Turkana oil field, Kenya

Narrative Report

Johnny West, Stephen Gugu, December 2018

Context

Turkana is Kenya's first oilfield. Discovered in 2012 by the Anglo-Irish firm Tulllow, estimated oil in place has reached over three billion barrels, appraisal is underway and a final investment decision (FID) is due in 2019. Other consortium partners are Africa Oil (25%) and Total (25%), the latter having bought out the share of Maersk Oil in 2017.

InVhestia Africa & Open Oil have prepared a financial model, according to the FAST financial modelling standard[1], to address major questions of public interest, including:

- What levels of revenues are likely to flow to county government?
- What scale of project is likely to be developed under an FID taken in 2019?
- What will be the effect of state participation rights of up to 20% in the fields, to be exercised by the National Oil Corporation of Kenya?
- What are key factors in determining the project economics and profitability of the Turkana South Lokichar fields?
- What is "government take" of profits in the project under various price and cost assumptions?

The Turkana discovery has aroused great interest in Kenya, which has licensed many other blocks but has no commercial oil development yet. It came as Kenya introduced new rules to share revenues from natural resources, part of a broader move to strengthen the county governments in the East African country. The newly elected government of President Kenyatta has also stated that exploitation of the country's natural resources forms a key part of planned economic growth over the next few years.

Executive Summary

- Caps on revenue flows to county government are unlikely to be hit
- The Final Investment Decision (FID) projected for 2019 is likely to be for over 600 million barrels, not the "Foundation Stage".
- A 20% participation of National Oil Company NOCK will not yield extra profits until the 2030s
- Government take is in the low 60s% under most scenarios.
- Pipeline and grade of oil are key elements in – and the economics of the project are still not locked in.

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[1] www.fast-standard.org/about-fso/

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An "Early Oil" scheme to truck small quantities of oil before full field development, which began in mid-2018, is not modelled, though is discussed.

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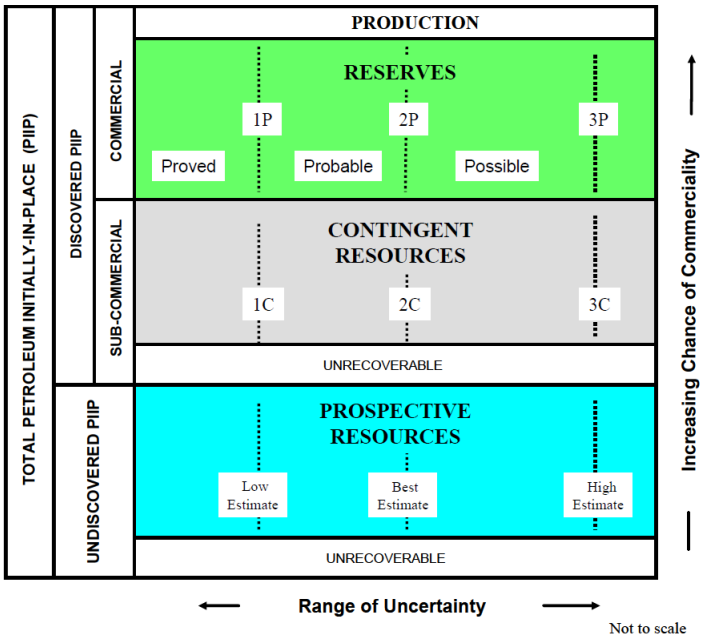
Key Features & Assumptions

We have used the below Petroleum Resources Classification Framework for our modelling purposes. Important to note is that Tullow has identified the amount of oil and that is looking to develop as varying between 600 million barrels under a "2C" and 1.2 billion barrels under a "3C" scenario. The "C" in this case stands for "Contingent".



Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies e.g. projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality.

Source: Petroleum Resources Management System, 2007 p. 4

Economic Parameters	
Life of field	2020-2045 (production)
Production profile	Scenarios built against three reserves levels, using standard ramp-up, plateau and decline profile: Tullow's announced Foundation Stage development – 250 million barrels; "2C" – 600 million barrels; "2.5C" – 900 million barrels. We have chosen a 2.5C for our analysis as we feel the 3C discussed by the Tullow in their reports represents a 'best' case scenario. We think a 2.5C is more feasible for development.
Forecast price	EIA Reference Price to 2050, Feb 2018
	Constant USD per barrel, user-set parameter

Costs	$1.6 billion exploration and appraisal costs to 2017 (Tullow)
	$1.8 billion Foundation Stage development, $1.1 billion pipeline (Tullow); $1 billion extra for expansion of each of two production profiles 2C and 2.5C
	$8.60 per barrel operating costs, $13.16 operating costs per barrel pipeline fees separate
	$0 currently modelled project finance costs

The model uses three development scenarios: the so-called Foundation Stage development planning announced by Tullow and expounded in its 2017 annual report[2], and then two larger developments called "2C" and "2.5C", representing production of 600 million and 900 million barrels respectively. Tullow has yet to announce reserves levels formally, but current (October 2018) contingent resources declared are 250 million (1C), 600 million (2C) and 1.2 billion barrels (3C).

Assumptions on capital expenditure for the Foundation Stage are taken from the Tullow 2017 report: $1.8 billion for development of production reaching a plateau of 80,000 barrels a day, and $1.1 billion for a pipeline to run to Kenya's Indian Ocean coast, near Mombasa. The model also assumes a 15% discount to Brent based on reports of the "waxiness" of Turkana crude as assayed from appraisal wells, and references in previous reports on the project.[3]

Fiscal Regime	
Profit Petroleum	Split based on daily rate of production, starting at 50 / 50
Cost Recovery	60% ceiling per annum
Income tax	Paid on behalf – no Contractor obligation
Windfall Profits Tax	26% of positive cash flows on realized price above $50 per barrel, adjusted to real terms, from signature date (2010).
State Participation	20% back-in right, declared at commerciality, carried through development

[2] https://www.tullowoil.com/investors/2017-annual-report pp28-29
[3] http://kcspog.org/early-oil-from-turkana-report/

The fiscal regime is challenging since the contracts for the two areas in the Turkana project, 10BB and 13T, have not been published. Consequently, we have modelled the fiscal regime on the contract for 10BA, which was licensed in the same round and for which headline terms are available and, where appropriate, public comments by officials.

The main revenue stream under all conditions for the Kenyan government is the profit split mechanism, since Corporate Income Tax is deemed as "paid on behalf" – not a separate cost to the Contractor. The cost recovery ceiling of 60% generates profit oil at any level of production, with a sliding scale increasing the government share as production goes up.

The National Oil Corporation of Kenya has a back-in right of 20%, exercised at the time the Contractor declares commerciality. This model assumes NOCK exercises that right and finances its participation by borrowing from cash flows in the project at a rate of LIBOR plus four percent (4%).

A windfall profits tax is levied when the price of Turkana blend rises above the equivalent of $50 per barrel at the date of signature in 2010, indexed against a USD consumer price inflation index.

Findings

Local Revenue Flows will be substantial - and caps are marginal

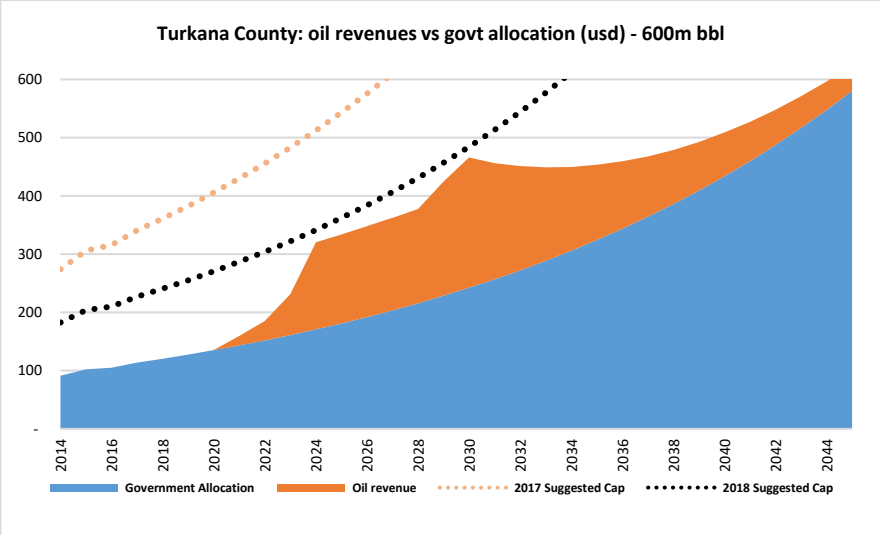
The model shows clear results in terms of revenue flows to Turkana County, and the community level which could go some way to assuaging concerns. Local revenue sharing of profits from natural resource projects has been a hot political topic in Kenya for the last few years. Following the 2016 Mining Law, which allocated 20% of mining royalties to the county level of government, and an additional 10% to the immediate community of a mine, parliament passed a similar law for petroleum revenues in late 2017, with the same proportions applied to the profit split instrument.

But that bill was not signed by the president, and in early 2018 a counter proposal was made of 15% to the county government, and 5% to the community. According to media reports there has been an agreement over a third proposal, where the County Government will get 20% of the revenue share the Government received with the community receiving 5%.[4] This is the baseline scenario used.

The arguments on both sides are complex. Advocates of a higher local share argue that national government has long kept too much state revenues

[4] https://www.standardmedia.co.ke/article/2001283426/why-turkana-residents-want-oil-money-in-their-pockets-not-projects

across the board, and there is no guarantee that revenues which go into central accounts will result in services across the country. On the other side, many officials argue that Turkana county government will not have the ability to absorb the large sums involved.



An absolute cap on oil revenues to Turkana County has also been controversial. The cap rule means that oil revenues in any given year could not be more than the allocation made by the central government to the county. But comparison of likely oil revenues against Turkana's continued ongoing allocation from the national government shows that the lower cap of 100% of the allocation from central government is unlikely to be reached, and that at both county and community levels revenue flows are going to be considerable. Turkana County's allocation from central government is currently just on the $100 million a year mark, and has been rising by about 6% a year since the new system was introduced in 2013. Assuming a continued 6% rise, oil revenues under the base scenario of 600 million barrels of production, and a March 2018 Brent oil price of $65 per barrel, the allocation to Turkana county will never hit the proposed 100% cap compared to government allocation. The nearest point would be in the late 2020s and early 2030s. In 2030, for example, Turkana County would earn $224 million from oil revenues, under the currently proposed scheme, but the "cap", its allocation from national government, is then likely to be $240 million.

Under this same scenario, the local community at Lokichar are due to receive some $700 million of revenues over the life of the project but will never hit the cap of 25% of the level of the government's allocation to Turkana County as a whole.

Under Tullow's currently publicised "Foundation Stage" development plan of 250 million barrels, neither level of cap, at county or community level, is reached at any historical level of oil price.

There are scenarios of very large scale production combined with high price under which the caps would be hit. For instance, the table below demonstrates revenue levels assuming 900 million barrels of production.

Figures in $USD (mn) nominal	*Snapshot years*					
Turkana County Government	2020	2025	2030	2035	2040	**Project**
County 20 % Profit Share	-	231	339	204	126	4,677
Cap Reached?	No	Yes	Yes	No	No	Yes
Amount of Excess	-	50	97	-	-	620
County Retained Oil Revenues	-	181	242	204	126	4,057
Turkana Community	2020	2025	2030	2035	2040	**Project**
Community 5% Profit Share	-	58	85	51	31	1,169
25% County Cap Reached?	No	Yes	Yes	No	No	Yes
Amount of Excess	-	12	24	-	-	155
Community Retained Oil Revenues	-	45	61	51	31	1,014

Over the life of the project, Turkana County would receive some $4.6 billion of oil revenues. Just over $600 million, or about 13%, would have hit the cap. Under the 2018 proposals Turkana County will receive $3.3 billion before the cap relative to funding from central government even comes into play.

Under the base scenario of 600 million barrels at a 2018 oil price, escalated by inflation, the community would receive just over $1 billion, with about $150 million held back under the cap rule. Similarly, under any scenarios of increasing price, or production, overall government revenue is driven up, which means that, at the 2018 proposed level of 5% of profit split, community level revenues reach over $700 million during the life of the project before the community level cap comes into play. In fact, since the community cap is based on the government's allocation to Turkana County, the cap on revenues to the community is more affected by lower allocations from national government, through the mechanism of the Commission for Revenue Allocation, than by caps introduced to the Turkana oil project.

The lower splits of profit share affect the community allocation at lower levels of production. But it is important to understand that such revenues would still be significant. For instance, in the Foundation Stage scenario of 250 million barrels at $65 oil price, the community share would be about $200 million under the 2018 proposals.

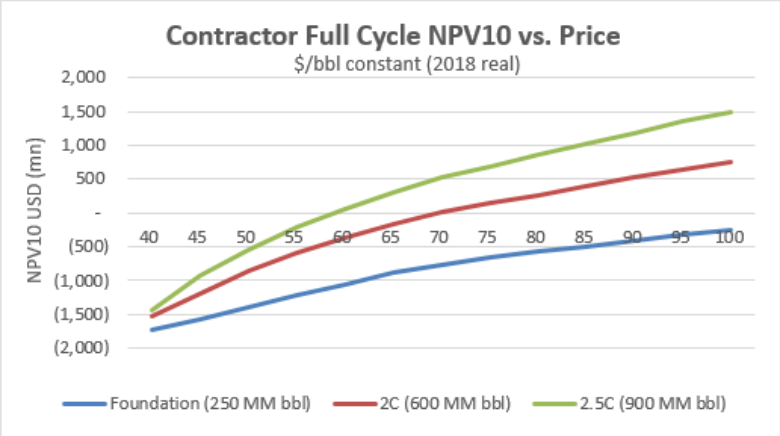
Tullow's Final Investment Decision will be about a 600 million barrel field – and the economics are still not locked in

Since the Turkana field was discovered in 2012, estimates of its scale and profitability have been volatile. On the one hand, Tullow, as operator, has continued to add to its estimate of the overall resource in place, until latest estimates (early 2018), put estimates of Stock Tank Oil Initially in Place (STOIIP) at 4.1 billion barrels, with contingent resource estimates ranging from 240 million barrels at high certainty ("1C") to 1.2billion barrels at low certainty

("3C")[5]. Such ranges are not unusual at the early stages of an oil project, although it is notable that Tullow has not upgraded its classification from "contingent resources" into actual reserves figures, despite extensive appraisal drilling[6]. On the other hand, there have been frequent delays to initial expected timelines.

Tullow's 2017 annual report describes a phased approach to development, with what it calls a Foundation Stage to be built first, which would suffice to produce 250 million barrels of oil at a production plateau of 80,000 to 100,000 barrels a day. The company estimates $1.8 billion of capital development for this stage, together with $1.1 billion to build a pipeline to carry the oil to the Indian Ocean coast. The company also says it is working towards a Final Investment Decision (FID) in 2019.

What the model suggests is that such an FID will be around a substantially higher production profile than the Foundation Stage itself. The economics of a smaller field development look relatively weak since the fixed costs of developing the field and the pipeline are high, compared to running costs. Tullow has put on record that exploration and appraisal costs had reached $1.6 billion by mid-2016. A report in the Petroleum Economist also suggests that a project of 750 million barrels would be viable at a price of $55 per barrel[7].



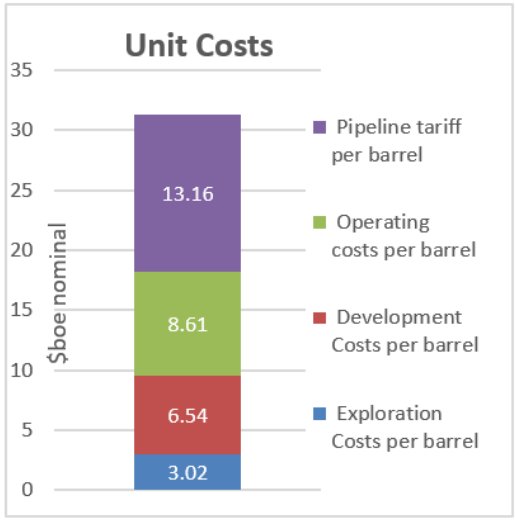
The graph on the right demonstrates that the Turkana project would actually achieve negative NPV under the Foundation Stage scenario across the full life of the project, assuming a discount rate of 10 percent. Even under the 2C scenario, breakeven point would be $70 per barrel, constant price, while under the 2.5C expanded production scenario it would be in the mid-$50s.

In reality, the FID will be driven by so-called "point forward" economics, where the sunk investment will be largely disregarded. But the "full cycle" economics offer a perspective on the fact that while in Kenya expectations, and

[5] https://www.tullowoil.com/operations/east-africa/kenya
[6] The most widely used classification system for hydrocarbons is that developed by the Society of Petroleum Engineers http://www.spe.org/industry/reserves.php.
[7] http://www.petroleum-economist.com/articles/upstream/exploration-production/2018/kenyas-oil-trucking-along

perception of potential profits, may be high, the commercial logic of the Turkana oil project is still not locked in.

From the investor perspective, there are still two large unknowns. One is a valuation for Turkana crude. This model posits a 15% discount to Brent, based on an earlier report's citation of a Kenyan government official[8], and recurring references to its waxy nature. We assume the extra cost of catering to this characteristic has been built into Tullow's own public estimates, which include heating the oil in the pipeline and in storage. What may be less predictable is a market valuation for Turkana crude, and also the requirement to heat the oil constantly adds engineering complexity, meaning the margin of uncertainty in costs might be higher.



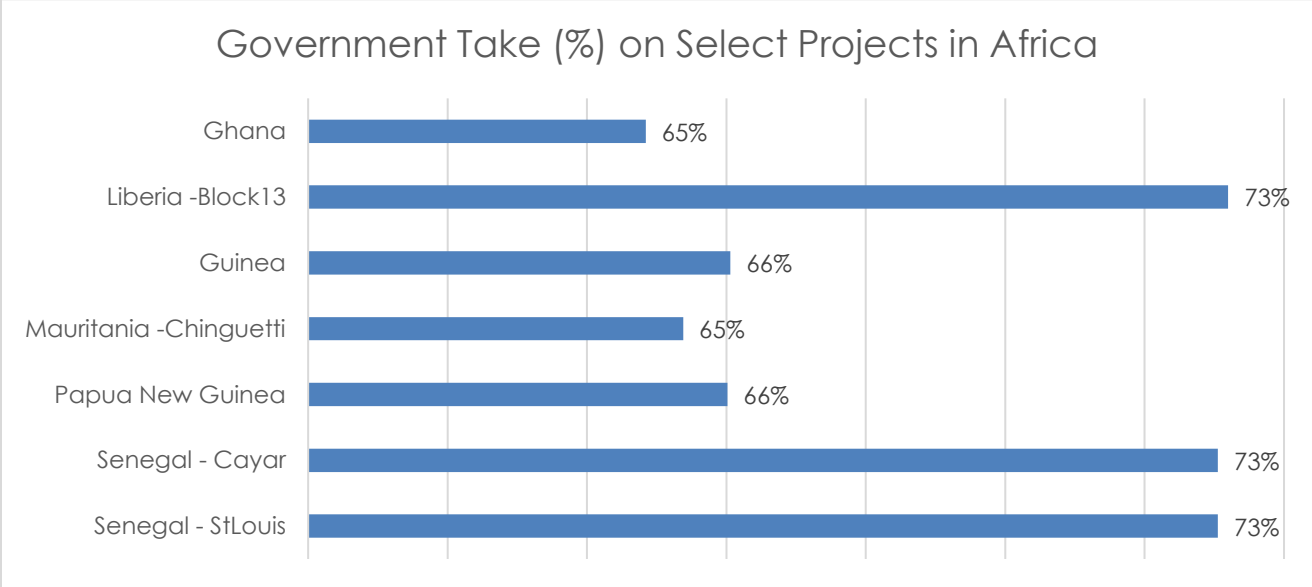
A second unknown stems from continued political uncertainty, both at national level and around the project itself. Tussles between county authorities and the national government have included public sparring between the governor of Turkana County and the president, and blockading of sites where appraisal wells are being drilled. For now, there seems to be a truce with the government recently flagging off the Early Oil Pilot Scheme which will see oil from the Turkana region transported by trucks to Mombasa before the pipeline is constructed. The pipeline needed to bring Turkana oil to market runs 850 km through several counties, this might complicate how easy and fast the oil gets to market. In the current environment of county government seeking autonomous funding, including from natural resource projects, the route to market may appear to Tullow and its partners to still be some long way away from secure. From this perspective, it is even possible that the national government's desire to truck oil early from the fields, which makes little commercial sense for either government or companies[9], is triggered by a desire to normalise oil production and shipping in terms of national politics. It may be that Turkana's Early Oil proposal, itself delayed several times by ongoing debate, is intended to drive towards an FID for the project as a whole rather than simply provide early production.

Government take is in the ballpark

The IRR for the contractor is at 9.25% under the baseline scenario of 600 million barrels and a constant price of $65 per barrel. The government ends up taking 62% of the total project revenues at NPV0 These government take

[8] http://kcspog.org/wp-content/uploads/2016/04/Revenues-from-Turkana-Oil-April-2016.pdf p16
[9] http://kcspog.org/early-oil-from-turkana-report/

ratios are well within the ballpark of what an early producer country could expect, especially considering the 'waxiness' of the Turkana Oil. As seen below from our internal analysis while the Government take is slightly lower than other early producer regimes we have analysed in Africa, this can be accounted for by the 'type of oil'. When we remove the 18% due to waxiness of the Turkana Oil the Government take increases from 62% to 66%. Even with a "2.5C" level of 900 million barrels, the contractor only gets to 13% rate of return, and it is important to note that under any of the scenarios in the model the contractor does not make super profits, which might be defined as a rate of return over 20%.



Source: Internal Analysis

NOCK's participation will not add state profits until the 2030s

One surprise result of the model is the relatively modest impact of a 20% back-in right by the National Oil Corporation of Kenya (NOCK), assumed to be in the contracts. So-called "state participations" have become a common feature of oil contracts in the last 30 years or so, as countries seek to capture more of the value of their national resources, and develop their own industries. The model assumes a 20% back-in stake, which the government can choose to exercise at the time when a company declares commerciality – in other words, goes from saying there is oil in the ground to committing to investing the money to extract it.

What the model shows is that such participation is likely to have only marginal impact on revenues flowing into the Kenyan treasury. The main issue here is: what are the terms of the "carry", under which NOCK comes into the project after Tullow and its partners have discovered oil and then built a development plan?

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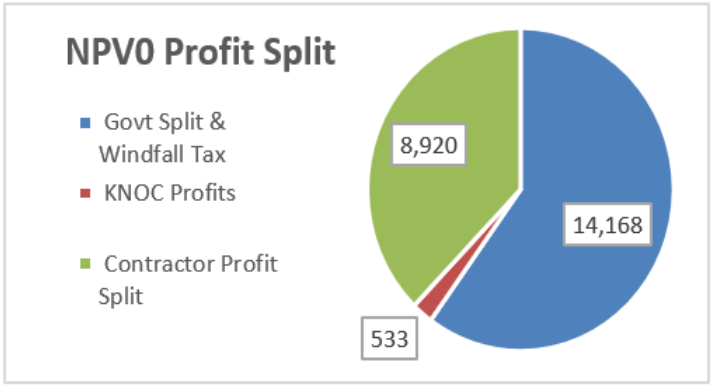
NOCK Economics				
Constant $	55	65	75	85
Breakeven		2036	2032	2030
Profits	-	533	1,049	1,473
% Govt $	-	4%	5%	6%

This model assumes that a standard industry practice is carried out, whereby the Kenyan state borrows from the project itself to finance its own 20% stake. In other words, if and when Tullow announces an FID, the government declares its own 20% stake, which becomes immediately operative. But NOCK must pay 20% of all costs from that point forward, which include the heavy investments of development and the pipeline. It effectively borrows these sums from the Contractor, which it agrees to repay out of its 20% share of the Contractor's share of the profit split (which is separate to the government's core share) – once oil is being pumped. But since production will not start until several years after development, and then take further time to ramp up to high levels, the financing is extended as a loan with an interest rate attached, and the interest rate is payable too. The model assumes an interest rate of about 5%, which would be within the range for such a loan.



Once all these terms are put together, the model then predicts net financial results for NOCK's participation. Once the payback of the carry is factored in, NOCK will not start earning extra income for the state of Kenya until the 2030s under most scenarios. For example, assuming a field size of 600 million barrels and constant price of $65, it would take NOCK until 2036 to pay back the carry. It would earn $530 million over the life of the project, representing less than 4% of the government's total earnings in the project. Under a high price of $85 in today's money, escalated by inflation over time, NOCK starts to earn extra net revenues in 2030.

Media reports in early 2018 have quoted officials as stating NOCK could seek a flotation on the Nairobi, London, and other stock exchanges[10]. This could change the economics of the company, as it would then be able to contribute its share of development costs, and reduce or eliminate a loan and the interest charges attached to it. But such a flotation would be unlikely to substantially change the assessment of NOCK's contribution to state revenues, unless private investors were prepared to pay a substantial premium. If flotation goes ahead within a suggested timeline of 2019, this would be a suitable scope for a further modelling exercise.

[10] www.africanbusinesscentral.com/2017/12/07/kenya-plans-1-billion-dual-listing-of-national-oil-corp-by-early-2019/

The total government take, undiscounted, is in the low 60s% under most price and cost scenarios for a 600 million barrel field or above. This is within the range of comparable deals, since the contract was signed before there was any known prospectivity.

Information Gap Analysis

There are several significant gaps in information that, if filled, would improve the model:

- Publication of the full text of the contracts governing the development of the Turkana South Lokichar project.
- Estimates of operating costs and pipeline fees.
- More refined forecasts of capital expenditure in the case of expansion of development into the 2C and 2.5C resource scenarios.
- Project finance: loans and interest rates to be used by the Contractor to finance the project, and their allowability against tax liabilities.