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TECHNICAL ASSISTANCE REPORT—IMPLEMENTING FISCAL REGIMES FOR EXTRACTIVE INDUSTRIES: TECHNICAL NOTES

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Fiscal Affairs Department

UGANDA

IMPLEMENTING FISCAL REGIMES FOR EXTRACTIVE INDUSTRIES: TECHNICAL NOTES

Philip Daniel, Lee Burns, Diego Mesa Puyo, Emil Sunley

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ACRONYMS

AETR	Average Effective Tax Rate
APA	Advance Pricing Agreement
B2B	Business-to- Business
B2C	Business-to-Consumer
BEPS	Base Erosion Profit Shifting
BOPD	Barrels of Oil Per Day
CNOOC:	China National Offshore Oil Corporation
DROP	Daily Rate of Production
DTA	Double Tax Agreements
EAC	East African Community
FARI	Fiscal Analysis of Resources Industries
FOB	Free on Board
IFRS	International Financial Reporting Standards
IRR	Internal Rate of Return
ITA	Income Tax Act
LOB	Limitation of Benefits
LTO	Large Taxpayer Office
MEMD	Ministry of Energy and Minerals Development
METR	Marginal Effective Tax Rate
MOFPED	Ministry of Finance, Planning and Economic Development
NPV	Ministry of Finance, Planning and Economic Development
PE	Permanent Establishment
PEDPA	Petroleum Exploration Development and Production Act
PL	Production License
PSA	Production Sharing Agreement
RFP	Request for proposal
TIEA	Tax Information Exchange Agreement
UPD	Uganda Directorate of Petroleum
URA	Uganda Revenue Authority
VAT	Value added Tax

PREFACE

This report sets out technical notes at the conclusion of the second mission under the project in Uganda on extractive industry (EI) fiscal regimes (Module 1) under the IMF Topical Trust Fund on Managing Natural Resource Wealth (MNRW). It takes up implementation of recommendations set out in the report of the first mission, "Uganda: Fiscal Regimes for Extractive Industries: Next Phase," FAD (June 2015).

In response to a request from the Delegation of the Republic of Uganda at the Spring Meetings 2015, a second mission visited Kampala and Entebbe during the period July 6-17 2015. The mission was led by Philip Daniel (FAD External Expert) with Diego Mesa Puyo (FAD), Emil M. Sunley (FAD External Expert) and Lee Burns (LEG Expert).

The mission acknowledges valuable discussions with many officials including the following: At the Ministry of Finance, Planning and Economic Development (MFPED), Mr. Lawrence Kiiza, Director of Economic Affairs, Mr. Moses Kaggwa, Commissioner for Tax Policy, and Mr. Francis Twinamatsiko, Head of Oil and Gas Taxation Division. At the Ministry of Energy and Minerals Development (MEMD): Mr. Kabagambe-Kaliisa, Permanent Secretary; Petroleum Exploration and Production Department, Mr. Ernest Rubondo, Petroleum Commissioner and Acting Director, Mr. Robert Kasande, Assistant Commissioner (and Head of the Refinery Project); Geology and Mines Department, Mr. Joseph Okedi, Principal Inspector of Mines. At the Uganda Revenue Authority: Ms. Doris Akol, Commissioner General, Ms. Patience Tumusiime Rubagumya, Commissioner, Legal Services and Board Affairs, Messrs. Silajji Kanyesige, Mayanja Walakira , and Cyprian Chillanyang, Assistant Commissioners; Mr. John Mayanja, Commissioner LTO. The mission met frequently with the Technical Group on Petroleum consisting of officials from MFPED, MEMD, and URA.

The mission met jointly with representatives of Tullow Uganda, Total E & P Uganda, CNOOC Uganda, and PwC. The mission met with Mr. Kyrre Holm, First Secretary, Royal Norwegian Embassy. The mission also met Mr. Nganou Jean-Pascal, Senior Economist of the World Bank office in Kampala.

The mission appreciates the excellent cooperation and warm hospitality of the authorities. Thanks are also due to Ms. Caroline Ntumwa and Ms. Winifred Bisamaza of the IMF Office, Ms. Vanessa Ihunde and Ms. Stella Nabakooza, MFPED, for administrative and logistical support.

INTRODUCTION AND EXECUTIVE SUMMARY

This report covers key issues that arise in the implementation of the existing fiscal regimes for upstream petroleum and mining, the midstream segment of the Uganda Oil project, and the design of new regimes.

Note I discusses Uganda's first licensing round and the new model Production Sharing Agreement (PSA). It considers options on how to conduct future licensing rounds, including possible bid variables and bid evaluation methods. It then provides detailed comments on the draft model PSA dated July 2015, along with simulations of its fiscal terms. Finally, the note offers alternatives to the existing cost recovery rules for financing costs in future PSAs.

Note II analyzes key fiscal issues arising from midstream infrastructure. It first discusses crude oil pricing, both for export via pipeline and for domestic sales to a refinery. The note explains how crude oil price into the refinery is likely to be a negotiated outcome using the pipeline tariff as a guide. The note then discusses two main commercial configuration options for a pipeline offering transportation services. Finally, the note discusses options for pricing and taxation of refined products.

Note III covers various mining fiscal Issues. It first offers brief commentary on fiscal issues in the Draft Mining Policy of 2015. Then, it discusses export rules and subsidies for domestic processing, including examples from other mining countries in the region and elsewhere. Finally, the note describes gaps and uncertainties in the mining royalty regime, and offers solutions on how to address them.

Note IV addresses general taxation issues as they apply to extractive industries. The note starts with a discussion of issues relating to the 2015 legislation that amended the Income Tax Act (ITA) and the Value Added Tax (VAT) Act, and suggests several technical amendments. The note also discusses general principles for the application of VAT on imported services, and provides recommendations on how to improve the taxation of imported services under the VAT Act. Finally, the note provides guidelines on how to develop a Double Tax Agreements (DTA) policy and a model DTA.

This final report reflects legislation and circumstances prevailing during the mission of July 2015. Where relevant the report notes changes of substance that occurred up to the end of October 2015.

I. A NEW MODEL PRODUCTION SHARING AGREEMENT

A. New Licensing Rounds and Bid Variables

1. **Uganda's new licensing round reached the prequalification stage by mid-2015**. Some 16 companies successfully entered for prequalification – meaning that they were under assessment to become prequalified for the main bidding process. Once that process was concluded, the prequalified companies were sent requests for proposals (RFP) and the model PSA, and were required to purchase further data. The RFP contained the bidding or tendering criteria and requirements.[1] The prequalified bidders may be asked to combine as joint ventures for bids, although there was no separate prequalification of operators and non-operators. The government set January 15, 2016 as the deadline to receive bids from qualified applicants. In what follows, the mission set out its suggestions for bid criteria and procedures.

2. **The required exploration work program and expenditure could either be a bid item, or a fixture, or some combination of the two**. The new Uganda Directorate of Petroleum (UPD) may prescribe a minimum work program, in terms of quantities of seismic acquisition and numbers of wells per period, and may or may not open the tendering process for additional work commitments above those levels. If it decides to make a work program element part of competitive tender, and combines that with other bid items, then the weighting of the respective bid items must be decided. In monetary value, work commitments are comparable with a signature bonus payment though should have slightly lower monetary value since they are deferred. Any commitments beyond the first exploration period, of course, are at this stage contingent and do not have a clear present value. One possibility is to require a minimum work commitment of a significant extent from prequalified companies, then to decide amongst them according to financial proposals.

3. **Financial proposals should be restricted to at most two variables**. More than that, and bids become difficult to evaluate. Multiple bid variables also reduce the transparency of the process and make the tender little different from the "beauty contest" approach with discretionary evaluation by the regulator.

4. **Agencies of government may have differing views on the priorities in tender results**. Where there is emphasis on the immediate fiscal position, a signature bonus will command attention. Where the emphasis is upon the nature of competing work programs or company qualifications, the technical proposals may be given priority. In principle, the

[1] See FAD report June 2015 (¶16-¶22). Six blocks have been offered, two of which are open to licensing at different stratigraphic (depth) levels, possibly because non-associated gas deposits may become targets at stratigraphic levels different from those anticipated for oil.

prequalification process should deal with technical issues, leaving the tender clear for financial bids, so long as the work program is specified adequately for the expectations of the authorities.

5. **Financial bids could cover an upfront payment, a higher government share of production, or both**. The upfront bonus would usually be a lump sum amount payable on the signature date or effective date of the agreement (a Signature Bonus). The payment is certain as long as no contingencies are attached to the date of signature or effectiveness. The higher government share of production would add a factor in percentage points ("x") to the higher (tier 2) state share of production, currently set at 75 percent. The expected yield to the state from this higher share would, of course, be heavily discounted both for the probability of commercial success and for the time value of money. Thus it may be more practical to restrict financial proposals to the bonus alone. If both variables are open to bidding, then possible means of evaluating the results are suggested in Box 1.

6. **Competitive tender does not have to mean auction with open outcry**. A full and transparent competitive process, however, would mean public opening and verification of bids with no subsequent negotiation of bid terms. If both the work program and financial variables are bid then a "two envelope" system is common, with an order of priority for each. The work program bid, for example, could be required to meet a minimum standard and be opened first; after that, the financial commitment is essentially a decider between equivalent technical bids.

7. **A bonus bid could be conducted as a "Dutch Auction" commencing from a specified minimum level**. Under this scheme, the authorities nominate a minimum signature bonus and invite companies to compete by proposing both a maximum bid, and the intervals by which they will counter a competing offer. Thus if the nominated bonus is $10 million, Company A could offer a maximum of $20 million, approached by $1 million intervals above the next highest offer. If Company B offers a maximum of $26 million, approached in $2 million intervals above the next highest bid, the result will be a winning signature bonus of $22 million: $2 million from Company B above the maximum bid from Company A. The advantages of this system are: price discovery for the government, coupled with assurance to bidders that they will not have to gamble on an exceptionally high offer in order to secure a winning position. If there are eventually 5 or 6 bidders, the likelihood of effective collusion is low.

Box 1. Methods of Bid Evaluation

Method 1:

The discount rate used to generate the NPV (Ministry of Finance, Planning and Economic Development) can be chosen to reflect the government's rate of time preference. Thereafter, the two biddable items in NPV terms can be weighted equally in bid evaluation.

*Bid = Signature Bonus + NPV (Additional Profit Oil Tier 2) * Probability of Commercial Discovery*

NPV (Additional Profit Oil Tier 2) = Additional government revenue from biddable 'x' on Tier 2 profit oil discounted by a rate reflecting government time preference for early revenues. (This might be guided by the likely cost of alternative sources of government financing, such as borrowing).

Method 2:

Alternatively, weights could be assigned to each of the bid variables. The weights would be chosen to account for the government's time preference for early revenues and the probability of commercial discovery.

*Bid = W1 *Signature Bonus + W2 *Additional Profit Oil Tier 2*

Where W1 + W2 = 1

Additional Profit Oil Tier 2 = Additional government revenue from biddable 'x' on Tier 2 Profit Oil

B. Comments on the Model PSA[2]

8. **The new model PSA is at an advanced stage of preparation**. The mission found the draft to have strong new features (such as the R-Factor production sharing system), represents an important development to modern standards of Uganda's important experience with petroleum agreements.

Main text of the model PSA

9. **The definitions adopted require change for consistency with the Petroleum Exploration Development and Production Act (PEDPA) 2013**. The opening of Article 1 (1.1) should add that: "Unless the context otherwise requires, any term that is not defined in this Agreement but is defined in the Petroleum (Exploration Development and Production) Act, has the meaning in that Act". A definition in Article 1 of any term defined in the PEDPA can then be

[2] The FAD mission of July 6 to 17 2015 was provided with a draft Model PSA of July 1, 2015, for review and marked-up that version. This section reports on the principal substantive comments, not on all drafting issues that were marked. Many of the suggestions accord with decisions taken by the authorities in issuing the eventual Model PSA of August 24, 2015; this report records such outcomes where appropriate.

deleted unless it is intended that the term has a different meaning in the model PSA. Nevertheless, a different definition cannot be used to override the PEDPA. This change is made in the Model PSA issued.

10. **Reference to voting rights is needed in the definitions of Affiliated Company and Control**. Where the definition (1.1.3) defines Control, in part, as control of the right to cast votes in respect of not less than two-fifths of the total number of votes in respect of *issued equity shares*, the reference should be to *issued equity shares carrying voting rights*. This would make the definition of control refer to two-fifths of the voting shares and not two-fifths of the share capital. For example, a company may issue redeemable preference shares to a financial institution as part of a financing arrangement. The shares will form part of the share capital but may not carry voting rights.

11. **Ring-fencing for cost recovery needs clarification for consistency with the Income Tax Act, and thus for ease of administration.** Under the new terminology in the Income Tax Act, "Contract Area" is defined to mean the exploration or development area subject to a Petroleum Agreement. For the purposes of the Income Tax Act, "exploration area" and "development area" have their meanings in the PEDPA. "Exploration area" is defined in the PEDPA to mean the area constituted by a block or blocks subject to a petroleum exploration license and "development area" is defined in the PEDPA to mean an area constituted by a block or blocks that, following a commercial discovery, has been delineated for production according to the terms of a petroleum agreement. Thus the new terms create ring fencing, in effect, by Production License (PL) Area if more than one PL is granted within an area originally falling within an Exploration License Area (Article 12). The model refers, for example (1.1.37) to a "Development Area" with respect to a Joint Venture Agreement, but Development Area is not defined, although it is defined in the PEDPA as stated above. The position is clear, though different from the ITA, in the Model PSA issued.

12. **The model changes the definitions of "Petroleum" and "Petroleum Activities " from that in the PEDPA**. (1.1.53 and 1.1.54). The definition of petroleum in the model appears to include petroleum derived from shale, whereas the PEDPA definition excludes it. The definition of Petroleum Activities in the model adds specific exclusion of activities "beyond the Delivery Point". The model, however, contains an Article on pipelines that appears to cover activities beyond the Delivery Point. The model PSA issued is now clear, and consistent with the PEDPA.

13. **State Participation is defined as "commercial involvement"**. (1.1.63.) That term is too broad and does not usually refer the acquisition of a Venture interest by the State or its Nominee, as set out in Article 11.

14. **Joint and several liability is appropriate for contractual obligations, but not for income tax liability. (2.3.)** A special insertion of several liability for tax purposes in the Article 14 on taxation will deal with this problem.

15. **The Licensee must declare discoveries of other minerals but not of water.** (3.5.) Sub-surface discovery of water is potentially important and should be treated at least comparably with discovery of other minerals by a petroleum licensee. The issued model PSA refers to "natural resources" and thus includes water.

16. **The escalation index for minimum Exploration Expenditure requires updating.** (4.6). The index used in terms "A" and "B" is probably now a "Producer Price Index" and, since 2004, the industrial classification used in the US has changed. The point should be reviewed at source on the web site of the US Bureau of Labor Statistics. The issued model PSA now refers correctly to the Industrial Goods Producer Price Index. The review should also consider whether the index should be a composite, as at present, or specific to the petroleum industry.

17. **Production Bonuses become redundant under the R-Factor system for production sharing**. (9.2). The Production Bonus payments are triggered at successive levels of cumulative production. Under the Daily Rate of Production (DROP) sharing system these bonuses on cumulative production would play a role in offsetting the decline in State shares of profit oil as the daily rate of production falls. Under the R-Factor scheme these bonuses are unnecessary: the R-Factor sharing scales respond to cumulative levels of the R-Factor, where the R-Factor number is reduced only by significant reinvestment. The simplification of the system, by removal of these bonuses, would also be valuable. The model PSA issued still contains Production Bonuses but in a simpler form with amounts and levels of cumulative production made specific and not negotiable.

18. **The Royalty provision of the PEDPA leaves room for interpretation of the base for the Royalty charge**. The model PSA (10.1) repeats the wording of the PEPDA (s 154) in saying that "the licensee shall pay to the Government," and while specifying that the amount is a percentage of gross daily production, the source of the payment is left unclear. At the point of production, the licensee does not "own" gross production; the Operator will conduct field production but each party will lift and market according to Article 17 of the PSA. The intention seems clearly for government to take royalty as a primary charge on gross production, after which the cost recovery limit applies to the balance and profit oil is calculated for subsequent sharing. The provision as it stands, however, could be read to say that the Licensee must pay the amount out its own share of production – a method that has quite different economic effect. The issue also affects income tax calculations; if royalty is paid out of the Licensee's share of cost and profit oil, it will become a deduction for income tax purposes, whereas a royalty levied before any sharing will not enter the Licensee's revenue and will not form a deduction. The model PSA issued now makes the intent clear by saying, instead that only "the Government shall take the following royalty…"

19. **The Royalty calculation is written as gross on the total daily amount of production**. (10.1) In other words, each increment of production is charged royalty at the highest resulting rate instead of the weighted average rate of royalty applicable in each incremental tier of production. Thus at rates in excess of 130,000 BOPD, the royalty rate on all production is

18 percent, whereas the initial royalty on a tranche of production up to 25,000 BOPD is 8 percent. This makes the overall impact of royalty more severe on the Licensee as production rises than it would be under the incremental system. To some extent, this will be offset by the operation of the R-Factor, since the cumulative revenues of the Licensee will be proportionately reduced, but the overall effect, given other parameters of production sharing should be re-assessed. The scheme as written also gives the Licensee incentive to organize production rates so as to avoid triggering a higher royalty rate for as long as possible. The issued model makes explicit that royalty is not incremental, and thus the applicable rate is levied on total daily production.

20. **A fixed rate of Royalty on natural gas is feasible**. The model leaves this rate for negotiation upon establishment of commerciality, yet many jurisdictions with royalty on petroleum fix the rate in advance with a rate of five percent is fairly common. The ability to negotiate this rate offers little advantage to government within the R-Factor system; it also introduces more uncertainty into the overall fiscal framework. "Commerciality" itself, for the Licensee may depend in part on the rate of royalty.

21. **The terms of the "carry" provided for the State or its Nominee through development to production are not yet clear**. (11.1) The source of repayment is stated as "the Licensee's cost recovery oil," which will include the cost recovery oil attributed to the state participation share but is not limited to the State's share. Unless it is the aim to make the terms of State Participation negotiable, the source and terms of repayment should be spelt out, including the rate of interest on the outstanding liability. The model PSA issued stipulates that the costs are recoverable from the Government's (or Government Nominee's) share of cost petroleum and also sets the maximum share of carried state participation at 20 percent.

22. **The "Contract Area" ring fence for cost recovery appears now to include any or all PL(s) drawn from the original Contract Area**. (12.2) The Income Tax Act now operates a ring fence license by license. Thus, one PL is a separate ring-fenced entity even if another PL is drawn from the same original exploration license area. This procedure appears not to be the intention for cost recovery of the model PSA as written. Consistency with income tax rules is desirable on administrative grounds, though not essential. In practice, the government's interest in a ring-fence by contract area, rather than by license, was stronger under the DROP system where aggregation of production across fields (PLs) would produce higher rates of sharing in favor of government. Under the R-Factor system, the government can be neutral as between ring fencing by "contract area" (original exploration area) or by PL.

23. **Different cost recovery limits for gas and oil are cumbersome, and unnecessary with the R-Factor scheme**. (12.3) The differences proposed earlier were in any case small (five percentage points). Although non-associated gas may become a possibility in Uganda, the expectation from discoveries to date will be for associated gas. In this case, the separation of oil and gas costs, so many of which will be joint, is both difficult and to a large extent arbitrary. The R-Factor scheme will take sufficient account automatically of differences in cost structures among

types of production. The model PSA issued sets the maximum limits for both cost gas and cost oil at 65 percent

24. **Uplift, if provided, is recovered together with Development Expenditures**. In the present model PSA (12.9), interest charges are recovered out of Cost Recovery oil ahead of Development Expenditures. If, as proposed in the June FAD report, uplift replaces recovery of interest, then there is no need for recovery in an order distinct from overall development expenditures. The model PSA issued does not adopt uplift: interest and financing charges are recoverable, provided that debt does not exceed 50 percent of the Licensee's financing requirement.

25. **The "arm's length" price of oil at the delivery point in Uganda is affected by the "non-arm's length" tariff charged by a pipeline.** Thus the part of the criterion for valuing oil that depends on arm's length transactions needs review. Provided that an agreed pipeline tariff is 'deemed' or otherwise treated as leading to an arm's length price for oil the principles of Article 15 can remain the same. The wording, however, may need to make this clear. The form of the term "arm's length sales", or any similar concept, is now made consistent a various points in the model PSA. The issued model provides a clear procedure for agreement on valuing natural gas not sold in arm's length sales

26. **The transfer of assets to government may not be to government's advantage**. This optional provision (Article 21) is inherited from circumstances many years ago when abandonment and decommissioning obligations were not regarded as seriously as they are today, and when national oil companies were interested in cheap acquisition of assets that could be used in other activities. Environmental concerns and the pace of technological change now make the motivation for government acquisition of assets in this way questionable. Government may have no use for the assets and may face a liability for disposal that has not been covered by the Licensee under the decommissioning provisions of the PEPDA. Acquisition by government remains optional, not obligatory, in the issued model.

27. **The stability assurance under Applicable Law should be reviewed**. (31,2,3, and 4, numbered Article 30 in the model PSA issued). Firstly, it is invoked only in a case where the Licensee may be disadvantaged; thus it is not symmetrical when the interests of the State may be damaged. Secondly, the exception for a tax on additional profits suggests that "original economic benefits" accrue at some base level and the tax is imposed on something additional – this is reasonable, but seems not to accord with the wording of 31.2. Moreover, additional taxation could come in the form of a surcharge or higher rate of normal income tax on petroleum income: there seems no good reason to treat this separately from an "additional profits tax".

28. **The PSA itself is both a grant of public rights and a revenue-raising instrument and thus should be in the public domain.** The confidentiality provision (34.1, or 33.1 as issued) reasonably applies to information treated as confidential by one party or another under the

Agreement, but still applies also to the PSA and its terms themselves. The parties can agree to make a PSA public. This mission reiterates its support to Uganda's intention to become a candidate in the Extractive Industries Transparency Initiative, and for public disclosure of PSAs as recommended in the IMF Guide on Resource Revenue Transparency and in the consultation draft of the Natural Resource Revenue Management Pillar of the new Fiscal Transparency Code.

Accounting and Financial Procedure (Annex B)

29. **The Chart of Accounts required under the Agreement reflects petroleum industry accounting standards.** These standards will be those applicable internationally, including International Financial Reporting Standards (IFRS). For these purposes, any Chart of Accounts prepared by a government authority (such as the Accountant-General, or a Bureau of Standards) can play a useful advisory role but should not be mandatory for accounting and reporting under the PSA.

30. **Sale of petroleum though an export pipeline or other regulated midstream facility affects the Accounting Procedure at a number of points.** The regulated or agreed tariff will partly determine the value of production (paragraph 1.2.(f).(ii)) and thus needs to be included in the budgeting and reporting obligations. The audit and inspection rights of government under the PSA (1.5) need to be available for midstream facilities that affect the price of upstream output: if these rights are not directly available under the PSA, they will need to be pursued under other agreements or laws. Paragraph 1.5.(c) of the issued model now provides the necessary extension of audit and inspection rights.

31. **Decommissioning costs should feature separately in the classification of costs.** (Section 2). The treatment of decommissioning costs is set out in the PEDPA: compliance with its terms should be the subject of reporting under the PSA. This treatment is different from that of other costs, requiring separate classification and reporting.

C. Simulations of Fiscal Terms in the New Model PSA

32. **The fiscal terms in the draft model PSA dated July 2015 are compared with existing and alternative terms modeled in FAD (June 2015).**[3] The fiscal regimes are assessed on a set of fiscal indicators, including the minimum effective royalty rate, annual government share of profit petroleum, average effective tax rate (AETR), break-even price, and government share of total benefits. The mission used FAD's Fiscal Analysis of Resources Industries (FARI) modeling framework to perform the simulations.

33. **The project example used, with a price assumption of $80/bbl FOB Mombasa yields a real pre-tax IRR of 29 percent**. The project example is the large project described in FAD

[3] All numbers are in presented in real terms of 2015 unless noted otherwise.

(June 2015). The three fiscal regime options evaluated are: (i) the PSA applying to area EA1, signed in 2004; (ii) the July 2015 draft of the new model PSA; and (iii) the terms included in R-factor option 1 discussed in the June report. Table 1 describes the fiscal terms of the three PSAs:

Table 1. Fiscal Terms of Proposed New Model PSA and Alternative Options

	PSA EA1 (2004)		**Model PSA (July 2015)**		**Option 1 (June 2015)**	
Royalty	Increments of DROP	Incremental rate	DROP	Rate	Fixed rate	8%
	First 2,500	5%	< 25,000	8%		
	Next 2,500	7.5%	25,000 - 50,000	10%		
	Next 2,500	10%	50,000 - 75,000	12%		
	> 7,500	12.5%	75,000 - 100,000	14%		
			100,000 – 130,000	16%		
			> 130,000	18%		
Cost recovery limit	60%		65%		70%	
Interest/uplift	Interest recoverable		Interest recoverable		15% uplift on development. costs	
Production sharing	Increments of DROP	Gov. Share	R-factor	Gov. Share	R-factor	Gov. Share
	First 5,000	45.0%	0 < 1	50%	0 < 1	50%
	Next 5,000	47.5%	1 – 3	Formula	1 – 3	Formula
	Next 10,000	52.5%	> 3	75%	> 3	75%
	Next 10,000	57.5%				
	Next 10,000	62.5%				
	Over 40,000	62.7%				
Corporate tax	30%		30%		30%	
State participation	15% Carried through development		20% Carried through development		15% Carried through development	

Minimum effective royalty rate and government share of profit petroleum

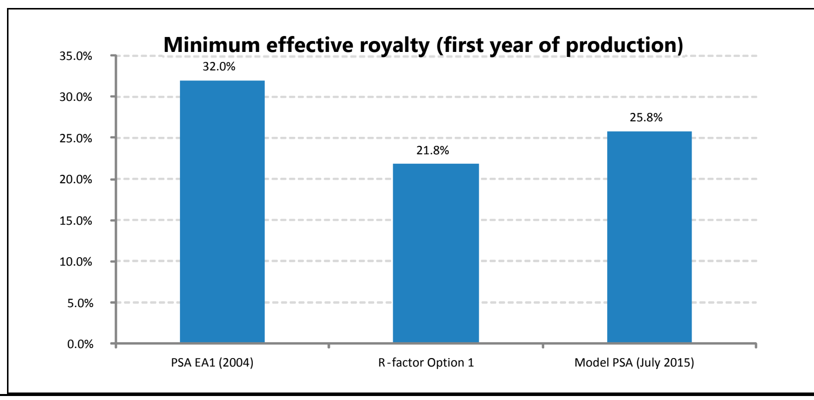
34. **The combination of a cost recovery limit and a minimum government share of profit petroleum, like a royalty, yields government revenue from the start of production.** A limit on the amount of revenue that can be used to recover costs ensures there is always a minimum quantity of profit petroleum to be shared between the government and the licensee.

35. **Uganda's existing PSAs and the proposed model PSA include royalty, cost recovery limit, and minimum government share of profit petroleum.** The combination of these three

mechanisms creates a higher implicit royalty—the "minimum effective royalty rate".[4] For example, the 65 percent limit in the new model PSA implies that 35 percent of gross production is treated as profit petroleum, of which 50 percent goes to the government. In the absence of a formal royalty, the government would receive 17.5 percent of gross petroleum production. However, since the minimum royalty in the model PSA starts at 8 percent, and the cost oil is calculated on the balance after royalty, then cost oil is 65 percent of 92 percent, or 32.2 percent, and the minimum share of profit oil to government is 16.1 percent. The effective minimum royalty to government is then 8 plus 16.1, or 24.1 percent. [5]

36. **Figure 1 shows the minimum effective royalty in the first year of production under EA1 PSA, new model PSA, and R-factor option 1.** The combination of a relatively modest flat-rate royalty (in option 1) or a royalty structured not to reach its maximum level in the first years of production (new model PSA), a higher cost recovery limit, and the R-factor production sharing scheme reduce the minimum effective royalty rate compared to existing PSAs.[6] The minimum effective royalty under the new model PSA is higher than under option 1 due to a lower cost recovery limit (65 vs. 70 percent), and the fact that in the first year of production, the royalty rate reaches 10 percent compared to the fixed rate of 8 percent.

Figure 1. Minimum Effective Royalty



[4] Depending on how the CIT is structured, it could also add to the minimum effective royalty. In the case of Uganda, however, the immediate expensing of exploration expenses combined with unlimited loss carry forward, and a straight-line depreciation schedule means that no CIT is paid in the first year of production. The same is true of state participation.

[5] A similar calculation applies to option 1, where the fixed royalty rate is 8 percent and the cost recovery limit 70 percent, which results in a minimum effective royalty rate of 21.8 percent.

[6] The PSAs signed in 2012 included an additional royalty on a scale of cumulative production, which results in an increase of the minimum effective royalty almost equal to the additional royalty rate (FAD June 2015).

37. **Once each royalty rate is triggered in the new model PSA, this rate applies to total production instead of each production increment as in existing PSAs.** The scheme has a rate of 12 to 14 percent as its midpoint, starting at 8 and rising to 18. This means that at DROP rates up to 75,000 barrels of oil per day (bpd), achievable at sustained plateau production on a field of 300 million barrels (mm bbl) of recoverable reserves, the royalty rate stays at or below 12 percent. This is a workable scheme when taken in conjunction with a slightly higher cost oil limit of 65 percent included in the July draft of the new model PSA. In addition, the sliding scale scheme could be useful late in field life if a single field remains from an original contract area. If production tails off at a relatively slow rate, the reducing royalty could prolong field life without the need for discretionary remission of royalty.

38. **There are mechanical differences between the petroleum sharing system in existing PSAs and the proposed R-factor approach in the new model PSA.** As a result, comparing only headline rates of government share of profit petroleum provides an incomplete picture of how the two systems work. Under DROP, the government share of profit petroleum is determined by increments of daily rates of production. By comparison with the royalty scheme in the new model PSA, the increase in the effective government share is a gradual process. As a result, the applicable government share at a given rate of production is the weighted average of each DROP tranche and the corresponding government share at each tranche. Table 2 below offers a very simple illustration of how the DROP sharing works for daily rates of production of between 20,000 to 50,000 barrels of oil.

Table 2. Government Share for Daily Rate of Production of 20,000 to 50,000 barrels per day

Daily rate of production (in b/d)	Government share	Government share of profit petroleum (in b/d)	Effective Government Share
A	B	A x B = C	D = ∑C ÷ ∑ A
First 5,000	45%	2,250	45.00%
Next 5,000	47.5%	2,375	46.25%
Next 10,000	52.5%	5,250	49.38%
Next 10,000	57.5%	5,750	52.08%
Next 10,000	62.5%	6,250	54.69%
Next 10,000	67.5%	6,750	57.25%

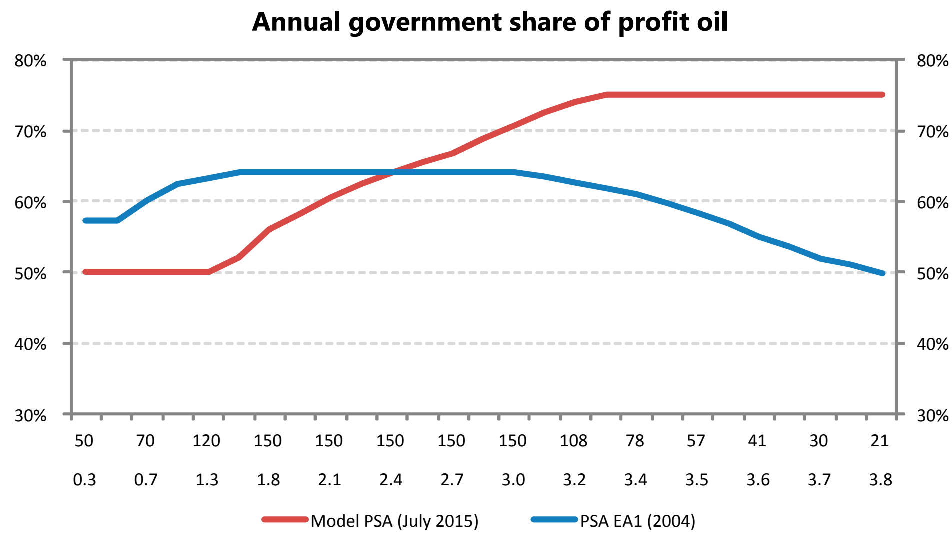
39. **The results in the last column of Table 2 show that under the existing DROP system, the effective government share never reaches the highest tier of government share.** Regardless of the rate of daily production, there will always be portions of profit petroleum subject to lower tiers of government share. In the example discussed above, the effective government share (when the daily rate of production is 50,000 bpd) is 57.25 percent, well below the highest tier of government share of 67.5 percent.

40. **In contrast, the effective government share in the R-factor scheme is the rate derived from the tranche reached at the applicable date.** Thus, if the R-factor ratio at the end

of a particular period is above 3, the effective government share for the next period would be 75 percent. Since the R-factor is calculated from periodic results, and not increments of daily rate of production, the highest tier of government share is achieved when its threshold is reached.

41. **DROP does not respond to project profitability**. Thus, after a field has reached its peak production rate, the government's share of profit petroleum decreases even if the profitability of the project continues to rise. Under the R-factor scheme, on the other hand, the government's share of profit petroleum increases with project profitability (measured as the R-factor in Figure 2).

Figure 2. Annual Government Share of Profit Petroleum



Profile of government revenue

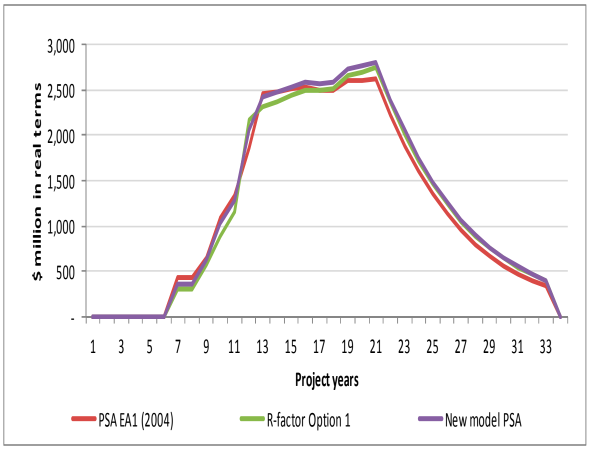
42. **The profile of government revenue under the three fiscal regimes differs.** Figure 3 displays the aggregate revenues collected from royalty, profit petroleum sharing, CIT, and state participation. The results show that the three sets of fiscal terms modeled yield relatively similar revenue profiles for the government. In all three PSAs the government starts receiving revenue from day one of production, mainly due to royalty, and the combination of a cost recovery limit with a minimum share of profit petroleum. The magnitude of these early revenues is larger under the EA1 PSA than under the R-factor options, largely due to higher levels of royalty in the early years of production and a lower cost recovery limit. However, as the profitability of the project improves over time, the government share of profit petroleum from the R-factor alternatives more than offset the revenue shortfall in the early years of the project.

43. **Total government revenue over the life of the project at different prices illustrate the properties of the different schemes.** Figure X shows that while the EA1 PSA generates slightly more revenue for the government under low price conditions (below $75/bbl), as prices

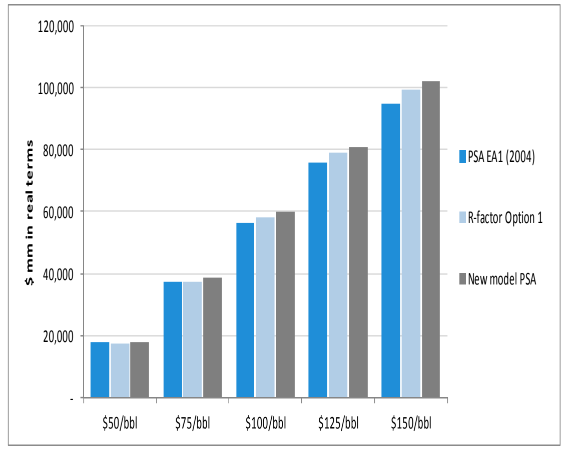
increase, the revenue generated by the new model PSA and option 1 increase at a faster rate. In fact, in medium to high price scenarios ($75/bbl and above), the two R-factor options generate more revenue than existing PSAs.

Figure 3. Government Revenue under Existing and Proposed Terms

Profile of government revenue at $80 FOB Mombasa



Total government revenue at different prices



Government take, progressivity, breakeven price, and implied bid bonus

44. **The revenue generating capacity of the three fiscal regime options appears similar on the assumptions used.** Figure 4 shows the Average Effective Tax Rate (AETR) or "government take" of the three fiscal regimes evaluated using different discount rates. In undiscounted terms, the three regimes yield relatively similar AETRs of between 81 and 85 percent. Using a discount rate of 10 percent, the model PSA has an AETR of 93 percent, followed by the EA1 PSA at 91 percent, and the R-factor option 89 at percent.

45. **The ability of the fiscal regime to capture a higher share in highly profitable projects is evaluated by estimating the government share of total benefits over a range of project results.** A more progressive regime allows the government to increase its share of revenue when the investment is highly profitable, while giving some relief to investors in projects with low rates of return. Figure 4 below illustrates the government share of total benefits over a range oil prices. The range of pre-tax IRR's is used to indicate how project profitability increases with prices, and by no means implies a ranking of projects by IRR.

46. **The new model PSA and option 1 are more progressive than the EA1 PSA, with option1 exhibiting a higher degree of progressivity.** The main reason for this is the switch from the DROP mechanism to the R-factor. The difference in progressivity between the new model PSA and option 1 is due to the difference in the royalty schemes (flat low rate vs. a variable rate that applies to total production instead of increments). It is important to note, however, that while progressivity allows countries to capture a higher share on the upside, it may

also mean that countries share some risk by reducing their share on the downside (unless there is sufficient minimum government revenue whenever production is occurring).

Figure 4. AETR and Share of Total Benefits

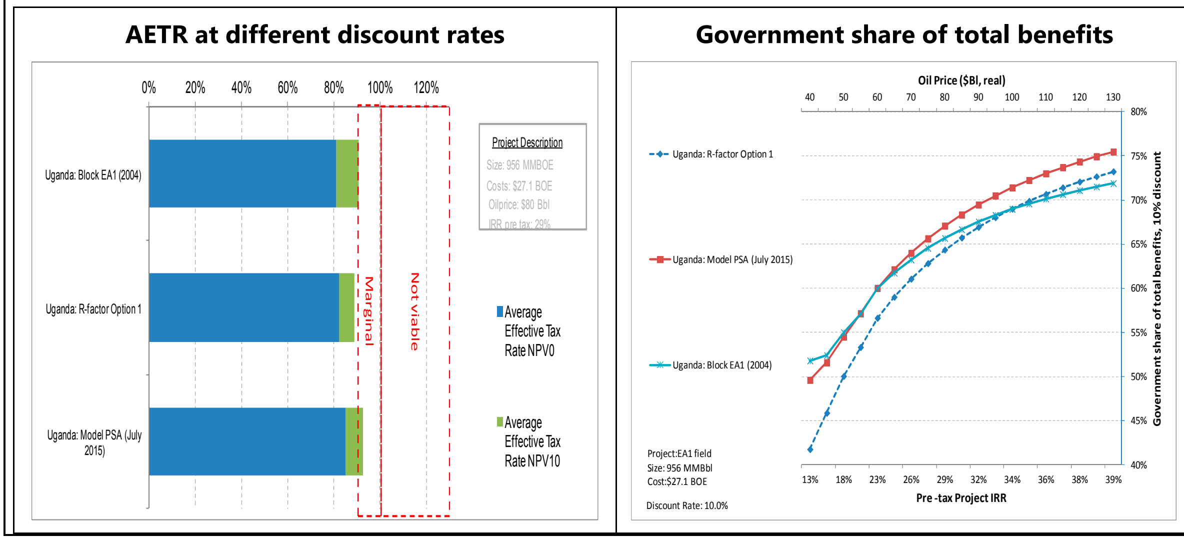
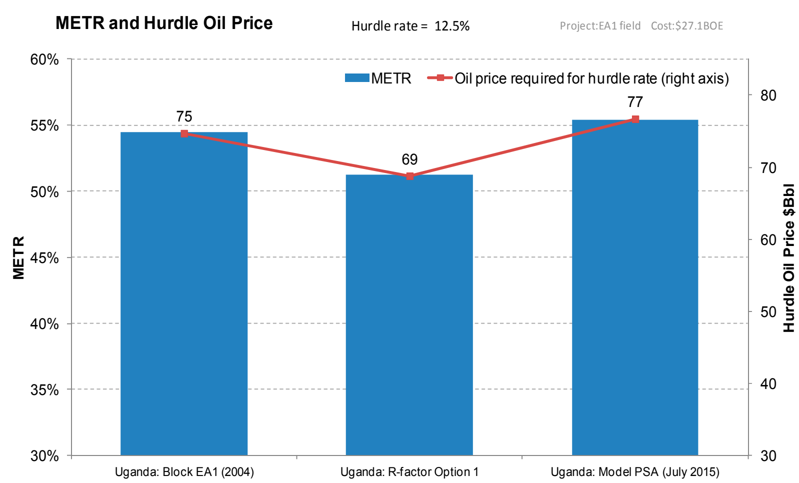


Figure 5. Breakeven Price and METR

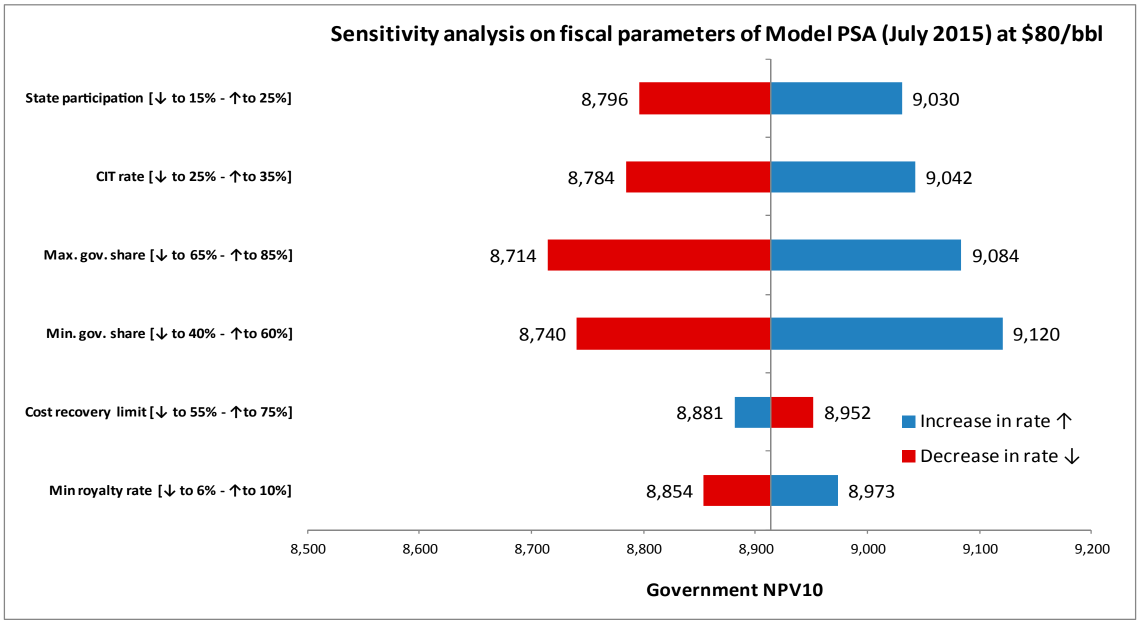


47. **The "breakeven price" illustrates how the three PSAs would treat a marginal project.** The "breakeven price" is the minimum price required to meet the minimum rate of return required by the investor (assumed in the model to be 12.5 percent in real terms). The new model PSA appears to place a higher burden on marginal projects than option 1 and the EA1 PSA. This is a result of three factors: higher royalty rates that once triggered apply to total production, a lower cost recovery limit, and higher state participation. A related measure to the break-even price is the marginal effective tax rate (METR), which shows the relative burden that a

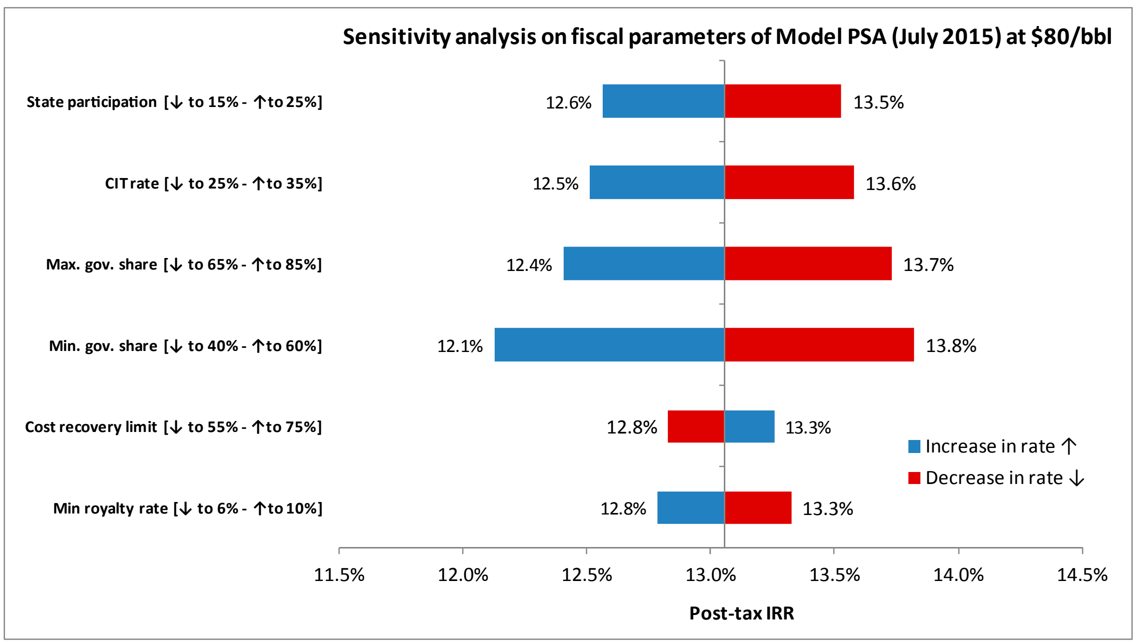
fiscal regime places on a marginal project[7]. The new model PSA have the highest METR of the three regimes, which is consistent with the breakeven price analysis. (Figure 5)

Figure 6. Sensitivity Analysis on Fiscal Parameters

Results on government revenue



Results on post-tax IRR



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[7] The METR calculates the tax burden that a fiscal regimes places on a marginal project (that is, a project that yields just the minimum rate of return required by the investor) by estimating the difference between pre and post-tax IRR as a proportion of the pre-tax IRR.

Sensitivity analysis on the new model PSA: government NPV and post-tax IRR

48. **Changes to the minimum and maximum government share of profit petroleum have the greatest effect on both government revenue and post-tax IRR**. The mission ran a sensitivity analysis on the fiscal parameters contained in the new model PSA, and evaluated the results on government revenue and investor return. The analysis shows that, for example, a 10 percentage point increase in the maximum government share would increase government revenue by $170 million, while a 10 percent point decrease will reduce revenue by $199 million. Conversely, a 10 percent point increase would reduce the post-tax IRR of the project from 13.1 to 12.4 percent, while a 10 percent point decrease would increase it to 13.7 percent. Other results are displayed in Figure 6 below.

D. Cost Recovery Rules for Financing Costs

49. **Eliminating of recovery of interest expense could be replaced with a one-time uplift for development costs.** FAD June 2015 recommended 15 percent.[8] Several countries apply uplift in lieu of recovery of interest expense under PSAs, which can be perceived as a modest level of recompense for the time value of money when limits on cost recovery apply.

50. **The uplift approach has several advantages compared to allowing the recovery of interest expense.** First, if set a modest level it is likely to be less expensive for the government, bringing forward the triggering of higher tiers under the R-Factor scheme. Second, it avoids the requirement for detailed provisions limiting the recoverability of interest when it is recoverable. Third, it does not discriminate between sources of finance. Finally, companies may view the change as an incentive to development investment and, as with any measure that accelerates or increases cost recovery, it reduces risk to the licensee.

51. **Simple simulations indicate that the uplift amount is likely to be lower than the amount otherwise allowable as recoverable interest expense.** Generally, the interest payment on a simple loan is a function of three main variables: the amount borrowed, the interest rate charged on the loan, and the repayment period[9]. Figures 7a and 7b below compare the uplift amount under the recommended mechanism with the interest expense under various loan and cost recovery assumptions. Figure 7a assumes total development costs of $500 million, along with five debt-to-equity (D/E) ratio rules for interest expense recovery, ranging from D/E of 1:1 to 3:1. Under a very conservative assumption of a fixed 7.5 percent annual interest rate in nominal terms, the uplift amount is always lower than the interest expense in all five D/E scenarios.

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[8] The uplift should be granted in the year of investment at 15 percent of the capital costs incurred. Under the uplift mechanism, the licensee recovers its development costs plus a 15 percent amount, however, uplift is limited to the first five years of development expenditure.

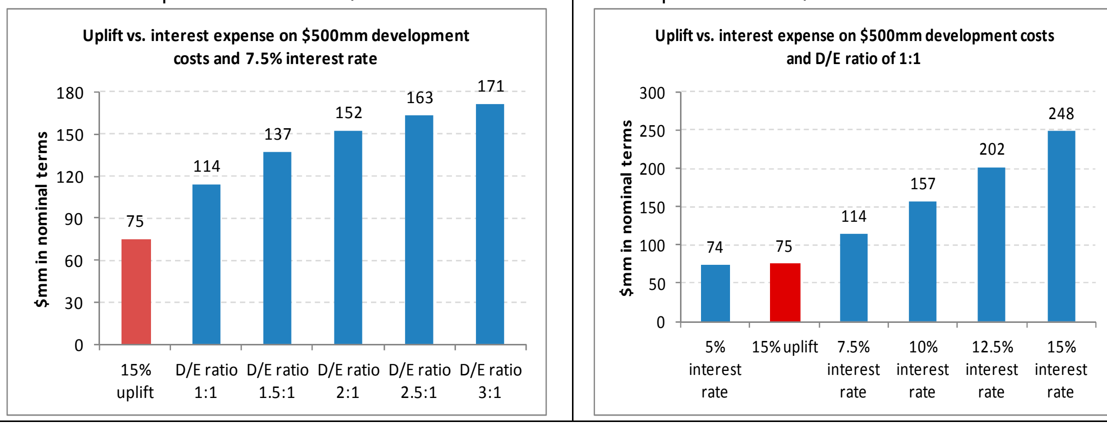
[9] The results presented in Figure 7 would vary if under the terms of the loan early repayment is permitted, or if a grace period before commencing the loan repayment is allowed.

Similarly, assuming a relatively strict D/E ratio rule of 1:1, Figure 7b shows that the interest rate would have to be 5 percent or lower in order for the uplift amount to exceed the recoverable interest expense.

Figure 7. Uplift for Development Costs vs. Interest Expense for Cost Recovery

a. Uplift vs. various D/E rules

b. Uplift vs. 1:1 D/E at various interest rates



Note: in all loan scenarios the repayment period is assumed to be 10 years

II. MIDSTREAM INFRASTRUCTURE: CONFIGURATION, PRICES, AND TAXATION

A. Pricing of Crude Oil

52. **Pricing of crude oil is market-determined.** The PSAs provides for an arm's length standard for pricing of crude oil. In the FAD Report June 2015 it was assumed that crude oil would be sold to the refinery at export parity pricing, resulting from the netback from an arm's length price at a seaport of export to the inlet flange of export pipeline facilities in Uganda. This procedure, however, begs the question of the determination of the transportation tariff levied by the pipeline entity for moving the crude oil from Uganda to the seaport. The assumption here has been of a tariff derived from the capital costs and a "reasonable" rate of return on the pipeline capital investment. This tariff will in practice be determined by negotiation and regulation.

53. **The tariff modeled is an annual reservation charge for the pipeline capacity.** The capital cost and rate of return yield an annuity payment over 21 years that repays capital with the specified return. Operating costs are divided into approximately 25 percent fixed and 75 percent variable to reflect, to some extent, variations in throughput volumes. The calculation implies an average tariff per barrel, in respect of capital, over the life of the fields but not an actual tariff for each barrel of oil as it passes through the pipeline at a specific time. This calculation procedure backloads the tariff payment. Alternatives could be devised in which the actual tariff mirrors throughput more closely, but these alternatives cannot deviate far from the initially assumed procedure without increasing throughput risk on the pipeline owners.

54. **The crude oil price into the refinery will be a negotiated outcome using the adjusted pipeline tariff as a guide.** This probably means an indicative deduction per period from the FOB price of Ugandan crude at the seaport. Thus an 'export parity" price into the refinery is not necessarily exactly the same net price as will be received in each period by the upstream producers for oil exported through the pipeline. On the other hand, the price could be the same if the contract with the refinery specified that the average price for each month would be the average export price netted back for the average tariff that month. There could be a provisional price when the oil is delivered to the refinery with an adjustment the following month.

55. **A higher price for crude oil sold to the refinery could result.** If market pricing remains the rule, and the upstream producers have an attractive option in exports through a pipeline, then the refinery could offer a higher price for crude. If the upstream producers are required to deliver 30,000 bpd, there would probably be a pricing formula, which would be considered an arm's length price.[10] The analysis of refinery economics in FAD (June 2015) suggested a strongly

[10] Provided that the presence of state companies on both sides of the transaction does not prejudice arm's length status, and provided that prices and quantities delivered remain the only consideration in the transaction.

positive pretax result on the assumptions used. One way in which the refinery could expand, and at the same time provide higher returns to the upstream, is by purchasing crude oil on contract at a higher price than pipeline export would yield.

B. Pipeline Commercial Configurations

56. **Two core models for commercial structure of a pipeline offering transportation services may exist, and a transition from the most likely initial model (model 1) to another structure could occur over time**.

- In Model 1, the pipeline owners bear no throughput risk and earn the minimum return on capital. This model is compatible with ownership in proportions identical to those for the upstream, and with initial reservation of capacity entirely for crude oil from the Uganda Oil Project. The pipeline provides only transportation services; the owners do not engage in trading.

- In Model 2, the pipeline company is freestanding, negotiating tariffs and contracts with shippers but taking no throughput risk once a contract is made. In mature form, a pipeline under this model may also make spot transactions. This model requires pipeline owners to take risk on obtaining throughput contracts in the first place, though that risk is obviously negligible if the pipeline is constructed using a prior contract commitment from the Uganda Oil Project. Again, the owners do not engage in trading of crude oil themselves.

57. **The two models have different implications for third party access**. Model 1 will restrict access to the "foundation shippers" who have provided the initial capital. Model 2 may have foundation shippers, but provides access to other users on negotiated terms.

58. **The full form of Model 2 is very unlikely for the Uganda Oil project since multiple crude suppliers to the pipeline are not initially available**. In principle, each party to PSAs in Uganda, including the state, could market its shares separately and negotiate separately with the pipeline company. That is unlikely to be a foundation for initial investment in a pipeline, even if it were to be a long-term possibility. It might however be the way in which the sale of transportation services through the pipeline evolves. There are clearly gradations possible in between each of the three basic models.

59. **A structure for the Uganda Oil project beginning with Model 1 and evolving towards Model 2 seems most likely**. In accordance with understandings already reached, the pipeline would be owned by an independent entity and pipeline costs and revenues would not be included in the framework of the PSAs (thus not under the upstream fiscal regime). The interests in the pipeline company, however, would probably be the same as those for the upstream venture, with the possible exception that the State might or might not participate. Ownership could remain the same in the transit country. If, for example, that is Kenya, then state participation, if any, by Kenya and Uganda could be maintained over the pipeline as a whole.

Access to the pipeline for oil from Kenyan fields might require an initial commitment to larger capacity.

60. **An option with differing ownership shares between upstream and pipeline is possible.** The upstream producers seek to have effective control of pipeline operations but that does not require that the shares be the same. The pipeline construction firm or another third party, for example, might take an equity interest in the pipeline. The government share might be higher than its share in the upstream. The upstream producers could have shares that vary from their shares in the upstream.

61. **Initial capacity will depend upon proposed initial use**. Nevertheless, unlike a gas pipeline, where initial throughput quantities are maintained in line with contracts, capacity use in an oil pipeline initially designed for one set of field users will inevitably fall from peak as the fields mature and enter a decline phase. The pipeline owners thus have an interest in encouragement of new sources and third party use.

62. **The choice of initial capacity is difficult**. Should this be predicated upon higher eventual throughput than the initial plateau production from the Uganda Oil Project, or should an assumption be made that the initial plateau capacity will become spare in time for additional sources of oil to make use of it? The decision affects the initial commercial configuration, since the manner of access for potential crude oil from Kenya for part of the pipeline's length and capacity has to be addressed.

63. **The two commercial models also affect the choice of tariff**. Under Model 1, an exact match of capital cost recovery with oil throughput is not necessary; under Model 2, such a match is essential and so pipeline revenue will fluctuate to some extent with capacity use.

64. **Where the pipeline investors do themselves take throughput risk, the weighted average cost of capital will most likely determine the required tariff.** In FAD (June 2015), a post-tax real return of 7.5 percent was used: that is, a discounted cash flow return on total capital expended over the chosen project life irrespective of the source of funds. This rate approximates a pre-tax real return of 10 percent and a nominal pretax return of 12.5 percent. The equivalent nominal pre-tax figure from a data base of industry rates of return is 9.3 percent[11]

C. Pricing and Taxation of Refinery Products

65. **Imported products will be the marginal supply in the Uganda market, and the cost of importing products will determine the domestic price of products**. In FAD (June 2015), the refinery was assumed to purchase crude oil at export parity from the upstream segment and sell products into the domestic market or to neighboring countries at market prices. Given the high

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[11] See Ashwath Damodaran's estimates of cost of capital by industry and region, accessible online at: http://pages.stern.nyu.edu/~adamodar/

cost of petroleum products in the Democratic Republic of Congo (DRC), exporting petroleum products to DRC would likely increase the profitability of the refinery. Exporting products to neighboring countries will not improve Uganda's balance of trade, since more products will need to be imported to supply the domestic market. The refinery will have an initial capacity to process 30,000 bpd, increasing to 60,000 bpd after approximately seven years. Uganda's current consumption of petroleum products is about 28,000 bpd, but is expected to exceed 30,000 bpd when the refinery comes on stream. Therefore, the refinery will be able to sell products into the domestic market at prices up to the price of imported products—the marginal supply. The refinery may undercut the price of imported products to increase market share, but it will not have the initial capacity to meet the full domestic demand for products. When the refinery capacity is increased to 60,000 bpd, the refinery may be able to fully supply the domestic market up to that level for a few years.

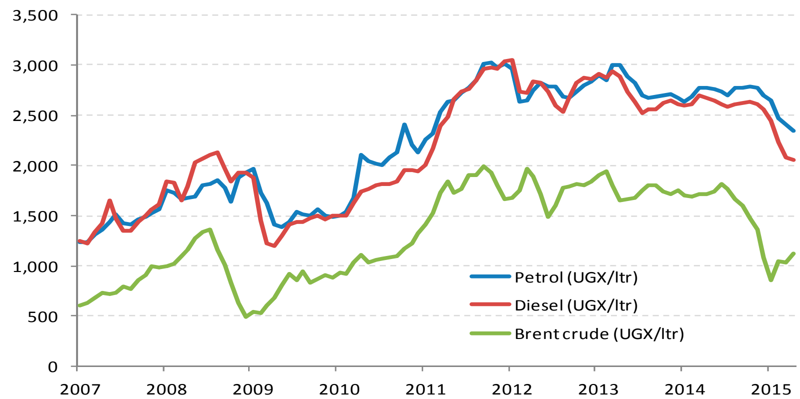
66. **The profitability of the refinery will depend, in part, on its cost of refining products and transporting the products by pipeline to Kampala.** The product pipeline to Kampala is an integral part of the refinery project The refinery will be designed to process Uganda crude oil with its high wax content, and the design will take into account the trade-off between a more costly refinery that can produce a higher share of the light and middle distillates, and a less costly refinery that can produce only a lower share of light and middle distillates. Designing a refinery to process Uganda's crude oil will reduce refinery costs compared to a similar size refinery designed to process a wider range of crude oils. Given the small size of the refinery, however, its costs per barrel will be higher than the cost of a larger refinery that can process several 100,000 bpd and produce a larger share of the lighter products.

67. **The profitability of the refinery will depend on the crack spread.** The crack spread is the difference between the cost of crude oil delivered to the refinery and the domestic market price of petroleum products obtained from a barrel of crude oil. Crude oil will be delivered to the refinery at an approximation of the export parity price, which is assumed to be Brent minus a quality differential and transportation costs from Uganda to a port for export. That will apply unless the refinery offers a higher price for crude supplies. The current import price of gasoline and diesel refined in Mombasa and shipped by pipeline to Eldoret, and then by truck to Kampala is UGX 2,300 per liter for gasoline and UGX 2,000 per liter for diesel excluding excise. A continuation of the product pipeline from Eldoret to Kampala is planned and when completed will reduce the price of imported products and improve the crack spread. At the current price of crude oil delivered to the refinery, and the prices of gasoline and diesel, the refinery is projected to be highly profitable.

68. **The margin between the price for crude oil and the import market prices for gasoline and diesel has historically varied.** Figure 8 shows that the implied margin between the price of Brent (which will be the basis for Uganda crude) and domestic fuels is not constant over time. For example, in 2009 and 2011 the implied margin was significantly lower than what

has been observed in recent years. The future variation in this implied margin is likely to have a direct effect on the profitability of the refinery.

Figure 8. Crude Oil Brent, and Gasoline and Diesel Prices in Uganda



Note: It is assumed that there are 159 liters in one barrel of oil. The mission used the official midpoint monthly USD:UGX exchange rate published by the Bank of Uganda.

69. **The refinery may be highly profitable and this has implications for income taxation.** The refinery is likely to be highly profitable because of (1) the projected crack spread and (2) the guarantee of supply to the refinery of an initial 30,000 bpd rising to 60,000 bpd. One option would then be to impose an excess or windfall profit tax on the refinery. The excess profit tax would tax at a higher rate on earnings in excess of a "normal" rate of return.

70. **Another possibility would be to regulate the rate of return earned by the refinery and adjust the price paid for crude oil accordingly**. This would shift profits to the upstream producers. The excess profit tax approach is superior to the regulatory approach as an excess profit tax would not tax away all of the "excess profits" and therefore retains an incentive to minimize costs and maximize revenues.

71. **All options assume that petroleum products produced will be subject to excise duty and VAT**. If VAT is fixed at the standard rate, excise should normally be fixed to cover the negative externalities (local and global pollution) arising from fuel consumption. The excise rate could, of course, be set higher or lower than this, depending upon the government's policy preference for additional revenue or for encouragement of lower cost fuel supplies to the population. Reducing excise to encourage consumption amounts to a subsidy, thus diverting revenue from other uses and increasing environmental costs. Subsidies to fuel consumption tend to benefit richer segments of society, rather than the poor, and should be avoided.

III. MINING FISCAL ISSUES

A. Fiscal Issues in the Draft Mining Policy

72. **The Draft Green Paper on Minerals and Mining Policy, dated July 9, 2015, was not yet a functioning policy document at the time of the mission.** [12] Under the various headings, there should be a description of the problem, an analysis of options including a discussion of the impact of each option, and a justification for the proposed policy.

73. **The Draft presupposes major decisions including the reassignment of functions within government.** For example, the Department of Mines within MEMD is given the primary responsibility for establishing the legal and fiscal framework for mining and for administration and monitoring of all laws, regulations and procedures. The current draft does not take account of the recent tax law changes or the 2015 Public Expenditure Management Act. The draft needs further work before it is shared with stakeholders or given to Cabinet for approval.

B. Export Rules and Subsidies for Domestic Processing

74. **Some governments have adopted policies to encourage or require downstream processing of domestic mineral products.** This processing is referred to as value addition or beneficiation, aiming to increase the domestic value-added component of exports, to provide additional jobs, and to encourage industrialization. For example, the Uganda government and the Guangzhou Dongsong Group agreed that the Sukulu project would include a fertilizer factory to process phosphate rock, a steel factory to process iron ore, and additional processing facilities. Policy instruments that governments use include export prohibitions, export taxes, differential royalties, and reduced corporate tax rates for processing plants.

75. **While the overall policy objectives are worthwhile, it is not clear that restrictive measures to encourage downstream processing have the desired effect.** The measures can have a high cost in terms of lost government revenue, export earnings and foreign direct investment (FDI) if net returns to the domestic economy are higher when the ores or concentrates are exported to a large efficient processing facility in another country. Changing patterns of international trade suggest a growing trend towards location of manufacturing and processing close to major consuming markets, and moving away from sources of raw materials or cheap labor. Reliance on downstream processing of domestic minerals, in the longer term, increases dependence on the exhaustible mineral production rather than encouraging diversification into other economic activity. Above all, the source country may sacrifice the possibility of exporting a premium raw material and using the resulting revenue for infrastructure, social capital and diversification.

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[12] The mission provided comments to the authorities on the fiscal parts of the document. The lack of comments on other parts of the documents does not imply endorsement of those parts.

Examples of "beneficiation" measures

76. **Zambia's 10 percent export tax on ores and concentrates resulted in stockpiling of copper concentrate and a delay in a nickel project.** In 2013, Kansanshi Mining stockpiled 100,000 tons of copper concentrate, representing potential royalty payments of about US$10 million, as there was insufficient smelter capacity in Zambia. The problem was likely to become worse in the near term, as new mines and mine expansions would further ramp up of copper production. This production was likely to exceed smelter capacity even after new planned smelters were placed in service. Also, the Enterprise nickel project would not have gone forward if the export duty were levied on the production of nickel concentrate. The Zambian government suspended the levy from October 2013.

77. **Differential royalty rates for processed and unprocessed are often poorly targeted.** South Africa's sliding-scale royalty has a top rate of 5 percent for processed minerals and 7 percent for unprocessed minerals. Western Australia also has differential rates but limited to copper and iron ore. Where the value-added of downstream processing is low, relative to the sale value of the processed mineral (as is the case for gold and copper), the reduction in the royalty is a significant subsidy to downstream processing. Where the value-added of downstream processing is high, relative to the sale value of the mineral, mining companies will choose to pay the higher royalty and export concentrates. An obstacle to effective discrimination in royalties is that the owners of mining operations and downstream processing such as a smelting plant are often different. Ensuring that the tax benefit of the differentiated royalty flows through to the owners of the downstream processing plants and not the mine operators would be administratively complex.

78. **Madagascar's lower corporate tax rate on income from processing facilities has resulted in a windfall benefit for the Ambatovy nickel/cobalt mine.** Ambatovy's corporate tax rate is 25 percent for the mining company and 10 percent for the processing company. Having a differential tax rate between the mining and processing companies gives an incentive to shift profits to the lower-taxed processing company by shifting costs to the processing company or underpricing the mineral product that is sold to the processing company. The benefit of the lower rate—the amount of tax reduction—increases with the profitability of the processing facility. If the processing facility is highly profitable, it may not need incentives. If the processing facility is marginally profitable, it receives a much smaller benefit from the rate reduction.

79. **An alternative to export prohibitions, export taxes, and differential royalty or corporate tax rates would be a tax incentive directly linked to investment in processing facilities, only if it is absolutely necessary.** The amount of the incentive would depend on the amount of investment made in processing facilities (for example, in building a smelter or refinery). If necessary, this incentive could take the form of an initial allowance or a tax credit equal to a percentage of the cost of depreciable assets.

80. **Direct government support to the investment needed for economically efficient processing is preferable**. A subsidy for a processing plant could take the form of direct government spending, or of spending upon supporting infrastructure. The amount of the subsidy would be more transparent than a tax subsidy that reduces tax revenue and not separately accounted for in the annual budget. Serviced infrastructure facilities with good access to transport facilities, power and water more reliably support manufacturing ad processing for export than do tax incentives.

Recommendations

- Refrain from export prohibitions and export taxes on unprocessed minerals.
- If a subsidy is wanted for domestic processing it should take the form of direct government spending or an initial tax allowance directly related to the amount of investment in the processing facility.

C. Royalties

81. **There are gaps and uncertainties in the royalty regime that should be addressed.** These gaps relate to the royalty base, the royalty rates, and the allocation of royalty revenue to local governments, landowners and lawful occupiers of the land. Shifting the administration of the royalty to URA should also be considered.

Royalty base

82. **Reliance on the term "gross value" is not sufficient to create a practicable base for assessment of royalty**. Under the Mining Act (s 98), all minerals obtained in the course of prospecting, exploration, mining or mineral beneficiation operations are subject to the payment of royalties on the "gross value" of the minerals based on the prevailing market price. The Mining Act Regulations (s 72) provide that reference prices shall be used in determining the value of precious metals or non-precious minerals – namely the latest price on the London Metal Exchange or any other Metal Exchange or market known to the Commissioner. The regulations further provide that in the absence of proof to the contrary: (a) gold shall be deemed to be 95 percent fine, (b) tin ore shall be deemed to contain 75 percent tin, and (c) the valuable contents of other metals, ore or minerals shall be such as the Commissioner may determine. Furthermore, if a mineral is exported to a refinery, the value shall be the gross sum realized without any reduction or abatement for transport, marketing, insurance, or other charges (that is, net smelter return).

83. **The gross *sales* value offers a more workable royalty base.** The gross sales value would be the sales value before any selling, transport, and insurance costs attributable to the minerals sold. For mineral products that are smelted or refined, the "gross sales value" would be the net smelter return. Reference prices would be used in determining the value of precious

metal or non-precious mineral, as under current law.[13] If minerals are exported before being sold, a provisional royalty would be imposed on the mineral. If the first saleable mineral product is sold to a related party, the government should have the power to adjust prices where the price of a mineral product has been understated.[14] The simplification suggested here would not be much different from what is current practice,[15] but the rules for determining the royalty base would be easier to understand. [16]

84. **Advance pricing agreements are useful for determining the royalty base with confidence for all parties**. To minimize protracted disputes on the gross sales value when there are related party sales, particularly where the market for the mineral is extremely limited, the government could enter into an advance pricing agreement (APA) (Box 2) with a company. The agreement would set out, in considerable detail, how the sales value would be determined for a period of years. APAs are now used by many countries and have proved very useful in reducing transfer-pricing disputes, where products are sold to a related party and there are no international prices for the product.

Royalty rates

85. **Under a reasonable reading of the Mining Act, all royalty rates are ad valorem, as the base is "gross value".** The Mining Regulations prescribes both ad valorem and specific royalty rates.[17] The rates are: (i) 5 percent for precious metals, (ii) 10 percent for precious stones, (iii) 5 percent for base metals and ores, and (iv) specific rates for various listed minerals including coal, vermiculite, limestone, marble and granite. The rate for phosphate rock is UGX 10,000 per ton.[18] The 5 percent ad valorem rate for base metals and ores applies unless a specific rate is given for the mineral or the mineral is included under (i) or (ii).

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[13] The Mining Act could provide that the sales value will be the greater of the actual sales value or value of the mineral determined by use of a reference price.

[14] The URA has the power to adjust related party prices, which it could use if administration of royalty is transferred to URA.

[15] The "royalty event" under current law is when minerals are obtained after beneficiation. The proposal shifts the "royalty event" to when minerals are sold with a special rule for minerals that are smelted or refined. Tanzania recently moved from a mine-gate royalty rate base to a gross market value of mineral sale.

[16] A useful presentation on issues of the royalty base for minerals by Pietro Guj is available at http://www.imf.org/external/np/seminars/eng/2015/natrestax/pdf/guj9.pdf.

[17] These rates were last adjusted in 2011 by statutory order.

[18] The specific rate of UGX 10,000 per ton is about 2.5 percent of the current benchmark price (US$115 per ton) for phosphate rock 32-33 percent P_2O_5 FOB Morocco.

Box 2. An Advance Pricing Agreement

- Designed to resolve actual and potential pricing disputes in a principled, cooperative manner;
- Binds the taxpayer and the country usually for a period of up to five years;
- Could be unilateral (between the taxpayer and the government of Uganda) or multilateral (between the taxpayer, the government of Uganda and the governments of one or more foreign countries, when the pricing rules are important for the taxpayer to obtain foreign tax credits).
- The government and the taxpayer will need to employ experts to develop an APA.

86. **An Amendment to the Mining Act could specify the minerals subject to ad valorem and specific rates.** In general, high value minerals, mainly metals, should be subject to ad valorem rates. Construction minerals, such as clay and limestone, and marble should be subject to specific rates. The actual rates would be set in a regulation or statutory order. Uganda's ad valorem royalty rate for base metals is on the high side by African standards, but we do not recommend reducing it. Any reduction in royalty rates would increase the public perception that mining companies are paying little for the resource in the ground, particularly as the royalty payments are a shared revenue source. Specific rates should be reviewed every year or two and adjusted in line with any change in the value of the Uganda shilling and mineral prices. If specific royalty rates are given fiscal stability in a mining agreement, the rates should be set in US dollars or be adjusted by formula each year.

Royalty assessment and administration

87. **The administration of the royalty is shared between the Department of Mines and URA.** The Commissioner of Mines assesses the royalty, and under the Mining Act Regulations, the royalty is payable within 30 days from the assessment date. Payment is made to URA.

88. **The best international practice is for mineral companies to self-assess the royalty and make monthly or quarterly payments.** The agency administering the royalty can undertake risk-based audits of royalty returns (and make default assessments in cases where a royalty returns is not submitted). Not all returns are audited. In contrast, under Uganda's current rules, each company must be assessed before royalty is payable.

89. **A strong case can be made for shifting the administration of the royalty to URA.** First, when the royalty is administered by the Department of Mines and the income tax by URA, there is considerable duplication and overlap as both must review or audit the value of mineral sales. Second, if the royalty administration is shifted to URA, all the rules and powers in the Tax Procedures Act of 2014 would apply – including registration of taxpayers, tax identification numbers, record keeping, tax returns, self-assessment, objection and appeals, tax collection, and interest on late payments. Uganda's Mining Act and Regulations have only limited enforcement powers. S 104 of the Mining Act includes a penalty for failure to pay royalty on the due date,

which requires the Commissioner to prohibit the company from disposing any mineral obtained. This penalty is too harsh and is likely seldom imposed. Under s 71(3) of the Regulations, the Commissioner may issue an export permit only where the royalty due on the minerals has been paid or secured.[19] In recent years Liberia, Sierra Leone, and Zimbabwe have shifted the administration of the royalty to the tax authority. Liberia has also shifted the authority to impose royalty out of the mining legislation to the Liberian Revenue Code.

90. **Amendments to the Tax Procedure Act are required to shift the administration of the royalty to URA.** First, tax would be defined to include mineral royalties and the Mining Act of 2003 would be added to the list of tax laws in Schedule 2. Second, tax return would be defined to include a royalty return. The Mining Act of 2003 would be amended to state that URA administers the royalty. The power of the Commissioner to issue an export permit only where the royalty has been paid or secured would be retained in the Mineral Regulations. Once the administration of the royalty has been shifted to URA, the Department of Mines would continue to cooperate with URA on valuation and other mining-specific issues.

Sharing royalty revenue

91. **Royalty revenue is shared with local governments and local owners and lawful occupiers**. The Mining Act and the Second Schedule of the Regulations specify that royalty payments be shared among the central government (80 percent), district council (10 percent), urban or sub county council (7 percent), and owners or lawful occupiers of the land subject to mineral rights (3 percent). The central government has responsibility for the allotment of royalty revenues to local governments and owners and lawful occupiers. Identifying the local government jurisdictions where the mine is located is straight forward. If a mine is located in two or more district councils or two or more urban or sub county councils, a rule is needed to allocate the respective shares of royalty revenue. In this situation, the respective shares could be allocated according to the population and land area.[20]

92. **Allocating royalty revenue to owners or local occupiers of the land subject to the mineral right is problematical but important**. It can be particularly difficult to make the allocation where there is customary communal title to land, the incidence of which is not always capable of precise definition and may vary from community to community or within a community. Ownership of land can be separated from lawful occupancy of the land or ownership of developments by lawful occupiers. In some situations, the mining company may be the owner of the land subject to the mineral right and the 3 percent of the royalty revenue reserved for the owners should be allocated back to the mine company. Mine companies will want to reduce their

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[19] See also sec. 83 of the Regulations, which specifies a fine for failure to keep certain records up to 100 currency units (UGS 2 million or about US$580) and jail time up to one year.

[20] Philippines uses a two-factor allocation formula with weights of 70 percent for population and 30 percent for land area.

royalty payment by 3 percent to short circuit the payment and allocation system. Payments or royalty revenue to local governments should be paid promptly even though the allocation of revenue to owners or local occupiers of the land is being determined.

93. **The allocation of royalty revenue is tied to the surface location of the mineral right.** A large-scale mining project, however, may require significant processing facilities, which are located on land not covered by the mineral right. As these facilities can disrupt local communities and pollute the water and air, there may be a case for sharing the royalty revenue with local governments and landowners where the processing facilities are located.

Recommendations

- Define the royalty base for ad valorem royalties as the gross sales value of the mineral product.
- Allow the government to enter into Advance Pricing Agreements when there are related party sales.
- Amend the Mining Act to provide for specific royalty rates for construction minerals.
- Ensure that specific rates are reviewed every year or two to keep them in line with the value of the Uganda shilling and changes in the market value of minerals subject to specific rates.
- Require mineral companies to self-assess the royalty and make monthly or quarterly payments.
- Shift the administration of the royalty to URA.
- Study the allocation of royalty revenue to local governments and owners and lawful occupiers of the land and consider amending the Mining Act or issuing a statutory order.

IV. GENERAL TAXATION ISSUES

A. Issues Relating to the 2015 Amending Legislation

94. **Laws to amend the Income Tax Act ("ITA") and the Value Added Tax Act ("VAT Act") as they apply to extractive industries were passed with effect from July 1, 2015.** The amending legislation implements many of the tax law recommendations made in FAD (June 2015), in particular the amending legislation provides for the introduction of the deemed paid VAT system and reverting to the pre-2010 regime for the computation of the chargeable income of licensees based on the normal rules under the ITA.

95. **After consulting with stakeholders (particularly MEMD), MOFPED prepared the Bills, incorporating advice from the FAD/LEG mission team.** As noted below, Parliament amended the Income Tax Amendment Bill. The discussion below focuses largely on: (i) matters requiring clarification and (i) matters requiring technical correction.

VAT Issues

96. **The VAT Amendment Act 2015 implements the deemed paid VAT regime.** The regime applies to taxable supplies made by a contractor to a licensee for use by the licensee solely and exclusively for mining or petroleum operations. A "licensee" is a person granted a mining right or has entered into a petroleum agreement with the Government. A "contractor" is a person supplying goods or services (other than as employee) to a licensee in respect of mining or petroleum operations. The definition of "petroleum operations" extends to authorized operations under a petroleum agreement for the construction of a pipeline or refinery. "Petroleum agreement" means an agreement entered into under either the Petroleum (Exploration, Development and Production) Act or the Petroleum (Refinery, Conversion, Transmission and Midstream Storage) Act. Thus, the deemed paid VAT regime applies to the upstream petroleum operations and the construction phase of the midstream petroleum operations (both pipeline and refinery).

97. **As the legislative framework is in place for the deemed paid VAT regime, the issue now is the practical implementation of the regime.** This requires development of a Practice Note under s 44 of the Tax Procedures Code Act, designed in consultation with the petroleum licensees.

98. **The Practice Note could include guidance on when taxable supplies are for use by licensees solely and exclusively for mining or petroleum operations.** The scope of the regime is defined by the concepts of mining and petroleum operations, which are defined in s 1 of the VAT Act. The definition of "mining operations" is narrower than the definition of "petroleum operations". "Mining operations" are limited to mining exploration and the process of winning minerals from the soil. Consequently, mining operations end at the run-of-mine stockpile or at least at the mine gate. The definition of "petroleum operations" includes export, and the

transportation and storage of petroleum. As noted above, "petroleum operations" also include the construction of a pipeline or refinery. The deemed paid VAT regime applies only when the taxable supply is for use by the licensee solely and exclusively in mining and petroleum operations. Consequently, there is no scope for apportionment in the case of a taxable supply, partly for use in mining or petroleum operations and partly for some other use (such as purely administrative functions of the mining or petroleum licensee). The normal VAT regime applies to such taxable supplies.

99. **Two recommendations from FAD June 2015 relating to the import of goods for mining or petroleum operations remain outstanding.** First, because contractors import a large share of the inputs required for mining or petroleum operations, FAD June 2015 recommended that an import of goods by a contractor for direct and exclusive use in mining or petroleum operations should be exempt from duty[21]. Second, the scope of the exemption for mining licensees should be broadened to align with the exemption for petroleum licensees. These exemptions should also be extended to VAT (the imports would be treated as exempt imports under the VAT Act).

100. **The implementation of these recommendations requires amendments to the East African Community Customs Management Act.** These amendments must be agreed to at the EAC level before they can be implemented at the national level, although understood to have been accepted by the authorities. Thus, there is limited scope for Uganda to act unilaterally on duty exemptions. As an interim measure, the mission team suggested including an import of goods by a contractor for direct and exclusive use in mining or petroleum operations as an exempt import to at least provide relief in relation to VAT. However, this would have created the inconsistent outcome that the import is subject to duty but not VAT; the authorities decided instead to pursue the duty exemption at the EAC level first and, when implemented, the exemption will apply automatically for VAT under s 20 of the VAT Act.

101. **The input tax credit for the reverse charged VAT on imported services was to be reintroduced for licensees and contractors. (FAD June 2015.)**The VAT Amendment Act 2015 has provided for this but uncertainties remain as to the meaning of imported services for this purpose.

102. **Uganda currently levies excise duty on gasoline, diesel, and illuminating kerosene while exempting these products from VAT.** In anticipation of the establishment of a refinery in Uganda, FAD June 2015 recommended that the VAT exemption for petroleum products be repealed and the excise duty rates adjusted accordingly. A draft based on recommendations of FAD June 2015 provided for the repeal of the VAT exemption. The authorities decided, however, to delay the implementation of this reform until closer to the commencement of refinery

[21] It is understood that the EAC Secretariat has notified member States that imports by contractors for supply to licensees are exempt imports. However, this will require legislative authority.

operations so as to allow further time to determine the appropriate adjustment to the excise duty rates and also to manage the change in the public environment.

Income Tax Issues

Petroleum Exploration Expenditure and Petroleum Development Expenditure

103. **The enacted definitions of "petroleum exploration expenditure" and "petroleum development expenditure" differ significantly from those recommended.** They also differ from the equivalent definitions in relation to mining operations. It is understood that the enacted definitions were based on advice received from MEMD (referred to as the "MEMD advice"). In reviewing the MEMD advice, it is clear that MEMD provided the advice on the assumption that the income tax treatment of expenditure would continue to be aligned with the cost recovery treatment. That was not the intention; rather the intention was to revert to the pre-2010 approach under which the normal rules under the ITA apply in determining the allowable deductions of a petroleum licensee in computing chargeable income.

104. **Uncertainties now arise as to the scope of the definitions of "petroleum exploration expenditure" and "petroleum development expenditure".** Ideally, these uncertainties would be eliminated by reverting to the definitions suggested earlier by the mission team, which would then align with the equivalent definitions for mining operations. In the meantime, some of the uncertainties could be dealt with through a Practice Note.

105. **"Petroleum exploration expenditure" is defined to mean expenditure incurred by a licensee in undertaking petroleum exploration operations authorized under a petroleum exploration right.** There is uncertainty as to whether the following expenditures are petroleum exploration expenditure: (i) the cost of acquiring an interest in a petroleum exploration license; (ii) the cost of acquiring petroleum exploration information; (iii) the cost of acquiring a depreciable asset for use in petroleum exploration operations; and (iv) social infrastructure expenditure compulsorily incurred in relation to petroleum exploration operations. It was intended that each of these items of expenditure would be petroleum exploration expenditure and, therefore, expensed under s 89GB of the ITA.

106. **The cost of acquiring a petroleum exploration right or an interest in such right would probably not be petroleum exploration expenditure as defined.** The cost of the right will therefore be dealt with under the normal operation of the ITA. The right would be an intangible asset and, therefore, the cost would be deducted under s 31 of the ITA over the useful life of the right (life of the petroleum exploration operations). Importantly, the cost would not be expensed as would be the case for exploration expenditure.

107. **The cost of acquiring petroleum exploration information may be petroleum exploration expenditure if it is authorized expenditure under the petroleum exploration license.** The MEMD advice indicates nevertheless that the cost of acquiring information would

not be authorized expenditure. On that basis, the treatment of the cost of acquiring petroleum exploration information would be the same as for the cost of acquiring a petroleum exploration license on the basis that information is an intangible asset. There may be scope, though, for such expenditure to be treated as petroleum exploration expenditure under a Practice Note.

108. **The cost of acquiring a depreciable asset for the purposes of petroleum exploration operations would seem to be petroleum exploration expenditure.** The terms of s 89GB(1) would support this characterization (as does the MEMD advice) and, therefore, the cost is expensed under s 89GB. This could be clarified in a Practice Note.

109. **Social infrastructure expenditure will be petroleum exploration expenditure only if the expenditure is authorized under the petroleum exploration license.** The MEMD advice states that such expenditure would not be authorized expenditure. On that basis, the deductibility of such expenditure will be determined under general principles. The issue is whether the expenditure is incurred in deriving business income (in which case it will be deductible) or is an application of business income after it has been derived (in which case it will be non-deductible).

110. **"Petroleum development expenditure" is defined to mean expenditure incurred by a licensee in undertaking petroleum (development) operations authorized under a petroleum production right.** The characterization issues for the cost of acquiring an interest in a petroleum production license, the cost of acquiring petroleum development information, and social infrastructure expenditure are the same as discussed above for the equivalent expenditure in relation to exploration.

111. **The cost of acquiring a depreciable asset for the purposes of petroleum development operations would seem to be petroleum development expenditure.** This is the position taken in the MEMD advice. This means that the cost of such assets is depreciated on a straight-line basis under s 89GC(2) of the ITA over the lesser of: (i) the expected life of the petroleum development operations; or (ii) six years. This was not intended; rather, it was intended that the normal depreciation rules apply to depreciable assets used in petroleum development operations.

112. **The classification of expenditure as petroleum development expenditure is not limited to capital expenditure.** Technically, this means operating expenditure incurred during petroleum development operations is amortized under s 89GC, rather than deducted outright under s 22. This will need technical correction. In the meantime, this could be clarified in a Practice Note.

Computation of Gross Income

113. **As noted above, the amending legislation reverts to the pre-2010 tax regime under which the chargeable income of a licensee is based on the normal income and deduction**

rules under the ITA as modified by Part IXA. The Income Tax Amendment Act 2015 inserted a definition of "gross income of a licensee" in s 89A(1). The definition includes "cost oil, licensee's share of profit oil and any credits earned by the licensee from petroleum operations". The definition was inserted as a result of MEMD advice. As stated above, the MEMD advice did not fully appreciate that the amending legislation was reverting to the pre-2010 tax regime. Consequently, the gross income of a licensee for a year of assessment includes the total sales revenue derived by the licensee on an accrual basis for the year. While this will largely align with the value of the licensee's cost and profit oil, the gross income amount under the normal income tax rules may not be exactly the same as the value of the licensee's production share.

114. **The term "gross income of a licensee" is not actually used anywhere in Part IXA so the definition has no operation.** The petroleum licensees have noted the confusion that the definition creates and, therefore, the computation of gross income should be clarified in a Practice Note. Ideally, the definition of "gross income of a licensee" should be deleted.

Ring Fencing

115. **Ring fencing under s 89GA of the ITA is done by reference to the "contract area" of a licensee.** "Contract area" is defined in s 89A to mean the exploration or development area subject to a petroleum agreement. "Exploration area" and "petroleum area" are not separately defined and, therefore, under s 89A(2), have their respective meaning under the PEDPA. Consequently, "exploration area" means the area constituted by a block or blocks subject to a petroleum exploration license and "development area" means the area constituted by a block or blocks, which, following a commercial discovery, has been delineated for production according to the terms of a petroleum agreement. Consequently, the basic definition of "contract area" under the ITA aligns with PEDPA.

116. **For the purposes of ring fencing, when the contract area is a development area, the area is treated under s 89GA(5) as including the relevant exploration area provided the development area is wholly within the exploration area.** This recognizes the fact that the development area under a petroleum agreement will normally be a smaller area than the exploration area under the agreement and, therefore, ensures that losses arising from petroleum exploration operations can be deducted against income derived from petroleum development operations.

117. **Under Article 12.2 of the model PSA, ring fencing applies by reference to the contract area as defined in the model PSA.** "Contract area" is defined in Article 1.1.16 to mean: (i) initially, the area described in Annex A of the model PSA; and (ii) thereafter, the whole or any part of such area that, at any particular time, remains subject to a petroleum exploration license or petroleum production license. While this definition of "contract area" is similar to the definition in s 89A of the ITA, it may not be exactly the same, particularly in relation to petroleum development operations. It will be important to ensure that the definition in the model PSA is aligned with that under the ITA and PEDPA.

118. **There is no provision, under s 89C of the ITA, for the transfer of a loss for a license area at the end of mining operations to another license area.** Similarly, there is no provision under s 89GA of the ITA for the transfer of a loss for a contract area at the end of petroleum operations to another contract area. Consequently, such losses are terminal losses and this was confirmed by MOFPED as the policy adopted. The impact of this will, however, be reduced by the allowance of deductions for contributions to a rehabilitation fund (mining operations) or decommissioning fund (petroleum operations).

Farm-outs

119. **S 89GD(2)(a) of the ITA provides that the value of work commitments undertaken by a farmee, in relation to the part of the mining or petroleum right retained by the farmor under a farm-out agreement, is subject to tax to the farmor.** As an incentive to encourage exploration or development, FAD June 2015 proposed that the value of work commitments be excluded from both gross income and the consideration for the transfer of the interest in the mining or petroleum right. The mission was advised that the decision to tax the value of work commitments was based on MEMD advice. It is recommended, in FAD (June 2015), that the value of work commitments is not taxed as an incentive to encourage exploration (para 169).

Changes in Underlying Ownership of Licensees

120. **S 89GF(1) of the ITA obliges a mining or petroleum licensee to immediately notify the Commissioner-General of any change in the underlying ownership of the licensee.** The Bill included a threshold with the reporting obligation applying only when there is a 10 percent or greater change in underlying ownership. The 10 percent threshold was apparently deleted from the Bill in Parliament. This means that the reporting obligation applies to any change, no matter how small, in the underlying ownership of a licensee. In practice, this will be next to impossible to enforce particularly in relation to publicly listed companies. It is suggested that this could be dealt by way of Practice Note providing for an administrative *de minimis* exception to the reporting obligation.

Non-resident Contractor Tax

121. **S 89GG of the ITA provides for imposition of non-resident contractor tax at the rate of 10 percent of the gross amount of a service fee paid by a licensee to non-resident contractor.** The tax is a final tax and, therefore, is not included in the gross income of the contractor. It was intended that the tax should apply only to a service fee paid to a non-resident contractor who does not have a branch in Uganda. If a non-resident contractor has a branch in Uganda, then the service fee should be included in the computation of the chargeable income of the branch and taxed on an ordinary assessment basis. S 89GG was, however, amended in Parliament to apply to service fees paid to non-resident contractors irrespective of whether or not the contractor has a branch in Uganda. Given that the change was made in Parliament, it may

be difficult to revisit this; one possibility is to retain the withholding tax for service fees paid to all contractors but amend s 89GG so that the tax is non-final (and creditable) for a non-resident contractor who derives the fee through a Ugandan branch.

122. **While acknowledging the reduction in the withholding tax rate from 15 to 10 percent, the petroleum companies continue to argue against the tax.** The absence of a withholding tax on service fees paid by a licensee to a non-resident contractor will lead to tax base erosion in Uganda (FAD June 2015). The base erosion arises because the licensee is able to deduct the fee at the corporate rate of 30 percent but without any corresponding Ugandan tax imposed on the fee. The 10 percent withholding tax limits the impact of such base erosion.[22]

123. **Non-resident contractor tax (s 89GG) applies in priority to the taxes imposed under s 83 and s 85 of the ITA.** While this is not expressly provided for, s 89GG would have priority under the principle of statutory interpretation that the specific prevails over the general. This should be clarified in a Practice Note.

Source Rules

124. **The source rules in s 79 of the ITA should be modernized, including in relation to an indirect transfer of immovable property (defined in s 78(aa) to include an interest in a mining or petroleum right).** (FAD June 2015.) The source rules were drafted over 20 years ago and have not kept fully in pace with modern cross-border trade and investment. Modernizing the source rules is still on the agenda, but revisions to the rules have been postponed until the finalization of some cases currently before the courts concerning the application of the existing rules. MOFPED is concerned that any changes made to the source rules now may prejudice the outcome of those cases.

125. **It will be necessary to prepare transitional rules in relation to the new regime for taxation of mining and petroleum operations.** Such rules will be particularly important in relation to petroleum operations. Section 164(2)(a) of the ITA provides that transitional rules can be promulgated by regulations. These should be prepared in consultation with the petroleum licensees.

Technical Corrections

126. **The following technical corrections need to be made to the ITA in relation to the amendments made by the Income Tax Amendment Act 2015:**

[22] Base erosion under the income tax arising from cross-border services is part of the OECD Base Erosion Profit Shifting ("BEPS") project. A likely outcome of the BEPS project is greater recognition of source country taxing rights in relation to cross-border services in line with the approach taken in s 89GG.

(1) The definition of "immovable property" in s 79(aa) includes "petroleum information". S 79(c) provides that "petroleum information" has the meaning in s 89A. Based on MEMD advice, the definition of "petroleum information" was deleted from s 89A. A definition of "petroleum information" will need to be re-included in s 89A to accommodate the cross-reference in s 79(c). Alternatively, the definition could be included in s 79.

(2) Definition of "licensee" in s 89A(1) – delete "Petroleum (Refining, Conversion, Transmission and Midstream) Act and substitute "Petroleum (Exploration, Development and Production) Act".

(3) The definition of "mining exploration right" in s 89A(1) is repeated. There is a conflict between the two definitions as the first version of the definition does not include a reference to a prospecting license. Consequently, The first version of the definition should be deleted.

(4) Delete definition of "participation dividend" in s 89A(1) as the term is not used in Part IXA.

(5) Definition of "petroleum development right" in s 89A(1) – delete "exploration operations" and substitute "petroleum development operations".

(6) Delete s 89G(4) and (5) as they reproduce s 89GA(4) and (5).

(7) Delete s 89GC(6), which defines "commercial production" in relation to petroleum operations. There is also a definition of "commercial production" in s 89A that is in different terms to the s 89GC definition. The definition in s 89A aligns with the definition in the model PSA and, therefore the definition in s 89GC(6) should be deleted. The definition in section 89A should be renamed "commencement of commercial production".

(8) Delete "or licensee" in s 89GG(1).

(9) Change the cross-reference in s 89GG(4) to "subsection (3)".

(10) Delete s 89GG(7). What is now s 89GG(8) was intended to replace s 89GG(7).

(11) The amendment made to s 89MA(b) needs to be corrected. The paragraph should read:

> "(b) taxes payable to the Government not included in ~~Government~~ **mining or** petroleum revenues, in this Part referred to as "other taxes"."

(12) In s 89QA(3), the cross-reference to "subsection (2)" needs to be changed to "subsection (1)".

Recommendations

- Prepare a Practice Note on the operation of the deemed paid VAT regime.
- Pursue at EAC level the following amendments to the East African Community Customs Management Act: (i) the exemption of imports by a contractor for direct and exclusive use in mining or petroleum operations; and (ii) the alignment of the exemption for imports by a mining licensee with that applicable to imports by a petroleum licensee.
- Plan to delete the exempt supply treatment under the VAT for petroleum products and adjust the excise duty rates accordingly.
- Revert to the original proposed definitions of "petroleum exploration expenditure" and "petroleum development expenditure". If the current definitions are retained, amend the definition of "petroleum development expenditure" to cover only capital expenditure. Prepare a Practice Note on the scope of the definitions.
- Delete the definition of "gross income of a licensee". Prepare a Practice Note on the determination of the gross income of a petroleum licensee.
- Ensure that the definition of "contract area" and the ring-fencing rule in the model PSA align with the ITA and PEDPA.
- Amend s 89GD(2)(a) so that the value of work commitments is not taxable.
- Prepare a Practice Note to give effect to a *de minimis* exception to the reporting obligation in s 89F(1) for small transactions, particularly on a stock exchange.
- Provide that the non-resident contractor tax is non-final and creditable for service fees paid to a Ugandan branch of a non-resident contractor. Clarify in a Practice Note that s 89GG has priority over ss 83 and 85.
- Modernize the source rules, including for indirect transfers of immovable property.
- Make transitional provisions by regulations.
- Make the technical corrections to Part IXA listed at paragraph 32.

B. VAT and Imported Services

General principles for VAT on imported services

127. **The taxation of imported services is more complicated than the taxation of imported goods because services do not "pass through" any border control.** This means that, unlike with goods, the VAT on imported services cannot be collected at the border. Two

situations need to be distinguished: (i) services provided in a "business-to-business" (B2B) transaction when the recipient is a registered person; and (ii) services provided in a "business-to-consumer" (B2C) transaction.

B2B Transactions

128. **The most effective way to collect VAT in relation to the service is by reversing the normal operation of the VAT and charging VAT on the registered person receiving the service (referred to as "reverse charging")**. This is because the recipient of imported services in a B2B transaction is a registered person. Two situations are distinguished:

(1) If the registered person receiving the imported services uses those services solely to make taxable supplies, the reverse charged VAT and the resulting input tax credit offset each other so there is no net VAT payable by the registered person in respect to the imported services. The VAT on the imported services is then effectively captured in the VAT imposed on the subsequent taxable supplies, made by the registered person, for which the imported services were an input. Because the net VAT position is unchanged, whether the reverse charge is applied or not, some countries do not apply the reverse charge rule in this case.

(2) If the registered person receiving the imported services uses the services wholly or partly for purposes other than making taxable supplies, then the reverse charge rule produces a net VAT liability as no offsetting input tax credit is allowed to the extent that the imported services are not used to make taxable supplies. The main example is when the imported services are used in making exempt supplies (such as supplies of financial services).

It is important that a reverse charge rule applies in (2) above otherwise there is an incentive for registered persons who also make exempt supplies (such as financial institutions) to acquire services in relation to those supplies from outside the jurisdiction. As VAT is not charged on exempt supplies, the value added by the services would not otherwise be included in the domestic VAT base. This puts local suppliers of the same services at a competitive disadvantage as compared to foreign suppliers as local providers must charge VAT. The reverse charge rule prevents this bias.

B2C Transactions

129. **Taxation of imported services in a B2C transaction is more problematic.** It is generally not feasible to require the recipient of the services (usually a final consumer) to report and pay VAT on imported services received under a reverse charge rule. In this case, the VAT law will usually include place of supply rules that locate certain foreign-provided services to unregistered persons as supplied in the country if they are consumed in the country. Provided the other conditions are satisfied, the provision of the services is a taxable supply. If the taxable

value of taxable supplies made by a foreign-service provider exceeds the registration threshold, the foreign-service provider is registered for VAT. If the foreign-service provider does not have a physical presence in the country, then they are required to appoint an agent in the country who is responsible for meeting their VAT obligations.

Internal Transfer of Services

130. **The reverse charge rule can be avoided through the acquisition of services from another part of the same entity located abroad (such as the entity's headquarters or a foreign branch).** For example, there is an incentive for a Ugandan branch of a foreign bank to acquire services related to the making of exempt supplies in Uganda from its foreign headquarters (or another part of the bank outside Uganda) rather than from a supplier in Uganda, thereby avoiding any VAT on the acquisition. Again, this puts the Ugandan providers of the same services at a competitive disadvantage because they must charge VAT on their supplies. This is avoided by extending the reverse charge rule to the internal acquisition of services from another part of the same entity located outside the country.

Taxation of Imported Services under the VAT Act

131. **S 4(c) of the VAT Act imposes VAT on the "supply of imported services (other than an exempt service) by any person" and s 5(c) provides that the recipient of a supply of imported services is the person obliged to pay the VAT due in respect of the supply.** Consequently, s 5(c) creates a reverse charge rule in respect of a supply of imported services. Prior to the VAT Amendment Act 2015, no input tax credit was allowed for the reverse charged VAT paid by a registered person. However, the VAT Amendment Act 2015 has amended s 28(1)(b) to allow a contractor or licensee an input tax credit for the VAT paid on imported services.

132. **There are no further provisions relating to supplies of imported services in the VAT Act.** Technically, under the VAT Act, every supply of imported services is charged to VAT and the recipient, whether they are a registered person or a final consumer, is liable to pay the VAT on the supply. This is confirmed by Regulation 13(1), which obliges a person receiving imported services to account for the VAT payable in respect of the services (although, it is noted that regulation 13(2), which provides a taxable value rule for imported services, refers only to a registered person).

133. **Certain foreign-provided services made to unregistered persons are treated as supplied in Uganda (s 16(2)).** This is consistent with the usual place of supply rule that applies to B2C foreign-provided services. However, the combined operation of the reverse charge for imported services and s 16(2) has created uncertainty in the application of the VAT to foreign-provided services to unregistered persons. It appears that both rules can apply with no clear priority rule.

134. **It is unusual to apply the reverse charge rule to unregistered persons.** Previously, during the exploration phase, a mining or petroleum licensee could not voluntarily apply for registration as the licensee was not making supplies of goods or services during that phase of operations. It is possible, therefore, that mining and petroleum licensees engaged in exploration were the main class of unregistered person liable for the reversed charged VAT on imported supplies. However, as a result of amendments made by the VAT Amendment Act 2015, mining and petroleum licensees are now permitted to apply for registration during the exploration phase. Consequently, it would be better practice to confine the reverse change rule to registered persons. This would be consistent with regulation 13(3), which applies the reverse charge rule to internal transfers of services only by registered persons.

135. **There is no definition of "imported services" in the VAT Act.** This has been a source of confusion in the application of the reverse charge rule. On the basis that the reverse charge rule applies only to registered persons, imported services could be defined as a supply of services that satisfies all the following conditions:

(1) An unregistered person makes the supply of the services to a registered person.

(2) The supply is not made in Uganda under the place of supply rules for services.

(3) The supply would have been a taxable supply if a registered person had made the supply in Uganda.

136. **S 16(2) of the VAT Act specifies a place of supply rule for foreign-provided services to unregistered persons.** If the person providing the services exceeds the registration threshold, then the person must register for VAT. If the person does not have a place of business in Uganda, the person should be required to appoint an agent in Uganda responsible for meeting their VAT obligations.

Recommendations

- The reverse charge rule in s 4(c) and s 5(c) of the VAT Act should apply only to registered persons. Amend regulation 13 accordingly.
- Include a definition of "imported services" in s 1 of the VAT Act.
- Require a non-resident person who is a registered person but who does not have a place of business in Uganda to have an agent in Uganda for the purposes of the VAT Act.

C. Double Tax Agreements

Background

137. **Double tax agreements ("DTAs") can have a significant negative impact on the level of government revenue from the resources sector.** A DTA is an international agreement between two or more countries (referred to as "Contracting States"). The preamble to a DTA will often state that the purpose of the DTA is to provide relief from double taxation. Today, though, most countries provide relief from double taxation unilaterally and, therefore, the main role of a DTA is the allocation of taxing rights as between the Contracting States in relation to income or gains arising from economic activity occurring between the States. In particular, a DTA will usually involve a Contracting State accepting reduced taxing rights as source country.

138. **Over the last few years, there has been a moratorium in practice on the negotiation of new DTAs.** Uganda has nine DTAs currently in force. Nevertheless, a DTA with UAE was signed very recently, but the text of the DTA was not available. In addition, negotiations have commenced recently for other new DTAs. . An East African Community tax treaty has been negotiated but to date ratified by only two countries (Rwanda and Kenya). Before any further DTAs are negotiated, it is timely for the Government to develop a DTA policy to ensure that any future DTAs operate in the best interests of Uganda.

DTA Policy

139. **Because of the potential negative impact on tax revenues in Uganda, it is important for the Government to develop a DTA policy.** It is certainly not incumbent on the Government to negotiate a DTA with every country that seeks a DTA with Uganda nor would this be in the country's best interests. The DTA policy should include: (i) clear guidelines for choosing DTA partners; (ii) a baseline for negotiations (what is negotiable and what is not); (iii) the development of a Uganda draft model DTA that can be shared with a potential DTA partner to strengthen Uganda's negotiation position; and (iv) the preparation of a DTA impact statement once the DTA has been negotiated but before it is signed. In addition, it is vital that finance and tax officials that are trained and highly skilled in the application of DTAs are involved in Uganda's DTA negotiations, so that the process is fully integrated with national tax policy.

140. **It is essential that clear guidelines be developed for choosing DTA partners.** The main argument for developing countries entering into a DTA is that it will facilitate existing trade and investment into the country and attract new investment. In choosing a DTA partner, regard is therefore to be had to the current level of trade and investment coming from the potential DTA partner into Uganda. If that level of trade is significant, there may be greater justification for negotiating a DTA. Where there is little or no current trade and investment with a potential DTA partner, then greater care should be taken in making the decision to negotiate with that country. In particular, an investigation should be undertaken into why there is currently little or no trade or investment from the country. If there are impediments to such trade and investment, a realistic

assessment must be made as to whether a DTA will help remove or overcome those impediments. If it is unlikely that a DTA will have any significant impact on the level of trade or investment coming into Uganda, then there would seem to be little justification in negotiating the DTA.

141. **Uganda's DTA policy should prohibit negotiations with any country whose rules or practices pose a revenue risk to Uganda.** In negotiating a DTA, the intention is that treaty benefits are limited to genuine residents of the other Contracting State. Consequently, in choosing a DTA partner, it should be clear that the potential trade and investment from that country is genuinely sourced from that country. Some countries negotiate a broad DTA network to facilitate treaty shopping. In this case, the aim is to attract residents from outside the country to establish a base company in the country to take advantage of the broad DTA network. The base company is usually established under a preferential tax regime in the country. If Uganda negotiates a DTA with such a country, the revenue loss from the DTA can be expected to be much greater than would be the case if the application of the treaty were confined to genuine residents of the other country.

142. **There are mechanisms alternative to a DTA enabling the tax administration to detect and prevent tax evasion.** These mechanisms include exchange of information, and reciprocal assistance in recovery of tax and service of process. This can be done under a tax information exchange agreement ("TIEA") or by becoming a party to the Multinational Convention for Multinational Administrative Assistance. The advantage of a TIEA or the Multinational Convention is that the administrative benefits are obtained without giving up any taxing rights.

143. **As a DTA will involve a loss of revenue through the reduction in Uganda's taxing rights under the DTA, a DTA impact statement should be prepared before the DTA is signed.** A DTA impact statement should set out the following:

(1) The reasons for choosing the other country as a DTA partner, including a statement of the current volume of trade and investment into Uganda from the country.

(2) An assessment of how the DTA will increase the level of trade and investment into Uganda.

(3) A statement of any other benefits to Uganda that may be obtained under the DTA.

(4) A quantification of the potential revenue loss for Uganda under the DTA.

144. **It is good practice for Uganda to develop its own model DTA to facilitate future DTA negotiations.** There are two main model DTAs that could be used as a base for developing a Uganda model DTA: the OECD Model Tax Convention on Income and on Capital ("OECD Model DTA") and the UN Model Double Tax Convention between Developed and Developing Countries ("UN Model DTA"). Given that the UN Model DTA provides for greater protection of source

country taxing rights, it should form the basis of Uganda's model DTA, although some elements from the OECD Model can be incorporated. The Ugandan model DTA should take account of regional efforts to develop a common approach to DTA negotiation.

145. **Uganda is developing its own model DTA for use in future negotiations.** The mission was supplied with a draft of a model DTA (referred to as the "Draft Model DTA"), which is based on a current DTA negotiation. It does not clearly follow the UN or OECD Model DTAs, nor does it adequately take into account Uganda's domestic law and existing DTAs. Rather than using a model that has been crafted through a current DTA negotiation, it would be preferable for Uganda to develop a new model DTA that clearly and independently sets out Uganda's negotiating position on all the articles of a DTA. As stated above, the UN Model DTA could form a good starting part for developing such a model. The model DTA should take account of any new developments in tax treaty policy resulting from finalization of the BEPS Actions by the OECD, particularly in relation to the definition of "permanent establishment". The discussion below focuses only on those aspects of the Uganda draft model DTA supplied that are relevant to the resources sector.

Business Income

Domestic Tax Law

146. **A non-resident person is liable for income tax only on Ugandan-source business income (s 17(2)(b) of the ITA)**. Income derived by a non-resident person in carrying on a business through a branch in Uganda is Ugandan-source income (s 79(a)(ii) of the ITA (inserted by the 2015 Amendment Act)).

147. **The definition of "branch" in s 78(a) of the ITA is broadly similar to the DTA concept of permanent establishment ("PE")**. The definition has the following inclusions:

(1) Standard branch – a place where a person carries on business.

(2) Agency branch – a place where a person is carrying business through an agent, other than an agent of independent status acting in the ordinary course of business.

(3) Substantial equipment branch – a place where a person has, is using, or is installing substantial equipment or machinery for a period of more than 90 days.

(4) Construction branch – includes supervisory activities and with a 90-day threshold before the branch is established.

(5) Services PE – based on a 90-day period (inserted by the 2015 Amendment Act).

148. **The taxable income of a branch of a non-resident is calculated in the same way as the taxable income of a resident person, namely gross income minus allowable deductions.**

Regulation 4 of the Transfer Pricing Regulations provides for the separate entity approach in the attribution of income and expenses to a Ugandan branch. The taxable income of the branch is taxed on an assessment basis.

Uganda Draft Model DTA

149. **Article 7 of the Uganda draft model DTA provides for the taxation of business profits.** The Uganda model DTA follows the international norm that business profits derived by a resident of a Contracting State are taxable only in that State unless the resident has a PE in the other Contracting State. If there is a PE in the other Contracting State, that State can tax only so much of the business profits that are attributable to the PE.

150. **Article 5 of the Uganda draft model DTA defines "permanent establishment" for the purposes of the DTA.** While the definition is primarily relevant to Article 7 of the Uganda draft model DTA, it is also relevant to Articles 11, 12, 13 and 14 of the draft model.

151. **The definition of PE in the Uganda draft model DTA largely follows the definition in the OECD and UN Model DTAs.** As a baseline, the definition of PE in the Uganda draft model DTA should include every category of branch under domestic law. The following observations are made about the definition of PE in the Uganda draft model DTA:

(1) The definition should include the substantial equipment and services PE inclusions to align with the definition of "branch" in s 78 of the ITA. The inclusion of a services PE rule is particularly relevant to extractive industries because of the high use of contractors in the sector. It is also important that the services PE rule is based on a period of presence in Uganda (rather than a fixed place of business) as a non-resident contractor may have employees moving around the country between different mining or petroleum sites.

(2) The definition in Article 5(2)(h) of the Uganda draft model DTA includes "a mine, an oil or gas well, a quarry or any other place of extraction of natural resources" and in Article 5(2)(i) includes "an installation or structure used for the exploitation of natural resources". The references to "extraction" and "exploitation" are unlikely to include exploration. While it is expected that there would be a fixed place of business through which exploration activities are conducted and, therefore, a PE within Article 5(1), it is preferable that Article 5(2)(h) and (i) expressly refer also to exploration to avoid any doubt.

(3) The time limit for a construction PE is one month. This is very short by international standards (the equivalent in the OECD Model DTA is 12 months and the UN Model DTA is 6 months). It is also short in comparison to the definition of "branch" in s 78(a) of the ITA (90 days). The time limit for a construction PE in the Uganda draft model DTA should be aligned with the 90-day period in the s 78 definition of branch.

(4) While Article 5(4) excludes delivery as a preparatory or auxiliary activity (consistent with the UN Model DTA), delivery by an agent is not included in the agency PE rule in Article 5(5).

152. **Article 7(2) and (3) of the Uganda draft model DTA provide for the attribution of profits to a PE and are based on the pre-2010 OECD Model DTA.** Over the last twenty years, there has been much debate within the OECD as to the most appropriate basis for attributing income and expenses to a permanent establishment. Two methods of attribution have been identified: (i) the separate entity approach; and (ii) the single entity approach. Under the separate entity approach, internal transfers of goods and services are valued based on separate entity accounting (the two parts of the entity are treated as separate entities dealing with each other at arm's length). The single entity approach is based on the legal position that an entity cannot deal with itself. Under the single entity approach, the overall profit of the entity is computed and then attributed through sourcing rules to the different parts of the entity.

153. **The OECD has officially adopted the separate entity approach.** This involves treating a head office and PE as separate entities and, in broad terms, applying the same analysis (based on functions, assets and risks) as for inter-company transactions. This is now reflected in the new Article 7(2) in the OECD Model DTA, which has replaced the former Article 7(2) and (3). Importantly, not all OECD countries have accepted the separate entity approach and some OECD countries continue to apply the single entity approach. In light of this, retaining Article 7(2) and (3) from the pre-2010 OECD Model DTA is the preferred position for the Uganda draft model DTA.

154. **The Transfer Pricing Regulations provide for the separate entity approach in the attribution of income and deductions to a Ugandan branch.** Regulation 4 should be amended to apply the separate entity approach only when the other country also applies the same approach. This will give Uganda flexibility to use the single entity approach when used by the other country and thereby limit any mismatches in the attribution of income and expenses between the two countries.

Services Income

Domestic Tax Law

155. **The provision of independent services is a form of business activity.** The taxation of services income derived by a non-resident therefore depends on whether the non-resident has a branch in Uganda. In the extractives sector, a non-resident contractor is liable for non-resident contractor tax at the rate of 10 percent on the gross amount of fees derived by the contractor in providing services to a licensee (s 89GG). In other sectors, the rate of tax on service fees is 15 percent (s 85)

Uganda draft model DTA

156. **Article 13 of the Uganda draft model DTA provides for the taxation of administration and management fees.** While the definition of "administrative and management fees" in Article 13(3) includes a payment in consideration for any service of an administrative, technical or managerial nature, it would be preferable to include technical fees in the heading of the Article. While technical service is likely to have a broad meaning, the definition of administrative and management fees should include professional and consultancy services so as to align with existing DTAs that provide for the taxation of technical fees.

157. **The definition of "administrative and management fees" in Article 13(3) is time limited so that the Article applies only when the relevant service is performed in Uganda on a regular basis or for period of three months.** This means that a fee can be an administrative and management fee only when the relevant service is physically performed in Uganda. This creates a conflict with the source rule in Article 13(5), which provides that an administrative and management fee arises in Uganda when a resident or a Ugandan PE of a non-resident pays the fee. Further, it confuses Article 13 with the services PE rule, which is based on the period of presence in Uganda. It is suggested that the words "but only to the extent that the services are performed on a regular basis or for period of three months" are deleted from Article 13(3). This will allow the sourcing rule in Article 13(5) to apply more effectively.

Investment Income

Domestic Tax Law

158. **S 83 of the ITA provides that Ugandan-source dividends, interest and royalties derived by a non-resident are liable to tax at the rate of 15 percent of the gross amount of the dividend, interest or royalty.** A dividend paid by a resident company is treated as Ugandan-source income. Interest and royalties are Ugandan-source income if they are paid by: (i) a resident person; or (ii) a Ugandan branch of a non-resident person. S 83 does not apply when the dividend, interest or royalty is attributable to a branch in Uganda of the non-resident and such income is taxed on a normal assessment basis through the operation of s 17.

159. **An important issue for royalties is the scope of the definition of "royalty".** Under s 2(mmm) of the ITA, "royalty" is defined broadly and includes:

(1) Amounts for the use of industrial and intellectual property rights (such as patents, trademarks and copyrights).

(2) Know-how payments

(3) Amounts for the use of any tangible movable property (including equipment lease rentals).

Uganda draft Model DTA – Dividends

160. **Article 10 of the Uganda draft model DTA provides for a differential rate structure for dividends.** One rate is specified for participation dividends based on a 25 percent ownership threshold and the other rate applies to all other dividends. The Uganda draft model DTA specifies the same rate for both, but presumably a lower rate (such as 5 percent) is intended for participation dividends. This approach is consistent with the OECD and UN Model DTAs.

Uganda draft model DTA - Interest

161. **Article 11 of the Uganda draft model DTA provides for the taxation of interest.** The rate limit under the Model on interest arising in Uganda and derived by a resident of the other Contracting State is 15 percent. Interest arises in Uganda is if it is paid by a resident or a Ugandan permanent establishment of a non-resident. Article 11 does not apply when the interest derived by a non-resident is effectively connected with a PE of the non-resident in Uganda.

162. **Taxation under Article 11 of the Uganda draft model DTA aligns with the taxation of interest derived by non-residents under domestic law.** It is noted, though, that under most of Uganda's existing DTAs, the rate limit is 10 percent. The 15 percent rate applies under two DTAs (UK and Italy), but these are older DTAs. It would seem appropriate to adopt the 10 percent rate as the rate in the Model given that it is the rate in Uganda's recent DTAs. Certainly, Uganda can expect that potential DTA partners will rely on Uganda's existing DTAs as the basis for negotiating a 10 percent rate.

Uganda draft model DTA - Royalties

163. **The taxation of royalties under Article 12 of the Uganda draft model DTA is closely aligned to that of interest.** The rate limit under the Model on royalties arising in Uganda and derived by a resident of the other Contracting State is 15 percent. Royalties arise in Uganda if they are paid by a resident or a Ugandan PE of a non-resident. Article 12 does not apply when the royalty derived by a non-resident is effectively connected with a PE of the non-resident in Uganda.

164. **Taxation under Article 12 of the Uganda draft model DTA largely aligns with the taxation of royalties derived by non-residents under domestic law.** It is noted, though, that Uganda's existing DTAs reduce the rate on royalties to 10 percent. The only exception is the UK DTA under which the rate limit is 15 percent, but this is an old DTA. For the same reason as stated above for interest, it would make sense to adopt the 10 percent rate in the Uganda draft model DTA. Given the Uganda's existing DTAs, it is difficult seeing a potential DTA partner agreeing to the 15 percent rate.

165. **In the context of extractive industries, an important difference between domestic law and the Uganda draft model DTA is that the definition of "royalties" in Article 12(3) of the draft model does not include equipment lease payments.** This means that, for the

purposes of the Model, equipment lease rentals will be treated as business profits and taxable in Uganda only when the rental income is attributable to a PE of the non-resident lessor in Uganda. Given the high level of equipment leasing in the resources sector, it is important that the domestic law characterization of equipment lease payments as royalties is carried through to Uganda's DTAs.

Gains on Indirect Transfers of Interest in Immovable Property

Domestic Tax Law

166. **Uganda asserts jurisdiction to tax gains on indirect transfers of immovable property.** S 79(g) provides that a gain derived on the disposal of a share in a company the property of which consists, directly or indirectly, principally of an interest or interests in immovable property in Uganda is Ugandan-source income, but only when the share is a business asset. The definition of "immovable property" in s 78(aa) includes mining and petroleum rights and, when the immovable property represents such rights, the shares are treated as a business asset under s 89GE(3).

167. **S 79(g) should be extended to apply to the disposal of an interest in any entity and not be limited to the disposal of shares in a company.** (FAD June 2015.) This would prevent 79(g) being avoided through the interposition of a unit trust or limited partnership in the chain of foreign entities. As noted above, MOFPED will revisit source rules once the current cases involving s 79 have been finalized.

Uganda draft model DTA

168. **Article 14 of the Uganda draft model DTA provides for the taxation of capital gains.** Article 14(4) provides for the taxation of indirect transfers of immovable property and is copied from the UN Model DTA. There may be an argument that Article 14(4)(a) excludes taxation of gains on indirect transfers of mining or petroleum rights on the basis that the right is used in the business activities of the company holding the right. For this reason, it is preferable to adopt Article 13(4) of the OECD Model DTA but with two modifications. First, in anticipation of a future change in s 79(g), it should be extended to cover also gains on the alienation of interests in non-corporate entities, such as partnerships and trusts. Second, it should be made clear that "immovable property" in Article 14(4) has the same meaning as in Article 6. This is done for the purposes of Article 14(1) but not Article 14(4). Immovable property is defined in Article 6(2) to have the meaning under the law of the Contracting State where the immovable property is located. In Uganda's case, this will pick up the definition of immovable property in s 78(aa).

Treaty Shopping

169. **Uganda's future DTAs should include protection against treaty shopping.** This is the purpose of Article 23 of the Uganda draft model DTA, which provides for the limitation of benefits ("LOB"). Article 23 is complex and looks like it may have been copied from a developed country's DTAs (such as the United States). It is suggested that a simpler LOB rule is adopted based on s 88(5) of the ITA with an additional exception when there is substantial economic activity in the other Contracting State.

170. **A LOB Article should apply generally for the purposes of the DTA and not be limited to specific Articles in the DTA.** The recent DTA between Malawi and the Netherlands includes separate LOB rules in the dividend, interest and royalties Articles, but leaves open the possibility of treaty shopping in relation to other Articles of the DTAs, such as in relation to indirect transfers of immovable property.

Recommendations

- Develop a DTA policy with clear guidelines for choosing DTA partners.
- Prepare a DTA impact statement, after negotiations are completed and before signing the DTA, setting out the advantages and disadvantages of the DTA, and including the estimated revenue impact.
- Develop a model DTA using the UN Model DTA as the starting point. The model should take account of domestic law and Uganda's existing DTAs.
- Uganda's future DTAs should include a LOB Article to limit the revenue loss through treaty shopping.
- Amend regulation 4 of the Transfer Pricing Regulations so that separate entity approach does not have to be followed when the other country does not use it.