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DEBT RELIEF FOR GREEN AND
INCLUSIVE RECOVERY PROJECT

Compensating Indebted Countries for Keeping Fossil Fuels in the Ground

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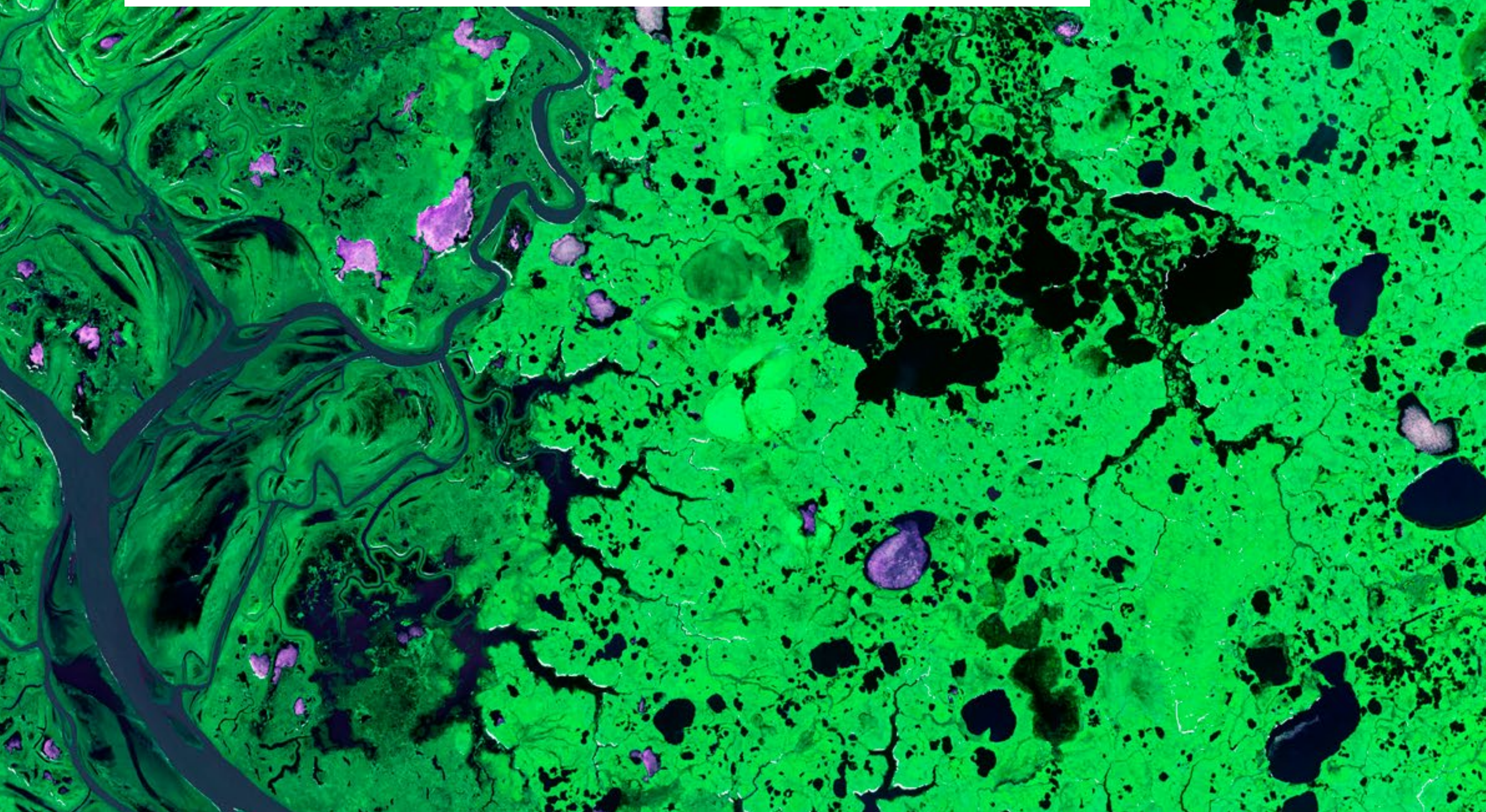

Compensating Indebted Countries for Keeping Fossil Fuels in the Ground

A Proposal

By Johnny West

Published by Heinrich Böll Foundation, Center for Sustainable Finance (SOAS, University of London), and Global Development Policy Center (Boston University) as Background Paper to the Debt Relief for Green and Inclusive Recovery Project

Contents

Abbreviations

ADB	African Development Bank
ANRC	African Natural Resources Center
EIA	Energy Information Administration
FID	final investment decision
LITG	leave it in the ground
NPV	net present value
OPEC	Organization of the Petroleum Exporting Countries
SPE	Society of Petroleum Engineers
UNEP	United Nations Environment Programme

Disclaimer: This background paper is a content contribution to the discussions of the Debt Relief for Green and Inclusive Recovery Project. The views expressed are those of the authors alone and do not reflect the views of the Debt Relief for Green and Inclusive Recovery Project: Heinrich-Böll-Stiftung, the Center for Sustainable Finance (SOAS, University of London), or the Global Development Policy Center (Boston University).
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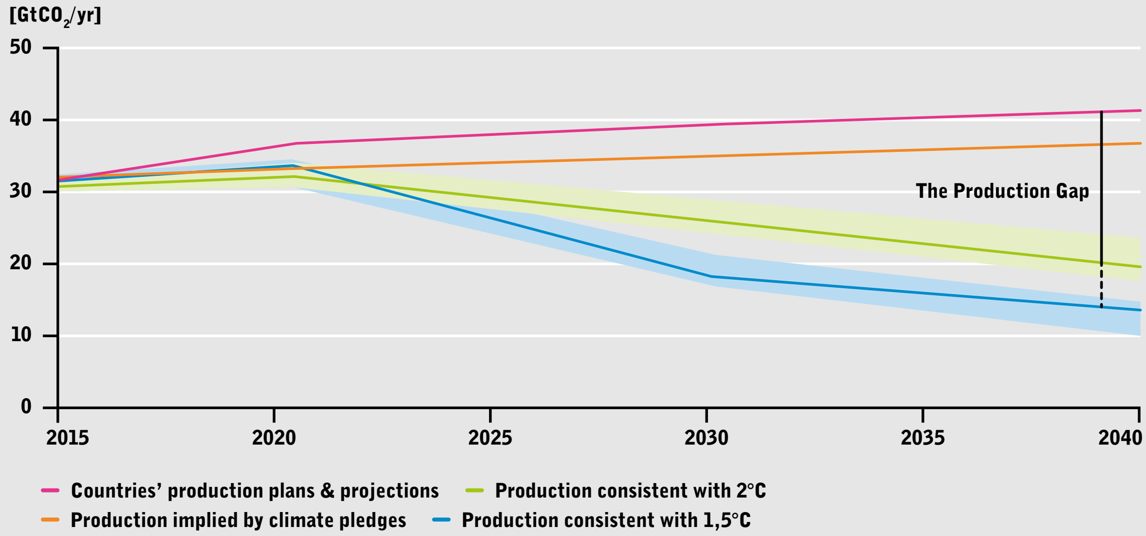
Foreword

Effective climate action requires leaving vast amounts of fossil fuels in the ground. In contrast, the 2019 report *The Production Gap* (UNEP, 2019) demonstrated convincingly that countries across the world are planning the continued expansion of fossil fuel production.

Although fossil fuel development, in particular oil and gas, promised vast riches in the past, today it is exposing fossil fuel producers and their creditors to a massive stranded asset risk. Technological disruption with the rapid cost-reduction of renewable energy and storage technologies, in conjunction with the inevitability of increased climate action, are at the root of unprecedented uncertainties over the future of the sector.

This is particularly true for new, hitherto unexploited reserves, which on average require 10 years and massive upfront investment in infrastructure (pipelines, terminals) before the first oil begins to flow.

Fig.: Globil fossil fuel CO_2 emissions



Nevertheless, the pressing needs of servicing debt and the prevailing mindset of associating fossil fuels with wealth may still push new producer countries into subsidising fossil fuel development and entering into risky contracts with oil and gas firms.

This paper proposes an innovative solution to this dilemma: a contract between international creditors and the government to leave certain hitherto undeveloped and unassigned oil and gas reserves in the ground for an initial 10-year period.

In exchange, a participating government would receive debt relief. The amount could be calculated based on traditional oil industry methods of asset evaluation, applying them to future revenue profiles of governments with potential oil and gas projects.

The urgency of the climate crisis requires thinking outside of the box. This proposal does so and merits wider discussion and consideration.[1]

Berlin, December 2020

Jörg Haas,
Head of International Politics
Heinrich Böll Foundation

1 Graph Source: UNEP (2019).

Executive Summary

This paper proposes a mechanism by which states could be compensated for leaving fossil fuels in the ground. It takes traditional oil industry methods of asset evaluation and applies them to future revenue profiles of governments with potential oil and gas projects. The result is to produce an evaluation of future oil production in today's money, which can then be used as the starting point for a negotiation with the government to leave the fossil fuels in the ground. This «leave it in the ground» (LITG) value can be leveraged as the basis for debt forgiveness or a debt-for-climate swap, as advocated in this series of papers. The paper examines the crucial question of how to structure the value created by leaving fossil fuels in the ground in a way that keeps owner governments engaged and respects their sovereignty.

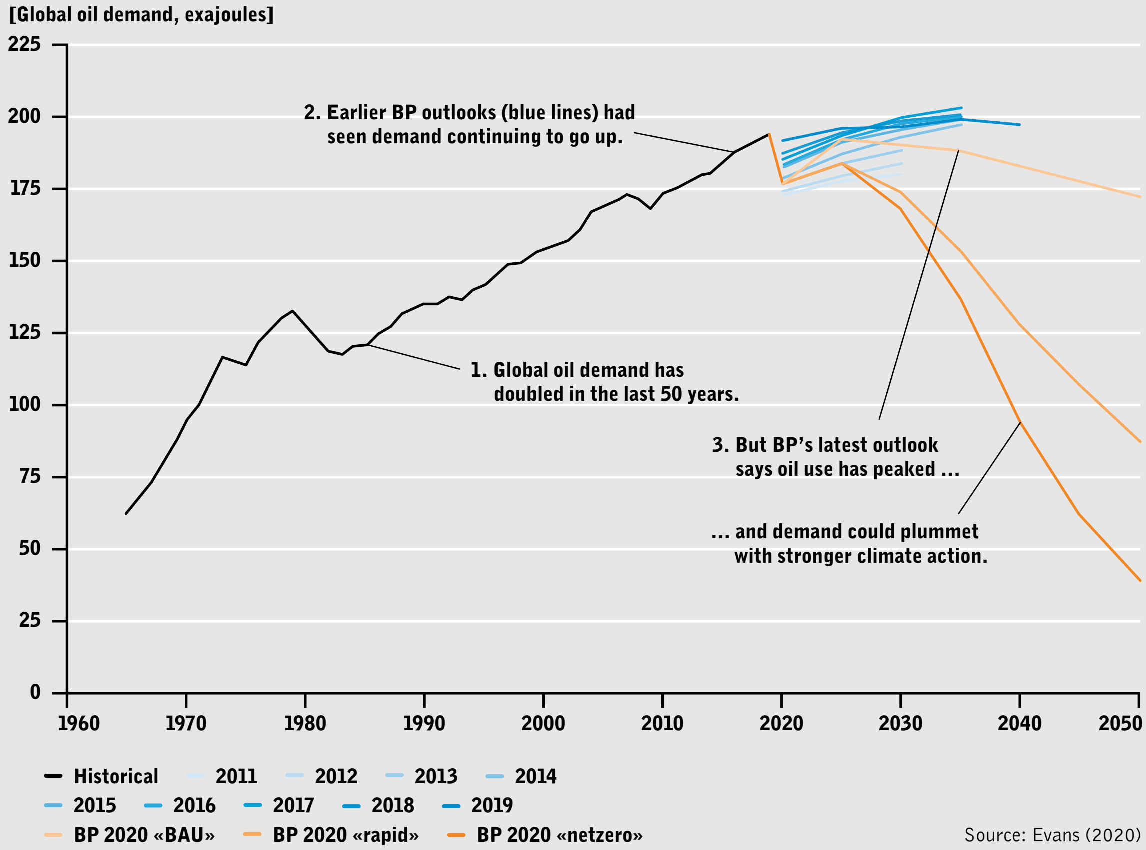
It proposes a contract between international creditors and the government to leave certain oil and gas reserves in the ground for an initial 10-year period. In exchange, a participating government would receive debt relief corresponding to a signature bonus and a series of annual payments. The mechanism allows for an opt-in at the level of the individual assets (oil and gas fields). Such an approach globally could prevent up to 400 gigatonnes of carbon emissions at a cost varying between US$2 and US$10 per tonne, just among the so-called new producer countries. It could also provide a precedent with the power to challenge the idea of fossil fuel-led economic development, which still prevails among many political elites around the world, despite clear signs that this era is coming to an end.

One of the spill sites near Kegbara Dere community, Nigeria.

1 The Context: 2020 and Corporate Managed Decline

Covid-19 has created two separate crises in the oil and gas industries. The collapse in prices in early 2020 led to companies recording huge losses.[2] But it also created – or rather exacerbated – a crisis of confidence in the future of the industry. The supermajor BP, for example, announced in June that it would no longer start exploration in any country where it was not already present, and its CEO, Bernard Looney, speculated that peak oil demand may already have arrived. The industry leader BP suggests indirectly in its *Energy Outlook* report that oil demand may have already peaked[3] (Figure 1).

Fig. 1: Global oil demand according to the 2020 edition of BP's energy outlook
BP now concedes that oil demand has already peaked – and could soon plummet.
Last year's outlook had seen peak oil still being 15 years away.



Source: Evans (2020)

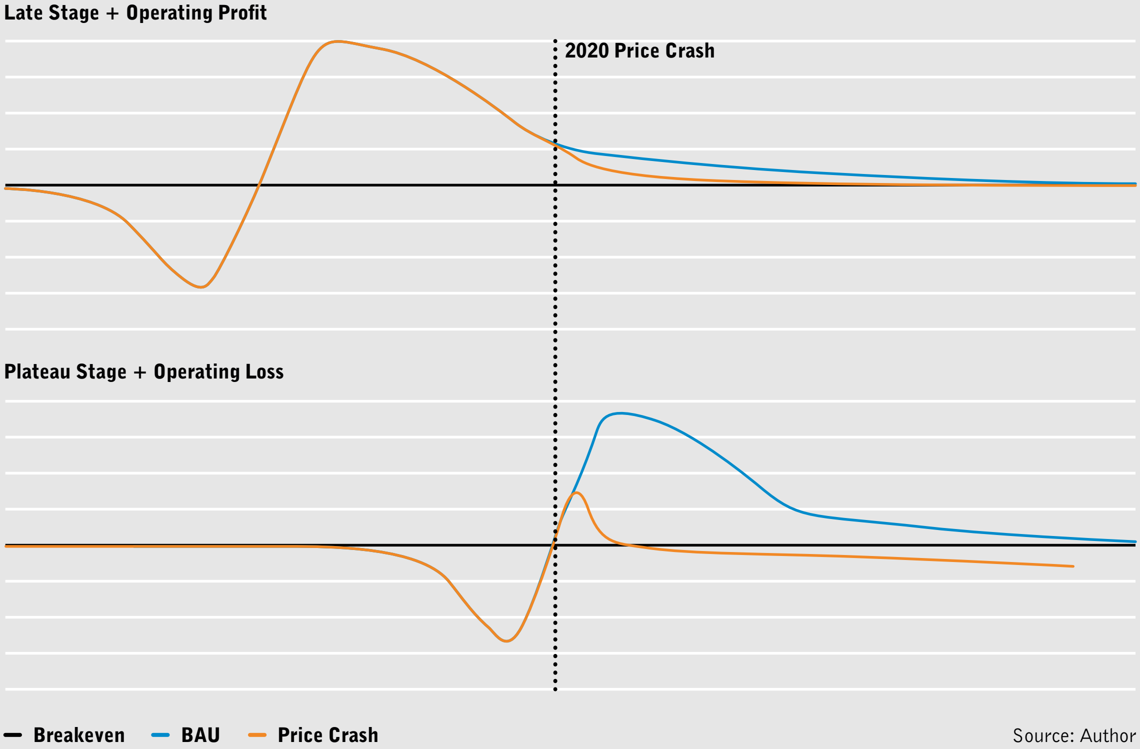
2 For instance, a 40% decline in the value of shares of oil companies on the New York Stock Exchange from September 2019–2020, and a 30% decline in the Standard and Poor's index of oil companies over the same period.

3 The 2020 edition of *Energy Outlook* foresees that even in the «BAU» scenario, oil demand will not reach pre-crisis levels (Evans, 2020).

Industry information provider Rystad reported in May 2020 that oil major sanctioning of new projects in 2020 was 95%, down on 2019, and that around the world projects under development were stalled or cancelled, as companies reconsidered their debt structures, or even went out of business.

Fig. 2: How market collapse affects oil projects in different life stages

To see how 2020 might hit new projects particularly hard, it is important to understand the generic cost structures of the oil industry. Both projects graphed below have identical cash flows, with high up-front capital investment that need to be recovered from sale of production over time. But the price collapse has hit them at different life stages. The project on the left is near end of life and 2020 losses are relatively small. The project on the right in early stage production, however, will now earn billions less – critically, it may never achieve a rate of return investors normally consider viable. Projects still in development or exploration would be more drastic again – many would likely never even reach positive cash flows.



Source: Author

The reason the impact has been so great is that it has changed perceptions about the future profitability of oil in the ground – and therefore the monetisable value of those assets today. Prior to Covid-19, oil and gas companies were already evolving to deal with probable long-term price declines caused by energy transitions. Because new oil and gas projects take so long before beginning production – a decade between signing an exploration contract and «first oil» is not uncommon – this was already affecting the estimates of commercial viability in new fields. But there was still a perception that peak oil demand would be reached in 10 or 15 years. New projects were sanctioned on the calculation that there was enough time to get enough oil out of the ground and sell it for a profit before long-term decline set in.

Covid-19 has changed that. By collapsing the market, it raises the possibility – some would say probability – that even if prices recover, they will not recover enough, or for long enough, to create operating profits that can earn back all the massive upfront investments before energy transition kicks in (Figure 2).

The change in thinking is reflected by the three indicative long-term price scenarios in Figure 3. At the end of 2018, the International Energy Agency was still issuing forecasts that predicted oil prices would be maintained in real terms indefinitely.[4] However, the red line represents a «gradualist» view, whereby energy transition leads to a long-term, but structural, price decline.[5] Covid-19 has forced a re-evaluation of that in the short term (2020s), throwing the viability of any new greenfield investments into doubt.

Asset writedowns

Commodity markets have always been volatile, which means that there are standard ways to deal with price fluctuations affecting the value of extractives companies. Since in financial markets the share prices of oil companies are based to a large degree on their booked barrels[6] – the fossil fuel assets in the ground that they have access to as a result of licences and infrastructure – companies are required to certify those reserves using formal systems and to re-evaluate the monetisable value of those reserves as the price goes up and down.

Accordingly, the oil companies have reacted to the 2020 market crisis with massive asset impairments[7] – reducing the estimated monetary value of the fossil fuel reserves they have on their books.[8]

4 This projection is the «sustainable development scenario» from 2018.

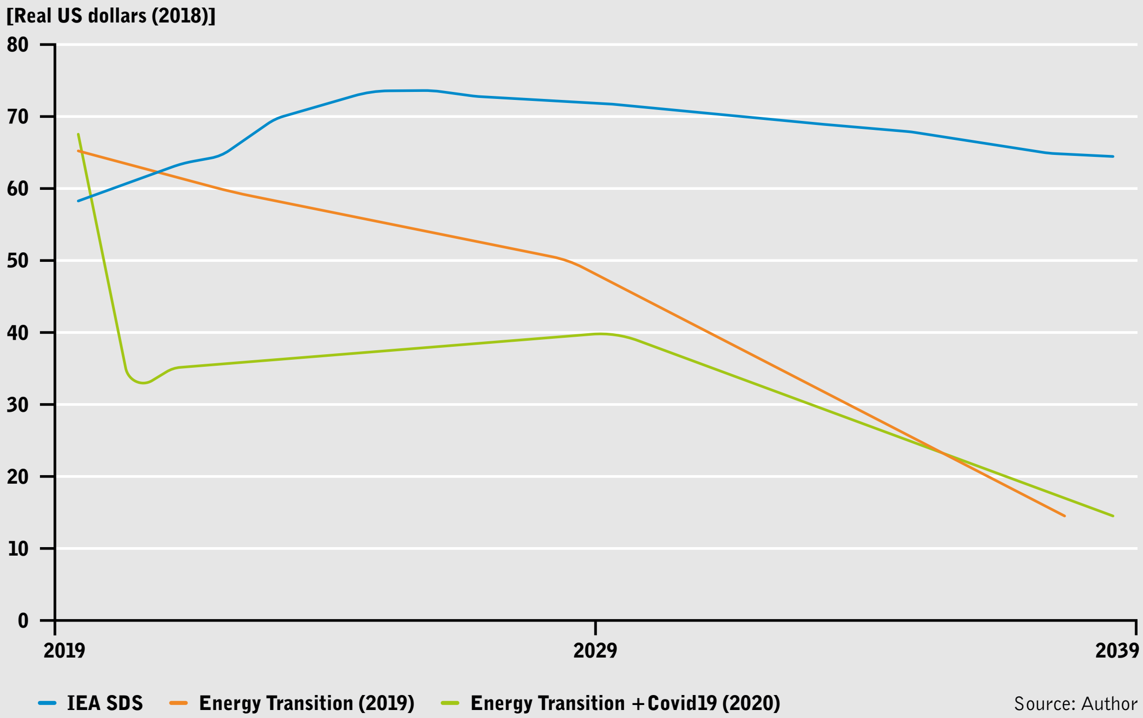
5 The red line «Energy Transition (2019)» is derived from a policy paper issued by the International Monetary Fund in 2017 speculating that peak oil demand could come «as early as» 2023 and decline to US$15 per barrel in real terms by 2040.

6 «Booked barrels» means those fossil fuel resources that an oil company can list in reporting to the stock market and shareholders that it has licence to produce.

7 Oil and gas that has been discovered – and that an oil company has «booked» because it has access to it – form a significant part of the asset base of oil and gas companies. This means that if the value of those assets declines – whether because the price has dropped, or because there has been an overestimate of the amount of the resource – the company must file an «asset impairment».

8 For example, in the first half of 2020, BP recorded an asset impairment of US$18 billion, Total US$8 billion, Occidental Petroleum US$6 billion, and Shell US$6 billion.

Fig. 3: Energy transition – crude oil price scenarios



Source: Author

This has led to a corresponding decline in the market values of the companies themselves, as shown in the indexes of oil and gas companies listed on various stock exchanges.[9] Share values are likely to be affected further because, since exploration has been slashed, the «reserves replacement ratio» will drop even further.[10] Not only will oil that the companies have located in the ground be worth less because of falling prices, their overall reserves figures will fall because, even with depressed demand, they are producing far faster than they are discovering new resources.[11]

9 As one example, ExxonMobil's share price of US$71 in September 2019 to US$35 in September 2020.

10 This had already reached a historic low of 12% in 2019, according to Rystad, and is likely to drop further in 2020.

11 The situation is more complex in the case of the Organization of the Petroleum Exporting Countries (OPEC) and the vast reserves of the national oil companies in the Middle East. But what concerns us here is the way open financial markets react to falls in the price of oil.

Transferring the managed decline paradigm to government

There is no dispute that the oil industry needs to go into managed decline to meet the targets of the Paris Agreement. Much research[12] has documented the gap between the carbon budget needed to limit CO_2 to below the estimated cap to limit global warming to an average of 2°C or even 1.5°C relative to preindustrial levels. If this is the case for oil and gas companies, then it must also be true for the governments that grant licences and collect taxes and profit shares on fossil fuel production. If three quarters of the world's current reserves are unburnable downstream in target energy markets, they are also unextractable upstream (Fuhr and West, 2014) in the oil fields of the world.

But the concept of managed decline is largely missing from the political debate on oil and gas in scores of countries, for several reasons. Among existing producers, such as Angola and Nigeria, the political dispensation has depended heavily for decades on oil revenues. There are also dozens of «new producer» countries, where the discourse is still largely about the transformative potential of oil and gas projects.[13] Most governments around the world are poorly placed to analyse the consequences of managed decline on revenue flows because they have never regularly accessed reliable financial analyses of their natural resource assets in the first place.[14]

Lastly, and perhaps most critically, is the «something for nothing» argument. It is not that scepticism has been absent from the public's thinking about the oil and gas industries. Dozens of countries have vivid experiences of resource curse. But this scepticism about how things have turned out, or might turn out, has been tempered by the idea that even if revenues, or economic growth, end up being substantially lower than predicted, projects that go ahead will still yield something – a few jobs and some foreign currency revenue flows to the Treasury.

It is this last calculation that a «leave it in the ground» (LITG) mechanism that addresses governments in the new context of 2020 has the power to challenge for the first time. Debt relief could be just one application of this mechanism. I am describing the mechanism in the form of payments to producer countries, but it would be relatively easy to convert this into relief from debt payments due.

12 E.g. Carbon Tracker's *Unburnable Carbon* report (Carbon Tracker, 2017), and UNEP's *Production Gap* report (UNEP, 2019).

13 For instance, 30 countries are members of the Chatham House initiative for New Producer Countries (Chatham House, n.d.).

14 See, for instance, the joint Open Oil–African Development Bank survey «Running the Numbers» (ANRC and ADB, 2017), which concluded – based on interviews with hundreds of officials in 25 African countries – that the systematic capacity to run, or even adequately understand, analyses of natural resources existed in fewer than 20% of relevant government agencies.

2 How to Structure the Value from an LITG Mechanism

The LITG mechanism applies conventional oil industry asset valuation, as described below. Technically, the principles are mature and straightforward, even if they may need some adjustments for a public policy context. The greater challenge is one of political economy, namely how to structure offers to governments based on an LITG valuation so that they lower the barriers to entry, respect national sovereignty, and keep the interests of all parties aligned.

The proposal examined here is that of a contract between international creditors and upstream governments, mirroring a form of contract used in the oil industry.

Service contract paradigm

Under a service contract, governments would sign up to an agreement in order to be paid a certain amount to not allow the development of fossil fuel resources. The economic benefits that the government would receive from an international party – whether in the form of debt forgiveness, a debt-for-climate swap, or any other mechanism – would therefore be in return for the decision not to develop or produce oil and gas for a particular period of time, rather than «forever». The contract would last for an initial period of 10 years but be renewable through a negotiation process specified within the contract. This is key to lowering the barrier to entry for individual governments. It would be theoretically possible for a country to be simultaneously developing some fossil fuel assets while mothballing others, allowing proponents of the LITG scheme to position it as a pilot project, rather than an irrevocable new course, or as an issue of national sovereignty.

Experience suggests that specialised agencies and departments such as oil ministries and national oil companies and regulators often have a disproportionate influence on government policy because they represent concentrated interest groups, even when there might be broader, but more diffuse support for environmental policy across government and society. Service contracts that offer granularity in duration (10 years, not forever) and place (a single licence or group of licences, not the whole jurisdiction) remove the zero-sum nature of the policy debate. This reduces the level of risk for governments so that they can commit to keeping at least some fossil fuels in the ground. The Covid-19 market context then sets up a situation in which LITG is now «something for nothing» versus signing a licence with

Training workers to install solar panels at health clinics in Rwanda provides clean energy, creates jobs, and improves health service delivery.

an oil company. Signing contracts for potential oil and gas projects with long lead times[15] now becomes the riskier choice.

A key point in an LITG contract is that the state retains ownership of the resource at all times. It merely contracts to manage those resources in a certain way, receiving value in return. This form of management then mirrors the service contracts that exist for oil production. This form of petroleum contract has been adopted by many of the oldest and most established oil-producing countries[16] because it offers the highest degree of retention of sovereignty when entering into commercial agreements with oil companies. In oil service contracts, the state retains ownership of the oil through the entire production process and pays the oil company a fee to extract it. In an LITG service contract, the state is paid to manage its own resources. The valuation would be achieved according to a common –published – methodology, and in consultation between the creditor and the government. The state therefore freely enters a commercial transaction in which it is to perform certain

15 Conventional oil and gas contracts routinely last a decade before a government receives substantial revenue flows, due to long development lead times and a contract structure that favours the recovery of investor costs from sales in the early years of production.

16 E.g. OPEC members Iran, Iraq, Kuwait, Mexico, Ecuador, Venezuela, and others (Ghandi and Cynthia Lin, 2014).

obligations in return for compensation, as in any other contract. Any disagreements between the parties would therefore be dealt with under commercial arbitration mechanisms and contract law,[17] rather than international law.

Compensation structure

The valuation process itself should be a one-time event for the life of the 10-year contract. Continually renegotiating due to shifting market conditions would be unrealistic. This should not be a barrier, because contracts for fossil fuel production typically last several decades with no formal recourse to renegotiation. The 10-year lifespan of an LITG contract therefore already offers more flexibility than business as usual fossil fuel production.[18]

But payments should also not be a one-off, since that would create potential future risk. Once a country has been paid to stop developing its fossil fuels, there would be no incentive to stop a future government from reversing course.

The service contract should offer a series of annual payments for its duration, combined with a signature bonus up front. These would be determined by the initial valuation, which would be performed according to market conditions in 2020, or whenever the valuation was made. Once assessed, there is no revision of the means of calculating the value of the contract.

Opt-out penalties

Most significant commercial contracts offer explicit opt-out clauses. To preserve the principle of a contract that was entered into freely, a government could also revoke the LITG contract, but only under opt-out clauses that were agreed at the time of negotiation and are enforceable under international commercial arbitration. Typically, an opt-out would attract a financial penalty, which would be a multiple of whatever the assessed value of the fossil fuel assets was to begin with. The goal is to use an ensemble of contract mechanisms to strongly deter any development of new fossil fuel resources throughout the 2020s. This entails trusting in the rising competitiveness of renewables and the development of energy

17 Preferably the same arbitration venues as are typically used in oil production contracts, such as the International Commercial Court in Paris, or the International Centre for Settlement of Investment Disputes.

18 It would be theoretically possible to assign value according to formula that shift dynamically in response to agreed benchmark prices on a continuous basis. Such an approach would then offer continuous evaluation according to market conditions, but still only one negotiation up front. This paper does not illustrate that for reasons of simplicity. It should also be noted though that such an approach would be more difficult to negotiate with an international party, which would then need to build considerable uncertainty into the overall value to be allocated, as well as potentially perverse incentives.

transition policy over the decade, which should lead to a situation in which new fossil fuel development is no longer seen as being viable from a number of different perspectives.

No state investment in fossil fuels

A recurring issue among countries seeking to develop new oil and gas fields is the use of foreign investment to build a national oil company. This is based on the history of the oil industry, when the dominance of the «Seven Sister» Western oil firms was first challenged and then overcome in the mid-20th century by the rise of national oil companies in the Middle East and within OPEC countries. But experience suggests that once national oil companies are created, they form a powerful lobby for the interests of the fossil fuel industry. Regardless of market realities, there is then a powerful agency whose entire raison d'être depends on the production of oil.

But in many early producer countries, the government lacks the capital to fund the stake of the national oil company, even though such a stake is typically 20% or less. The only way that new national oil companies can acquire stakes in licences on terms that international investors will accept is therefore to take a loan from the project based on its future earnings. Yet, with a short-term price collapse, a long-term structural decline, and any such loans being subject to project finance interest rates,[19] there are real questions about the security of any new state liability incurred in the fossil fuel sector.

«Leave it in the ground» contracts could made debt forgiveness or other financial assistance conditional on there being no new state financial liabilities in the sector.

19 Which are expressed as a premium to LIBOR, the benchmark interest rate, often ranging between 4% and 6%, liable in the currency of the contract, which is usually US dollars.

3 The LITG Mechanism: How the Oil Industry Values Asset

The oil industry has long-established ways of evaluating the present monetary value of oil in the ground for oil companies. This paper proposes simply taking these and, by running financial modelling, calculating a present value of how much potential future oil production in any particular field is worth to *governments* – in terms of future tax revenue and royalties – in exactly the same way.

Classification of resources

Key to this exercise is to deploy a formal system of resource classification. In 2007, the Society of Petroleum Engineers (SPE) in the United States published a system that has become the most widely used standard globally.[20] In major financial markets, oil assets need to be classified with a precise degree of certainty by accredited, independent experts in order to be counted towards an asset base that a company can present to shareholders, bond holders, and other interested parties. In theory, these same classification systems are recognised around the world, but they are less rigorously observed in practice. Typically, asset estimates per barrel are in the Reserves and Contingent Resources categories of the SPE classification system.

Three steps to the commercial evaluation of oil and gas in the ground

There are three steps to achieve the valuation of oil and gas still in the ground:

1) **Future cash flows:** Project economics in as far as they are known are input into a model with estimated future prices, generating revenues and operating profits. Then the tax regime is applied. This creates a projection of revenues for both the oil company and the government for any given project across its lifetime.

2) **Net present value (NPV):** Because conventional oil projects typically last decades, the projections of future revenue streams need to be collapsed into an equivalent sum today. This needs to take into account not only inflation, but also the opportunity cost

20 SPE's Petroleum Resources Management System was revised in 2018, which is the document referred to here.

of investing in the project. Using a discount rate, future revenues are *discounted* to see if they are competitive with other potential investments.[21] This creates the NPV.

3) **Chance of Development:** If the field has not yet been operationally developed, the NPV figure then needs to be run through an additional filter – the «Chance of Development». The fact that oil has been physically discovered is only the first step in proving its commercial viability. A long process of assessing *how* to develop it is required, which includes everything from the porosity of the rocks to above-ground infrastructure, licensing, and political risks. In the current environment, these risks will also include the fact that some, if not all, of the resources can never be produced because they will become stranded assets under an energy transition policy – for example while attempting to achieve the temperature targets of the Paris Agreement. If an asset, or the company that owns the asset, is being sold before development has started, the NPV needs to be multiplied by the Chance of Development.

To illustrate this with the simplest possible example: A company estimates that it would earn US$2 billion over the 30-year lifespan of a new project, after tax. It then applies a 10% discount rate to these future earnings, which results in an NPV of US$300 million. Lastly, because the oil has been discovered but the project has not yet been developed, a Chance of Development of 50% is introduced, which creates an «expected monetary value» of the field of US$150 million. This would then be used as the basis for negotiations between companies over the sale of the asset.

Contractual obligation

The same techniques can be applied to government tax revenues, with one complicating factor. Once an agreement has been signed, a government may be under contractual obligation to allow the project to proceed if the oil company wants it to. Normally speaking, governments grant licences to companies to cover both the exploration and production of oil and gas. Once the contract is signed, it is the company that takes the initiative in determining where to explore, if there is enough oil to develop and produce, how much to produce, and so on.[22]

21 Standard commercial discount rates vary by sector and field, but they are typically in the 7% to 15% range, with 10% being widely used as a default or proxy commercial discount rate.

22 There are typically contractual obligations on companies to commit to a minimum amount of exploration, but beyond that, most operational decisions lie with the company.

4 Application to Government Revenue Profile

In order to demonstrate how these techniques could apply to government revenue profiles, a couple of country examples are needed.

There is a tension here between the need to find a universal and objective method of assessment on the one hand – so as to achieve valuations that provide a monetary value with confidence – and the fact that each country and project context is different. Both the discount rate to be applied and the Chance of Discovery are subject to interpretation. It should be noted, however, that standard investor analysis, such as the NPV, typically embed complex and hard to quantify factors.[23] The paper therefore adopts a position of illustrating a number of different use cases, pointing out potential methodological challenges without seeking to resolve them in the scope of this paper.

Uganda

The East African country has been considered a potential new oil producer since petroleum was first discovered in 2006. Currently, there are four blocks being operated by Total, CNOOC, and Tullow. Estimates for the total amount of recoverable oil in the country vary between 1 billion and 1.8 billion barrels. Following is an order of dimension illustration of valuation.

Taking a median figure of 1.4 billion barrels of recoverable reserves and assuming a price of US$45 per barrel for Brent, Ugandan crude could achieve total sales of US$56 billion.[24] A discounted cash flow model of one of the contract areas[25] suggests that if the fiscal regime «held», the government would be due to receive US$25 billion between now and 2050 (future cash flows). That would be worth US$9.6 billion in today's money (NPV), if a standard commercial discount rate of 10% were applied. But there is still significant doubt about the development of the fields because of a number of complex issues. A nearly 1,000 kilometre pipeline needs to be built across Uganda and neighbouring Tanzania, and infrastructure needs to be developed in the fields near Lake Albertine. The government would also like to use the finds to commission a large refinery. The companies want the government of Uganda to make financial commitments to enable all of these

23 The risk of a civil war in Indonesia over the next 25 years, for example, cannot reliably be quantified, nor the risk that a future government might revoke an agreement or nationalise an asset. These are nevertheless routinely factored into discount rates used by any investor in an oil or gas project in that country, which in turn determine the NPV.

24 Ugandan crude will sell at a discount to Brent because the «slate» of petroleum it produces is less valuable.

25 Terms differ between contract areas. One contract is taken here to interpret the country's entire resource base, just as an illustrative example.

things, and it is not clear how financing can be managed. For such a technically demanding project, it would be ambitious – even without Covid-19 – to imagine the first oil flowing in five years. This means that a production plateau might not be reached until 2030, and clearly – in the current environment – there is a high level of uncertainty over what the state of oil markets will be at that time. All of this leads to a Chance of Development of 40% being reasonable.

This would lead to a valuation of US$3.8 billion as being a fair market value offered to the state of Uganda to leave all of its oil in the ground, representing a price of US$8.50 per tonne of CO_2 emissions saved.

Lebanon

Lebanon has been hoping to discover and develop offshore oil and gas for decades. Encouraged by the recent development of fields in the Eastern Mediterranean near Israel and Egypt as well as discovery in Cyprus, the government held an offshore licensing round in 2017. After a licence was awarded, a well that was drilled came up dry in April 2020. Nevertheless, the government would like to organise a second round of bidding. Resource estimates are difficult. There has been extensive seismic data and interpretation in the run-up to the bidding rounds, but no history of successful drilling. In light of that, the government's estimate of 25 trillion cubic feet of gas must be considered as «prospective resources» according to the SPE classification system.

The approach first seeks to «convert» prospective resources into an equivalent Contingent Resource volume using a ratio of 5 to 1.[26] Five trillion cubic feet of gas at US$5 per million British thermal units would yield revenues of US$43 billion in nominal terms. Of this, the government would receive about US$18 billion in the profit split and from other taxes from 2020 up until 2055 (future cash flows). A project would likely be developed using floating liquefied natural gas plants, which have a relatively low throughput capacity to the size of reserves. This would push back the production timeline and therefore result in a larger discount of both company and government revenues. Using a standard commercial discount rate of 10%, the government's revenues then collapse into an NPV of US$1.9 billion. Applying a Chance of Development of 40%, this would create a valuation for Lebanon of about US$800 million, representing a price of about US$3.20 per tonne of carbon emissions prevented.[27]

26 This ratio would need to be more firmly established, perhaps as a weighted average of thousands of data points worldwide. For the moment, it is sufficient to say a multiple of five to one is not at all uncommon.

27 Arguably implicit carbon price estimates for gas should be adjusted by estimates of fugitive emissions.

Mozambique

Mozambique has estimated gas resources of more than 100 trillion cubic feet. Companies in one of its licensing areas, Area 1, made a final investment decision (FID) in May 2020, which has triggered US$16 billion in project financing. The FID is to build two trains of LNG on land in the north of the country to process about six million tonnes a year of LNG. It is presumed that sales agreements for most of this amount have already been secured,[28] probably using contracts linked to the price of oil.

This case is representative of many greenfield oil and gas projects because the first phase of development only represents a small proportion of the total resource amount – about 12 trillion cubic feet. Because the government is bound by contract and the oil companies have already taken the FID, the mechanism is not applied to the resources to be produced under the declared first phase, in which, according to the financial model, the government could earn about US$29 billion (with an NPV of about US$3 billion). Instead, it is applied to the remaining 90% or so of Mozambique's offshore gas, which is treated here as though it is a Contingent Resource under the SPE definition.[29]

If the additional 90 trillion cubic feet or so of gas were produced over the same time scale, it would generate an additional US$405 billion of income, of which the government's share would be an additional US$190 billion (future cash flows), which is reduced to an NPV of US$29 billion. Unlike the first phase of development, however, during which the gas was classified as an actual reserve under the SPE system, the remaining 90 trillion cubic feet are at best Contingent Resources. The economics of expansion highly marginal in the current environment, especially as global LNG markets will be oversupplied well into the 2020s. If a 30% Chance of Development is allocated, we arrive at a valuation of US$8.4 billion for Mozambique's remaining 90 trillion cubic feet, representing a price of US$1.90 per tonne of CO_2 not emitted.

Costed example of LITG debt relief

Uganda's public debt before Covid-19 was about US$13 billion – 49% of gross domestic product. The country was not classified by the International Monetary Fund as being in debt distress during a 2019 Article IV mission. But interest levels were already predicted, pre-Covid, to reach about 20% of government revenues, or US$1.2 billion per year.

28 Most scaled gas developments do not go ahead until sales agreements for the majority of production have already been secured for the life of the project.

29 Most contracts contain relinquishment rights within them for the government. Thus, if the company develops one part of the licence area originally awarded for exploration, but not another, the government can exercise its right to revert the inert parts of the licence area back to its direct control.

Reflection in an oil polluted river in Kegbara Dere, Nigeria.

Luka Tomac – Friends of the Earth International/Flickr (CC BY-SA 2.0)

If the US$3.8 billion valuation of Uganda's fossil fuel reserves described earlier were applied across the interest obligations, then it would equal three years of interest payments. But the valuation could go higher if larger oil reserve estimates were to be verified. It is also possible that creditors might find themselves in a position to offer a *factor* of the valuation, rather than just the valuation itself. Such a factor could be determined by other spending plans or performance.

Suppose a factor of 2 was applied to the original US$3.8 billion valuation, because it fell within the desired debt restructuring or debt forgiveness parameters. The US$3.8 billion valuation then translates into US$7.6 billion of debt relief.

A relief structure could then work in the following way: 2021, Year 1, would see complete coverage of interest payments as a form of «signature bonus» (value US$1.2 billion). This would then drop to half that level of coverage in Year 2 (US$600 million) but increase from that point by 6.5% per year.[30] It would then reach a billion dollars in relief in Year 10, the last year of the LITG contract. The impact of the entire LITG contract over 10 years would then, broadly speaking, have halved the burden of interest payments.

Of course, different approaches would be possible based on the structure of the debt principal, the mix of creditors, and the policy priorities of the Ugandan government.

30 In nominal terms.

5 Scope

Such an approach clearly has limitations in scope. It cannot be applied – or at any rate would be much harder to apply – to oil fields that are already in production, since the nature of most contracts is that, by the stage of production, it is the operator who is taking all such decisions.[31] Core producer countries may see little incentive and may not fit the right profile in terms of a debt-for-climate initiative. Also, with public creditors and international financial institutions, the outlines of a deal might be clear, but less so for private-sector creditors of sovereign debt.

Nevertheless, taking the public debt crisis as an initial starting point, we can get some sense of the dimension involved. The 76 countries classified by the Jubilee Debt Campaign as having high debt service requirements[32] have proven oil reserves of some 380 billion barrels, and gas reserves of some 600 trillion cubic feet.[33] These represent 20% of proven oil reserves, and just under 10% of proven gas reserves – according to the widely used BP Statistical Review of World Energy – or somewhere between 300 and 400 gigatonnes of CO_2, which is six to eight times the amount of global annual emissions. In fact, the amounts of reachable assets are likely to be considerably higher. The BP analysis is conservative in the sense of only including accumulations of oil and gas assets that have been declared in the public domain for some time. There are large categories of contingent resources from new producer countries that it does not list. For instance Cyprus, Guyana, Kenya, Senegal, Suriname, and Tanzania are listed without any reserves at all according to the data of BP and the EIA data, even though discoveries have been made there, and in some cases development is underway. Guyana alone now has 8 billion barrels of recoverable oil in one field, and the formation as a whole – stretching into neighbouring Suriname – might have double that.

31 In addition, reserves growth out of existing fields would be considerably more challenging, methodologically speaking, than greenfield projects.

32 Defined by the Jubilee Debt Campaign as a Debt Servicing Requirement equal to more than 10% of the government budget.

33 According to data from the US Energy Information Administration (EIA) and the BP Statistical Review of World Energy 2020.

6 Difficulties and Objections

Empirically-based resource estimates

The biggest technical issue is arriving at estimates of agreed-upon, empirically-based resources. Although the SPE classification standards are robust, they are most rigorously applied when shareholder interest in companies listed in major financial markets are at stake. Large numbers of assets held elsewhere are not systematically certified. The OPEC countries, in particular, have had a long history of secrecy when it comes to their reserves levels.[34]

It is also important to avoid misaligned incentives, such as increasing exploration activity in order to qualify more stranded assets.[35]

Fully embedded carbon cost of fossil fuel development

This paper also only outlines a mechanism to value fossil fuels left in the ground relative to carbon emissions of what would be produced and consumed. In reality, the LITG mechanism would need to be refined to bring it fully into alignment with the true carbon cost of fossil fuel production. To give just a couple of examples: All fossil fuel projects require massive infrastructure, which brings with it large amounts of embedded CO_2, and with any natural gas production, for example, there is a real question about the fugitive emissions of methane. Logically, then, the LITG valuation should rise in accordance with this, to provide true parity. The balance here will be between complexity and transparency: arriving at a valuation process that is comprehensive enough, without being opaque to policy-makers.

Unrealistic expectations

The sums mentioned in the three country examples are realistic ballpark estimates of what fair market value would be using standard oil industry techniques. But it remains the case that many governments continue to hold unrealistic expectations about what a petroleum

34 For a long time, OPEC production quotas were directly linked to stated reserves levels, creating an incentive to inflate statistics.

35 In practice this is unlikely, as exploration activity is controlled overwhelmingly by oil and geophysical companies, which would have no incentive to explore just to declare stranded assets.

sector can bring them in terms of revenues.[36] Persuading them that these are fair amounts for leaving fossil fuels in the ground could therefore be challenging.

This might particularly be the case if spot market prices rise again in 2021 and 2022. The entire 10-year LITG contract should be set against a valuation at the time of the deal, since if it were open to continual re-evaluation, it would be unworkable. This is in principle no different to selling ownership or use of any asset – one can always buy or sell at the «wrong» time in a business cycle. But it might be hard to sell as a reasonable policy over a treasured national asset. This is why it is important to offer deals asset by asset so that a government never feels trapped in a policy it fears may affect its sovereign national interests.

Just transition

Because oil and gas are so capital-intensive, new jobs often cost more than a million dollars each of the investment. Loss of employment opportunities due to the non-development of fossil fuel assets are therefore likely to be limited in terms of the economy as a whole.

But there are other aspects of just transition that could be affected. The valuation method offers a value related to the money that a government could earn from producing the oil or gas, but because this is based on underlying contracts, which can vary widely regarding what share of the revenues the governments receive, it can also yield a widely varying carbon price. Since every ton of CO_2 emissions has the same environmental impact, why should Uganda be paid US$8.50 per tonne of CO_2 emissions prevented, compared to just US$1.90 per tonne for Mozambique?

36 Political debate in countries such as Senegal, Mozambique, Uganda, Lebanon, and Kenya has for years been centred around the transformative potential of these industries, even when reasonable modelling suggests the impacts would be much more modest.

Geothermal power plant Olkaria IV of KenGen the kenyan power company in the Rift valley.

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