Leaving Fossil Fuels in the Ground: An Evaluation of Kenya and Uganda

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Summary

This paper proposes that international finance institutions build a new deal for Kenya and Uganda and offer both countries a service contract not to produce the fossil fuels that have been under development in both countries for many years.

Instead of waiting for final investment decisions that may or may not happen, as energy transition advances, the governments can accept sizeable and certain payment now – for providing the service of keeping fossil fuel resources in the ground.

International financial institutions (IFIs) such as the International Monetary Fund, the World Bank, and the African Development Bank would agree to Net Present Values NPVs of $2.41 billion for Uganda's four fields, and $1.19 billion for Kenya's Turkana field, against the governments' loss of future revenues. These valuations would be fed into annual payments over 10 years, under a service contract signed by the two sides, and regulated by UNICTRAL (just like both countries' current exploration and production contracts).

- The governments of Kenya and Uganda would invoke their prerogative of relinquishment within existing exploration and production contracts in the face of continued non-development by the companies.
- The IFIs and governments would then sign Leave It in the Ground (LITG) service contracts, with signature bonuses of $604 million (Uganda) and $296 million (Kenya).
- Interest of 7% would be payable on the balance of the remaining LITG principal.
- Payments would total $3,363 million (Uganda) and $1,651 million (Kenya) over the course of the 10-year agreement.
- In adopting LITG contracts, Kenya would avoid potential liabilities of $1.27 billion and Uganda of $2.70 billion, required by investment in the oil projects as currently formulated.
- The LITG contract could be extended after that time, or the governments could reassume direct control of the areas, including moving forward with fossil fuel production if that was their considered choice.
- Both governments retain full ownership of the sub-soil resources at all times.
- The transaction would result in the abatement of approximately 1.2 gigatonnes of carbon dioxide equivalent (CO2E) at a cost of $4.10 per CO2E (nominal).
- IFI counterparties or others could apply a factor to increase payments based on agreed policies, such as the scaling of renewable energies, or public finance initiatives.

These LITG transactions would offer the chance to turn current uncertainties into a major new opportunity. The scale and timing of payments would enable increased access to energy, at least as great as what would have been provided by oil projects largely destined for export.

Legal and Contractual Considerations

The first significant question to address is whether the governments of Kenya and Uganda are able, or have the right, to decide to enter these kinds of deals in the first place. Both countries' constitutions give responsibility for managing natural resources to the government.. In Kenya’s 2010 Constitution, Article 69 states that the government should ensure the conservation of natural resources and that exploitation is sustainable. Article 71 requires that any transaction dealing with a natural resource is ratified by Parliament. In Uganda, the 1995 Constitution likewise imposes (Article 13) responsibility on the government to manage natural resources, including oil, on behalf of the people.

Nevertheless, while public ownership of natural resources is enshrined, both countries have also entered into contracts with companies to explore and produce oil. Discoverieshave only been made, and reserves established, as a result of exploration and production agreements signed with oil companies over the last 20 years, including Total, the Chinese state oil company CNOOC and Tullow, who hold shares in the projects today.

Significantly, the mode of contracts in both countries is the “production sharing agreement.” Under PSCs, ownership of the natural resource lies with its original owner, in this case, the government, until it is produced. The contract then specifies arrangements to split ownership of the oil produced between the operating company and the state. Meaning that the agreements signed with oil companies have not, in this case, led to a transfer in ownership of the underlying resource[1].

One of the primary purposes of such contracts is to allocate rights to produce and sell petroleum to the signing company. This could lead to a simplistic and immediate assumption that once agreements are signed, governments are bound by contract to allow the companies unfettered decision making about how much oil and gas to produce when. However, most petroleum contracts, including those in force in Kenya and Uganda, frame production rights for the company under an intricate sequence of steps and actions with obligations on both sides. It is, therefore, necessary to study the details of each contract.

[1] This is in contrast to many forms of concession agreement which predominated earlier in the life of the petroleum industry, where the agreement itself could transfer ownership.

The specific contracts governing the potential producing fields of Kenya and Uganda have not been published, despite contract transparency becoming a mainstream part of the natural resource governance agenda in recent years. Nevertheless, both countries have published so-called “model contracts”, and several full contracts in license areas other than Turkana have been published. Experience suggests that most changes between model and final signed contracts are around commercial terms of the fiscal regime and stabilisation clauses leaving a reasonable degree of confidence that the language of the model contracts can be interpreted as applicable in the case both of Turkana and Lake Albert.

Kenya

In recent years, Kenya has issued two model contracts, in 2013[2] and 2015[3]. Terms relating to production rights are identical in these two contracts, as well as in contracts published by oil companies Camac[4], and ENRC[5] signed in 2012.

Under these contracts, the company acquires the right to explore for oil and gas for an exploration period. There are rules about how long this lasts and the conditions under which this could be extended. In the case of Turkana the contract was signed in 2007, leading to discovery in 2012.

Once a discovery has been made, the company must communicate to the government. The next stage is then for the company to appraise the discovery to see if it is commercially viable. This has taken many years in the case of Turkana, as the appraisal program included drilling 14 more wells. It is important to understand the context. Many oil discoveries never go into production because there is not enough oil to make a project viable, or the costs of developing the project are too high.

All of this exploration and drilling still does not mean that the project is yet considered commercially viability. That comes when the company makes a declaration of commerciality, which has legal consequences. Once there is commerciality declaration, the contract moves out of the exploration stage and into the production stage. In the case of Kenya, the contract guarantees an initial period of 25 years.

The contract lays out distinct stages for the process of development. First, the company must prepare a Development Plan within six months of declaring commerciality[6]. Then the

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[2] https://resourcecontracts.org/contract/ocds-591adf-5028294581/view#/pdf
[3] https://resourcecontracts.org/contract/ocds-591adf-8711222221/view#/pdf
[4] https://resourcecontracts.org/contract/ocds-591adf-5507758701/view#/pdf
[5] https://resourcecontracts.org/contract/ocds-591adf-2656241484/view#/pdf
[6] 2015 Model Contract, Article 28

government has 60 days to review it. Finally, the company should start implementing the plan within six months of its approval. Thereafter, the company submits a new development plan each year throughout the project life.

But the contract also factors in a situation in which a discovery has been judged to not be commercially viable. In that case, “the Cabinet Secretary may request the contractor to surrender the area corresponding to such commercial discovery and the contractor shall forfeit any rights relating to any production therefrom.”[7]

The question here is what stage the process has reached in the case of Turkana. Despite the high publicity the project has received, and the large appraisal program, and even some early production shipped to the port city of Mombasa by truck, the project has not received a Final Investment Decision from its operating companies. Indeed, Tullow, the operating company, attempted to sell its stake in 2020 but could not find a buyer. Tullow officials aim to present a Development Plan by the end of 2021[8].

There has been no declaration of commerciality conforming to the PSC terms . The government has accordingly extended the exploration period to the end of 2021. The project's future is clear in two out of three scenarios. . Scenario one, the operating company (Tullow, at least for the moment) declares commerciality, the project will enter the production stage, and the Kenyan government would no longer be able to regain direct control of the reserves. Scenario two, Tullow declares it does not see the discovery as being commercially viable anymore: the government regains the right to do whatever it likes with the reserves free of any further obligation imposed by the contract.

The trickiest scenario to interpret is a middle one where there is no clear decision: if, for example, Tullow reaches the end of the current extension of the exploration period without either declaring commerciality or the lack of it.

Uganda

A similar situation prevails in Uganda, as far as can be ascertained from public documents. The 1999 Model Contract lays down a similar process ofdiscovery followed by the appraisal and then an evaluation of the commerciality of the discovery . This contract explicitly envisages the possibility that a company might decide that a project which it had earlier declared viable is no longer so: “If, as a consequence of the said award, the Licensee determines that the development project (in respect of which the Development Plan was

[7] 2015 Model Contract Article 31.2
[8] https://www.bloomberg.com/news/articles/2020-09-22/tullow-reviewing-kenya-operations-after-suspended-stake-sale

submitted) ceases to be commercially attractive, the Licensee may so notify the Government in writing within six (6) Calendar Months of the date of said award, whereupon the Government shall have the right to require the Licensee to relinquish its rights with respect to the Discovery Areas which are the subject of such Development Plan and to forfeit its rights to any subsequent production therefrom."

Adapting the Concept of Relinquishment

All existing contracts are premised on the idea that production of any oil or gas identified is a shared goal of the government and the contracting company. The contract is there to regulate how that happens. But while the overall shared goal is conceived as discovery and production of oil, there are plenty of potential conflicts of interest which the contract needs to regulate. The reason the sequence of actions after discovery is laid out is to handle potential differences between the parties. Once a discovery has been made, the company wants maximum flexibility to decide what to do about it. However, the state does not want to give total flexibility because it wants action as soon as possible, and maximum exploitation of its resources. Each party requires the other: the company because they can only produce oil with the permission of the state, which owns and manages the resource, and the state because it needs the capital and expertise of the company.

The contract therefore mediates a middle position: the company can have time to consider how to develop a discovery, but not unlimited time. If it chooses not to develop the resource after the given amount of time, the resource reverts to the direct management of the state, in a process known in the industry as "relinquishment".

Relinquishment is a common process even in fields which go forwards into production. When the company confirms a commercial discovery, for example, it is nearly always in an area smaller than the area it was awarded permission to explore. A "development area" is defined as a region within the original exploration block[9]. The terms of the original license, with respect to limited periods of time to make a discovery, and then to decide what to do with it, continue to apply to the rest of the exploration license area. Frequently, a company subsequently relinquishes most or all of the rest of the block, and the state will then seek to bid out those other parts of the block as a new exploration license.

Although the terms relating to relinquishment were designed to allow a government to recover areas for potential oil production, there is nothing in the contracts that specifically binds it to that use. A government which then forces relinquishment to turn those areas over to *non-production* cannot be held in breach of contract.

[9] Kenya Model Contract 2015 Article 4, Uganda model contract 1999 Article 3.5, also referencing the Petroleum (Exploration and Production Act 1985 Articles 17-19 https://ulii.org/ug/legislation/consolidated-act/150

In the Kenyan and Ugandan cases, therefore, the government's ability to regain direct control of the reserves in Turkana and Lake Albert depends on where the formal processes of notification, appraisal, and declaration of commerciality, as defined by the signed contracts, have reached. Prima facie, the fact that no Final Investment Decisions have been made in either project suggests that the governments could either initiate relinquishment straight away or after the elapse of whatever extension in contractual timelines they may have offered[10].

Arbitration Procedures

The likely worse-case scenario in either project would be if it appeared a company would seek to dispute a government's enactment of relinquishment. The contracts in Kenya and Uganda stipulate identical dispute resolution procedures: following any prolonged failure to reach an agreement, the parties can refer an issue to a panel of three experts, which meet under UNCITRAL arbitration rules[11].

This study adopts the assumption that it is the case now, or will become so, shortly, that Kenya and Uganda can invoke the relinquishment clauses in their contracts with the international oil companies without risk of breach of contract.

The Political Economy of Leaving Fossil Fuels in the Ground

Becoming oil producers has been a dream in both Kenya and Uganda for many years. Uganda first licensed blocks out in the 1990s and the discoveries which led to the current proposed pipeline to the Indian Ocean date to 2006. In Kenya, the first discovery in Turkana was in 2011, and the government has licensed out many other blocks both on- and offshore. Both countries have devoted considerable energy to laying out legislative and regulatory frameworks for the industry, including national oil companies.[12]

In Uganda, the development of a domestic oil industry has been part of the long-term goals of President Yoweri Museveni.[13] Development of the oil fields has been inextricably linked to a concept that oil production would drive the country forward into a new stage of economic development, even though various studies over the years have suggested the industry would be a relatively modest contributor to the country's GDP[14].

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[10] The end of 2021 in the case of Turkana, for example.
[11] Kenya model contract 2015 Article 52, Uganda model contract 1999 Article 23.
[12] Uganda National Oil Company and the National Oil Corporation of Kenya.
[13] https://www.monitor.co.ug/uganda/oped/commentary/museveni-was-unlikely-to-go-with-pending-oil-plans-3270706
[14] For instance, a 2012 study by the Brookings Institute estimated that an oil industry might increase the country's Gross Domestic Product by five percent per year https://www.brookings.edu/research/managing-a-modest-boom-oil-revenues-in-uganda/

The Turkana discovery has long been a vibrant political issue in Kenya. It became the trial case of a key aspect of the country's 2010 Constitution – how would resources be allocated between the central government in Nairobi and the newly empowered county governments in the regions. Turkana county governor Josphat Nanok contested the revenue sharing formula proposed by the national government in Nairobi, and he and President Uhuru Kenyatta traded criticisms on the issue on television.[15] Proposed regulations were revised several times. Such public disputes fueled a widespread perception[16] that the "oil billions", when they came, would transform Kenya's economy. As the OpenOil and Invhestia model of 2018 showed, such expectations were never justified by the scale of the resources found or the likely flow of revenues to either company or state, and have since been thrown into great doubt by Covid 19 and the coming Energy Transition.

In both countries, the industry's development has been framed as a patriotic priority, responding to a deep and widely shared view of economic nationalism. It is this political environment that any mechanism designed to leave fossil fuels in the ground must address.

At the same time, the development of both projects remains as uncertain as ever. In Kenya, Tullow tried to find a buyer for their interests but failed and wrangled some tax concessions from the government.,There have been almost endless announcements about an imminent declaration of a Final Investment Decision (FID) in Uganda. But Total, the lead operator, remains coy on when such a decision could take place and talks in terms of finding a way to run the project which can survive in a low-price environment.

Both projects face considerable logistical and geopolitical uncertainty in managing long pipelines needed to connect the fields to ports for export on the Indian Ocean. Uganda's case is further complicated by the need to get agreements covering all legal and commercial arrangements with its neighbour Tanzania[17]. Development in Uganda is also more complex because multiple agreements need to be concluded in lockstep with each other to make the sector viable: not just the fields themselves, but the East African Crude Oil Pipeline (COP) running to Tanga on the Tanzanian coast, a large oil refinery at Hoima, and support infrastructure such as approach roads in the fields.

The uncertainty of early 2021 creates an opportunity for an LITG proposal. Although both countries have been waiting for more than a decade for oil to flow, current market conditions and the coming energy transition make future revenue flows look as far away as

[15] https://www.youtube.com/watch?reload=9&v=jH9KJjAVWVA

[16] https://www.standardmedia.co.ke/business-news/article/2001281026/uhuru-nanok-agree-on-how-to-share-oil-billions

[17] Transnational pipelines are notoriously complex to negotiate. Out of 44 landlocked countries in the world, only seven export oil or gas, and the only pipeline set up by a landlocked country in Africa was the Chad Cameroun pipeline in 2004, in a project which received large scale international attention and support.

ever. In such circumstances, LITG has the potential to offer money in the hand, and look like a better potential outcome after all[18].

The proposal outlined in this paper is to adopt a granular and contractually led approach, interacting with the government much as it has already interacted with the oil companies in striking exploration and production agreements. It respects the sovereignty of each country, and proposes what is essentially a commercial arrangement. Kenya and Uganda would provide the service of *not* producing fossil fuels, resulting in a deal with a value equivalent to the revenues they would forego by doing so.

Service contract paradigm

We propose that the international community offers Kenya a deal, structured as a service agreement between the state of Kenya and the financiers, to reclaim direct management of the Turkana project and shutter the project. The Turkana assets would be given a present day valuation of $1.19 billion, which will then be structured into a series of payments over the next 10 years.

In the case of Uganda, a similar approach would be followed for all fields where drilling has established discoveries classified as contingent resources.

In each case, the structure of the contract would pay the government for the decision not to develop or produce oil and gas for an initial period of 10 years. It would still be be renewable through a negotiation process specified within the contract.

This granular approach could remove the zero-sum nature of the policy debate. This reduces the level of risk for governments allowing them to commit to keeping at least some fossil fuels in the ground. It also sets up a situation in which LITG is now the "something for nothing" option versus signing or continuing a licence with an oil company. Signing contracts for potential oil and gas projects with long lead times now becomes the riskier choice.

Arriving at a Current Valuation Figure

The critical question in the LITG proposition is on what basis to establish a valuation figure or formula. There are three critical components to consider: first, which evaluation methodology to use. Second, how to estimate the volume of oil and gas to be included in the deal; and third, which values to set on price, discount rates and other technical factors.

[18] The broader market background is laid out in a separate paper published by the Heinrich Böll Foundation in November 2020 https://www.boell.de/sites/default/files/2021-01/Background%20Paper%20_6.pdf

Income-Based Valuation Approach

The model adopts valuation based on assessing future income through a Discounted Cash Flow (DCF) model. Various valuation techniques are used in the market, such as Capital Asset Pricing Models (CAPM), Real Options, or cost-based methods to tally compensation in commercial arbitration. We choose the income-based approach of DCF for several reasons.

First, techniques such as Real Options and CAPM are not appropriate to the position of these governments, who are not directly overseeing development of these resources, nor do these oilfields fall into a wide and diverse investment portfolio. Secondly, DCF modelling is the most common form of financial evaluation at the project level already in use by governments, so there is something of an addressable user base. The technique is widely used by the oil industry to establish valuations of oil reserves and integrated into corporate reporting compliance in several jurisdictions.[19] It is also widely accepted as a means of judging the value of assets under dispute.[20]

Use of the DCF would therefore establish a common basis on which to evaluate either a single field, as in the case of Kenya, or a group of fields, as is suggested in Uganda, and to provide a wide comparison between countries.

It also has the merit of being conceptually straightforward. The valuation process requires three basic steps:

1) **Estimate 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 revenue projection for both the oil company and the government for any given project across its lifetime.

2) **Net present value (NPV)**: The fields 'expected project lifetime in Turkana and Lake Albert is decades, which means that 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 of investing in the project. Using a discount rate, future revenues are discounted to see if they are competitive with other potential investments. This creates the NPV.

3) **Chance of Development:** If the field has not yet been operationally developed, as is the case with both Kenya and Uganda, 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

[19] For instance the SEC in the United States https://www.sec.gov/info/smallbus/secg/oilgasreporting-secg.htm and similar rules in Canada and Australia.

[2020] The broadest discussion of this is the ICSID ruling in the Tethyan case of 2019 https://www.italaw.com/sites/default/files/case-documents/italaw10737.pdf Paragraphs 300-370.

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. These risks also include the possibility that some resources can never be produced because they will become stranded under an energy transition policy – for example while attempting to achieve the temperature targets of the Paris Agreement. If an asset or the company owning it, is sold before development starts, the NPV needs to be multiplied by the Chance of Development.

Scope of Petroleum Resources Included

The question of how oil and gas resources are classified and which scope is included in a LITG deal, is critical. It is a little understood fact that in any given oilfield the quantity of petroleum *resources* in the ground is quite different to the *reserves* expected to be produced. Historically, the ratio of oil reserves to resources was only 25% before a well was capped and abandoned. In recent years, enhanced recovery techniques have brought the recovery rate to above 50%, for example in the Norwegian part of the North Sea. But even reaching half is regarded as an unprecedented technological success.[21]

The cause is financial. In a typical petroleum reservoir, natural pressure is at its highest when production starts, and this is what drives the field towards a plateau within a few years of the start of production. Gradually, the natural pressure in the reservoir subsides and production rates fall. However, they can be restored by an ever increasing array of technical options – injecting gas, or water, or carbon dioxide under the oil to make it rise. These techniques are expensive and therefore raises the production costs. . Inevitably, it stops being profitable to produce oil in the field long before that oil has physically run out.

The oil industry deals with this by having a classification system for all oil and gas discovered, which has many different categories - the Petroleum Resource Management System[22] (PRMS) maintained by the Society of Petroleum Engineers (SPE) is now standard. Broadly speaking there are three categories of commercial viability: the top category is "reserves." then "contingent resources" then, at the bottom, "prospective resources."

The issue with Uganda and Kenya is that despite all the years of appraisal and billions of dollars of investment, and some production in the case of Turkana, not a single barrel of oil has reached the top level of reserves under PRMS. Reserves require a Final Investment Decision by the company, with a determination made of how much oil or gas will be

[21] https://www.equinor.com/en/how-and-why/increasing-value-creation.html
[22] There have been several different systems in use around the world but in recent years practise has largely converged on the Petroleum Resources Management System developed and maintained by the Society of Petroleum Engineers, last updated in 2018 https://www.spe.org/en/industry/petroleum-resources-management-system-2018/

produced under an agreed development plan[23]. The highest classification of any oil in Uganda and Kenya is that of "contingent resource" – its existence has been proved by actual drilling, but it has not been confirmed as commercially viable.

Within each class, there are also different degrees of confidence: for example, some reserves are classified as "proved", some as "probable" and some as only "possible". Financial markets often set reporting of oil reserves to particular categories, in order to prevent companies overstating reserves levels to drive up share price and market value.[24] Reserves inflation has always been a concern in the oil industry. In OPEC countries, for example, governments have often not adjusted reserves for years at a time to take cumulative production into account, and then announce sudden and massive increases in reserves figures. This is due to the fact that for many years OPEC production quotas were directly linked to each country's stated reserves.

In Uganda and Kenya, the "oil discourse" has driven expectations up, and diminished attention to the difference between different resource categories.

Ugandan Oil Reserves

Bloomberg has repeatedly and mistakenly cited Uganda as having six billion barrels of oil "reserves" (instead of "resources").[25] The government has consistently quoted the figure of 1.4 billion barrels as recoverable. This is slightly higher than the figure issued in 2017 by Tullow, one of the companies in the fields, of 1.2 billion barrels[26], but the same as an overall estimate released by industry analyst Wood Mackenzie.[27]

This study therefore incorporates the 1.4 billion barrel figure to cover the four fields that would be developed to feed the EACOP[28]. Because the fields' economics suggests that all four have to be developed simultaneously to make the pipeline and refinery projects viable, and the same companies are involved, these are grouped together in the model as one set of reserves[29].

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[23] Critically, a qualified expert must attest to the fact that the quantities in the development plan are producible "under current market conditions and with existing technology".

[24] So the Securities and Exchange Commission in the USA restricts reserves reporting to the highest category of *proved*, but the Canadian exchange requires companies to list both *probable* and *proved* reserves.

[25] E.g. https://www.worldoil.com/news/2019/10/22/uganda-to-pick-investors-for-five-new-blocks-start-oil-export-plans

[26] https://www.tullowoil.com/media/press-releases/tullow-announces-substantial-farm-down-total-uganda/

[27] https://www.woodmac.com/reports/upstream-oil-and-gas-tilenga-blocks-1-and-2-8078160/

[28] EA1A, EA1, EA2 and EA3A

[29] It is possible that the different fields have fiscal terms that differ, but the study takes the approach of modeling one fiscal regime, based on EA1A. Differences are unlikely to be material in terms of a Net Present Value calculation from the entire project lifetime.

Turkana Oil Reserves

Declarations of reserves in the Turkana project follow a similar pattern[30]. The operating company Tullow has declared contingent reserves estimates respectively of 230 billion barrels (“1C”), 560 million barrels (“2C”), and 1,230 million barrels (“3C”).[31]

The study takes the largest category of contingent reserves as the basis for inclusion in the LITG deal.

Price Scenario

Price scenarios are the hardest element to make objective in a future valuation. All commodities and especially oil, exist in volatile markets. For example,since the year 2000, , oil was sold for about $20 per barrel, then built up to an all-time high of $147 per barrel in 2008, followed by a crash to $37 in 2009. Followed by four years where it traded within a relatively narrow range (between $90 and $110 per barrel), only to crash to under $40 in mid-2014. Then it slowly built up again until it was trading at about $65 at the start of 2020, but then collapsed to under $30 per barrel in response to Covid-19.

From the start of 2020 there has also been a rapidly evolving view of the long term future of oil and gas markets. Virtually all actors have moved towards acknowledging that in response to the need for energy transition a peak in oil demand is coming. The issue is that there is still a strong divergence about when. Industry analysts such as Rystad estimate the second half of the 2020s. Others, such as the International Monetary Fund, have speculated that it might be in the first half of the decade[32], and there have even been some suggestions that peak demand may already have happened[33].

Although it is a hard problem, thousands of such valuations are conducted in financial markets every year[34], and best practises have evolved to deal with a range of different commercial circumstances.

This model’s baseline scenario assumes a constant price in real terms close to where the market is today ($50 per barrel) and then factor in escalating carbon taxes. This has the advantage of being simple to understand and close to the publicly stated investment

[30] The project includes two separate blocks, 10BB and 13T.
[31] https://www.tullowoil.com/our-operations/africa/kenya/ These are against an estimate of Stock Tank Oil Initially in Place (STOIIP) of four billion barrels.
[32] https://www.imf.org/~/media/Files/Publications/WP/2017/wp17120.ashx
[33] http://www.erpecnewslive.com/article/3763/could-it-be-peak-oil-possibly-says-bps-bernard-looney
[34] When companies buy or sell assets to each other, for example, or when a company is acquired or merges with another.

techniques of the oil supermajors. In mid-2020, BP announced a long-term target price of $55 per barrel in real terms.[35]

An alternate price scenario is based on the IMF paper, which suggested energy transition could cause a structural decline in oil prices to $15 per barrel in real terms by 2040.

Carbon Taxes on Scope 1 and 2 Emissions

Project-level scenarios which model energy transition are challenging because the transition will happen at a global level. It is unlikely the impact will be uniform across all current and potential oil fields in the world, but instead be a complex mixture of market and policy instruments. Nevertheless, a scenario has to be built to generate estimates of future revenue streams.

The baseline scenario assumes carbon taxes are introduced in 2021, starting at $50 per tonne of carbon dioxide equivalent ("CO2E"), and rising to $150 per tonne over the next tenyears. This is in line with many company expectations on carbon taxes. For instance, Total has announced it works with estimates of a $50 per tonne tax on all potential investment projects,[36] and oil majors are known to have applied similar prices for internal review of new projects for some years. Most have now become advocates of some form of carbon tax[37] and higher level of $150 per tonne within a few years is also consonant with expectations.[38]

Scope 3 emissions from the oil and gas industry are five to eight times higher than Scopes 1 ,and 2, since fossil fuels are by their very nature carbon intensive. But the model adopts a principle of "user pays". The carbon tax is modelled as a cost of production. Still it is not assumed to be levied by the host government, since to introduce such a material new tax would clearly breach the stabilisation clauses in the contracts.

Discount Rate

The discount rate is a critical component of collapsing future revenues into a present day value needed to set up the compensation mechanism. Discount rates roughly correspond to perception of risk and opportunity cost. If a project holds high risk, or the party undertaking

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[35] https://www.bp.com/en/global/corporate/news-and-insights/press-releases/bp-revises-long-term-price-assumptions.html
[36] Emmanuel Pradie, head of Total E&P Carbon Footprint Reduction https://www.youtube.com/watch?v=OVRs69JjfCU
[37] https://oilandgasclimateinitiative.com/about-us/#members
[38] Forbes, for instance, discusses the impact of $100 per tonne tax in the USA in 2020 https://www.forbes.com/sites/edhirs/2020/07/21/what-will-an-american-carbon-tax-cost-you/?sh=1f5dae3c6c76

it has strong other earnings possibilities, a higher discount rate will be imposed on estimates of future earnings.

A discount rate is always conditional on *who* is using it: the same project could have radically different risks for different parties leading each, correctly, to apply a different discount rate. There are broad and unresolved debates among analysts about how governments should price risk, in general, compared to companies, and how climate risk should impact discount rates in both the short- and long-term.[39]

The study takes the approach of assuming a standard industry discount rate of eight percent on the future earnings of the governments of Uganda and Kenya in their projects. This is close to the standard rate used in analysing private sector revenues when a company's internal project-specific rate is unknown[40]. Although the risk for the government that the project may never get developed is treated separately, there are still many risks to government revenues even if the project goes ahead. As the Tullow example of 2020 shows, companies may extract fiscal concessions from governments in response to difficult market conditions. There are large uncertainties over long-term price, and substantial risks of cost and time overruns in development and production which are generic to megaprojects of this nature[41], which will affect the government revenue profile.

The study also assumes that the discount rate is activated on January 1, 2021 *regardless of when an LITG agreement would actually be signed*. This is to incentivise governments to consider such a deal sooner rather than later, and reflects a perception that the risk to the government of loss of oil revenues only increases as time progresses, since energy transition must lead *at some time* to decreased demand.

Chance of Development

Finally, in both Kenya and Uganda no final investment decision has been taken. This means that an extra factor has to be introduced of the "chance of development". The inclusion of such a factor balances the inclusion of resources which, as discussed above, are only in the "contingent resource" category and not formally defined reserves[42]. For comparison, many

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[39] Cf "Climate Shock", Gernot Wagner and Martin Weitzman, 2016.
[40] Inflation is set to zero in the model to allow analysis of "real dollar" values, which means a discount rate of eight percent (real) is slightly over 10% in nominal (inflation-adjusted) terms.
[41] Cf the repeated statement by Professor Bent Flyvberg of Oxford University that only one in ten megraprojects across all economic sectors are delivered on time and on budget, and the extensive survey run by Ernst And Young of 205 megaprojects in the petroleum upstream, which found overruns in 70% of cases https://www.offshore-energy.biz/ey-oil-gas-megaprojects-exceed-budgets-cost-overruns-at-500b/
[42] Value assessment in private sector transactions based on the underlying value of upstream petroleum assets is typically driven mostly by "proved reserves", the highest level category, and to a lesser extent by "probable reserves" ("2P").

investment analysts looking at transactions between companies might decline to assign any value at all to resource bases under such circumstances.

Both projects face the challenge of long pipelines which need to be highly engineered to deal with the attributes of the crude oil in the two fields.[43] The politics of both pipelines are also not easy. Uganda's pipeline requires a smooth and unbroken relationship with neighbouring Tanzania, but even in Kenya the route of the pipeline from Turkana to Mombasa on the coast is 1,200 km long and passes through six of seven counties at a time when transit taxes (or "cess") are becoming an increasingly significant part of the drive by sub-national government to be self-funding.[44] Maintenance of the Turkana pipeline might also involve continuous dialogue with multiple partners, and therefore represent commercial risk.

The "Chance of Development" ("CoD") is a concept borrowed from techniques of exploration economics in the oil industry. It embodies the recognition that having discovered oil or gas is only the first step to establishing a commercial project. Traditionally, it has been used in combination with the "Chance of Geological Success" to establish what is called the Expected Monetary Value of a field. Companies use this to manage risk in the exploration process: even if large deposits might be found, it might be that the costs of exploration itself might be higher than future revenues, once they have been depreciated by the discount rate and run against the risk of unsuccessful exploration[45].

Since the discoveries have been made at Lake Albert and in Turkana, the model decouples the chance of geological success and uses only the Chance of Development factor.

Nevertheless, it is hard to justify a particular value in the CoD. To provide a ballpark indicator, the model assumes a 50% chance to balance between the fact that on the one hand, both projects have advanced about as far as they can without an actual FID, and on the other hand, that the companies demonstrate continued uncertainty about proceeding.

LITG Valuation Results

Kenya

[43] Both Ugandan and Kenyan crude oil is classified as "waxy", and the pipelines carrying them to market will need to be heated to maintain flow rates.
[44] https://www.the-star.co.ke/business/kenya/2021-02-02-construction-cost-set-to-rise-as-kra-consolidates-cess-collection/
[45] Traditionally, the global chance of exploration success has been between 15% and 20%, meaning that to be on the safe side companies would typically be looking for a Net Present Value to a successful drilling campaign that was at least five or six times the actual costs of the exploration.

VALUATION FOR TURKANA FIELD BASED ON DCF (1,200 mln barrels)				
	Govt Revs NPV0	**Govt Revs NPV8**	**Chance of Development**	**LITG Valuation**
$55 / bbl Brent +carbon taxes	$15.95 bln	$2.37 bln	50%	$1.19 bln
Energy Transition Price Scenario	$8.02 bln	$1.34 bln	50%	$670 mln

Each column shows a successive stage in the valuation process. If the project were developed now, which eventually produced all 1,200 million barrels of contingent reserves declared by the Tullow field, the government would stand to earn nearly $16 billion through the project's life, until the late 2040s. The revenue profile is quite back ended, though, with peak cash flows not occurring until the 2030s. This means that when the discount rate of 8% is applied, it is equivalent to just under $2.4 billion in today's money. When that is multiplied by a 50% chance of development, to factor in all the risks in the project, the model produces a valuation of $1.19 billion using a constant price of $55.

The energy transition scenario uses projections of a bigger and earlier structural decline in price, leading to lower profits, and a correspondingly lower final valuation of $670 million.

Further delays in project execution would have significant impact on valuation. The baseline model assumes production will start in 2024. A year's extra delay would drop the valuation to $1.09 billion, a loss of $100 million, while a two-year delay would result in a valuation of almost exactly $1 billion.

Uganda

VALUATION FOR LAKE ALBERT FIELD BASED ON DCF (1,400 mln barrels)				
	Govt Revs NPV0	**Govt Revs NPV8**	**Chance of Development**	**LITG Valuation**
$55 / bbl Brent +carbon taxes	$17.85 bln	$8.05 bln	30%	$2.41 bln
Energy Transition Price Scenario	$12.57 bln	$6.35 bln	30%	$1.91 mln

In Uganda the more stringent fiscal regime changes the reckoning. Two heavy royalties, which are front-ended instruments and depend on sales, mean that the discounted government revenue figure is closer to the undiscounted figure than it is in Kenya. There are many scenarios where the government take is above 100% of the positive cash flows of the project. This clearly would not happen in the real world on a sustained basis, as operators would either ask for and get fiscal concessions or shut the project down. Therefore, the model simulates concessions in the fiscal regime, and the abandonment of the Additional Royalty mechanism in such a case. Even so, investor rates of return are negligeable under both price scenarios, of $55 constant[46] and the Energy Transition scenario. Therefore the model reduces the Chance of Development filter to 30%, on the grounds that Total and CNOOC will be unlikely to invest under a wide range of market conditions.

The end result, then, is to create a valuation range between the two different scenarios of $1.9 billion and $2.4 billion.

Impact of Fiscal Regime and Project Economics

The differences between Uganda and Kenya are instructive. A more stringent fiscal regime in Uganda leads to a higher valuation against a scope of resources that are not very different. The result in terms of the price per tonne of CO2E abatement is significantly different. While Kenya's valuation is effectively at 99 US cents per tonne, in Uganda it is significantly higher, at $1.72 per tonne in the base scenario.

Pay Out Mechanism

Once the valuation has been established it is fed into a calculation engine which sets up a signature bonus in the first year, and then a series of annual payments which increase as they go along. An interest rate of 7% is applied to the balance of the valuation remaining each year after a payment is made. This leads to the total amounts being paid out being greater in nominal terms at the end of the 10-year period than the valuation at the start.

The table below shows the payment structures.

(USD mn)	LITG	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10	Total
Kenya	1,186	296	113	121	130	139	148	156	167	178	191	1,651
Uganda	2,415	604	230	247	264	282	302	323	346	370	396	3,363

It is important to note that a system of annual payments should be maintained to keep the incentive aligned of not producing the oil or gas.

Structuring Options

The system described here is the most straightforward and illustrates the core concept. Two other options could be exercised to develop the structure of the transaction.

Use a price formula that adjusts to spot markets. This could make an LITG offer more attractive because it protects the governments against the downside risk that they take an

[46] Of particular significance here given that Total SA is the operator, and has announced it is targeting $55 per barrel constant as a long-term price target.

LITG deal but the price of oil recovers strongly, to a point where the valuation would have been higher if it had been at that price when the negotiations were made. Each year of actual prices would be added into the project model which both sides agreed at the start of the transaction. The LITG Valuation would be adjusted, and the calculations rerun. Since the transaction carries a running total of principal and adds interest each year, the principal would be raised by whatever increase in value was triggered, and the remaining payments adjusted upwards. It would be unlikely to make the LITG deal that much more expensive in practice. The only scenario in which the entire transaction would become considerably more expensive would be if the oil price went up to unexpectedly high levels, which were maintained for some time. However, in that case the real underlying financial value of the CO2E abatement would have risen in lockstep with the oil price, and the cost per tonne would still represent good value compared to other abatement options. While it might carry a mild financial risk for international policymakers, it would be marginal to the achievement of the policy goal.

Apply a factor to some or all of the payments: Since an LITG transaction would come in the context of an ongoing relationship between the governments of Kenya and Uganda with international financial institutions, the two parties could agree to apply factors to some or all of the payments if they were used for designated purposes. For instance, any sums from the LITG fund transferred to a Green Finance initiative might have a factor of 1.5 applied to increase funds available, or 1.3 for servicing of public debt, and so on. It would also be possible to structure the transaction so that a third party was putting up the factoring finance relative to the underlying LITG transaction itself.

These options would be pre-agreed modalities activated at the time of negotiation and signature. It is important to distinguish between these and any question of re-negotiation of mechanisms. It would not be feasible or practical to make the LITG deal open for renegotiation. Since both markets and the political climate are changing all the time, if the principle of renegotiation was admitted, it could easily lead to a permanent state of negotiation.

But it is worth remembering that this length of transaction is considerably less than the exploration and production contracts both countries already entered into. The length of commitment compared to the certainty of benefits and their level over the 10 years of the contract would actually compare favourably to many contracts both states have already entered into.