tar sands production now dominates oil production, conventional oil has been in decline for a number of years.[37]

Oil resources in other countries considered friendly and stable for IOCs, such as Japan, South Korea, Australia, and New Zealand, are also limited. These countries have never really provided the major growth potential that the IOCs seek and their limited resources are already in decline.[38]

Thus, there is little prospect for the IOCs to maintain current levels of conventional or easy oil production. This is due to declining production in regions where access is relatively straightforward or because access is severely limited or too risky in regions where easy and abundant reserves of conventional oil still exist. The IOCs have therefore been grappling with access and depletion issues for some time. This explains why their response has primarily been the development of technology to access increasingly difficult and marginal sources of oil.

1.5 The challenge from "international" NOCs and service companies

Another factor increasing pressure on the IOCs to move into marginal resources is the emerging strength of national oil companies in the international arena. NOCs are forging partnerships with each other, such as that between the Chinese state company China National Petroleum Corporation (CNPC) and Venezuela's Petróleos de Venezuela, S.A. (PDVSA), and also increasingly with private oilfield service companies.[39]

Where once NOCs looked to the major IOCs for technical assistance as well as capital investment, they may now look to independent service contractors for technical help and finance the project from their own vast reserves of capital.[40] Recent evidence of this is Petrobras' successful share issue of $70 billion in September 2010, the biggest in corporate history.[41]

Some expert analysts see this trend as putting "the current business model of the international oil companies (IOCs) in question, possibly as dramatically as did the shift that occurred in the late 1960s and early 1970s."[42] Not only are IOCs losing deals to NOCs, the nature of the deals that remain on offer is also changing. Rather than gaining an equity share in an oil field through production sharing agreements, IOCs increasingly have to accept new arrangements such as partial equity sharing and fees-for-services arrangements.[43]

There are certainly profits to be made from these new arrangements, but they fail to deliver a key factor of oil company value: reserves replacement. Many of these arrangements involve ownership of the reserves in question remaining with the state or NOC. This is particularly problematic when investors look to oil companies to maintain reserves replacement ratios above 100 percent despite the increasing difficulty of doing so.

1.6 Investor pressure: Is the tail wagging the dog?

IOCs are publicly traded companies, that is, owned by shareholders who trade shares on stock exchanges around the world – in the case of the big five IOCs, their shares trade in London and/or New York (or Paris and New York for Total). Institutional investors – pension funds, investment companies, mutual funds, and insurance companies – hold the bulk of shares.[44] These investors employ analysts to assess the value of individual companies and make recommendations as to whether to buy or sell shares in a particular company. Often analysts specialize in a sector such as oil and gas or pharmaceuticals and so on.

Four times a year, the IOCs publish and present financial results to investors and analysts. They also report annually via their General Meetings and produce a Strategy Update – the latter in particular is focused on communicating with the specialist sector analysts. Overall, there is tremendous pressure on the companies to show that they are performing well and making the right strategic decisions to maintain strong performance into the future.

The analysts examine a number of key value indicators to assess the performance of companies. For oil companies an important indicator 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.[45]

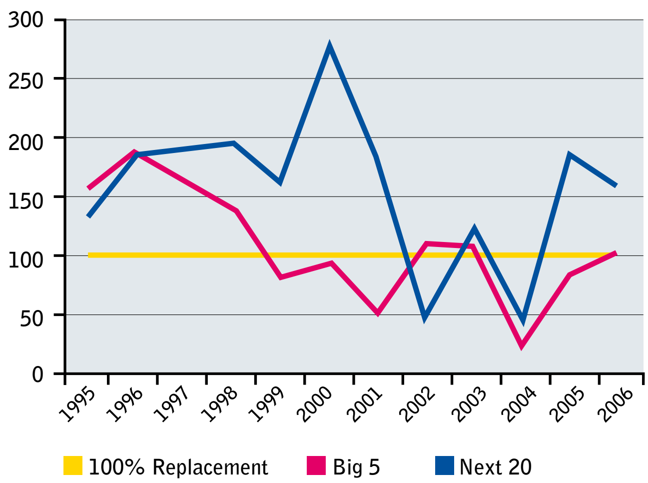
Investors want to see a ratio above 100 percent. This means, if a company extracts a billion barrels of oil in a year, the investors want to know it has gained access to another billion barrels for production at a later date. If RRR persistently comes in at less than 100 percent, then the company is essentially running out of oil and gas reserves.

While RRR is just one of many metrics used by analysts, it is one that demands strong performance in an area other than simple profit generation or return on investment: constant reacquisition of a fast-disappearing commodity. While investors are not forcing companies to acquire risky reserves in order to maintain RRR levels, there is a mutual expectation that the status quo in terms of reserves must be maintained.

Poor RRR was a feature of the top IOCs' performance in the late 1990s and early 2000s (see Figure 4 below). Companies were accused of focusing on generating short-term profits at the expense of reserves replacement.[46] The issue caught the attention of the wider world when the Shell reserves scandal broke in early 2004.[47]

Following the revelation that Shell had been booking some of its probable reserves as proven reserves for years, the company had to downgrade 4.47 billion barrels of oil equivalent, around 20 percent of the proven reserves on its books. Shell's share price plunged, heads rolled, and the company has spent the last six years struggling to regain its reputation and improve its reserves levels. Shell's subsequent acquisitions of tar sands resources have resulted in 30 percent of its total resources now consisting of Canadian tar sands.[48]

Figure 4: Reserves Replacement Ratio of top 25 IOCs 1995-2006



Source: Jaffe and Soligo, 2007

Figure 4 shows how for the biggest IOCs, their RRR was disappointing for much of the decade between the mid-1990s and mid-2000s (in this analysis, the "Big 5" are BP, Shell, ExxonMobil, ChevronTexaco, and ConocoPhillips). However, toward the end of this period, it starts to improve.

A recent analysis[49] of the top IOCs reserves additions shows that many of these companies have maintained higher RRR rates since 2005 by increasingly relying on tar sands to replace the production of fast-disappearing conventional oil. Four of the top six IOCs could not have achieved 100 percent RRR without the addition of tar sands reserves (see Figures 5 and 6).

Figure 5: Estimated tar sands reserves additions as a percentage of reserves additions 2005-09[50]

Company	As percentage of total reserves additions	As percentage of total liquids reserves additions
ConocoPhillips[51]	39%	71%
ExxonMobil[52]	20%	51%
Shell[53]	16%	34%
Total[54]	10%	26%
Chevron[55]	3%	7%
BP	0%	0%
Average (excl. BP) [56]	**19.8%**	**42.6%**

Source: Oil Change International, Greenpeace UK and Platform, 2011[57]

Figure 6: Reserves Replacement Ratio (RRR) for the period 2005-09[58]

Company	RRR	RRR excluding tar sands[59]
ConocoPhillips	145%	88%
ExxonMobil	114%	89%
Shell[60]	127%	106%
Total	85%	76%
Chevron	101%	98%
BP	100%	n/a
Average[61]	**112%**	**92%**

Source: Oil Change International, Greenpeace UK and Platform, 2011[62]

Box 2 Reserves terminology

Oil and gas companies are required by financial regulators to report their reserves according to defined standards. Reserves estimation is not a precise science and therefore reserves are divided into categories such as: proven, probable, and possible, among others. There is also a wider estimation used called total resources (TR). Standards for making estimations have been developed by the Society of Petroleum Engineers.

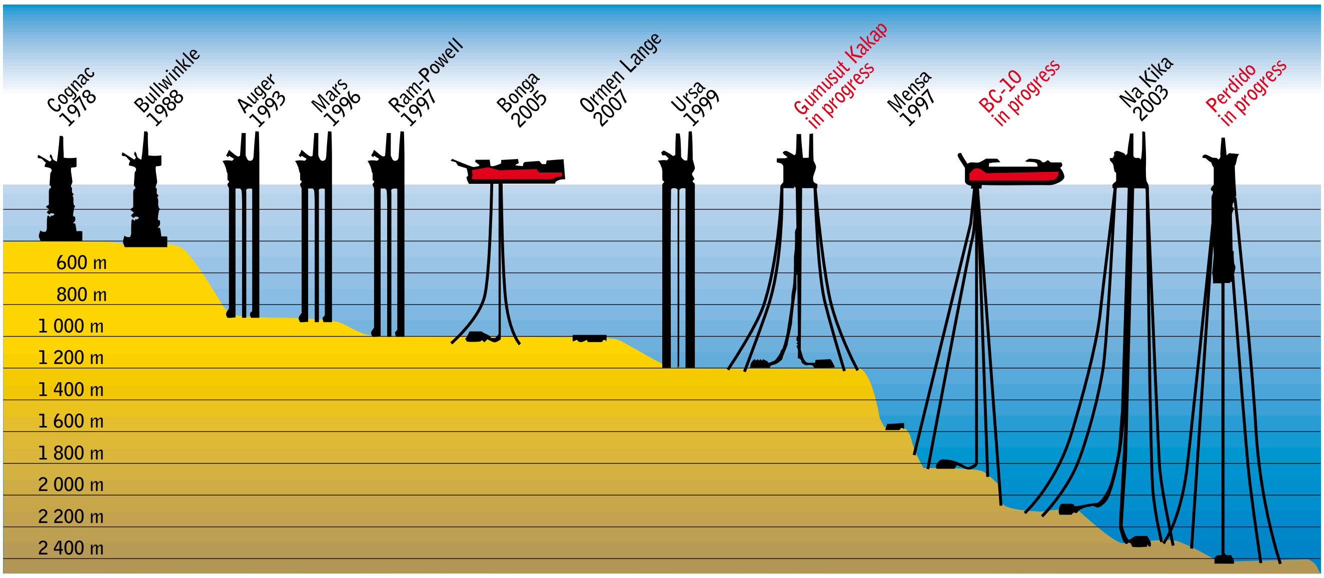
For the biggest IOCs, whose shares are listed on the New York Stock Exchange, the reporting of reserves follows the rules of the Securities and Exchange Commission (SEC). Up until January 2010, the SEC only allowed companies to report proven reserves. New rules now allow, but do not require, companies to report probable reserves. Shell's reserves scandal in 2004 was primarily about its reporting of reserves as *proven*, which under SEC rules should have been technically defined as *probable*, and therefore not reported at all to the SEC as reserves.

The new rules also allow companies to report unconventional sources of oil such as bitumen and coal that is intended for coal-to-liquids production as oil reserves, whereas in the past such resources had to be recorded as mining reserves.

Proven reserves are defined as follows: an estimated quantity of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.[63]

Total resources generally refers to all the oil and gas a company expects to extract in the future. It is a category not recognised by the SEC. However, the occasional disclosure of TR has shed light on the level of future dependence on marginal oil for many companies. For example, tar sands resources made up around 8 percent of Shell's proven reserves in 2008[64] but some 30 percent of its TR.[65]

Figure 7: A chart of Shell's deepwater engineering milestones showing the different types of rig designs developed for deepwater[67]



Source: Royal Dutch Shell, 2008

1.7 Growing in the margins

The IOCs' development of technology to access "difficult oil" can probably be traced back to the North Sea offshore oil boom of the 1970s and 80s. The North Sea presented drillers with frequently harsh weather conditions, with high winds and waves a regular feature of the offshore environment. It was here and in the Gulf of Mexico that the IOCs developed the engineering skills and technology to find and produce oil in treacherous and increasingly deep waters.[66] The political and contractual stability that companies enjoyed in these regions was essential to balancing the financial risks of developing cutting-edge technology to access and produce the resources.

By the early 1990s, drilling in waters over 1,000 ft (305 m) deep, generally considered deepwater, had become commonplace.[68] Drilling for oil and gas in waters deeper than 5,000 ft (1,524 m) is officially known as "ultra-deepwater" and is now the new frontier for the offshore oil industry, as shallower resources become scarcer.[69] The first oil discovered in ultra-deepwater was in the Gulf of Mexico in 1986.[70] However, regular production has only occurred over the last decade and current ultra-deepwater production stands at around 200,000 bpd.

While pushing back frontiers in offshore drilling has become one of the key engineering and technology pursuits of the IOCs, it is not the only one. The past decade has seen increasing involvement of IOCs in the offshore Arctic, Canadian tar sands production, the development of gas-to-liquids, and research and development of technologies to produce oil shale. For example, in 2007, research on oil shale extraction was the largest component of Shell's R&D budget.[71]

Box 3 The high costs of marginal oil

The development of high carbon oil resources and the push into the margin is more a symptom of high oil prices than a solution to them. Almost without exception, these resources are more expensive to develop and produce than conventional oil.

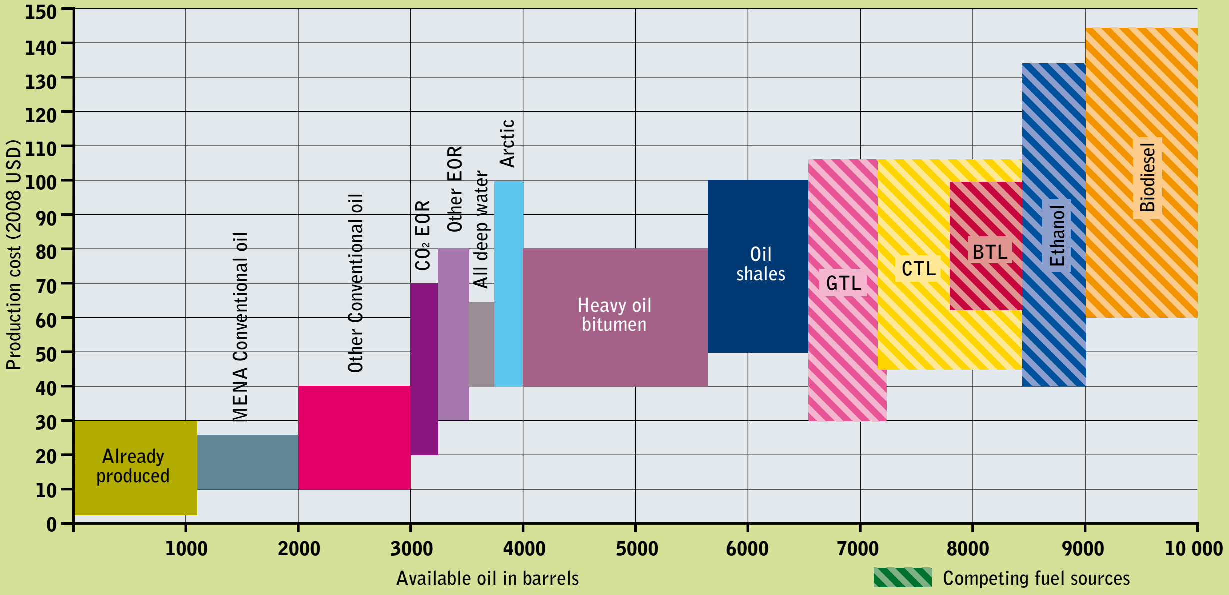
Canadian tar sands: exploration costs are low as the resource is shallow and onshore. The problem with this resource, however, is establishing how much can be extracted and at what cost. The thick, heavy bitumen is burdened with sand, clay, and water and requires intensive processing before it can be refined into useful products. With the shallower resources, companies can be confident of extracting a large percentage of the resource through opencast mining, but the processing required is intense.

After mining, the bitumen has to be separated from the soil using large amounts of heated water, creating huge amounts of waste known as tailings.[73] The bitumen then requires upgrading before it can enter a refinery to be processed into products (or if diluted with lighter products, it can be refined in complex refineries). Mining projects also have to deal with large land reclamation and water treatment costs.

Shell's Jackpine 1 tar sands mining project, which is in the final stages of construction and includes the expansion of Shell's upgrading capacity to process the mined bitumen, was described recently by a Shell executive as "some of the most expensive production that we have."[74] The $14 billion project will have a maximum capacity of 100,000 b/d and is said to require oil prices of *at least* $70–75 a barrel to turn a profit.

Deeper tar sands resources requiring *in situ* production rely on heating the bitumen underground using high-pressure steam. Initial infrastructure costs can be lower than in mining projects but profitability depends on low natural gas prices (*cont.overleaf)*

Figure 8: Production costs by resource



Source: IEA Resources to Reserves (forthcoming)[72]

(continued) and the stability of the reservoir in terms of its steam-to-oil ratio. Some in situ projects have not achieved, or maintained for long, the expected ratio.[75] Raising the steam-to-oil ratio requires more natural gas, thereby raising costs.

Another cost issue challenging the growth in tar sands production in Alberta is the intense competition for labor, equipment, and services in the region. The market in Alberta is among the most expensive in the world for oil field services and equipment and due to its remote location and the specialized nature of the skills and equipment required, the situation is unlikely to change much.[76]

Generally, Canadian tar sands production is regarded as the most expensive oil production in the world and has been described by the IEA as "the marginal barrel."[77] Minimum oil prices required for new projects to be profitable are variously quoted as between $60 and $90 per barrel.[78] The IEA claimed in December 2010 that at mid-2010 prices, "most new oil-sands projects are thought to be profitable at oil prices above $65 to $75 per barrel."[79]

However, as the IEA also stated: "the attractiveness of investing in unconventional oil is highly sensitive to the outlook for oil price, the extent of the introduction of penalties on CO2 emissions and the level of development costs relative to conventional oil."[80]

Thus in the longer term, the minimum cost of tar sands is likely to rise as carbon costs and other environmental remediation costs are factored in. Under the IEA's 450 Scenario, for example, a projected price of carbon of $120/ton would add an extra $5 per barrel of oil produced. One research report put the long-term price required to implement all proposed Canadian projects by the 2040s as between $119 and $134 per barrel at 2009 prices.[81]

This extra cost, combined with a lower oil price – given reduced demand under scenarios such as the IEA's 450 – "would make the economics of new oil-sands projects marginal and cast doubt over the most expensive projects."[82]

The frontiers: More extreme conditions, higher costs

The push into deeper water is also accompanied by spiralling costs. For both ultra-deepwater and offshore Arctic production, this starts with escalating exploration costs. Finding oil in ever-remoter locations, thousands of meters deep, drilling into rock and behind salt layers, quadrupled exploration costs between 2003 and 2008.[83]

Exploration and production rigs are becoming increasingly specialized, requiring more highly paid personnel, more sophisticated equipment, and more steel. Drilling 10,000 ft deep requires 10,000 ft of steel tubing, and steel prices have been booming. In the Arctic, drilling costs are increased by extreme conditions, leading to shortened drilling seasons, as the winter freeze shuts downs operations. This can mean that wells may take multiple seasons to complete. Additional hazards such as icebergs require ships to be at hand to push them from the path of the rig. Particularly large icebergs will require rigs to cease drilling and move from their path.[84]

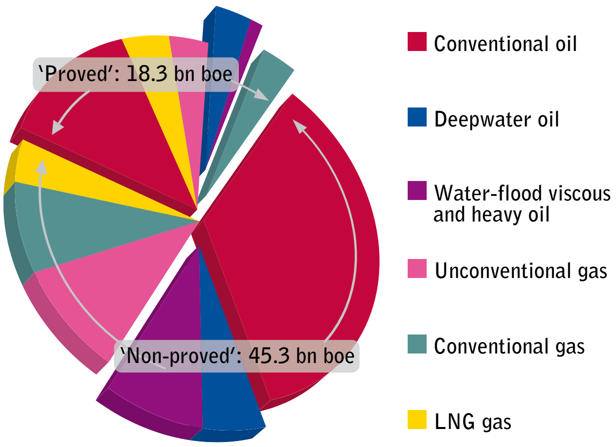
The IEA produced the above graph (Figure 8) as a guide to the costs of various forms of oil production. It highlights the high cost of Arctic production, which is listed here as potentially more expensive than bitumen. However, the graph states that carbon pricing has not been factored in, while various other sources suggest that for tar sands (bitumen) – and perhaps some of the other unconventional oils – the top end of this price scale would almost certainly be higher.[85] Finally, according to the IEA, while the breakeven oil price for Canadian tar sands projects is "comparable to that of deepwater offshore conventional oil projects [tar sands] production, and therefore investment payback periods, is spread over a much longer time period."[86]

Also worth noting is the low cost of Middle Eastern and North African (MENA) conventional oil and other conventional oils. The prospect of lower demand is much less of a threat to MENA producers and the resource remains sufficient, especially at lower rates of demand.

1.8 Increasingly marginal reserves[87]

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, as can be seen below.

Figure 9: BP proved and non-proved reserves 2009



Source: BP 2010 Strategy Update[88]

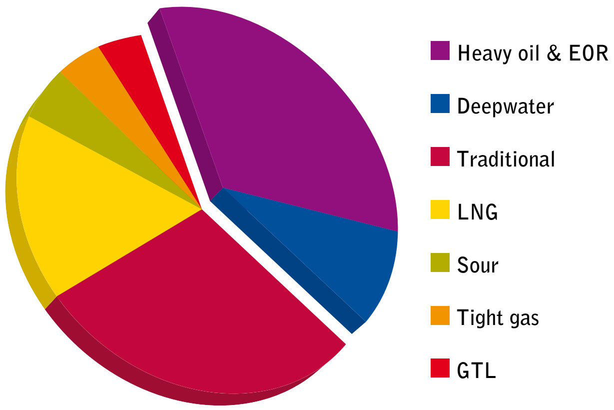
BP conveniently separates proven reserves from the rest of the resource base, enabling some insight into the changes in its production base that may take place in the future. This graph precedes the Macondo disaster and so does not reflect the asset sales that BP has had to make as a result.

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 steam-assisted gravity drainage (SAGD) project, which will move into the proven category in next year's accounts following project sanction on November 29, 2010.[89] 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.[90]

Shortly before publishing this graph, BP also acquired a stake in Value Creation's Canadian tar sands resource.[91] It seems unlikely that these resources are accounted for in the graph. We therefore expect this category to grow substantially 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.

Figure 10: Shell total resources 2008

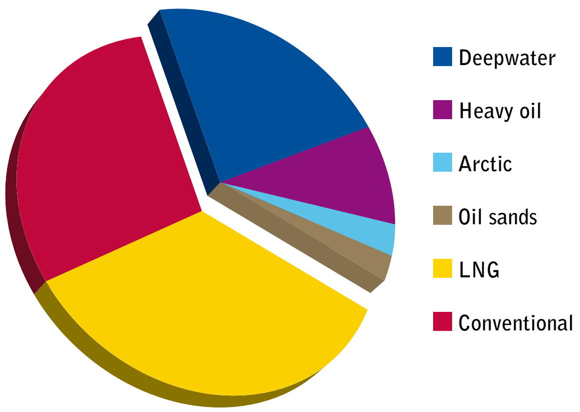


Source: Shell 2008 Strategy Update[92]

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 (boe) of which 20 billion barrels (30%) were Canadian tar sands.[93]

In subsequent publications, Shell has claimed that, of its proven reserves, only 8.4 percent is tar sands, while the resource will represent 4 percent of its production in 2011 when its latest tar sands mining expansion comes fully on stream.[94] 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.

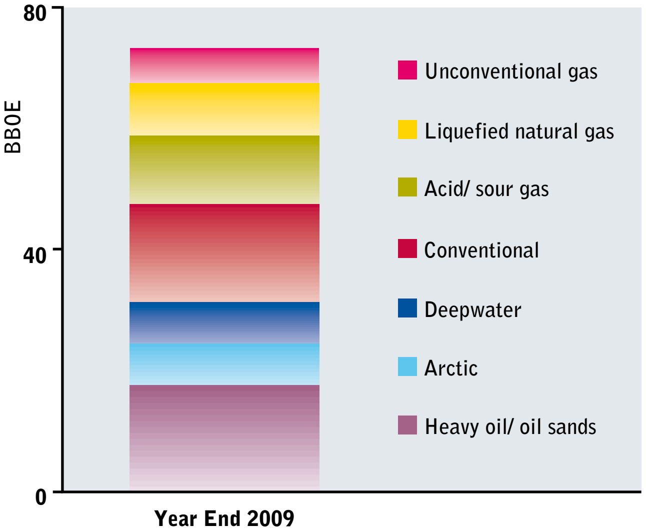
Figure 11: Chevron total resources 2010



Source: Chevron 2010 Upstream Strategy Update[95]

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 – a technique similar to the SAGD method used in tar sands production. Chevron also has significant Canadian tar sands and Arctic resources.

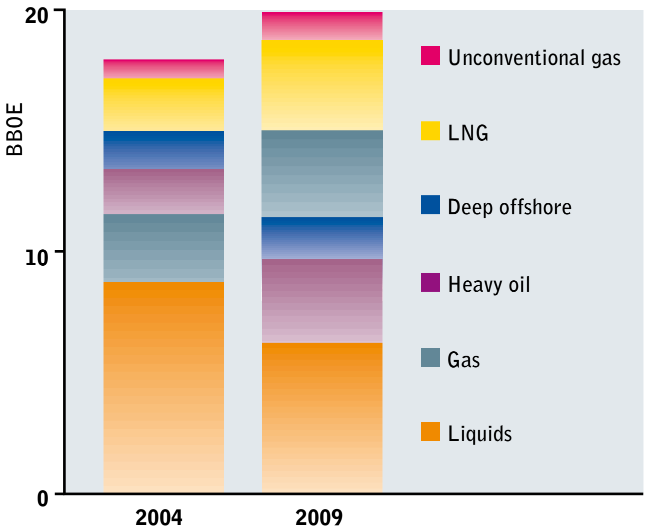
Figure 12: ExxonMobil resource base 2010



Source: ExxonMobil analysts presentation 2010[96]

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

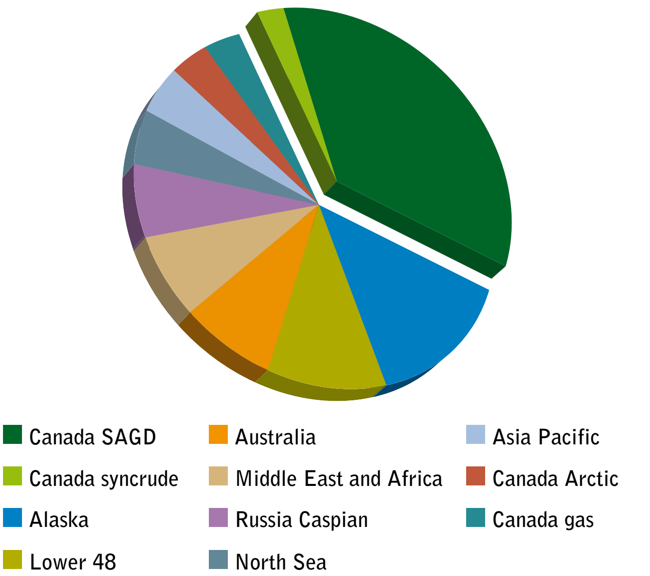
Figure 13: Total proved and probable reserves growth 2004–2009



Source: Total 2009 results and outlook[97]

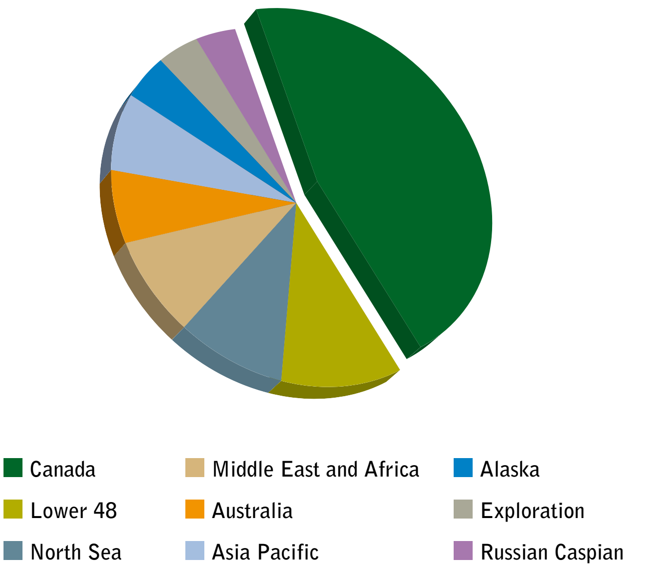
Total's report, rather than showing total resources as the others do, illustrates the growth in proved and probable reserves between 2004 and 2009, which gives a reasonable idea of reserves added in the period. We can see that while the reserves base has grown between 2004 and 2009, conventional liquids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

Figure 14: ConocoPhillips total resources by region 2009



Source: ConocoPhillips March 2010 analyst meeting, New York[98]

Figure 15: ConocoPhillips 2010–2014 reserve additions



Source: ConocoPhillips March 2010 analyst meeting, New York[99]

ConocoPhillips' Canadian tar sands resources are primarily in situ resources that will be produced through the SAGD method and are its biggest single resource. Our analysis of its reserves additions in the past five years shows that these resources made up 39 percent of its total reserves additions and a staggering 71 percent of its total liquids additions, far greater than any of its competitors.

The second chart above shows that the company also expects to make greater 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 percent in SAGD production through to 2019.[100] The company also holds substantial resources in the Canadian and Alaskan Arctic, some of which is offshore.

Box 4 **The "resource curse":** Is "rent seeking" another driver of marginal oil development?

Over 50 countries worldwide are defined as natural resource-rich.[101] In sub-Saharan Africa, nearly half of the population lives in oil- and mineral-rich countries, which account for about 70 percent of Africa's GDP and receive most of the foreign direct investment into the continent.[102] Yet most of these countries have low human development. Resource-rich developing countries are associated with high levels of poverty and income inequality, poor governance, high levels of corruption and authoritarianism, higher spending on military and security forces, a higher likelihood of civil war and social instability, high child mortality, low life expectancy, low spending on health, low levels of primary education, and high levels of illiteracy.[103]

A girl collects food for her community in the Congo rainforest. © Greenpeace / Davison

This has led economists and development specialists to develop the notion that resource-rich developing countries are characterized by "the paradox of plenty" or "the resource curse." Poor development outcomes are particularly notable in the case of oil wealth. Equatorial Guinea, for instance, sometimes called the "Kuwait of Africa," is sub-Saharan Africa's fourth-largest oil-producing nation with the continent's highest GDP per capita (over $30,000). This is comparable to that of wealthy nations like Italy and Spain. But its Human Development Index ranking is 118 out of 182 countries, and on the Human Poverty Index, which measures the average *progress* of a country in human development, it ranks in the bottom 25 percent of countries.

Oil is a finite or non-renewable resource, bringing large revenue inflows to a country, but over a limited time period. Oil revenues are also highly subject to price volatility, which means that without policy measures to address this, oil-dependent countries are exceptionally vulnerable to "boom and bust" cycles, making budgetary forecasting and provision difficult for governments. In addition, rapid oil sector development can cause "Dutch Disease," that is, currency appreciation and inflationary movement that weakens the non-oil sectors of the economy, rendering non-oil exports in particular less competitive.[104]

Other economic and fiscal impacts of sudden oil wealth are the increased likelihood of governments engaging in unplanned public spending sprees, leading to a loss of fiscal control (their effectiveness may also be hampered by weak administrative capacity); the strengthening or creation of patronage systems with political effects, that is, the undermining of democratic pressures; and an increase in foreign debt with some countries taking out expensive "oil-backed loans," ostensibly to fund public investment programs but often as a cover for illicit diversion of funds.[105]

Overall, developing-country oil producers are associated with a decrease in government accountability and a weakening of state institutions, as "easy" (unearned) money renders governments non-reliant on earned income (e.g., from taxation[106]). "If pre-existing institutions are weak or the state is only partially formed, the influx of rents from petroleum tends to produce a rentier state – one that lives from the profits of oil. In rentier states, economic power and political power are especially concentrated, the lines between public and private are very blurred, and rent-seeking as a strategy for wealth creation is rampant."[107]

As a logical extension of this, "rent-seeking" and corruption can be additional drivers of development of oil resources in countries with weak state infrastructure. Corrupt elites may seek to attract investment in order to cash in on the "honey pot" of unearned revenue flows to the state resulting from oil development. In turn, companies and middlemen may seek to exploit rent-seeking behavior, as they stand to benefit from lack of institutional capacity and oversight in obtaining terms for accessing resources that are favorable to them and which may divert wealth into the pockets of ruling officials, but offer a poor deal for the country's citizens.[108]

In oil-rich Angola, for instance, the OECD states that the business climate is characterized by "major bottlenecks due to endemic corruption, outdated regulations and rent-seeking behaviour."[109] There is no reason to suppose that – without concerted and far-ranging policy reforms to increase transparency and combat corruption – rent-seeking would not equally be a factor driving development of marginal resources in weak states.

1.9 Energy security – Does marginal oil really bring security?

Over the last decade, rising oil prices and growing concern over peak oil has pushed energy security toward the top of government agendas around the world. In the United States, energy security has been repeatedly cited as a national security priority, trumping climate protection concerns surrounding Canadian tar sands extraction.[110] The popular argument goes: Canada represents a stable and friendly source of oil that is not prone to the multiple threats of anti-Americanism, terrorism, or resource nationalism. Industry and government supporters often use this argument in defence of tar sands production.[111]

US energy security concerns are driving the call (postponed in the wake of the Deepwater Horizon spill) to open up new offshore exploration on the US continental shelf, as well as the drive into the offshore Arctic regions of Alaska and Canada.[112] It can also be argued that increasing attention is being paid to West African oil resources by Washington energy hawks.[113]

Energy security is equally a concern for Jordan in its quest to develop its oil shale resources, given it lacks any other oil resources.[114] Indeed, for any net oil-importing country, the opportunity to open up previously inaccessible oil resources – either domestically or in friendly, neighbouring, or even distant countries – is a strategy that has become increasingly urgent in the past decade. China's bilateral deals with oil producers from Kazakhstan to Venezuela, discussed below, are a good example of this latter strategy.

In the United States and to some extent in China, a concern about overdependence on imports from Middle Eastern oil producers is the main focus of energy security fears. However, on closer inspection, the energy security arguments for opening up marginal resources are at best weak, particularly if the drive into marginal oil is presented as the only solution to energy security concerns. Indeed, without aggressive demand reduction, no amount of "friendly, stable," and/or domestic oil production can ensure energy security for the big oil importers.

This discussion will now look at some of the (essentially weak) arguments in favor of energy security and how they do not stand up to close scrutiny.

1.9.1 Energy Security Argument No. 1: Marginal oil from non-OPEC sources reduces the power of the OPEC cartel

This argument runs: if more non-OPEC oil is produced, then less OPEC oil will be needed, reducing the power of the cartel to manipulate the market (revenues will be discussed in the following section).

This would seem intuitively to be correct. However, because the bulk of remaining non-OPEC oil is capital-intensive, expensive-to-produce marginal oil, while most OPEC resources remain relatively cheap and easy to bring onstream, OPEC's grip on the market is only likely to grow, particularly as demand increases. The IEA Reference Scenario forecasts OPEC's domination of global oil supply growing, despite development of unconventional oil and other marginal resources, from 44 percent in 2008 to 52 percent in 2030.[115]

As non-OPEC, marginal oil is so expensive to produce, the IEA suggests that with reduced demand under the 450 Scenario, OPEC's share of the global oil market would, in fact, be slightly higher at 55 percent because lower oil prices in this scenario would render many marginal oil sources uneconomic.[116]

However, this situation is still *more* secure for oil importers, as they will be importing significantly less oil. For example, US oil imports in 2030 will likely be around 15 percent less than in 2008 under the Reference Scenario, but double that, 33 percent less, in the 450 Scenario.[117] OPEC will export less oil in the 450 Scenario and with lower prices will have lower revenues. While its market share will be slightly higher, its overall production will be lower, in line with lower demand and prices.

The supply and demand balance that optimises energy security comes down to simple market principles. If demand remains at the edge of suppliers' ability to supply, then prices will be high and consumers will be at the mercy of suppliers' whims. Reducing demand turns the tables. OPEC may have more market share in a reduced demand scenario but it also has far less power, because demand for its products will be in decline. In such a situation, suppliers will have to compete for customer access rather than the other way around. The power will increasingly shift toward the consumer. This argument is also worth bearing in mind in relation to "resource curse" developing-country oil producers whose economies are heavily dependent on oil exports (see Box 4).

1.9.2 Energy Security Argument No. 2: More marginal oil is less money for unsavory regimes and sponsors of terrorism

The intuitive wisdom of this theory is also undermined by the simple facts of the global oil supply-demand balance. If Middle Eastern regimes and other OPEC members such as Venezuela are the source of oil importing countries' concern, as they generally are, the revenues lost to those countries from the opening of marginal oil resources will be negligible.

In fact, the drive to develop these expensive and risky resources signals to OPEC that the market can tolerate high prices, allowing the cartel to set the floor for prices at the level marginal oil demands for its development to be viable. This trend is likely to continue: The IEA stated in November 2010 that "unconventional oil, together with deepwater and other high-cost sources of non-OPEC conventional oil, is set to play a key role in setting future oil prices."[118]

Using tar sands as an example, at $75 a barrel, the roughly 900,000 b/d of tar sands oil the United States imported in 2009 resulted in revenues of around $24 billion for Canada. In comparison, OPEC countries netted over $1 trillion in 2011 a figure which is set to rise in coming years.[119] The $24 billion they are not earning because of the tar sands barely impacts their bottom line – especially because of the way the cartel operates.

As non-OPEC production increases, OPEC has the choice to either maintain its production levels, allowing prices to drop, or cut its production and maintain prices. The former spreads the loss between all members, whereas the latter primarily affects those members with the largest spare capacity – predominantly Saudi Arabia. Either way, the effect on any one producer is marginal. Therefore, any OPEC members intent on using their oil wealth to suppress their people or sponsor international terrorism will not be prevented from doing so by the diversion of oil funds to a non-OPEC country. As explained above, only when demand is brought under control will the wealth, and hence the power, of these countries be curtailed.

Additionally, it is clear that if demand is allowed to rise, more revenues will go to OPEC producers over the next two decades than ever before, despite the production of marginal oil encouraged by high demand. The IEA estimates that OPEC export revenues will grow enormously under both of its scenarios, with Reference Scenario revenues of around $4 trillion more than in the 450 Scenario for the period 2008–2030.[120]

So while higher demand supports the high oil prices that will open up marginal oil, the production of that marginal oil will not make any oil-importing countries more secure. Marginal oil is a symptom of *high prices and excessive demand* rather than a means of combating either one. The supply and demand balance that supports marginal oil is also a boon for OPEC producers, because it supports high oil prices.

1.9.3 Energy Security Argument No. 3: Marginal oil protects oil importers from "oil as a political weapon" and supply crises

Marginal oil production will not adequately protect oil importers from a supply crisis because of the global nature of the oil market and the fact that no marginal oil sources are likely to have significant spare capacity on hand to address a supply crisis.

Should OPEC or any other major exporter suffer a drastic loss of output or choose to cut off supplies to any country or group of countries, supply shortages and a price spike is likely to affect every major importing country regardless of how much marginal oil is in production. The only producers who could ameliorate the effects of such an event would be those with enough spare production capacity to raise production quickly to meet the shortfall.

The high capital intensity and financial risks of bringing marginal oil production on stream require companies to pump as much as they can whenever they can. In other words, spare capacity is simply not something they can afford. There is no spare capacity in the Canadian tar sands that could be brought on stream quickly in an emergency. On the contrary, tar sands production generally operates at around 20 percent under capacity due to maintenance and unplanned stoppages.[121] Only a handful of OPEC members can afford to maintain spare capacity, principally Saudi Arabia, which currently maintains about 4 Mbpd of spare capacity.

In fact, it is importing countries' strategic petroleum reserves (SPRs) that do the job of cushioning them against supply crises and arguably have done so successfully for the past 30 or so years. Decreasing demand will make SPRs even more effective and reduce further the likelihood of oil being used as a political weapon. SPRs were created in response to the first oil crisis in 1973 and were one of the reasons the IEA was established in 1974. Today, the combined SPRs of IEA member countries can respond to a supply disruption totaling 4 Mbpd for one year.[122] China, India, and Thailand are also now building SPRs, with the effect of further insulating the global market from a major supply disruption.

The development of SPRs has severely undermined the effectiveness of the "oil weapon," as is evidenced by the non-reoccurrence of any event similar to the 1973 oil embargo. Most major supply disruptions since have been caused by natural disasters such as Hurricane Katrina – when SPRs released 60 million barrels to calm the market – and political events that cause general supply disruptions such as the invasion of Iraq, the Iranian revolution, or the ongoing conflict in the Niger Delta. Whatever the cause of supply disruption, the inability of marginal oil suppliers to maintain spare capacity means they can only ever play a minor role in maintaining existing supply and have no ability to bring extra production on stream in times of need.

These three main arguments form the basis of energy security concerns in oil-importing nations. As such, they are weak arguments for expanding marginal oil, primarily because the high costs and risks of marginal oil only increase energy insecurity. In addition, for the United States in particular, the additional cost of military deployment to protect sources of oil overseas, estimated at over $137 billion a year, further supports the view that a more efficient energy path is urgently needed.[123]

1.10 Supply and demand: Hard truths or convenient assumptions?

The global demand for liquid fuels in 2010 was around 88 Mbpd.[124] Around 5 Mbpd of this demand is was met by deepwater production, with about 1Mb/d classified as ultra-deep.[125] Canadian tar sands production was around 1.6 Mbpd in 2010.[126] Production from other unconventional oil and offshore Arctic developments is insignificant at this point in time.

However, the long lead-in times required for major oil projects – particularly those in frontier regions or using unconventional or new production techniques – means that oil companies are constantly looking ahead, in some cases decades, to long-term forecasts of supply and demand.

To facilitate their forward planning, companies need to consider the trajectory of oil demand. Generally, only one kind of trajectory has ever been considered: upwards. The pace of this upward demand trajectory, however, has been keenly debated and there have been periods of relatively slow growth (1980s and 1990s) and periods of much faster growth (1960s and 2000–2007). One accepted rule for forecasting oil demand is that when per capita income reaches a certain level, oil demand "takes off": The IEA estimates this take-off point at around $3,000–$4,000 a year.[127] The high rate of growth in demand in the past decade has been primarily driven by rapid economic development in China and other Asian emerging economies, as well as in Latin America and the Middle East.

1.11 China leading demand growth

In the IEA's New Policies Scenario, by 2030 China's projected consumption of oil could be 14.5 Mbpd.[128] In terms of total global energy-related emissions, China may account for 28 percent of the world total in 2035.[129] Chinese demand as a driver of future investment in marginal oil in developing countries is therefore critical.

The country is investing heavily in both domestic and overseas oil exploration, both in conventional oil projects, as well as tar sands in Canada. According to one source: "Over the past year alone Chinese state-owned companies have signed major deals to extract or export oil, gas, coal, uranium and other key natural resources from Canada, Venezuela, Iraq, Australia, Turkmenistan and South Africa," with around $70 billion going into oil-for-loan deals, plus refinery joint-ventures and pipeline agreements.[130]

In addition, China is implementing a synergetic increase in domestic refining capacity and levels of crude imports aimed at enabling the country to be self-sufficient in oil products. Industry analysts Wood Mackenzie see this as a "marked shift" in strategy.[131] The country is also attempting to diversify its oil supply (to the limited extent possible) away from its current 85 percent dependency on Middle Eastern imports: Hence the loans have mainly targeted its Central Asian neighbors and Latin American producers.[132]

On the other hand, it is a moot point whether recent high growth rates will continue.[133] Recent data from the IEA suggests that the annual growth rate of oil demand is slowing down.[134] In addition, although increasing supply appears to be a key medium-term strategy, it can also be argued that China is equally concerned with demand reduction as a long-term energy strategy.

Its national climate plan proposes a cut in energy consumption per unit of GDP of 20 percent (from 2005 to 2010), and a 10 percent cut in emissions of pollutants. In the transport sector, the government is subsidising hybrids, electric cars, and fuel cell vehicles and incentivising the use of smaller cars through its taxation policies.[135] In addition, 10 percent of the huge $600 billion national stimulus package China introduced in response to the global economic crisis is directed toward low-carbon projects, mainly rail transport.[136]

1.12 Tight supply and demand triggers policy shifts

Meanwhile, oil demand in the developed economies of the OECD has peaked in the view of many observers.[137] Per capita car ownership has reached its limits, population levels are either stable or shrinking, and the fuel efficiency of private car fleets is set to improve. The only probable challenge to this is the continued growth in aviation and associated demand for jet fuel.[138]

What is also becoming clearer is that the related threats of reaching "peak oil" and the economic impacts of high oil prices are having an influence on energy policy in developing and developed oil-importing countries.[139] There is greater recognition that seeking to maximize supply alone cannot guarantee energy security and that improving energy efficiency must be part of the solution.

Yet governments are still not doing as much as they could do to constrain demand, while oil companies and their business associations are actively undermining such efforts by fighting to maintain "business as usual," justifying this position by pointing to supposedly inevitable growth in future demand, and choosing to ignore the vital role of demand reduction in achieving climate goals.[140]

1.13 Declining demand will hit marginal oil first

The issue of demand reduction is central to the debate on marginal oil because the very marginality of these oil resources means their production is highly vulnerable to policy measures aimed at conserving oil. In short, the less oil we consume, the less marginal oil will need to be produced.

This effect is primarily driven by price. As demand declines, oil prices should stabilise and the resources that are more expensive to produce become uneconomic. As discussed above, Figure 8 highlights the production/cost parameters of various types of oil production, demonstrating the vulnerability of marginal oil sources to lower oil prices.

Unfortunately, this is not as simple as it first appears. The expected decline in currently producing oil fields is so steep that even the most aggressive demand-reduction scenario would still require new production to be brought onstream. The IEA has calculated that of 69 Mbpd of conventional oil production available in 2010, only 22 Mbpd will be available in 2035[141]. New oil production capacity will inevitably be created to replace these depleting fields. However, the key challenge appears to be to reduce demand *as much as possible* in order to minimize the need for new production and so that as little of this new production comes from marginal sources, with their particularly intense environmental and social impacts[142].

The production cost curve in Figure 8 shows that if oil prices were lowered due to reduced demand, Middle East and North African oil would meet most of the world's oil demand. This, of course, means OPEC would retain more overall market share, but as discussed in relation to energy security, allowing oil demand to grow freely will hand even more money and power to OPEC. Where will oil demand head without any change in current policies and where might it go if effective efficiency policies are adopted?

1.14 "Business as usual" or "business as urgently required"?

IOCs regularly quote IEA forecasts when discussing the future of oil supply and demand. In communications with activist shareholders in 2010, both Shell and BP quoted IEA forecasts to support their claims that oil demand in 10 and 20 years would be adequate to justify the expense of developing

Canadian tar sands resources.[143] They highlighted that the IEA forecasts 40 percent growth in primary energy demand between 2007 and 2030, when around 80 percent of energy demand would still be met by fossil fuels.

They did not misquote IEA figures, but these figures were drawn from the IEA's 2009 Reference Scenario. The Reference Scenario is provided by the IEA as a guide to how energy supply and demand will develop under current energy policies. In other words, it presumed that no new measures will be adopted to address climate change or energy security concerns. As such the IEA warns that: "Continuing on today's energy path, without any change in government policy, would mean rapidly increasing dependence on fossil fuels, with alarming consequences for climate change and energy security."[144] It goes on to explain that:

> **"The rate of growth of fossil-energy consumption projected in the Reference Scenario takes us inexorably towards a long-term concentration of greenhouse gases in the atmosphere in excess of 1000 ppm CO_2-eq. The CO_2 concentration implied by the Reference Scenario would result in the global average temperature rising by up to 6°C. This would lead almost certainly to massive climatic change and irreparable damage to the planet."[145]**

Thus it appears that the oil companies are basing their business plan and future growth strategy on the collective failure of governments to address emissions and a scenario of runaway climate change. They would almost certainly contest such a claim, but beyond their public statements referring to the Reference Scenario, their increasing reliance on marginal resources is evidence that they lack any strategy for accommodating the shift to a low-carbon future. The IEA states that in order to avoid the consequences of its Reference Scenario, future oil demand must be reduced, which will severely impact production of marginal oil.

The IEA's 450 Scenario forecasts the trajectory of energy supply and demand necessary to stabilize the concentration of CO_2-equivalent in the atmosphere at 450 parts per million (ppm). The IEA uses this concentration level as the level necessary to prevent average global temperatures rising more than 2°C, which it claims will constrain climate change at a manageable level.

However, there is in fact no consensus on the 450 ppm figure and many experts and groups advocate that a "safe" level of CO_2 concentration is the much lower 350 ppm. The IEA describes the impact of its 450 Scenario on oil production as follows: "Lower global oil demand in the 450 Scenario results in a lower oil price than in the Reference Scenario. This, coupled with the introduction of CO_2 emissions targets in OECD+ countries, renders production in higher-cost fields uneconomic, particularly in the OECD+ region."[146]

Unconventional oil production still grows in the 450 Scenario but is some 33 percent less in 2035 than it would be in the baseline scenario.[147] Canadian tar sands, being the most advanced of the unconventional sources, is reduced by about 28 percent.

The IEA also suggests that offshore Arctic production and some of the more extreme deepwater projects would be affected by the 450 Scenario.

> **"…the need for exploration to find and then develop reservoirs that are as yet unknown is only two thirds of that in the New Policies Scenario, a difference of almost 60 billion barrels. This reduction is equivalent to two-thirds of the estimated volume of oil that is thought to remain to be found in the Arctic and is comparable to the total volume of oil discovered during the past five years. As the oil industry typically develops easy-to-find oil first, this reduced need to bring on new capacity allows the industry to dispense with some of the more costly and more environmentally sensitive projects."[148]**

> **"Investment in oil supply in the 450 Scenario is 21 percent lower than in the New Policies Scenario, with the bulk of the reduction coming after 2020. This drop results from the reduced need to bring on new production capacity, including the most costly deepwater offshore oil projects."[149]**

These statements and figures do suggest that reducing demand in line with climate goals dispenses with some of the more destructive and expensive oil production. But it appears that it would not dispense with them altogether. The precipitous decline of conventional oil production, particularly in non-Opec fields, appears to ensure a future for a proportion of these resources. Perhaps offshore Arctic is the most vulnerable as it has not actually started yet, is potentially very expensive (see Figure 8) and risky, and will require huge capital investments at precisely the time that demand could be stabilizing.

However, the IEA forecasts are merely an example of a demand trajectory based on a model using a particular set of policy instruments and a number of economic and political assumptions.

The 450 Scenario assumes a very limited set of policy changes to bring about the desired reduction in oil demand. They are primarily based on sectoral reforms – for example higher vehicle efficiency standards for private light duty vehicles that would encourage manufacturers to produce more efficient internal combustion engines and support the market penetration of hybrid and electric vehicles. Efficiency improvements are also expected in the aviation sector.[150] There is no expectation in the IEA model of behavioral change, nor is there much analysis of the impact of wider policies to reduce demand, such as urban planning policies that reduce demand for travel or encourage greater use of public transport.

Additionally, in using 450 ppm as a basis for climate stability, the IEA recognises that this has only a 50 percent chance of stabilizing the climate at a 2°C average temperature rise. It is thus the bare minimum necessary and, given the latest findings of climate science, likely too little too late.[151] To properly ensure climate stability, we need to be aiming for greater emissions reductions using a wider and deeper range of policy interventions. If this were to happen, the window of opportunity for marginal oil production would shrink much further.

1.15 Getting behind demand reduction: The key to killing marginal oil?

In order to avoid the current disastrous business as usual energy path, any policy measures taken will need to have what the IEA calls "a considerable impact on [global] energy demand, notably for fossil fuels."[152] Arguably, the inadequacy of the IEA's proposed level of demand reduction – based on a limited set of policy interventions – makes tougher action even more urgent.

In fact, the requisite policy instruments and associated technology exist to achieve significantly deeper cuts in oil demand than the IEA is advocating. The United States currently accounts for 22 percent of global oil demand[153] and, in the words of Deutsche Bank, constitutes "the last market-priced, oil inefficient, major oil consumer."[154] As such, it is *the* pivotal market whose transformation could have major repercussions across the global oil market.

It is also close to many marginal oil fields – ultra-deepwater in the Gulf of Mexico, offshore Arctic in Alaska, Canada, and Greenland, and the Canadian tar sands, not to mention the vast oil shale resources in Utah and Colorado. Given the influence of US energy security concerns, the transformation of US oil demand would considerably impact on the attractiveness of future marginal oil investment.

Reducing demand in China is also important, given the country will account for an estimated 48 percent of global oil demand growth in the period to 2035.[155] However, arguably China's actions to improve efficiency are already starting to shed doubts on how far its demand growth will continue.[156]

Some analysts point to China's reduction in consumption subsidies, adoption of vehicle efficiency standards that are similar to the EU's (and significantly more stringent than those being introduced in the United States), and tax incentives for the purchase of efficient vehicles as evidence that China can and will constrain its demand to more sustainable levels.[157] Its current investment in public transport infrastructure has been described as "the greatest boom in mass-transit construction in history."[158]

Moreover, even with the aggressive demand growth forecast in the IEA's New Policies Scenario, with a demand level of 14.5 Mbpd in 2030, China's consumption would still not reach the United States' current 18.0 Mbpd consumption.[159] Indeed, China's per capita oil use is unlikely to ever reach the level of the United States. US per capita oil consumption in 2030 under the 450 Scenario would still be around 230 percent higher than China's under the "business-as-usual" scenario.[160]

If the United States were able to achieve cuts in oil use of around 50 percent by 2030 (around 8–10 Mbpd), this would more than cancel out demand growth in China. If this reduction were matched – in whole or part – by action in China, Europe, and elsewhere, global oil demand would be on an inexorable downward path.

Thus, while the responsibility to constrain oil demand is shared by all nations, including the emerging economies, it is arguably action by the United States that will have the most significant impact. This can be done by deploying technologies available for roll-out on a commercial scale today, potentially cutting US oil demand by 40 to 50 percent by 2030 and putting it thereafter on a steady downward trajectory toward very limited demand.

The debate is, perhaps, over the *extent* to which this can be achieved through existing technology. Such a reduction will certainly take more than improved vehicle efficiency standards, requiring a whole range of policy mechanisms being rolled out to address every level of oil use in the American economy, from disincentivising private transport to greater efficiency in freight and aviation.[161]

However, hybrid vehicles are already available on the market, with electric vehicles not far behind. What is required is increased and concerted government support to accelerate their market penetration. Equally, addressing oil use by changing freight delivery systems, reducing travel through better planning and, crucially, increasing access to public transport, could all result in significant savings.

In the United States, for instance, 97 percent of private car trips are for distances of under 40 miles, with 91 percent under 20 miles.[162] This illustrates the vast potential of planning interventions through mixed-use development and better provision of public transport.

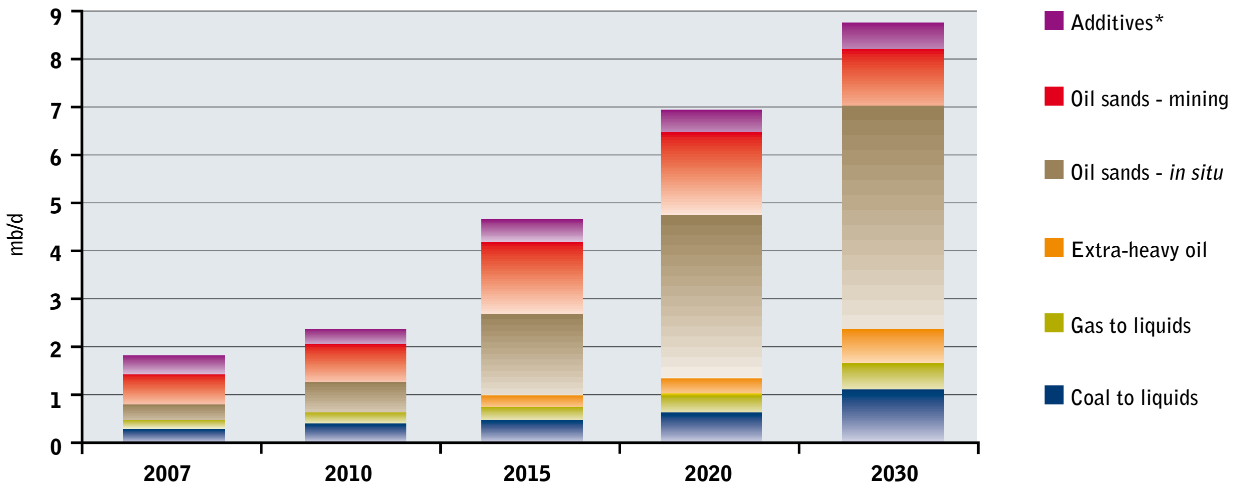
Analysis by Deutsche Bank, for instance, has also pointed out that the high density, stop-start driving conditions characteristic of these trips means that the hybrid car offers massive fuel savings over the internal combustion engine (it consumes no gasoline while idling and driving at slow speeds). Based primarily on the hybrid's efficiency potential, Deutsche Bank predicted that the "end is nigh for the age of oil" and that a global peak in oil demand would occur around 2016.[163]

It further warned that the "value of high [capital expenditure or] 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."[164]

Deutsche Bank's assessment may be accurate. Perhaps the hybrid car is enough of a game-changer to ensure that global oil demand will peak. However, its analysis points to a plateau in demand and only a very modest decline by 2030. To reduce demand enough to kill marginal oil will probably require a much more concerted effort.

2 Key marginal oil developments: A brief survey

Figure 16: Unconventional oil production by type of resource



*Methyl tertiary butyl ether (MTBE) and other chemicals.

Source: World Energy Outlook 2008[165]

The IEA's 2010 definition of unconventional resources includes extra-heavy oil, including from Venezuela's Orinoco Belt, natural bitumen (oil sands), chemical additives, gas-to-liquids and coal-to-liquids, and oil shales.[166]

The following discussion will focus firstly on extra-heavy oil in Venezuela, with some discussion of other bitumen and unconventional resources. One main reason for this is that, according to the IEA, in all of its demand scenarios the approximately 10 percent of world demand that will be met by unconventional resources will be dominated by Canadian tar sands and Venezuelan extra-heavy oil.[167]

However, also taking into account that the continuum between what are currently defined as unconventional and conventional resources (see Figure 1), it also considers some key conventional projects such as deep or ultra-deep offshore in Brazil and West Africa, heavy oil development in the Western Amazon and the rush to develop as yet unexplored basins in sub-Saharan Africa.

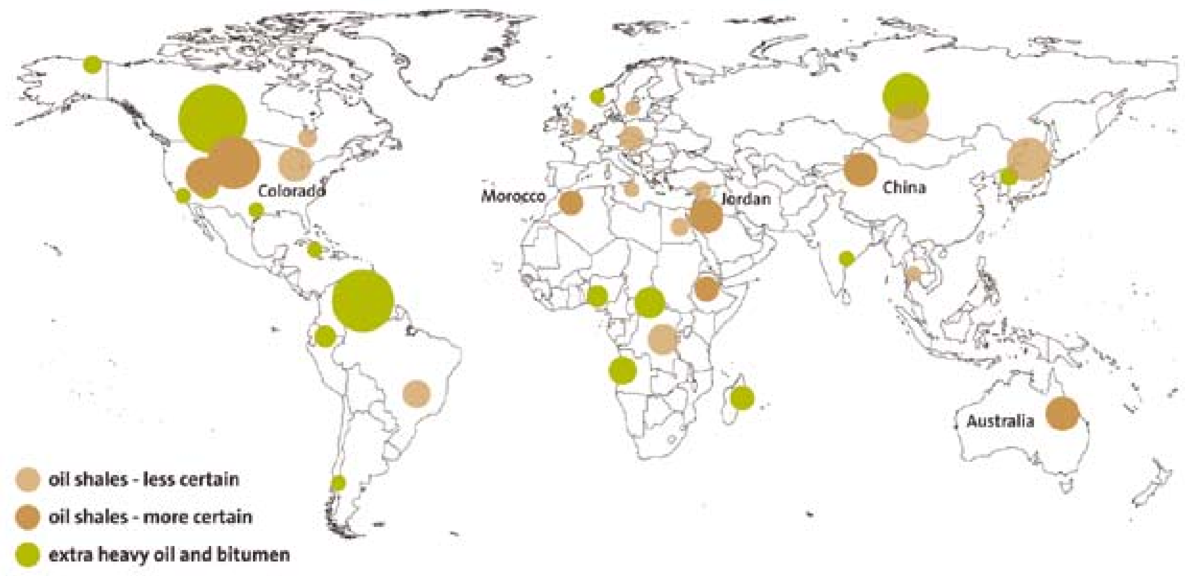
Such marginal developments are of interest for the following reasons, as outlined in Section One. Firstly, they are high-risk in terms of their structural implications, that is, they embody and illustrate the drive to access previously inaccessible or uneconomic resources and will further deplete our remaining carbon budget and exacerbate energy insecurity. Secondly they also risk (further) damaging vulnerable communities and ecologies in the South.

Apart from (relative) ease of access to the resource, or viability of current or future development, the principle of selection for the projects discussed is their fulfilling *all* or *a significant number* of the following criteria:

- **Project size, hence potential impacts in terms of climate damage;**
- **Potential local impact on vulnerable community, ecology, and/or economy (developing country);**
- **Critical attitude of local indigenous or host community to the project;**
- **Participation in the project of European or US-listed companies or significant financing by US/EU entities;**
- **Level of national and local civil society activity in the host country and/or "openness" of political space at the national level.**

The list of developments is, however, not intended to be exhaustive. Nor does this section offer an overview of marginal oil resources worldwide. In terms of the world's key *unconventional* oil resources, a May 2010 briefing by Friends of the Earth Europe (FoEE), *Tar sands: Fuelling the climate crisis, undermining EU energy security and damaging development objectives*, outlined many of these. This paper refers readers in search of more detail directly to the FoEE report. Mappings of unconventional resources and associated data – and particularly of proven reserves –[169] can also be found in publications such as the World Energy Council (WEC)'s 2007 *Survey of Energy Resources* or the IEA's *World Energy Outlook* or on company websites (for instance, see Figure 17).

Figure 17: Global unconventional oil resources



Source: FoE 2010[168]

2.1 Bitumen and extra-heavy oil[170]

Canada and Venezuela hold the vast majority of the world's reserves in bitumen and extra-heavy oil (that is, oil with an API gravity of less than 10). According to the 2003 *US Geological Survey*, Canada contains around 80 percent of the world's bitumen. Outside Canada "359 natural bitumen deposits are reported in 21 other countries."[172] The largest deposits after these two countries are found in Kazakhstan and Russia. However, the WEC points out that development of these resources is unlikely in the short to medium term since "both countries also have large volumes of undeveloped, and undoubtedly less costly conventional oil."[173]

Indeed, according to the IEA, "only Canada and Venezuela are likely to play a significant role in the exploitation of [bitumen and extra-heavy oil] in the timescale of [our] projections [i.e., to 2035]. This is because of the size of their resources and the facts that they are already in production, plans exist for their further development, significant reserves are considered as proven and they are geographically concentrated; their decline is not an issue over the 25-year horizon of these projections."[174]

Figure 18: Tar sands and extra-heavy oil resources

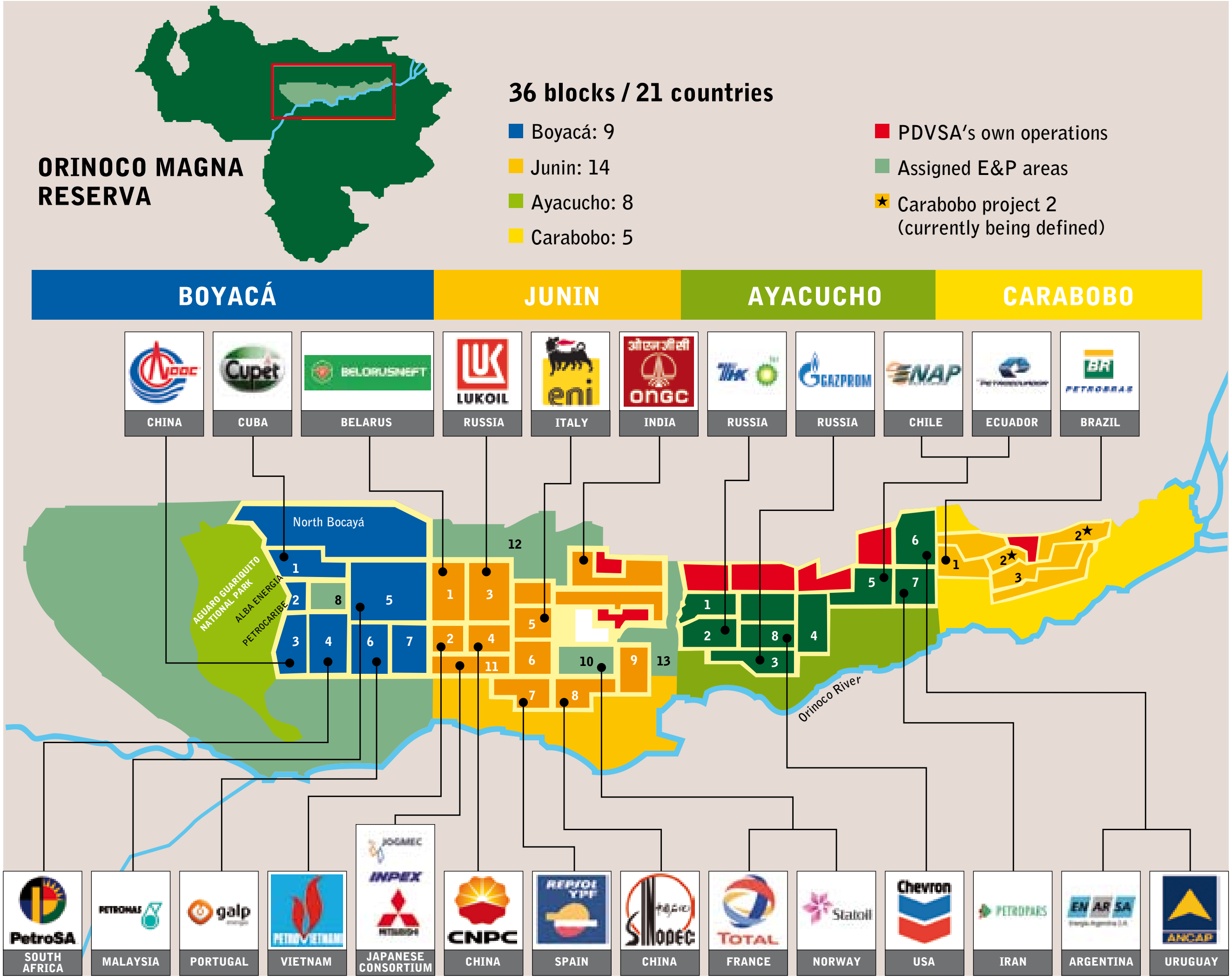
	Proven reserves	Ultimately recoverable resources	Original oil in place
Canada	19.0	≥ 800	≥ 2 000
Venezuela	60*	500	≥ 1 300
Russia	-	350	850**
Kasakhstan	-	200	500
United States	-	15	40
United Kingdom	-	3	15
China	-	3	10
Azerbaijan	-	2	10
Madagascar	-	2	10
Other	-	14	30
World	**230**	**≥ 1 900**	**≥ 5 000**

* As reported by the *Oil & Gas Journal* (O&GJ, 2009); the national oil company, PDVSA , currently reports 130 billion barrels as proven.

** From BGR (2009); Russian authors report significantly smaller resources, of the order of 250 billion barrels; the same applies to Kasakhstan. Bitumen resources in particular are poorly known , as a high percentage is located in the vast and poorly explored region of eastern Siberia. BGR reports 345 billion barrels recoverable, which is more in line with Russian publications.
Sources: BGR (2009); USGS (2009a); IEA analysis.

Source: World Energy Outlook 2010[171]

Figure 19: Orinoco Oil Belt Project



Source: caracaschronicles.com

2.2 Venezuela's Orinoco: the next big unconventional oil rush?

Venezuela holds around 90% of the world's proven extra heavy oil reserves, mainly located in the Orinoco Belt in the East of the country, which extends over 55,000 Km^2 to the south of the Guárico, Anzoátegui, Monagas, and Delta Amacuro states (see map). The Belt contains around 256 billion barrels of recoverable oil, according to state oil company PDVSA.[175]

This resource has now been certified with the result that, in July 2010, Venezuela overtook Saudi Arabia to become the country with the largest oil reserves in the world.[176] Petróleos de Venezuela SA (PDVSA), the state oil company, is now the world's fourth largest company in terms of proven reserves, production, refining and sales.[177]

Projected production costs per barrel for developing the Orinoco resource are estimated by some sources to be considerably lower than for Canadian tar sands or Brazil's pre-salt, because of the fluidity and reservoir conditions. The WEC states that "[c]urrent estimates of the supply costs for the Orinoco extra-heavy crude oil are as little as half of the supply cost for Canadian bitumen."[178] The IEA concurs that "[p]rimary production with multilateral horizontal wells, which gives higher recovery rates than in Canada, due to lower oil viscosity, is significantly cheaper." The agency also puts the average cost of new Orinoco projects at around a third lower than Canadian tar sands projects on a per-barrel basis.[179]

Indeed, prior to the incumbency of President Chavez in Venezuela – whose government has overseen an outflow of skilled workers from the national oil company (PDVSA) and of IOC investment, accompanied by a decline in production (see below): "Venezuela's deposits were favoured over Alberta's by the global oil industry because they are easier to produce, geographically better-placed - there are no costly open-pit mines and crude flows more easily to the surface - and easier to transport by tanker to the U.S. Gulf." [180]

Given these advantages, if the investment context in Venezuela were to become more favourable to IOCs, then Canada's tar sands industry would likely face major new competition for investment, U.S. market share and technical expertise.[181]

Today, development of the Orinoco Belt is the cornerstone of the Venezuelan government's future economic plans (oil accounts for 95% of the country's export earnings and around 55% of the federal budget)[182]- and was the engine of President Chavez's re-election campaign in October 2012. At the end of 2011, Chavez announced his *Plan Siembra Petrolera (Sowing the Oil Crop)*, with a target of boosting oil output to 3.5 million barrels a day by the end of 2012 rising to 4 million barrels by 2014 and 10 million by 2030.[183] To this end, the government is seeking $100 billion of new investment to develop the Belt.[184]

2.2.1 Challenges to Venezuela's Orinoco oil plans

The government's multi-billion dollar investment plans for the Belt are likely to be hampered by several issues. Firstly, there is a question mark over PDVSA's ability to provide its share of the huge capital investment required to ramp up existing production in the Orinoco and develop the new projects (PDVSA holds a 60% majority stake in all the new Orinoco blocks). Both its high debt burden and the political risks associated with the Venezuelan context negatively impact on PDVSA's chances of raising future financing and attracting investors and workers with the requisite technical expertise.

Overall, investment in Venezuela's oil sector including its Orinoco Belt is seen by many analysts as high risk.[185] This is due to financial factors such as estimated high development costs but also legal and political concerns, principally a lack of certainty over the stability of fiscal regimes and the ongoing impacts of the 2007 nationalization of assets belonging foreign companies in strategic sectors of the economy.[186] In the most high profile case, PDVSA is in dispute with Exxon over the latter's claim for US$12 billion damages for the expropriation of assets by the Venezuelan government. Exxon has been awarded US$908 million damages by the International Chamber of Commerce but is still seeking redress in other venues.[187]

Another recent concern raised by oil companies operating in the country relates to changes in taxation of "windfall profits" in April 2011, meaning the government take will rise more steeply as the price of a barrel rises.[188] According to the government, the new taxation regime will only apply to oil from the Orinoco projects once investment costs have been recovered, but some companies are complaining that the investment terms for the Orinoco Belt, including the application of the windfall tax, remain unclear.[189]

2.2.2 Orinoco investment – IOC-lite?

Indeed, there are few IOCs with new investments planned in the Orinoco, the notable exceptions being Chevron (already a minority partner on the Petropiar block), ENI & Repsol - Chevron having most technical expertise in light of its investment in tar sands projects in Alberta. Eni has a 40 percent stake in Junin 5; Chevron, a 34 percent interest in Carabobo 3; and Repsol has 11 percent of Carabobo 1.

In July 2011, ENI agreed a US$2 billion financing agreement with PDVSA.[190] Under the deal, ENI will fund PDVSA's costs for the development of the Junín 5 block's early production phase to the tune of US$1.5 billion, with the remaining US$500 million going to construction of a new power station on the Güiria Peninsula.[191] The development plan also includes construction of a new coastal refinery, to be completed by 2016 at a cost of a further $9 billion, designed to produce diesel for the European market. Overall, ENI has said that Venezuela will be a key investment for the company over the next decade.[192]

In addition, while IOC investment is to date limited, other national oil companies, banks and governments appear keen to get a piece of Venezuela's huge Orinoco pie, as 2011 investment in the country's oil sector showed.[193] For instance, in June 2011, 9 Japanese banks agreed to loan PDVSA US$1.5 billion loan, reportedly to finance the expansion of two refineries for completion by 2015.[194] In November 2011, China agreed a further US$4 billion dollar loan to PDVSA – its third for this amount – and on top of a US$20 billion credit line agreed in 2010.[195]

The loan is intended to enable the PDVSA-CNPC joint venture in the Orinoco Belt, Sinovensa, to increase production. China will also extend another US$1.5 billion to PDVSA for refining projects and US$500 million for drills and equipment,[196] and is also constructing a refinery in Guangdong Province to process crude from the Orinoco Belt as well as undertaking a joint refinery project with PDVSA in Guarico, in Venezuela.[197]

Most recently, in December 2011, it was announced that Russian state oil company Rosneft had signed an MOU with PDVSA for a 40% stake in the Carabobo-2 project.[198] The MOU also provided for construction of a 10-million-ton-per-year upgrader and for pipeline construction to ship upgraded crude to the port of Araya for export. PDVSA and Rosneft also signed MOUs for other joint ventures to provide drilling and construction services in the Belt.[199] Reportedly, Rosneft is to pay a $440 million signature bonus, followed by a further $660 million on finalization of the investment. Russia also agreed to provide a $1.5 billion credit facility to PDVSA, with annual disbursements capped at $300 million.[200]

2.2.3 PDVSA: over-indebted and under-skilled?

However, while PDVSA is still attracting financing for oil sector projects from non-IOC sources, analysts question how beneficial the terms of these deals, and the increasing debt burden they represent, are for the long-term interests of both PDVSA and the country's heavily oil-dependent economy.

According to company data, PDVSA owed US$31.2 billion at the end of the first half of 2011 (up from $21.9 billion over 2010), including US$9.3 billion to suppliers.[201] PDVSA also appears to be continuing to seek large amounts of financing from the BRIC countries - by mid 2011, Venezuela owed Brazil, China and Russia an estimated $US34 billion (with China topping the creditor list).[202]

Of the latter relationship, the *Financial Times* commented that: "the fact that China has lent more (now $32bn) to Venezuela than any other country in Latin America comes at a cost – and PDVSA is bearing the brunt of the burden."[203] Specifically, PDVSA is reportedly unable to discount the value of the oil it delivers to China (around 410,000 barrels a year) from the royalties it pays to the Venezuelan treasury. This means that: "PDVSA is sending oil to China but not being paid for it – by neither the Chinese nor the Venezuelan government. Assuming an average price of about $100 per barrel for 2011, that would cost PDVSA more than $15bn this year – money that the cash-strapped company with massive investment commitments can scarcely do without."[204]

In addition, in classic "resource curse" country fashion, PDVSA's high debt levels are intensified by the company being used as a cash cow by the government to fund state spending.[205] One source describes the upward spiral of PDVSA's - and the Venezuelan state's - indebtedness as follows:

> **"From 1998 to 2010 Venezuela's debt more than tripled (taking into account internal and external debt, PDVSA obligations, and commitments to its prime creditor, China). The country's total debt adds up to around USD 120 billion *and accounts for about 50 percent of its GDP, which is almost double the average debt amount being carried by the rest of Latin America.* The rising public debt derives from a serious mismanagement of oil revenue. Heavily subsidized oil exports to elsewhere in Latin America and China, in addition to the cost of extensive social programs have contributed the most to Venezuela's massive debt." [emphasis added][206]**

This policy of raiding the PDVSA piggy bank appears to be intensifying. In the first half of 2011, according to PDVSA's own corporate results, there was "a massive, ten-fold hike in [the company's] contribution to Chavez's off-budget special development fund Fonden to $7.3 billion, compared with $691 million during the same period of 2010".[207]

The increase in financing to Fonden, along with the steep rise in PDVSA's total contributions to the state (more than tripling from $5.2 billion in 2010 to $18.2 billion in 2011), has been described as part of "an accelerating spending spree" to ensure a favourable outcome for the incumbent in the 2012 presidential elections,[208] which is expected to be "one of the tightest elections of [Chavez's] 13 years in office."[209]

The government's desire to increase the country's oil production, at least in the short term, has also been linked to the President's re-election aspirations.[210] Most of this increase is sought from the Orinoco fields, with a target of adding an extra 2.1 million barrels per day to total production.[211] The government has claimed that the Belt will receive a further US$5 billion in 2012 to this end – however, the source of this financial injection is unknown.[212] Operations in the Belt were also declared an emergency in 2011, in order to speed up the normally lengthy licensing processes for companies wanting to contract services and equipment.[213]

However, this raises a second, related issue: whether PDVSA has the necessary technical and management capacity – apart from the financial resources - to increase production. In recent years, the company has announced higher production targets only to regularly revise them downwards.[214] PDVSA has experienced serious operational problems such as power shortages (highlighting a lack of gas supply for oil operations) while critics also point to the company's lack of transparency hiding an increasingly poor safety record.[215] It is also doubtful that enough expertise is currently available in the company on the scale required to develop a resource such as the Orinoco,[216] and unlikely to attract large numbers of expatriate or foreign skilled oil workers.[217]

PDVSA has also asked its minority foreign partners in the Orinoco to increase their production.[218] However, it is doubtful whether they can meet these demands. According to one source, "production from the Orinoco area is probably around 650,000 bpd right now, held back by the lack of expertise of the 30 companies involved […] that were picked for their ideological affinity with Mr. Chavez rather than their expertise."[219] For instance, the minority partner in the Junín 6 project, a consortium comprising Russia's five largest oil companies, will reportedly not meet its 2012 crude production target (50,000 barrels a day) and is likely to produce only a fifth of this amount.[220]

In addition, even where the expertise exists, the financing remains challenging. Chevron's regional CEO has stated that, while the company will start production on the Carabobo 3 block this year: "These projects are going to cost billions of dollars so we are going to have to figure out where are going to come up with such large amounts of money".[221]

2.2.4 Social and environmental impacts

According to the Venezuelan government, "Along with its tributaries, [the Orinoco] river is one of the lushest rivers in South America and the world. The basin of the Orinoco River occupies four-fifths of the Venezuelan territory and 94.5% of the basin unloads its water into the Atlantic Ocean."[222] This remote area is highly bio-diverse and is a "globally important wetland and a critical habitat to a number of endangered species".[223] Population density overall is low, "although many small villages of the native Waraos Amerindians live along the riverbanks."[224]

The massive Belt development is bound to have major environmental and social impacts on the Orinoco region, as well as climate impacts. There is currently little existing power, water and transport infrastructure in the Belt location,[225] and production of the unconventional oil will require a vast new infrastructure for extraction and upgrading of the crude and also for the transporting crude and equipment.[226] Some oil companies have already expressed concerns about how the current lack of infrastructure will impact negatively on development plans for the Belt, particularly on the transportation of the upgraded crude.[227]

For instance, development of the Junin and Carabobo license areas will involve the construction of five upgraders and a refinery project (to be undertaken by ENI). The upgraders for the Carabobo block will be located in Soledad, a town on the Orinoco river opposite Ciudad Bolivar.[228] In addition, services will have to be provided for the up to 100,000 additional workers that, according to the government, could be required.[229]

This massive influx of investment will take place not just in an area of sensitive eco-systems but also in a context of weak or unenforced environmental protection, according to a recent study by a network of 20 non-governmental organisations (called ARA).

ARA analysed the current state of the environment in Venezuela looking at: loss of biodiversity, pollution, management of solid waste, impacts of oil extraction, management of water resources, management of protected areas and global climate change.[230] Summarizing the overall socio-cultural context of *current* oil extraction in the country, the report concludes that: "the fact that the Venezuelan government has access to extraordinary economic resources and the persistence of an economy based on the existence of overly cheap fuels, have created a culture where waste, uncontrolled consumption, the devaluation of nature and a lack of foresight, are having intense impacts on the country, including air, soil and water pollution, huge volumes of solid waste, and the waste of energy and resources."[231]

The report highlights the following specific concerns relating to the country's oil sector and to current Orinoco production, in particular:

- **Deterioration of sensitive ecosystems in production sites in the area of the Orinoco Oil Belt and of the ecosystem of Lake Maracaibo as a result of continuous spills and leaks;[232]**
- **Loss of soil and the triggering of erosion processes in exploration and production zones in the Orinoco Oil Belt;**
- **Presence of environmental liabilities, including holding pits for waste products that are at risk of overflowing and leaching;**
- **Flaws in the handling of by-products of the refining process (mainly sulphur and coke) that are causing water, air and soil pollution;**
- **High levels of emissions of CO_2, SO_2 and NO_2 in refining and upgrading processes;**
- **Discharge of petroleum products and bodies of water, the product of failures in monitoring, maintenance and prevention processes;**
- **Pollution and degradation of soils due to the presence of waste products of oil exploitation, as well as from engineering works associated with this activity.[233]**

Additionally, the report warns of the "enormous environmental and social risks associated with the development of oil and gas mega projects [including further development of the Orinoco Belt], about which there is a lack of adequate public information regarding the environmental and socio-cultural standards that are to be applied".[234] According to ARA, developing the Orinoco Belt's extra heavy oil resources and other mega projects will mean:

> **[L]arge-scale industrial development in areas that are seriously deficient in services such as potable water and disposal of solid waste and wastewater. Some of these projects will affect [Areas Under Special Administrative Regime],[235] sensitive eco-systems and important water basins. There is no clear information on risk management and compensation, nor on the monitoring and oversight procedures necessary to avoid serious environmental and social damage.[236]**

Moreover, ARA highlights a worrying lack of implementation of existing environmental regulations and of environmental impact monitoring by the Ministry of Environment and by oil companies. Regulations are outdated and there is a lack of technical expertise in the Ministry of Environment, tasked with carrying out the environmental impact assessments (EIAs) of oil projects required under Venezuelan law.[237] Many oil companies investing in Venezuela also lack environmental impact management systems. Overall, the report recommends a substantive overhaul of the country's environmental protection policy framework in order to improve the management of environmental impacts by the oil industry.[238]

ARA's concerns are supported by the (extremely scant) public information PDVSA has released relating to assessment of the environmental risks from oil production in the Orinoco region. In August 2007, PDVSA presented 2 environmental studies relating to the "sustainable development" of the Belt to the Ministry of the Environment.[239] These studies estimated the current state of conservation in the Belt to be 80% while analysis of the Junín zone showed that current interventions by the oil industry had affected 6% of the zone's ecosystems and that measures must be taken to avoid future impacts.[240]

Most significantly, PDVSA's head of environment highlighted that: "the area is singularly fragile, with a limited amount of land available for use, in terms of agricultural activities, which is why intervention in this zone must be carried out carefully."[241]

However, despite the legal requirement for all oil projects to carry out EIAs, including baseline studies, the 2007 studies do not appear to have been published and there is no public information relating to any more recent EIAs carried out by PDVSA in relation to current or future operations in the Orinoco Belt.[242] The IEA notes that "production from the Orinoco will face similar challenges to those of in-situ Canadian oil-sands projects, notably the availability of energy for steam generation, the availability of water and

Figure 20: Characteristics and results of air quality studies conducted by PDVSA, its subsidiaries, businesses and organizations. Year 2010

Operating entity	Evaluation period	Number of stations used	Pollutants evaluated	Pollutants outside of normal range
Puerto La Cruz Refinery	January-March 2010	1 station (automatic)	SO_2, CO, NO_2, O_3; H_2S	None of those evaluated
	March-September 2010	2 stations (semi-automatic)	NO_2, H_2S, PTS, Pb in PTS and fluorides	PTS and fluorides
	March-September 2010			H_2S and fluorides
José Antonio Anzoategui Industrial Complex	January-September 2010	1 station (automatic and semi-automatic)	SO_2, CO, NO_2, PTS, O_3, H_2S	SO_2, PTS, H_2S
		1 station (automatic and semi-automatic)		SO_2
		1 station (automatic and semi-automatic)	CO and PTS	None of those evaluated
		2 stations (semi-automatic)	PTS	None of those evaluated
				PTS
Exploration and Production Centro Sur, Barinas District	October-November 2010	2 stations (semi-automatic)	SO_2, CO, NO_2, PTS and H_2S	None of those evaluated
Occidente Distribution Plants (EL VIGIA)	May-June 2010	3 stations (semi-automatic)	SO_2, NO_2, PTS and O_3	None of those evaluated
INTEVEP	Febuary-September 2010	1 station (semi-automatic)	PTS	None of those evaluated
Petroboscan Joint Ventures (Occidente)	March-June 2010	3 stations (semi-automatic)	SO_2, NO_2, PTS, O_3 and H_2S	None of those evaluated
				PTS

Source: PDVSA, 2011, p.61

CO_2 emissions" while highlighting that there is "very little information available on current performance and future plans for reducing the environmental impact."[243] For this reason, the IEA advocates "open, joint work between PDVSA and environmental non-governmental organizations" to obtain this information.[244]

2.2.5 Local concerns about air pollution from upgrading

PDVSA's 2010 environmental report does contain some limited information on current atmospheric emissions, air quality monitoring and environmental permits in the Orinoco Belt but it does not give a comprehensive environmental impact analysis.[245] One piece of information the report discloses pertains to the air quality at the Jose Antonio Anzoátegui industrial complex, which houses the 4 upgraders that process the crude from the Belt along with other related petro-chemical industries. As the table above shows, for the period January-September 2010, some pollutants emitted from the plant appear to be above the legal limit.

In fact, pollution due to the production of coke and sulphur waste from the upgrading process appears to be an ongoing problem at the José Antonio Anzoátegui industrial complex and civil society groups have expressed concern about the health impacts of air pollutants. In 2011, the Venezuelan press reported that a civil society organization had called on Chevron, Total, Statoil and TNK-BP (the four minority shareholders of PDVSA in the current projects under production on the Belt) to address the levels of coke being generated as a waste product from the upgrading of crude.[246] The organization claimed that the situation was in violation of the Venezuelan Constitution (Article 127) and articles 42 and 43 of the country's Environmental Law, claiming that: "there were complaints by the inhabitants of villages near to the Jose Industrial Complex that they are suffering respiratory problems and allergies due to the waste products. The multinational companies cannot avoid their responsibilities, despite being minority partners of PDVSA."[247]

In August 2011, it was reported that PDVSA had contracted the Italian company Energy Coal to repair and modernize the whole system at the plant used for managing

Figure 21: Venezuelan Orinoco Belt extra-heavy oil projects

Project Name	Foreign partners	Status	Capacity (kb/d)	Planned start
PetroAnzoategui (PetroZuata)	None (100% PDVSA)	Producing	120	n.a
Petrocedeno (Zuata)	Total (30%)/Statoil (10%)	Producing	200	n.a
Petroplar (Hamaca)	Chevron (30%)	Producing	190	n.a
Petromonagas (Cierro Negro)	BP 17%	Producing	110	n.a
Sinovensa	CNPC	Producing	80	n.a
Total producing			**700**	
Junin 2	Petrovietnam	Announced	200	2012
Junin 5	ENI	Announced	240	2013
Carabobo 1	Repsol/India/Petronas	Announced	480	2015
Carabobo 3	Chevron/Inpex/Mitsubishi/ Suelopetrol	Announced	400	2015
Junin 4	CNPC	Announced	400	2017
Junin 6 (Petromiranda)	Russian companies	Announced	450	2017
Junin 10	Total/Statoil	Under negotiation	200	
Total proposed			**2 370**	
Total producing + proposed			**3 070**	

Note: Dates and production capacity are somewhat uncertain, as PDVSA, which owns e majority interest in all projects, does not publish detailed plans.

Source: World Energy Outlook 2010

solid waste produced by upgrading crude from the Petropiar, Petromonagas, Petrocedeño and Petroanzoátegui projects, including for transporting waste from the plant to the river for onward transportation.[248]

This issue is particularly significant because the amount of toxic solid waste likely to be generated if full development of the Orinoco Belt occurs, particularly sulphur and coke, and the risks arising from its transportation to the Orinoco and then along the River to the coast are likely to be considerable.[249] Toxic solid waste products (an estimated 67,800 tons of sulphur and 52,250 tons of coke per day) will be transported by rail to the Orinoco River and then by barge to the coast at Punta Cuchillo while waste will be sent through a new 432 km pipeline to the Araya Peninsula and stored in terminals with an initial capacity of 800,000 b/d.[250] This complex oil transportation route will run through forest, river, and marine eco-systems.

2.2.6 Climate protection

According to a study carried out by the US National Energy Technology Laboratory (NETL) in 2009, Venezuela's ultra-heavy crude bitumen requires the same kind of "energy intensive extraction processes and pre-processing" as in Canadian tars sands, resulting in "GHG [greenhouse gas] emissions several times greater than that for extraction of conventional crude oil."[251] This means diesel from Venezuelan bitumen currently has well-to-tank GHG emissions second highest only to those of fuel derived from Canadian tar sands, according to the US Department of Energy.[252]

It should be noted that accurate emissions data on Venezuela's ultra-heavy oil production is less readily available than for Canadian tar sands. NETL currently estimates a mean value of 95 kg CO_2E/bbl, lower than that of Canadian tar sands (112 kg CO_2E/bbl).[253] However, in terms of a lifecycle analysis, this still means that "Venezuela bitumen, Canada oil sands, and Nigeria stand out as having high GHG emissions compared to other sources,"[254] with Venezuelan bitumen having emissions of 30.8 kg CO_2E/MMBtu LHV diesel, second only to that of diesel processed from Canadian oil sands (see Figure 20).

In terms of the country's emissions profile, while currently Venezuela produces only 1% of global emissions, according to environmental network ARA, the government's plan to increase oil production would mean an increase in oil production of around 5.8 million barrels per day (mbpd) in 2012, leading to a near tripling of GHG emissions from 30 million tonnes per year to almost 80 million tonnes.[256]

According to ARA, Venezuela not only has a "moral responsibility to contribute actively to finding a solution" to climate change, but is itself "highly vulnerable" to the impacts of climate change, which will impact on "food production, human health, energy demand, biodiversity and the risk of flooding, among other issues."[257] However, the current national policy framework for climate protection is inadequate, according to ARA:

Figure 22: Emissions of diesel by source

Crude Oil Source	Crude Oil Extraction and Pre-Processing	Crude Oil Transport	Diesel Refining Operations	Finished Fuel Transport	Total Well-to-tank
	kg CO_2E/MMBtu LHV diesel				
Canada Oil Sands	19.0	0.9	13.2	0.8	34.0
Venezuelan Bitumen	16.3[14]	1.1	12.5	0.8	30.8[14]
Nigeria	22.0	1.7	5.1	0.8	29.7
Mexico	6.6	1.0	15.7	0.8	24.1
Angola	14.0	1.9	6.3	0.8	23.0
Kuwait	2.8	2.7	13.2	0.8	19.6
Iraq	3.3	2.7	11.8	0.8	18.7
Venezuelan Conventional	4.1	1.1	12.5	0.8	18.6
Baseline WTT[15]	***6.6***	***1.3***	***9.5***	***0.9***	***18.4***
Canada Conventional	6.0	0.9	10.3	0.8	18.0
Ecuador	5.3	1.7	9.9	0.8	17.8
Saudi Arabia	2.3	2.7	11.6	0.8	17.4
Domestic	4.2	0.7	7.7	0.8	13.5
Algeria	6.0	1.5	4.0	0.8	12.4

[14] The GHG emissions estimate for extraction and pre-processing of Venezuelan bitumen has greater uncertainty than other crude sources due to limited data availability. Uncertainty analysis provides a 90% confidence interval of 11 to 20 kg CO_2E/MMBtu LHV diesel for extraction and pre-processing and 25 to 35 kg CO_2E/MMBtu LHV of diesel for the WTT GHG emissions. The total effect of this uncertainty on the baseline WTT is less than 1%.

[15] The baseline includes imported transportation fuels to the U.S. in 2005 and does not incorporate the new Venezuelan upgraded bitumen acquisition profile. The impact of the new Venezuela profile on the 2005 national average baseline WTW GHG emissions profile for each fuel is less than 0.5%.

Source: US Department of Energy, 2019[255]

"There is no clarity about the existence of mitigation and adaptation strategies, with clear objectives and specific activities including their respective scope, timetable, costs and allocation of resources and responsibilities. In practice, there do not appear to be any clear mitigation strategies, since there has been no effective action taken to reduce GHG in the motor and oil industry sectors. Similarly, the proposed changes to the country's model of energy generation are based on the substitution of energy generation processes, principally hydro-electric power, by thermo electricity, which appears to be a step in the opposite direction. "[258]

For these reasons, ARA recommends a number of concrete steps be taken, both in terms of mitigation and adaptation policies. These include: the creation of a National Climate Change Office to coordinate and promote cross-sectoral action; the mainstreaming of climate change action into all government planning processes; the development of a national climate change education strategy and the promotion of an inclusive public; regional and local adaptation planning; incorporating climate change into poverty reduction strategies; a national reforestation campaign; and roll-out of mitigation policies in the transport and energy sectors.[259]

Specifically in relation to the oil sector, the report calls for "the reduction in the volume of emissions from the oil industry, in particular from refining and upgrading of heavy oil."[260] In fact, full development of the Orinoco Belt could deal a fatal blow to climate protection efforts.

2.3 Tar sands in Africa

Resources of bitumen or extra-heavy oil are reportedly present in the RoC (Brazzaville), Madagascar, Nigeria, Angola, and the Democratic Republic of the Congo (DRC).[261] Four of these countries are already notorious "resource curse" countries.

Media and other reports suggest that of the five, Madagascar holds the tar sands and heavy oil resources most likely to be developed in the near future,[262] although to date, research and advocacy on tar sands investment in Africa has mainly focused on ENI's prospection over a 1,790 km², largely rainforested area in the RoC.

Madagascar's Bemolanga tar sands resource has an estimated 16.5 billion barrels in place with around 10 billion barrels recoverable. French oil company Total has a 60 percent equity stake in the project, which is operated by independent company Madagascar Oil. Given the resource is close to the surface and thus likely to be mined, exploration and operational costs would probably be lower than in Canada, with one analyst estimating in 2007 that prices would have to remain "at about $60 a barrel to make a decent profit on the investment."[263] More recently, at an oil price above $80 per barrel, operator Total has stated that Bemolanga "could produce 200 kb/d, with mining technology."[264]

There is little evidence that Madagascar will have the institutional capacity or governance context to turn new extractive investment into desperately needed sustainable development while avoiding the outcomes suffered by other producer countries in the region, particularly given the current political turmoil.[265] The World Food Programme classified 60 percent of the country's population as "extremely poor" in 2006.[266] Given the population's existing vulnerabilities, the weak governance situation and the potentially damaging impacts of such a development – Madagascar is one the most biodiverse countries in the world – this investment is environmentally, socially, and politically high-risk.

ENI's exploration in the RoC is in its early stages and it is not clear yet if the project is commercially viable, nor if ENI has the technical means to deliver the resource. However, ENI has already shown itself unwilling to address the genuine concerns raised to date over the project's potential impacts by Congolese and international civil society groups.[267] In the case of both the Congo and Madagascar investments, it is also worth considering the potential impacts at the local level in light of the IEA's assessment that "none of [these resources] are large enough to have a significant impact on world oil supply."[268]

There is little public information regarding bitumen resources in DRC and Angola. According USGS data from 2005, Angola has 4.65 billion barrels of original oil in place and 465 million barrels of reserves,[269] and DRC has 300 million barrels in place and 30 million barrels of reserves.[270] To date, neither country has been a focus for exploration. In August 2009, ENI announced an agreement with the DRC government to carry out feasibility studies "for the development of both conventional and non-conventional hydrocarbons, [and] gas valorisation in the eastern areas of the country."[271] However, it is not clear what kind of unconventional resource is referred to. DRC also appears to have oil shale deposits, located in the Bas Congo region.[272]

Nigeria's bitumen belt straddles the states of Ondo, Ogun, and Edo and the resource is potentially much larger than in Madagascar or Congo, estimated at 27 billion boe, according to the Nigerian Ministry of Mines in 2009, although proven reserves are only 1.1 billion boe.[273] There has been a push by the Ministry to attract foreign investment, after mining laws were revised in 2007 to create an "enabling environment," including corporate-friendly fiscal regimes. It is unclear whether any licenses were awarded in a bidding round on two blocks announced in 2009, although reportedly companies from the United States, Canada, Nigeria, South Africa and China expressed interest.[274]

Although at present development of Nigeria's bitumen block appears stalled, the social and environmental destruction resulting from existing oil production in Nigeria is well documented.[275] Expansion of investment beyond the Delta to new "frontier" regions - not only for bitumen exploration but deepwater (see below) – raises huge concerns about the further locking-in of the "resource curse" in Nigeria and the impacts of new developments on local communities previously not affected by oil activities.

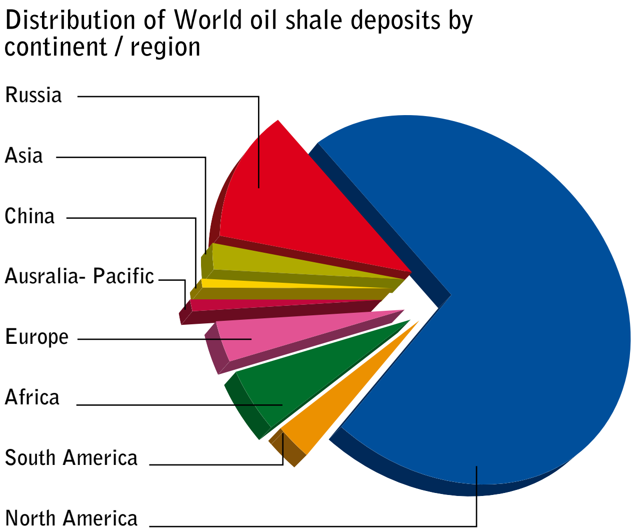
In the case of the bitumen resource, for instance, there have been references by tribal authorities to communities being displaced to facilitate exploration of the resource. The Nigerian NGO Environmental Rights Action/Friends of the Earth Africa raised concerns as early as 2003 over the lack of community consultation over bitumen exploration and its potential negative environmental and social impacts.[276]

2.4 Marginal oil in sub-Saharan Africa: Onshore and offshore "frontier" oil

Both West and East Africa are a focus of "frontier" exploration for conventional oil, both onshore and deep offshore. DRC and Uganda are targets for conventional onshore prospecting that is high-risk in technical and/or social, environmental, and political terms, particularly in the case of DRC. The country already produces 25,000 bpd offshore and new onshore exploration is currently targeted on the Albertine Rift Basin straddling the border with Uganda.[277] London-listed SOCO International has also been exploring on the onshore Nganzi block in the Western Bas Congo (now Congo Central) province bordering RoC and Angola[278] while in August 2010 ENI announced that it had obtained 55 percent of the Ndunda block (also in the Bas Congo).[279] There are reportedly plans for licensing in the Cuvette and Tanganyika basins.[280]

Also in the sightlines of IOCs are the prospective resources of the Horn of Africa – "one of the last remaining untapped frontiers" for conventional oil. The region is being targeted by several smaller IOCs, including the United Kingdom's Tullow Oil, currently carrying out a "joint regional exploration campaign" in Ethopia.[281] Ethiopia's Ogaden Basin is the "western half" of the East African Karoo Rift Basin (the eastern half being the Morondava Basin in Madagascar). Prospecting is also occurring in the 60,000 km2 Jimma Basin in South Central Ethiopia by the Ethiopian government and local (Hong Kong listed) company SouthWest Energy.[282]

Figure 23: Global oil shale deposits



Distribution of 3.3 trillion bbls shale oil in place from Dyni (2003) and Russell (1990)

Source: Exxon Mobil, 2007[287]

Nigeria is also experiencing increased interest in its deep offshore, along with Angola, with whom it vies for position as sub-Saharan Africa's top oil producer[283] (see below). West Africa overall is the "third-biggest deepwater area [in the world] with Angola and Nigeria working a combined 25–30 fields and continuing to add prospects in ever-deeper seas."[284]

Ghana is also the centre of a potential new oil boom, with around 600 Mb of proven reserves.[285] Oil and natural gas from Ghana's giant Jubilee field could bring the country as much as $20 billion by 2030, but civil society organizations are already sounding alarm bells about inadequate fiscal transparency controls and lack of environmental protection that could lead to a repetition of the "resource curse."[286]

Oil shales are "fine sediments containing kerogen."[288] According to the IEA, global oil shale resources in place are estimated at 5 trillion barrels, with more than 60 percent located in the United States, followed by Brazil, Jordan, Morocco, and Russia (see graphic), with around 1 trillion barrels potentially recoverable.[289] Oil production from shales is environmentally destructive and extremely energy- and carbon-intensive. The shales must be mined (or, for deeper deposits, exploited in situ) using similar techniques as those used for Canadian tar sands projects and the kerogen must be heated to between 350°C and 450°C in order to transform it into oil.[290]

For this reason, the EIA in its *Annual Energy Outlook 2010* comments in relation to US oil shale production that, due to the still experimental nature of in-situ extraction techniques and "because the underground mining and surface retorting process is unlikely to be environmentally acceptable, [...] oil shale liquids production projections should be considered highly uncertain."[291] The IEA concurs that "[l]arge-scale development of the Green River deposits in the United States is likely to face strong opposition on environmental grounds."[292]

Project costs, estimated to be in the range of $50 to $100 per barrel, are also similar to Canadian tar sands projects – the IEA at the end of 2010 stated oil shales exploitation would be commercially viable with a price of $60 per barrel at current costs. However, such projects would also be vulnerable to any carbon-pricing measures and demand reductions. In this kind of scenario, "the lower oil prices and higher prices of CO [would] make oil shales marginal from an economic point of view."[293]

For these reasons, oil shale is unlikely to be a major new source of oil supply, without significant technological breakthroughs or government intervention. As the IEA puts it: "There is a long way to go from pilot projects producing a few thousand b/d to an industrial scale activity able to produce quantities that are significant in terms of world oil supply." Concretely in relation to Shell's Green River project in the United States, a decision to exploit is unlikely before 2015 and the project would take a further decade to reach commercial production.[294]

Thus, their geographical location, technological challenges, production costs, and environmental concerns currently make forms of marginal oil investment other than oil shales a more attractive bet in the short- to medium term for companies and investors. Nevertheless, as noted in Section One, oil shale was reportedly "the biggest piece of (Shell's) R&D budget" in 2007.[295] A breakthrough in production technique could potentially put oil shale at the centre of development plans for companies such as Shell and Exxon that have been experimenting with developing the resource for decades.

2.5 Deepwater investments

Deepwater production forms an increasing share of the revenue stream of IOCs and other producers, as discussed in Section One. As *The Washington Post* puts it:

> **"The strategy of continuing to exploit the economic opportunities of deep-water wells, even as the hazards they represent become clearer, is being pursued the world over. Other countries [than the USA] – including Brazil, Canada, Nigeria and Angola – are also moving forward with drilling, lured by oil reservoirs they are discovering that are two to six times as big as the average Gulf of Mexico reservoir and taking advantage of new opportunities offered by the U.S. moratorium."[296]**

According to media reports, 17 countries are currently producing oil from deepwater fields and another 29 are potential producers (see Figure 23 below). According to one source: "Brazil takes the top slot, with deepwater production topping 1.5 million b/d last year from about a dozen fields mostly in the outer Campos Basin. It should consolidate this lead in the next couple of years as the Tupi area and surrounding fields in the Santos Basin start up."[297]

One view is that "countries [such as Nigeria and Angola] stand to gain from the uncertainties in the United States prompted by the disaster in the Gulf of Mexico," which resulted in a moratorium on drilling off the US coast, with some evidence of companies moved to divert rigs away from the United States to other deepwater locations.[299] However, other reports state that a large exodus of drillers to other regions did not materialise.[300]

Nevertheless, the Deepwater Horizon incident will lead to "renewed concerns about safety and environmental protection,"[301] and specifically to increased insurance premiums for companies: "Early reports indicate a 15–25 percent rise for rigs operating in shallow waters; and up to 50 percent for deepwater rigs."[302] Some analysts also cautioned that the accident would result in a slowing of deepwater investment globally, with governments shying away from opening them up, or companies deeming them too risky, as increased technical and regulatory risks were added onto other geopolitical and fiscal uncertainties.[303]

In contrast to this view, it can be argued that heightened regulation and higher risk premiums in the Gulf could make deepwater exploration in other regions, particularly

Figure 24: Oil and gas wells drilled by leading companies in water depths of 400 meters or more – number of wells in parentheses

Deepwater Wells Around the World		
Region	**Existing Producers**	**Potential Producers**
North America	United States (1,814)	Canada (21), Mexico, Greenland
West Africa	Angola (195), Nigeria (158), Congo (Brazzaville) (70), Mauritania (21), Equatorial Guinea (20), Cote d'Ivoire (4)	Gabon (6), Ghana (6), Sierra Leone (1), Namibia
South America	Brazil (622)	Trinidad (2), Colombia (1), Cuba, Suriname, Guyana
Asia	Indonesia (175), Australia (150), India (77), Malaysia (74), Phillipines (25)	Thailand (21), Brunei (11), China
Europe/FSU	Norway (119), UK (115), Italy (33)	Ireland (15), Faroes (4), Spain (5), Portugal, Russia, Ukraine, Turkey
North Africa	Egypt (53)	Lybia (1), Morocco (1)
East Africa		Kenya (1), Mozambique (1), Tanzania
Middle East		Israel (1), Yemen (1)
Total countries	**17**	**29**

Source: Deutsche Bank/Energy Intelligence[298]

those with weaker environmental regulation such as West Africa, more attractive.[304]

In contrast to this view, recent moves to open up the UK continental shelf along with BP's historic deal with Rosneft to explore in the Russian Arctic show no lack of appetite on the part of IOCs and governments to slow down the drive into risky deep offshore prospects.[305]

Brazil is set to become one important new deepwater production centre and its pre-salt resources also represent an important new technological "frontier."[306] The pre-salt is found at a depth of up to a maximum of 7,000 metres under a 2,000 metre layer of salt in an area around 800 km long and 200 km wide located around 300 km off the Atlantic coast of Brazil[307] (see Figure 25). Estimated reserves in place are up to 100 billion barrels, and state oil company Petrobras claims that production is viable at $35–45 per barrel.

The company plans to produce 5.7 million barrels of oil and gas per day by 2020 (more than half the current output of Saudi Arabia).[308] This would make state company Petrobras "one of the five largest integrated energy companies in the world."[309] However, the challenges are formidable. There are serious logistical issues and high infrastructure costs involved in accessing the resources[310]; while Petrobras is considered "world class" in deepwater exploration with a "state-of-the-art safety, environment and health programme,"[311] the company "currently has the skills to drill roughly one-third the depth to reach the pre-salt deposits."[312]

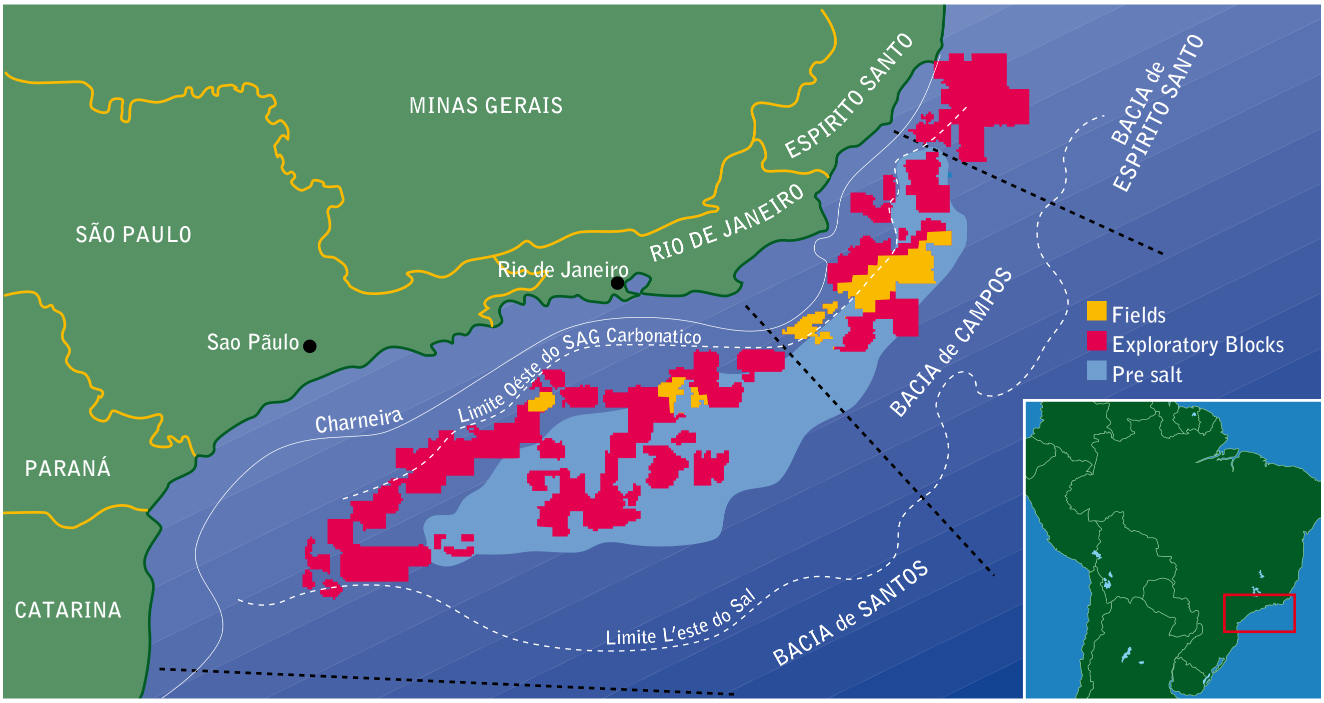
Petrobras also currently employs the same methods for dealing with spills as its peers in the Gulf of Mexico and will have to "invest heavily in developing new technologies and methods to deal with potential spills, such as an improved blowout preventer, which means operating costs may escalate to unknown levels."[313] This will be in addition to the current cost estimate of $19 billion+ for developing the new pre-salt resources (part of a huge overall capital expenditure plan of $224 billion by the company from 2010–2014).[314]

Brazil will also have to manage the sectoral challenges of structuring and regulate exploration, drilling, and the potential for a large influx of foreign investment,[315] along with the wider potential economic, social, and environmental impacts of becoming a major petro-state. Oil development in the country is seen as a national energy security priority and the government appears to be trying to learn the lessons of the "resource curse." For instance, the Brazilian Congress has passed legislation to create a social fund to channel 50 percent of the pre-salt revenues to support socioeconomic development programmes.[316]

In 2009, Brazil's Green Party candidate in the presidential elections, former Environment Minister Marina Silva, showed a clear understanding of the climate and developmental implications of Brazil's current and future energy path: "In terms of the model of development, obviously, in the first place, it must be clear that the energy systems of [industrialising] countries cannot follow the same course as that of the developed countries. We have to understand that if developed nations need to move from fossil to renewable fuels, then in our case we must put the emphasis very clearly from now on renewable fuels."[317] In terms of oil development, Silva stated interestingly that the pre-salt resources should be "leveraged" by "investing heavily in innovation and technological development that leads to a replacement of the model itself."[318]

According to the IEA, heavy oil projects are "active or planned in Brazil, in the North Sea, in the Neutral Zone between Saudi Arabia and Kuwait and several other places in the world."[319] The remote Western Amazon region, which

Figure 25: The Brazilian pre-salt deposit



covers parts of Bolivia, Colombia, Ecuador, Peru, and western Brazil (see Figure 27), is one region coming under increasing scrutiny by oil companies interested in accessing its large reserves of oil and gas, many yet untapped.

According to one study, the region is "the most biologically rich part of the Amazon basin and is home to a great diversity of indigenous ethnic groups, including some of the world's last uncontacted peoples living in voluntary isolation."[320] Unlike the eastern Brazilian Amazon, it is still a largely intact ecosystem. Growing global oil demand is leading to "unprecedented exploration and development in the region."[321] The type of oil resource is conventional, with heavy oil slated as a major source of future production in Peru and in Colombia.

Recent examples of this drive to expand oil activity in the region include, firstly, the announcement in May 2010 by Petroperu (the Peruvian state licensing agency) that 25 new blocks will be offered for oil and gas exploration over a million hectare area. The government is reportedly encouraging oil and gas exploration in a bid to become an energy exporter as well as meet growing domestic demand.[322] This drive will open up 75 percent of the Peruvian Amazon to exploration and Peru's national Amazon indigenous body, AIDESEP, has described the move as a new threat to indigenous peoples.[323]

Although oil revenues make up a relatively small part of Colombia's budget (around 30% of exports[324]), the country is further ahead than Peru in terms of its hydrocarbons infrastructure and investment plans. Colombia is described by one source as having been "a honeypot to oil and gas companies over the past decade as the country adopted market friendly fiscal and regulatory policies."[325] However, Columbia tightened its environmental regulations under the Álvaro Uribe Presidency, which increased upstream costs and shut down many parts of the country for drilling.

Incumbent President Juan Manuel Santos will reportedly ensure that environmental regulations "do not pose a barrier to exploitation of natural resources" and also "clarify the process for consulting ethnic communities affected by drilling, which have become more demanding in negotiations with oil companies as the government expands areas under concession."[326] The country is thus set to step up oil and gas exploration, with the mining minister claiming that investment in the mining and energy sectors, including biofuel projects, was expected to reach $57 billion over the next five years.[327]

In July, a licensing round for 225 new oil and gas blocks in Colombia received bids for 96 of the blocks, with state-controlled Ecopetrol winning rights for 14 of them.[328] Rights were also awarded to IOCs, including Shell and Talisman, although most awards went to smaller companies. There are potentially 35 blocks in the Amazonian Putumayo Basin, which contains heavy oil[329]: Talisman and another Canadian company, Pacific Rubiales Energy, were awarded rights in three blocks in the Putomayo area.[330]

In terms of Ecuador and Bolivia, new exploration may be less likely in the short term, as recent resource nationalism in both countries has increased state control over the sector and is likely to discourage an influx of new foreign investment.

In 2005, Bolivia nationalized its oil and gas production, with IOCs (Petrobras, Repsol YPF, British Gas and BP, Total, and Exxon) obliged to hand majority control to state-owned Yacimientos Petrolíferos Fiscales Bolivianos (YPFB).[331] One view is that Bolivia's oil production over the period 2009–2010 will fall (by 2.7%, with crude volumes peaking in 2011/2012 at 65,000 bpd, before falling steadily

Figure 26: Frontier developments in the Amazon – the Western Amazon region

Source: Save America's Forests, 2008[347]

to 56,000 bpd), while gas production will rise (Bolivia has the second-largest natural gas reserves in South America, after Venezuela).[332]

Ecuador has just passed a law that would make the state the sole owner of all oil resources, receiving 25 percent of gross oil revenues before production costs are accounted for. Producers will be paid a flat fee for production.[333] According to one analysis, as a result some foreign firms are expected to seek a negotiated exit from the country.[334]

Foreign companies currently operating in Ecuador include Repsol and also NOC Petrobras. Another company present is Andes Petroleum, a joint venture of CNPC and Sinopec. It was also reported in July that Ecuador was in negotiations with China for a $1 billion loan in exchange for supplying 36,000 barrels of oil or fuel per day to PetroChina.[335] In addition to restructuring the oil sector, Ecuadorian President Rafael Correa is promoting the Yasuni-ITT Initiative. This proposes not exploiting an estimated 850 million barrels of oil located in three underground deposits – the Ishpingo, Tambococha, and Tiputini (ITT) – in the Yasuni National Park.[336]

Yasuni is one of the most biodiverse areas in the world, covering 982,000 hectares of Amazonian rainforest. It is claimed this project will save emissions of around 40 million tons of CO_2, in return for an annual payment to Ecuador of $350 million over 10 years.[337] The initiative is reportedly supported by 75 percent of the population.[338]

However, there are concerns about the government's contradictory stance of allowing extractive activities to continue in the Yasuni (and in the Amazon region more widely) while at the same time promoting the Initiative.[339]

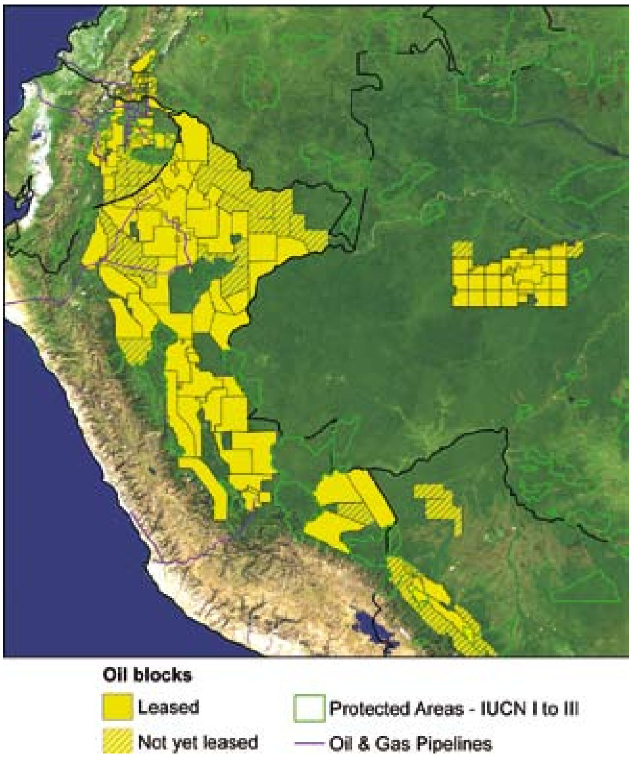
Some observers viewed Correa's rejection of the structure of a UN Development Programme (UNDP) trust fund to administer the financing in January 2010 (on the grounds it did not give Ecuador a majority say over how the money would be spent) as masking a move to abandon the Initiative in favor of renewed oil drilling.[340]

The Yasuni-ITT project also initially had difficulty finding the required level of funding from international donors.[341] However, on August 3 2010, Ecuador signed a deal with the UNDP, and countries including Germany, Spain, France, Sweden, and Switzerland have reportedly committed an estimated $1.5 billion to a trust fund. The fund "will be used to protect 4.8 million hectares in Ecuador's other national parks, to develop renewable energy sources and to build schools and hospitals for indigenous communities."[342]

However, some indigenous and environmental groups remain concerned that the Yasuni deal "may provide cover for the Ecuadorian government to open up other areas of the Amazon to exploitation."[343] Indeed, the same week as the deal was signed, the government announced it would open up areas of Ecuador's "roadless, pristine southeastern Amazon region, as well as re-offering older oil blocks that were unsuccessful due to indigenous resistance."[344]

Nevertheless, the Yasuni-ITT Initiative in Ecuador is an important test case for an alternative model of "leaving oil in the ground." Ecuadorian civil society pressure on the Correa government and its campaign to raise the international profile of the Initiative were critical to the deal finally reaching fruition.

Figure 27: Oil blocks in the Western Amazon region



Source: Save America's Forests, 2008[348]

3 **Conclusion:** Protecting the global climate, local communities and ecologies

This paper has discussed the macro drivers of increasing investment in marginal oil and surveyed some potential new developments outside North America. Increasing demand for oil, primarily from emerging economies, together with a decline in conventional and easy to produce resources, is driving development of these most environmentally and socially destructive and expensive resources. Continued restricted access by IOCs to the remaining "easy oil" in OPEC countries is forcing them to push harder into the frontiers.

This combination, along with a lack of appropriate policy incentives from governments globally to reduce demand, means that it is likely that marginal oil will expand beyond its current centre in North America, with companies pushing to open up ever-more risky and challenging resources. This expansion will inevitably have negative consequences for climate protection, for economic and energy security globally, as well as for local communities and ecologies at the sharp end of this relentless trend.

Given the particularly carbon-intensive techniques associated with developing unconventional resources, combating further investment in these "dirtiest" forms of oil development is an important step. It is essential to prevent us accelerating faster down the wrong energy path but it is also essential to highlight the underlying structural problems with the "business as usual" scenario.

Ultimately, the climate crisis can only be addressed by reducing demand for oil *from whatever source*, not just the riskiest and dirtiest forms. From this perspective, to the threat of increased investment in tar sands projects must be added the growing number of "frontier" conventional oil projects – whether they are deepwater projects in Africa, Brazil and the Arctic or onshore exploration in the Amazon or East Africa.

Furthermore, even if demand-reduction policies are rolled out with strong government endorsement and are successfully implemented – which currently looks unlikely, for instance, at the federal level in the United States – demand for oil looks set to increase in the short- to medium term, justifying further investment in marginal resources.

This expansion will likely include countries with weak governance frameworks that are particularly vulnerable to the economic distortions and social and environmental damage associated with fossil fuel extraction. Potential resources range from the tar sands of Madagascar to those located in the depths of the Atlantic and the pristine rainforests of the Amazon.

Indeed, in an atmosphere of heightened competition, oil companies may regard host countries with zero or minimal governance and a weak regulatory framework as more appealing investment centres.[345] Moreover, reducing demand for oil will not by itself – without other policy changes – address the environmental and social injustices endured by local communities affected by oil development.

For these reasons, and even when considered primarily through the lens of climate protection, both sides of the oil equation – supply and demand – need to be tackled in a coherent way. As commentator George Monbiot highlighted in a speech to the 2009 KlimaForum in Copenhagen, there is an inherent contradiction in governments promoting global policies aimed at mitigating emissions by reducing fossil fuel demand while at the same time seeking to maximize the supply of such fuels, for short-termist national security reasons, further undermining the political and economic case for clean energy sources.[346] As Monbiot and others have pointed out, it is still unclear what proportion of remaining global reserves of conventional oil – let alone unconventional resources – can be extracted without breaching the 2°C temperature rise "safety barrier."

Thus, for reasons of both climate protection and environmental and social justice, it is crucial that, along with strenuous efforts to reduce oil demand, new marginal oil investments are challenged and the voices of potential host communities are supported. Otherwise, further irrevocable damage will result to local communities and ecosystems.

Finally, it is important to question the wisdom of states becoming "locked in" – financially, technologically, and politically – by such investments to a retrograde carbon-intensive, export-driven resource extraction model. In developing countries, this model has led in the past to extremely poor human development outcomes. Without radical governance changes, the evidence points to states hosting such investments falling into, or becoming further mired in, the "resource curse" trap, making their transition to a sustainable development path even more difficult.

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The Heinrich Böll Foundation is part of the Green political movement that has developed worldwide as a response to the traditional politics of socialism, liberalism, and conservatism. Our main tenets are ecology and sustainability, democracy and human rights, self-determination and justice.

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List of Abbreviations

boe	barrels of oil
bpd / Mbpd	barrels per day / million barrels per day
CNPC	China National Petroleum Corporation
DRC	Democratic Republic of the Congo
EIA	US Energy Information Administration
GTL	gas-to-liquids
IEA	International Energy Agency
IOC	international oil companies
ITT	Ishpingo, Tambococha, and Tiputini deposits
MENA	Middle Eastern and North African
NETL	US National Energy Technology Laboratory
NOC	national oil companies
ppm	parts per million
RoC	Republic of the Congo
RRR	reserves replacement ratio
SAGD	steam-assisted gravity drainage
SEC	Securities and Exchange Commission
SPR	strategic petroleum reserves
TR	total resources
USGS	US Geological Survey
WEC	World Energy Council

Back cover: The PS10 solar tower plant at Sanlucar la Mayor outside Seville, Spain on April 29, 2008 in Seville, Spain. The solar tower plant, the first commercial solar tower in the world, by the Spanish company Solucar (Abengoa), can provide electricity for up to 6,000 homes. Solucar (Abengoa) plan to build a total of 9 solar towers over the next 7 years which will raise the electricity capacity for an estimated 180,000 homes. © Markel Redondo / Greenpeace