Offshore Petroleum Association of South Africa

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REF: PASA/NT0001/Fiscal Regime

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Dear Ms Reynolds

Representations of the Offshore Petroleum Association of South Africa in respect of the Fiscal Regime Tax Policy discussion document published by National Treasury

As preliminary comments, OPASA would like to emphasize the following:

- South Africa is considered as a frontier area when assessing area prospectivity and project economics:
    - (i) within the last seven years, only two exploration wells have been completed in South Africa, with most of the offshore exploration rights still to be explored is located in deep/ultra-deepwater which is both expensive and very high risk;
    - (ii) The low level of activity in the region and the withdrawal of major IOCs from the South African sector (Exxon-Mobil, Equinor, Eni & BHP) reflect the difficulty in identifying economically viable projects.
- The fiscal regime, including fiscal stability, is a key element of project economic modelling which constitutes a basis for investment decisions. The figures presented

in the National Treasury Discussion Paper demonstrate that the transition from the MPRDA to the UPRDA (MPRDA plus State Participation) increases the government revenue by 31% undiscounted (Figures 10 and 11). The introduction of the proposed flat rate of royalty at 5% further increases the government take by an additional 15.8% undiscounted, and it is no longer possible to generate a positive NPV even at USD80bbl (Figure 19).

Ensuring the fiscal terms are attractive and stable is a must to foster the oil and gas industry appetite. It is worth reminding that the oil and gas sector is also put under huge pressure by stakeholders, financial institutions, as a result of the commitment to the climate change objectives.

The submission made on behalf of the Offshore Petroleum Association of South Africa (OPASA) in response to the Media Statement inviting public comment on 15 December 2021 for representations on the proposed fiscal regime for Oil and Gas Companies proposed by the National Treasury is summarized below and developed further in the Attachment to this letter.

1. Fiscal terms proposed changes

The economics of South African Oil and Gas projects as demonstrated in the National Treasury's financial modelling are already constrained. The introduction of State Participation of (up to) 20% in the UPRD Bill introduces a more onerous fiscal regime. Any further changes to the fiscal regime, even such as the 5% flat rate royalty may likely be the "final straw" to commercial lending in support of Oil and Gas projects and will furthermore dissuade equity investors due to the negative NPVs and low IRRs.

OPASA proposes that the fiscal regime (captured in the Tenth Schedule and MPRRA) remains unchanged with the introduction of the UPRD Bill. If the legislator is intent on the introduction of a flat-rate royalty to replace the royalty formulae, it is proposed that the 5% royalty rate is limited to shallow water oil production and that a reduced 2% flat rate is applied in respect of deepwater and shallow-water gas (and condensate) production (CAPEX intensive development) but even this is likely to cause marginal fields not being developed.

In the view to shed some further light on market expectations in terms of project economics modelling, OPASA approached two leading financial institutions in South Africa (Standard Bank and RMB). These financial institutions have availed themselves to make independent presentations to National Treasury on what constitutes a bankable case for funding an oil and gas project.

2. Discussion around the fiscal stability clause

OPASA considers that fiscal stability should be embedded in the articles of the Petroleum Rights Contracts (TCP, Exploration and Production Rights) and cover, during the period where these contracts are in force, all fiscal terms (and not only taxes), that is to say, the taxes specific to oil and gas companies already considered in the Tenth Schedule, the royalty and the exemption from customs and excise duty in respect to equipment, machinery, materials, instruments, supplies and accessories utilised in the exploration of oil and gas imported under rebate item 460.23.

Fiscal stability provisions are a worldwide oil and gas practice and are of the utmost importance where the exploration area is not de-risked in terms of geological potential, as in South Africa.

Finally, OPASA recognises the importance of working with the National Treasury in positively developing a fiscal regime, which meets the economic criteria for investing companies and offers a strategic fiscal return for the State.

Thank you for your consideration and we welcome further discussions.

Yours faithfully

Adewale Fayemi
OPASA CHAIRMAN

Attachments:

1. Comments on the Discussion Document
2. Economics

OPASA Members

1. CNR International (South Africa) Limited
2. Impact Oil and Gas Limited
3. New African Global Energy SA Proprietary Limited
4. Sasol SA Proprietary Limited
5. Sungu Sungu Petroleum Proprietary Limited
6. Sunbird Energy Holding Limited
7. Shell Exploration and Production South Africa BV
8. The Petroleum, Oil and Gas Corporation of South Africa (SOC) Limited
9. Thombo Petroleum Limited
10. TotalEnergies EP South Africa B.V.

Attachment 1:

Comments on the discussion document:
"What is the most appropriate fiscal regime for the oil and gas industry?"

Thank you for the opportunity afforded to the Offshore Petroleum Association of South Africa (OPASA) to provide comment on the National Treasury's discussion document concerning an appropriate fiscal regime for the South African upstream oil and gas industry and the need for fiscal stability agreements. Before presenting specific comments to the discussion document it is appropriate to contextualise the hydrocarbon potential in South Africa.

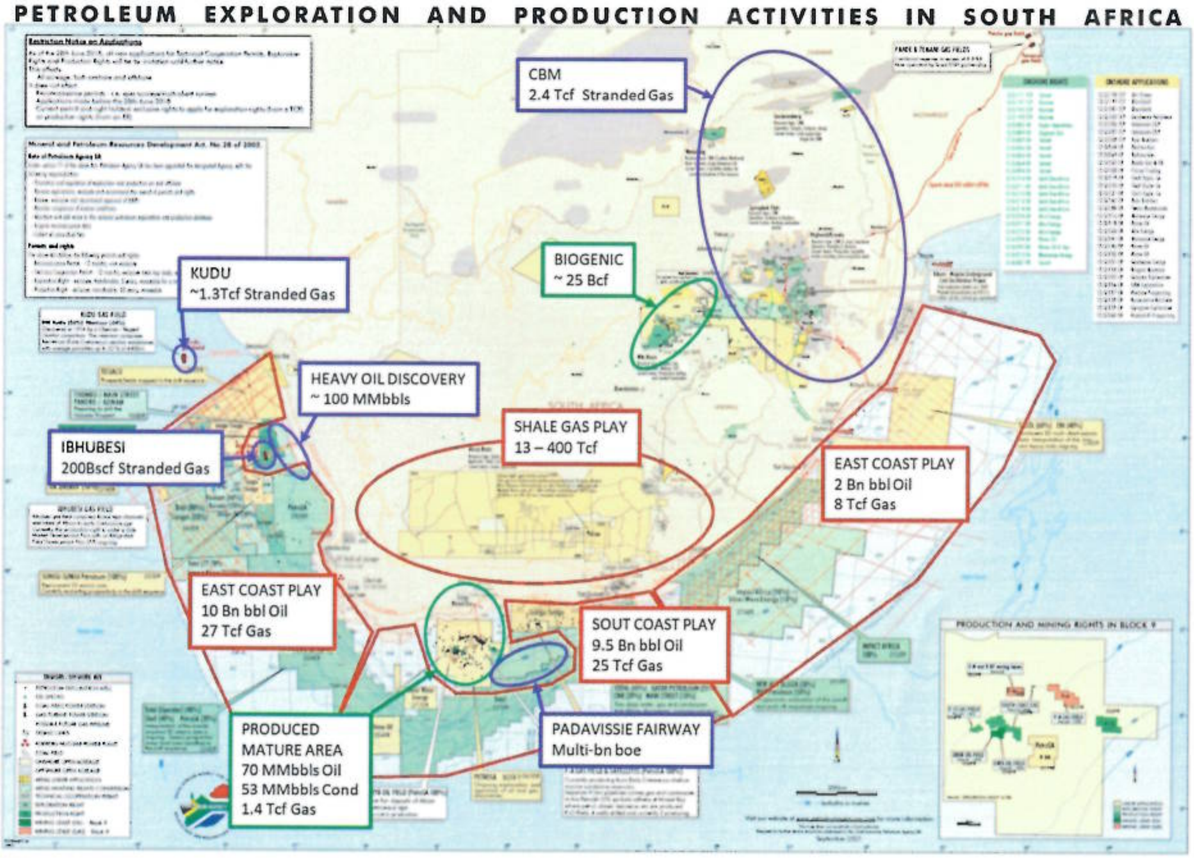
South Africa's Current Hydrocarbon Resources and Reserves

South Africa is not yet recognised as a 'proven' oil and gas jurisdiction. Whilst the recent deep-water discoveries in the Southern Outeniqua Basin by the TotalEnergies operated joint venture is exciting and could create renewed interest in the South African deep-water offshore opportunities, the commercial extraction and monetisation of the discovered accumulations have not yet been established.

To date, only two regions have been commercially developed. The first is PetroSA operated Block 9 fields and the second, is the biogenic gas accumulations onshore in the Virginia area operated by Renergen. The southern PetroSA operated offshore fields, which came online in 1994, are no longer able to provide sufficient gas feedstock to meet the minimum commercial threshold required by the GTL refinery onshore unless significant investments are made to re-develop some of the fields or to develop additional discoveries and upgrade infrastructure to achieve this.

The small Oribi/Oryx Oil fields as well as the Sable oil field discovered, developed, and operated by SOEKOR/PetroSA and IOC's are depleted and long ceased operations. These fields have shown that, under the current and prior fiscal arrangements smaller, marginal accumulations (compared to other jurisdictions) are viable exploration targets under the current fiscal regime (MPRDA & Tenth Schedule), but may not have been developed under different fiscal terms.

Some discoveries will remain classified as contingent resources until infrastructure or markets (for gas) are established. The commerciality of these stranded discoveries is likely to be further challenged if more onerous 'government take' provisions are implemented.



GREEN AREAS ON MAP:

South Africa currently only has two hydrocarbon producing areas, namely the PetroSA Block 9 Production Rights on the South Coast which feeds gas and condensate to the GTL Refinery in Mosselbay, and the small scale onshore Biogenic Gas being produced by Renergen.

PURPLE AREAS ON MAP:

A few gas, condensate and oil discoveries are indicated, the latest and biggest of which is the TotalEnergies discoveries in the Paddavissie fairway just south of PetroSA's south coast infrastructure. The other discoveries (the Ibhubesi gas field and onshore CBM gas) remain stranded (not commercially exploitable). Even though TotalEnergies is working on development studies with PetroSA it is not certain if these large gas and condensate discoveries can be monetized due to the following reasons:

1) The extremely large costs related to the development of the discoveries in these harsh deepwater conditions, far away from the international deepwater development supply chain
2) The production of the gas and condensate is dependent on the commerciality, viability and affordability of a large enough local or international market for the gas, which is currently uncertain. The development of a local market also requires significant investment in infrastructure.

RED AREAS ON MAP:

These areas are wildcat exploration areas where the resource estimates are highly uncertain as no drilling has been conducted to prove these. International oil companies have spent hundreds of millions USD's in the last few years on offshore 3D seismic acquisition and processing, but the resources can only be proven through drilling.

The full potential of oil and gas in South Africa remains uncertain;

- most fields are in the early exploration phase; the estimated volumes are technically recoverable resources, not proven reserves.
- Gas and oil sources have relatively high extraction costs: they're either deepwater sources, such as TotalEnergies' Block 11B/12B, or unconventional gas sources, such as Karoo's shale gas.

Fiscal Regime proposed in the discussion document

As a preliminary comment, the current fiscal regime is appropriate to the nascent maturity of the South African upstream oil and gas sector. The introduction of (up to) 20% State Participation envisaged under the UPRD Bill already significantly reduces the commercial returns for upstream Oil and Gas companies by an undiscounted 13% as reflected in NT modelling and it is recommended that any overhaul in which the 'government take' is further increased, be implemented only once South Africa is recognised as an attractive hydrocarbon jurisdiction from a risk/reward perspective.

The fiscal regime preferred in the NT discussion document (namely package 1) is a combination of the Upstream Petroleum Resources Development Bill (UPRD Bill) as introduced into Parliament on 1 July 2021 and the introduction of a flat-rate royalty of 5%.

IRR hurdles are non-negotiable for some investors. The scenarios summarized in figure 20 of the discussion document reflect the present IRR yield of less than 12% at USD80/bbl below 8% at USD60/bbl and below 3% at USD40/bbl. The banking community in Europe have been of late indicating WACC expectations of 15% for Europe and 20% for Africa based on perceived risk as well as ESG demands, so the IRR returns that the document is showing are falling far below international indicated benchmarks, especially at UDD40/bbl.

The economic modelling prepared by the National Treasury of best-guess estimates for oil and gas reserves of 200Mboe field with Capex cost of USD20/boe and Opex cost of USD10/boe (with an assumed WACC of 10%) reflects a negative NPV for the existing fiscal regime (namely MPRDA), the new UPRDA and all the packages 1 – 4 at an oil price of USD60/bbl. Using USD60/bbl for the base economic modelling under current circumstances is probably optimistic given the strict parameters employed by lending institutions to vet cash flows for oil & gas projects, but even at that, the resulting returns emanating from the NT analysis do not point to robust viability of the hypothetical case.

The transition from the MPRDA to the UPRD Bill increases the government revenue by 31% undiscounted (representing a 55% decline in investor NPV) and the introduction of the proposed flat rate of royalty at 5% further increases the government take by an additional 6% undiscounted (representing a 13% decline in investor NPV). In the sensitivity evaluation, the MPRDA generates a positive NPV at USD80/bbl, but the UPRDA terms only manage to break even at that price. None of the packages 1- 4 which propose a change toward a stricter fiscal regime achieves a positive NPV at USD80/bbl.

Countries with less favourable geological conditions normally offer better fiscal terms, while those perceived to have more potential offer tougher terms. Investment in hydrocarbon exploration will only occur if a combination of the fiscal terms, geological reality and the oil (or gas) price make it worthwhile to invest. Despite being rich in many hard minerals, South Africa has not shared the same success in oil and gas reserves. Exploration over the past thirty years has revealed only small deposits offshore in the South and the West. The shallower water targets have already been explored leaving only the high risk, high-cost deep water still to be explored. South Africa is still in a nascent stage of development and its true hydrocarbon potential is still unknown, as such there is justification for leniency in the choice of fiscal regime.

OPASA Economic Modelling

OPASA has performed its financial modelling of offshore Oil and Gas fields based upon generic data of South African reserves for deep-water and for shallow-water, considering an Oil prospect development and also a separate model for a gas prospect development and used IHS to test the reasonability of Capex and Opex assumptions used. A WACC of 10% to 12% is deemed appropriate for investments by a Large Multinational Oil and Gas Company BUT for Smaller International Oil Companies and HDSA Oil and Gas right-holders the company associated risk *beta* is higher and accordingly a WACC sensitivity analysis is provided to test the veracity of the modelling outcomes. The OPASA economic modelling accords with the outcomes of the National Treasury's economic modelling in terms of the directionality of the options considered.

Mineral and Petroleum Resources Royalty

The Mineral and Petroleum Resources Royalty Act (MPRRA) came into effect on 1 March 2010. It was created by statute, being the MPRDA, which requires all extractors of South Africa's non-renewable mineral resources to pay a levy (royalty) to the state for its exploitation. The Royalty, in the context of oil and gas, is imposed on an oil and gas company, as defined. The Royalty calculation is based on a variable royalty percentage rate, which would depend, inter alia, on whether the mineral resource is transferred as Refined or Unrefined. Oil and gas companies are included under the "refined" royalty percentage rate formula.

The Royalty was carefully designed to achieve a strong balance of ensuring that it is responsive to different economic circumstances, capturing rents when profits are high, and ensuring a measure of cover (for the *fiscus*) in the form of a minimum revenue stream, during weak economic cycles and low commodity prices. Tying the royalty percentage rate to a formula based upon the profitability of the mine, furthermore allowed small scale miners the benefit of a lower royalty while the minimum of 0.5% ensured that the State is still compensated for the extraction of its non-renewable resources.

The introduction of a 5% flat rate Royalty as proposed in the discussion document will damage the investment case for investors by a further undiscounted 6% per as the National Treasury modelling (the value depletion is \$53m of NPV or negative 13%, which is quite material). This, in addition to the effects of the introduction of the UPRDB (namely an undiscounted 31% increase in government revenue or a reduction in NPV to the investor of \$147m or -55% at \$60 oil), could make the SA sector unattractive to investors. Only marginal sized accumulations remain on the shelf area and therefore the flat 5% rate will only degrade the value and therefore commerciality of any small fields and result in such fields not being developed.

The IMF asserted that larger reserves (500Mboe and 1000Mboe), when modelled, "resulted in the royalty rate reaching a ceiling of 5% as soon as production started". As such the IMF argued that the flat rate is almost the same as the variable rate, with the added benefit of simplicity.

The economic modelling by National Treasury in the discussion document shows a USD218m cash-flow decline to the investor as a result of royalty rate change from variable to flat. This is significant as the impact of the change affects the field both during ramp up as profitability builds up as well as during decline towards the end of the field life when profitability begins to suffer and as such the impact of the change to a flat 5% is not insignificant as suggested by the IMF. The introduction of the 5% flat rate accordingly results in material attrition for the investor.

Recognising the higher cost associated with offshore deepwater exploration, development and production and the higher investment required in infrastructure (to overcome difficulties of storage and transport) for gas production, globally lower royalty rates are allowed for deepwater compared with shallow water and for Gas (and condensate) production compared with Oil production.

If National Treasury removes the formulae, which we advise against, OPASA proposes that the 5% is applied to onshore/shallow water oil production and 2% for deepwater and shallow water gas (and condensate) production to recognise the cost differentials. In addition, the Minister should have the authority to reduce the rate in the case of marginal fields.

Fiscal Stability Agreements

The government has asked to receive public comments on the following policy matters:

A. Given that Government has not signed any FSAs in the past 7 years, and in light of previous Budget announcements that Government intends to review all incentives to broaden the tax base and lower the corporate tax rate, should Government continue with the provisions of paragraph 8 of the Tenth Schedule (which enables the Minister of Finance to enter into an FSA)?

Yes, National Treasury should retain the FSA provisions. Both the Tenth Schedule to the Income Tax Act (ITA) and the Mineral and Petroleum Resource Royalty Act (MPRRA) makes provision for the Minister of Finance (the Minister) to enter into limited scope fiscal stability agreements (FSA) with Oil and Gas Rightsholders.

OPASA refers to its discussion document of 13 November 2019 which deals with the need for fiscal stability agreements – attached hereto as Attachment 2.

B. Should Government continue to provide for FSAs, please share your thinking on the following:

a. In what form and manner should FSAs be granted?

Fiscal stability should be embedded in the articles of the Petroleum Rights Contracts (TCP, Exploration and Production Rights) to provide certainty concerning the fiscal terms that will apply for the duration of the Petroleum Right.

b. What type of taxes should be covered by the FSA and why?

Fiscal stability should cover those taxes that are specific to oil and gas companies already considered in the Tenth Schedule (namely Corporate Tax and withholding taxes), the royalty, and the exemption from customs and excise duty in respect of equipment, machinery, materials, instruments, supplies and accessories utilised in the exploration of oil and gas imported under rebate item 460.23.

c. Should FSAs cover taxes payable by the oil and gas company only, or should they be extended to cover taxes paid by shareholders and providers of finance to the oil and gas company, and why is that so?

Fiscal stability should extend to the shareholders (see comment on withholding tax on dividends below) and providers of finance. The capital costs incurred in the exploration and development of an oil and gas field are denominated in USD and exceed local commercial banks foreign borrowing limits together with possible concentration risk where all local banks fund a single sizable project for example TotalEnergies' development of block 11A/12B that may exceed USD2.5billion. Accordingly, it is necessary even where local banks act as the Lead Arranger for financing to syndicate lending requirements that will include foreign banks and investors. It is also noted that during exploration and development the government is carried through State Participation under the UPRDA with no compensation for the time value of money or embedded interest charge. As such where external lending is secured to support exploration and development and withholding tax is levied on such foreign borrowings, the investor faces an additional charge to the existing State Participation carry arrangement.

d. A corporate tax package – consisting of a rate reduction from 28 to 27 per cent coupled with two base-broadening measures (restricting assessed losses and strengthening the interest limitation rules) – was included in the 2021 Budget. Should FSAs apply to all elements of the above-mentioned package or any other potential corporate tax proposals in the future?

The restriction of assessed loss offset to 80% of taxable income that accompanies the rate reduction from 28% to 27% is of concern to the Oil and Gas Companies. They create significant cumulative tax assessed losses that shelter production revenue in the initial years (1-3yrs) of production. To cap the assessed loss offset will reduce the efficacy of the tax capital allowances in the economic modelling of projects and erode NPV due to the earlier cash outflows toward Corporate Taxation. The MPRR already ensures that government receives a contribution toward royalties from the production of oil and gas irrespective of the profitability of the mine.

e. Considering South Africa's commitments in respect of climate change as an example, should sign FSAs, as contemplated in paragraph 8, have a limited lifespan (e.g. 10 years) to allow all relevant stakeholders to either re-assess or re-negotiate their positions due to changing variables during the long-term nature of the oil and gas industry?

No, to limit the FSA to a lifespan of 10 years, in theory, is to limit the FSA to cover only the duration of the technical co-operation permit (12months) and exploration right (3 years and 3 x exploration right renewal periods of 2 years each) when the decision whether or not to invest is based upon the NPV over the Life of Field. Investors will have no certainty as to how their production income will be taxed.

f. Do FSAs, as currently contemplated in paragraph 8, fairly represent worldwide practice?

The fiscal stability offered in South Africa is limited in scope relative to worldwide practice for those countries that do offer fiscal stability agreements as part of the rights allocation (under a concession legal design) or as part of the production sharing contract (under a contract legal design). OPASA would desire full fiscal stability.

Fiscal Stability is provided internationally and the types of fiscal stability clauses applied in practice worldwide are extensive. We refer you to an MCom (Taxation) dissertation by Ms Babalwa Melapi at the University of Cape Town, graduating in 2021 in this regard that examines fiscal stability on a comprehensive basis as a policy consideration for the government and also to an Oxford Institute for Energy Studies paper, from January 2016, *"Fiscal Stabilization in Oil and Gas Contracts: evidence and implications."*

C. If Government does not continue with the provision for FSAs, will that hinder companies from exploring and developing oil and gas reserves?

If Government does not continue FSA, it may pose a hindrance to attracting new entrants to Oil and Gas mining in South Africa. It will also create inequity in the tax terms applied to existing incumbents that have secured FSA agreements with the Minister, relative to new entrants. It would appear from the National Treasury discussion document that FSA is considered a benefit to first movers. If it is the intention of the legislator not to extend the FSA benefits to new entrants then as opposed to the removal of paragraph 8, consideration should be given to the transferability of FSA benefits as those blocks with FSAs are likely to become more attractive (by way of a farm-in) for new entrants than applying for, exploring and developing new oil and gas blocks.

D. Are there any other issues that you would like to highlight in respect of FSAs?

On 14 July 2015, the National Treasury released FSA templates for the Tenth Schedule of the ITA and MPRRA (Royalty Act) together with guidelines outlining the process to be followed by FSA applicants.

On 21 July 2015, the Offshore Petroleum Association of South Africa (OPASA) met with National Treasury to reach alignment on the proposed wording of the FSA templates. Since the 21 July 2015 meeting, there were no further meetings with National Treasury in terms of finalisation of the FSA template. The FSA templates and guidelines have not been finalised for the final issue by National Treasury.

The matter of FSAs was raised opportunistically on 26 June 2019 in a meeting with the DDG, Mr Ismail Mr Momoniat, in respect to the proposed new Upstream Petroleum Resources Development Bill, and on 13 November 2019, OPASA communicated a discussion paper that emphasises the need for FSAs.

As acknowledged in the National Treasury discussion document for the past 7 years, the Government has not approved any fiscal stability agreements. Members of OPASA have since 2008 made applications for FSAs (in the various formats of the FSA template provided by the National Treasury over time), OPASA is aware of two FSAs having were been entered into with the Minister, however, no response was received for the majority of applications for such FSAs by OPASA members.

OPASA has procured Senior Counsel Opinion from Adv Cedric Puckrin in respect to the discretionary nature of the FSAs and we would like to request a meeting with National Treasury to discuss the legal advice received. As such, any contemplation by the National Treasury to remove the provisions of paragraph 8 of the Tenth Schedule (which enables the Minister of Finance to enter into an FSA) will need to address outstanding FSA applications that have not been processed for Ministerial approval by National Treasury. National Treasury will need to also grant assurances that those FSAs entered into will continue to be honoured.

Attachment 2:

Economics

The intention behind these project economics is to demonstrate the potential impact of the proposed changes by the National Treasury on the commerciality of blocks offshore in South Africa. The area of focus is therefore the impact of the proposed change in the royalty formula from the current formula based to a flat rate of 5%.

Several conceptual field developments have been used in the process to further demonstrate how unique the impact of the proposed changes would be to each as there is no homogeneity in the type of fields that we have offshore. The point of departure in terms of field size has been largely based on what we have observed in the discussion document by National Treasury. There is a 100 million barrel (MMbls) field size,200 million barrel (MMnls) size and a bigger from our experience being about 400 million barrels. The 100MMbbls is the lower end reserves modelled in shallow waters where more information is available due to many exploration activities being conducted in these areas. The 200 MMbbls and 400mmbbls are located in deep and ultra-deep waters that are still unchartered territory.

The length of the life cycles of the different phases in the project life cycle that is exploration, appraisal, development and production is almost the same as what is in the National Treasury discussion document.

Oil Prices

Prices used in the economics are $40/bbl, $60/bbl and $80/bbl. These prices correspond with ones in the National Treasury document.

Discount Rate

The discount rate used in the project economies is 10%. The economic limit has been applied in all the economic results. Provision for decommissioning is provided for years in economics and is assumed to be a tax-deductible expenditure. It is important to note provision in the case is actual monies put into an escrow account for the ultimate decommissioning. This provision starts from the very first year of production up until the very last year of production.

Capex and Opex assumptions

Capital and operational expenditure for each field are captured on a $/bbl basis will form part of project summaries for each field.

Government Take

We have defined government take to be the NPV of State's 20%, royalties, and Income tax divided by NPV Project Cash Flows before taxes and State's 20%.

100 MMbls at $40/bbl

Economics summaries of a 100mmbbls shallow water field size with $40/bbl are shown below.

Economics Summary		
Reserves		
Reserves (Gas)	0	Bscf
Reserves (Oil)	66	MMbbl
Total Reserves	66	MMboe
Costs		
Capital Expenditure	23	$/boe
Operational Expenditure	30	$/boe
Life Cycle Cost	53	$/boe
Indicators		
Project NPV	-526	$MM
Project IRR		
IOC NPV	-600	$MM
IOC IRR		
BEE NPV	-70	$MM
State NPV	-35	$MM
Govt Take	-31	$MM
Aggregate Govt Take	6%	
20% State Participation	*7%*	
Royalties	*1%*	
Income Tax	*0%*	
State Carry Fully Repaid?	No	
IOC Repayment (by State)	4	Years
IOC Maximum Exposure	-1 432	$MM
IOC Payback	0	Years
Project DPIR	-0,66	

Table1

It is clear from table 1 that a 100mmbls field project economics at the project level does not make commercial sense. It follows then that all the other economic indicators would yield unsatisfactory results. Faced with these results the IOC or any other investor would not continue with this type of investment as its NPV would be negative and IRR below the 10% discount rate. It is important to note that royalties are applied using the current formula.

If an oil price based on this conceptual development costs is goal-seek to achieve a break-even project NPV (NPV=0), that price would be $69/bbl. The Zero NPV project becomes a negative $42 million if the 5% flat royalty rate is applied.

100 MMbls at $80/boe

Economics Summary		
Reserves		
Reserves (Gas)	**0**	**Bscf**
Reserves (Oil)	**95**	**MMbbl**
Total Reserves	**95**	**MMboe**
Costs		
Capital Expenditure	**16**	**$/boe**
Operational Expenditure	**38**	**$/boe**
Life Cycle Cost	**54**	**$/boe**
Indicators		
Project NPV	**254**	**$MM**
Project IRR	**19%**	
IOC NPV	**225**	**$MM**
IOC IRR	**17%**	
BEE NPV	**34**	**$MM**
State NPV	**78**	**$MM**
Aggregate Govt Take	**37%**	
20% State Participation	***21%***	
Royalties	***10%***	
Income Tax	***6%***	
State Carry Fully Repaid?	**Yes**	
IOC Repayment (by State)	**4**	**Years**
IOC Maximum Exposure	**-1 432**	**$MM**
IOC Payback	**14**	**Years**
Project DPIR	**0,32**	

Table 2

Table 2 is a project summary of the same 100 Mmbls field size but with an $80/bbl assumed. At an oil price of $80/bbl, the Project NPV is 254 million with a 19% IRR. The IOC's NPV and IRR are $225 million and 17% respectively. The government take is roughly 37%. These results are based on the current royalty regime that is formula based. If the flat 5% royalty rate is applied Project NPV reduces from $254 million to $218 million (14% decrease), whilst IOC NPV reduces from $225 million to $187 million (17% decrease). IOC IRR also reduces from 17% to 16% whilst government take increased from 37% to 43%. What these results show is that for low volume marginal shallow water protects, the impact of changing the royalty regime to a fixed 5% is more pronounced on project economics. The effect is worse for IOC due to the impact of the 20% state participation that IOC would have to carry.

200 MMbls at $40/bbl

Economics Summary		
Reserves		
Reserves (Gas)	0	Bscf
Reserves (Oil)	185	MMbbl
Total Reserves	185	MMboe
Costs		
Capital Expenditure	19	$/boe
Operational Expenditure	15	$/boe
Life Cycle Cost	34	$/boe
Indicators		
Project NPV	-384	$MM
Project IRR	2%	
IOC NPV	-552	$MM
IOC IRR	0%	
BEE NPV	-51	$MM
State NPV	43	$MM
Aggregate Govt Take	-29%	
20% State Participation	*-13%*	
Royalties	*16%*	
Income Tax	*0%*	
State Carry Fully Repaid?	No	
IOC Repayment (by State)	8	Years
IOC Maximum Exposure	-3 182	$MM
IOC Payback	23	Years
Project DPIR	-0,31	

Table 3

Table 3 shows the results of a mid-sized 200mmbls field at the $40/bbl. At this oil price, the project has a negative NPV of $384 million. At this level, there would be no project. A crude oil price that yields a break-even zero Project NPV project is $53 a barrel.

Unfortunately at such a price with zero Project NPV, the IOC has a negative $121 million NPV and thus a final investment decision by the IOC or any other investor would be against such a project.

It must be noted however that even if the project battles to be economic, moving from a formula based royalty to a flat-based rate of 5% leads to a more negative project NPV and even worse for the NPV for the IOC.

200 MMbls at $60/bbl

Economics Summary		
Reserves		
Reserves (Gas)	0	Bscf
Reserves (Oil)	194	MMbbl
Total Reserves	194	MMboe
Costs		
Capital Expenditure	18	$/boe
Operational Expenditure	16	$/boe
Life Cycle Cost	34	$/boe
Indicators		
Project NPV	179	$MM
Project IRR	13%	
IOC NPV	94	$MM
IOC IRR	11%	
BEE NPV	24	$MM
State NPV	117	$MM
Aggregate Govt Take	57%	
20% State Participation	*36%*	
Royalties	*12%*	
Income Tax	*9%*	
State Carry Fully Repaid?	No	
IOC Repayment (by State)	9	Years
IOC Maximum Exposure	-3 182	$MM
IOC Payback	18	Years
Project DPIR	0,14	

Table 4

The results in table 4 are based on $60 a barrel and formula based royalty. As is to be expected, the project has an NPV of $179 million and a $94 million NPV to IOC. IOC IRR is above 10%. These results assumed that we are still using the formula based royalty calculation.

If we then migrate to a royalty flat rate of 5% the results would be different as shown below.

Economics Summary		
Reserves		
Reserves (Gas)	**0**	**Bscf**
Reserves (Oil)	**194**	**MMbbl**
Total Reserves	**194**	**MMboe**
Costs		
Capital Expenditure	**18**	**$/boe**
Operational Expenditure	**16**	**$/boe**
Life Cycle Cost	**34**	**$/boe**
Indicators		
Project NPV	**148**	**$MM**
Project IRR	**12%**	
IOC NPV	**52**	**$MM**
IOC IRR	**11%**	
BEE NPV	**20**	**$MM**
State NPV	**110**	**$MM**
Aggregate Govt Take	**64%**	
20% State Participation	***34%***	
Royalties	***24%***	
Income Tax	***7%***	
State Carry Fully Repaid?	**No**	
IOC Repayment (by State)	**9**	**Years**
IOC Maximum Exposure	**-3 182**	**$MM**
IOC Payback	**18**	**Years**
Project DPIR	**0,12**	

Table 5

Project NPV drops by 17% to $148 million while project IRR drops from 13% to 12%. IOC NPV has dropped by 45% to $52 million and government take has increased from 57% to 64%. It is clear from these results therefore that for a marginal oilfield changing the royalty from formula-based to a flat rate based of 5% has a huge impact on the results of the economics for IOC.

200 MMbls at $80/bbl

Economics Summary		
Reserves		
Reserves (Gas)	0	Bscf
Reserves (Oil)	206	MMbbl
Total Reserves	206	MMboe
Costs		
Capital Expenditure	17	$/boe
Operational Expenditure	19	$/boe
Life Cycle Cost	36	$/boe
Indicators		
Project NPV	655	$MM
Project IRR	19%	
IOC NPV	562	$MM
IOC IRR	17%	
BEE NPV	87	$MM
State NPV	224	$MM
Aggregate Govt Take	44%	
20% State Participation	*22%*	
Royalties	*7%*	
Income Tax	*15%*	
State Carry Fully Repaid?	Yes	
IOC Repayment (by State)	6	Years
IOC Maximum Exposure	-3 182	$MM
IOC Payback	17	Years
Project DPIR	0,52	

Table 6

The results as per table 6 are summaries for the same 200mmbbls field size but with a crude oil price of $80/bbl. Results on this table are based on the formula-based royalty rate. If the royalty based formula is replaced with the flat 5% royalty rate as proposed, the project NPV drops by 4.6%, Project IRR drops from 19% to 18%. IOC NPV reduces by 6.6% and its IRR decreases to 16% from 17%. Government take increases from 44% to 46%.

450 MMbls at $40/bbl

Economics Summary		
Reserves		
Reserves (Gas)	0	Bscf
Reserves (Oil)	444	MMbbl
Total Reserves	444	MMboe
Costs		
Capital Expenditure	13	$/boe
Operational Expenditure	15	$/boe
Life Cycle Cost	28	$/boe
Indicators		
Project NPV	-856	$MM
Project IRR	4%	
IOC NPV	-1 134	$MM
IOC IRR	4%	
BEE NPV	-114	$MM
State NPV	66	$MM
Aggregate Govt Take	-12%	
20% State Participation	*-8%*	
Royalties	*3%*	
Income Tax	*0%*	
State Carry Fully Repaid?	No	
IOC Repayment (by State)	18	Years
IOC Maximum Exposure	-5 247	$MM
IOC Payback	24	Years
Project DPIR	-0,37	

Table 7

Results in the table show that a large field size will not be profitable, both at the project level and IOC level if the crude oil price is below $40/bbl.

A crude oil price that will yield a Zero NPV at the Project level is $62 a barrel. At such an oil price, however, the IOC NPV will be negative. These results are based on the royalty formula being in its current form.

These results will be worse if we migrate to the flat 5% royalty rate.

450 MMbls at $80/bbl

Economics Summary		
Reserves		
Reserves (Gas)	0	Bscf
Reserves (Oil)	444	MMbbl
Total Reserves	444	MMboe
Costs		
Capital Expenditure	13	$/boe
Operational Expenditure	15	$/boe
Life Cycle Cost	28	$/boe
Indicators		
Project NPV	705	$MM
Project IRR	13%	
IOC NPV	439	$MM
IOC IRR	12%	
BEE NPV	94	$MM
State NPV	405	$MM
Aggregate Govt Take	63%	
20% State Participation	*31%*	
Royalties	*8%*	
Income Tax	*23%*	
State Carry Fully Repaid?	Yes	
IOC Repayment (by State)	10	Years
IOC Maximum Exposure	-5 154	$MM
IOC Payback	20	Years
Project DPIR	0,30	

Table 8

At the crude oil price of $80/bbl, project NPV and IRR are $705 million and 13% respectively. The IOC IRR is 12%. These results are based on the current formula based royalty rate. If these results are migrated to the proposed 5% flat royalty rate, the project NPV reduces by 7.7% to $651 million. Project IRR reduces marginally. IOC NPV reduces by 8.22% to $381 million and IOC IRR reduces marginally. Government take however increases from 63% to 66%. It must be borne in mind however that even though the volumes are high for this case compared to others, Capex and Opex costs are relatively higher.