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April 11, 2014

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The African Department

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FISCAL IMPLICATION OF OFFSHORE NATURAL GAS[1]

A string of natural gas discoveries in Tanzania's deep offshore waters have generated considerable expectations. The discoveries form a regional pattern with finds of gas or oil (in varying amounts) in Mozambique, Uganda, and Kenya. Further exploration and appraisal is ongoing in Tanzania; none of the companies exploring for gas has yet declared the gas discoveries to be commercially viable. Uncertainty also remains about aspects of the fiscal regime that a large scale gas project would operate within and project negotiations have not yet commenced. A final investment decision is unlikely to be taken until late 2015 or 2016.

If the finds are confirmed as commercially viable, Tanzania faces an opportunity to use natural gas to transform the economy. The objective would then be to turn a subsoil asset into financial, physical, or human capital assets. The main vehicle for this would likely be through the fiscal channel. The challenge for policymakers is to maximize the fiscal benefits from natural gas in Tanzania, while still ensuring that the gas project can be successfully developed, and that the potential gas revenue is used to the benefit of the people of Tanzania, both current and future generations.

This paper discusses the potential fiscal impact of a large scale gas project and explores aspects of macro-fiscal management of the associated revenue flow. The next section will provide background and context focusing on recent offshore natural gas discoveries. Section II will describe features of the current petroleum fiscal regime in Tanzania and will present tentative simulations of the fiscal impact of a potential gas project. Section III will turn to macro-fiscal issues related to the management of the potential gas revenue; the section will highlight the significant but temporary increase in investment and, subsequently, revenue over several decades. Drawing on more recent research, the paper will highlight desirable features of the macro-fiscal policy framework and will present some illustrative fiscal policy frameworks and rules for managing the potential gas revenue.

A. Background and Context

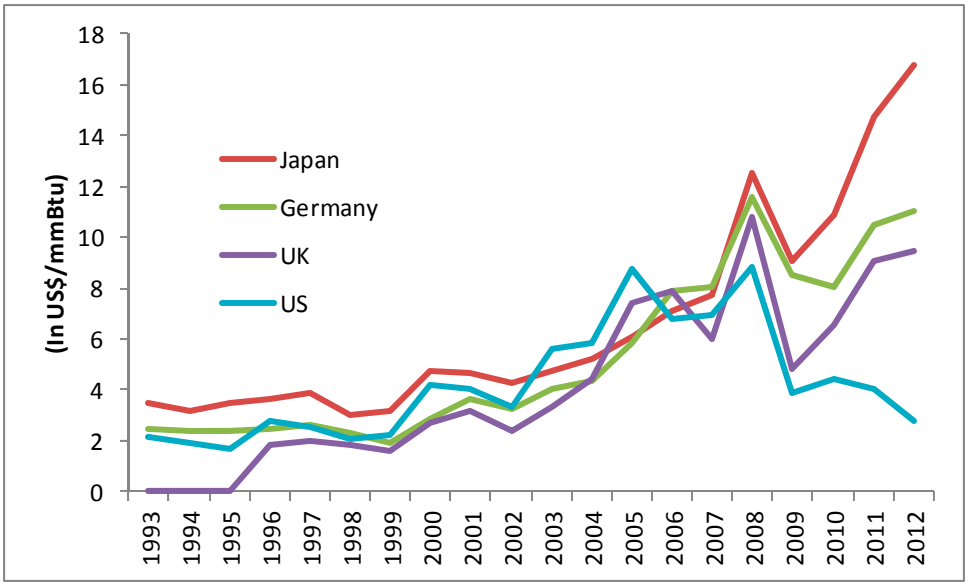
Oil and gas exploration has been undertaken for several decades in Tanzania, with 25 petroleum blocks licensed. Early successes have resulted in gas production from shallow water fields in Songo Songo and Mnazi Bay (in the case of the former, for more than a decade). Indeed, gas from the Songo Songo field already provides an important source of electricity in Tanzania, and the government is constructing a new pipeline as well as gas-fired electricity plants to scale up gas usage from the existing fields.

[1] Prepared by Thomas Baunsgaard

The current focus is on the maritime blocks in deep water at depths of 1,500–2,500 meters. None of the companies that have made gas discoveries in the deep offshore blocks have released final gas resource estimates; these await further drilling and reservoir testing. Nevertheless, exploration results indicate that recoverable deep offshore gas resources amount to at least 24–26 trillion cubic feet (tcf). The discoveries are scattered over a large geographical area, which will increase the development cost, including requiring an extensive pipeline network. The most likely project configuration would be a joint gas processing and liquefaction natural gas (LNG) plant fed by several gas fields. The liquefied gas would be exported but with a significant share of the gas allocated for domestic supply. With a common rule of thumb that 10–12 tcf of gas reserves is the minimum requirement for a two-train LNG plant, available resources potentially could support a four-train LNG facility.

Commercializing gas is complex and costly, with significant infrastructure requirements. Securing project financing for the billions of dollars needed for the investment is facilitated by entering into long term gas uptake contracts with customers. The current regional price segmentation in international gas prices in recent years adds uncertainty to the financial outlook for a gas project (Figure 1). The eventual implications for global gas markets of new technological developments in US oil and gas production are unknown at this stage, but could lead to downward adjustment in prices in Asia, a primary potential market for Tanzania. This could negatively affect the financial viability of a gas project in Tanzania.

Figure 1. Tanzania: International Natural Gas Prices



THE FISCAL REGIME FOR NATURAL GAS

Many countries have a special fiscal regime for taxing the extractive sector including natural gas. [2] The fiscal regime includes all fiscal charges, whether in the form of taxes (such as income tax or VAT) or non-tax charges (such as royalty, production share, state equity, or bonuses). An economic argument for treating the extractive sector differently is the presence of economic rent associated with a finite valuable economic resource—the above-normal return on an investment, which in principle can be taxed without discouraging the investment. There are also administrative reasons for taxing the extractive sector through a separate fiscal regime, if the interface between the regulatory and the fiscal regimes can be fine-tuned by having a separate fiscal regime. Often there is also heightened political attention to the taxation of the sector with both citizens and politicians looking for assurance that the country gets its "fair share" of revenue.

The fiscal regime provides the main mechanism for sharing *risk and reward* from a natural resource project between the investor and the government. The two dimensions capture how the government revenue stream responds to changes in profitability. Income tax-based instruments will lead to higher revenue shares for profitable projects, but may not provide much revenue for less profitable projects. On the other hand, royalty instruments will provide stable revenue from the start of production but do not respond well to changes in realized profitability of a project. A combination of some early revenue with a more flexible revenue stream reflecting realized profitability would usually enhance the stability and credibility of the fiscal regime. The government will aim at having a fiscal regime that provides the highest possible revenue share, without undermining the financial viability of a project and therefore discouraging the investment. Fiscal regime simulations can be used to explore the behavior of different tax instruments, both over time and under variable project outturns.

A. The Petroleum Fiscal Regime in Tanzania

All petroleum activities in Tanzania are regulated under the Petroleum Act. Exploration and development licenses are issued to the national oil company, Tanzania Petroleum Development Corporation (TPDC), which in turn enters into production sharing agreements (PSAs) with private sector companies (often operating as an unincorporated joint venture involving two or more companies with one designated as the project operator).

The fiscal regime in Tanzania is a hybrid between production sharing and income tax/royalty. The individual PSAs specify the royalty rate and the sharing of petroleum production between the contractor and TPDC. The fiscal terms vary across the individual PSAs, and none of the signed PSAs

[2] IMF (2012a) provides a recent overview of natural resource taxation. See also Baunsgaard (2001); Sunley, Baunsgaard, and Simard (2003); and Daniel, Keen, and McPherson (2010).

has been made publicly available.[3] There are also provisions in the Income Tax Act that apply to the petroleum sector, making it important to understand how the production sharing and the income tax interact. The first fiscal charge is the royalty, which is assessed on the total production value. Thereafter, the contractor can recover cost incurred developing and operating the field. The cost that can be recovered in any given period is capped typically as a share of 60–70 percent of production value, with any unrecovered cost carried forward to the next period. After deductions of cost, the profit petroleum is shared between the contractor and TPDC. Income tax is payable on the profit generated from petroleum production, and there are withholding income taxes on certain interest payments, contractor payments, and on dividends distributions.[4] The model PSA also makes provisions for an additional profits tax that applies if a cumulative rate of return of 20 percent in the project is reached (although this tax is excluded from many signed PSAs).

The cost recovery limit in the PSA implies that the government is always assured of receiving a minimum share of the production.[5] This is effectively equivalent to imposing a royalty of the same amount, at least as long as the cost recovery ceiling is binding. While the model PSA includes both an explicit royalty and the *de facto* royalty through the cost recovery limit, in most signed PSAs in Tanzania the royalty is paid out of TPDC's profit share rather than by the contractor. The government share of petroleum profit increases with the daily rate of production. The intention is that the government take should be higher for more profitable projects. However, two projects with similar volumes of production—one located in shallow water, the other in deep water—would likely have different profitability reflecting differences in cost. Therefore, while production sharing based on volume of production used to be common, many countries have since moved to profit sharing mechanisms that are more closely linked to the realized profitability of a project (e.g., Mozambique and Angola).

The model PSAs also enable TPDC to take equity in a project of up to 15–20 percent. This provides potentially important fiscal benefits. There are different options for financing the government equity ranging from fully paid-up equity to a carried interest equity.[6] The decision on whether to take up government equity can be guided by a cost benefit analysis. Do the additional revenue benefits outweigh the cost of government paying for its equity share either directly by contributing to development and other costs, or indirectly through repaying a carried interest? This assessment should also take into account the opportunity cost of alternative uses of these funds.

[3] The model production sharing agreement has changed over time and the different vintages are available on the TPDC website (http://www.tpdc-tz.com).

[4] For income tax purposes, profit petroleum and cost recovery petroleum will be included in the revenue base, against which deductions can be made for eligible costs under the income tax act. The taxable income is taxed under the ordinary income tax at 30 percent.

[5] Calculated as (1-cost recovery limit) * minimum production share.

[6] Under a carried equity interest, the contractor finances the government's contribution to the development of the project only to be repaid (with interest) from the future revenue to the government.

B. Fiscal Simulations of an Illustrative LNG project

It is premature to project the revenue impact of the offshore natural gas fields given the significant uncertainty about the project. None of the investors has yet reached a final decision to move forward with an investment. With an active exploration program underway, uncertainty prevails about the size and characteristics of the gas resources, which will impact the design of a potential gas project (or several projects). The fiscal regime may also evolve further either through a negotiation process or reforms to the general fiscal regime, which will in itself have an impact on the viability of the project.

Nevertheless, the fiscal impact can be simulated under specific project and fiscal assumptions. This is done below for two different sized projects (using common assumptions about project design and cost): (i) a two-train LNG plant (with 10 million metric tons per annum (mmtpa) LNG capacity) using 12 tcf in gas resources; and (ii) a four-train LNG plant (with 20 mmtpa LNG capacity) using 24 tcf in gas resources. It is assumed that the larger project will be implemented in phases starting initially with a two-train LNG plant and then adding another two LNG trains as production is scaled up. The fiscal regime applied reflects broadly the existing fiscal regime, although this is only approximately so given that each signed PSA differs in important aspects.[7] The simulations assume a natural gas price of US$11/mmBtu in real terms. For simulation purposes, the project is assumed to consist of an *upstream* segment (the extraction of the resource from the gas fields) and a *downstream* segment (the pipelines for transportation and the gas processing and liquefaction plant).[8]

The key fiscal elements applied in the simulations are:

- *Upstream tax*: (i) 5 percent royalty; (ii) corporate income tax rate of 30 percent; (iii) capital expenditure straight line depreciation over 5 years; and (iv) dividend and interest withholding tax of 10 percent.

- *Upstream production sharing*: (i) no production bonus; (ii) a 70 percent cost recovery limit[9]; (iii) a 6-tier profit gas sharing based on daily rate of production with rates from 35 percent to 60 percent; and (iv) government equity of 20 percent on a carried basis.

[7] The simulations are undertaken using an LNG fiscal model developed by the IMF Fiscal Affairs Department.

[8] A further refinement could be done by modeling the pipelines as a separate *midstream* project segment.

[9] The restriction on cost recovery in any period is equivalent to a 10.5 percent royalty in providing a minimum production share (with cost recovery capped at 70 percent and a minimum production share of 35 percent).

- *Downstream tax*: (i) corporate income tax rate of 30 percent; (ii) dividend and interest withholding tax of 10 percent; (iii) LNG plant depreciation straight line over 10 years; and (iv) government equity on a fully-funded basis at 15 percent.

- A tolling fee on gas sales between the upstream and downstream parts of the gas project set to cap the internal rate of return on the downstream segment at 8 percent. This also provides an illustration of a regulatory mechanism that preserves the economic value in the upstream, where the resource rent originates from, while treating the downstream akin to a public utility.

The simulated fiscal impact is significant (Table 1; figures 2-3). It is assumed that production will gradually be ramped up, after which annual revenue collections would increase to between US$3 billion and US$6 billion in the two different project configurations. On average over the project life, the government-take of the pre-tax cash flow amounts to 69 percent and 70 percent, respectively, in the two simulations. This provides an estimate of the effective average tax rate incorporating all sources of government revenue (including royalty, income tax, production sharing, and state equity).

Most of the fiscal revenue is collected in the upstream, where the economic rent from natural gas originates from. The government share (the effective tax rate) is appropriately higher at 74 and 77 percent, respectively, in the upstream than in the downstream segment of the project. However, achieving this revenue mix is a policy choice, by regulating the downstream as a public utility. Revenue collections will gradually increase during the first 4-5 years of production and remain at their peak for a period of about 15-20 years followed by a gradual decline in production over a decade or so. During the project development phase, there is no significant revenue to government; in the larger project, the development phase is extended over a longer period with two distinct investment surges. Given the fiscal assumptions, production sharing provides the lion's share of the upstream revenue to the government, followed by income tax. This highlights the importance of treating production sharing revenue as any other fiscal revenue, which should be paid to the Treasury and not retained by the collecting agency (TPDC).

Table 1. Tanzania: Illustrative Fiscal Simulations of LNG Projects

NOMINAL TERMS		Two-Train LNG		Four-Train LNG	
Contractor rates of return		Pre tax	Post tax	Pre tax	Post tax
Upstream IRR		26.0%	16.9%	23.7%	14.7%
Downstream IRR		8.5%	8.0%	9.6%	8.0%
Aggregate IRR		19.1%	13.4%	19.0%	12.2%
A. Illustrative Two-Train LNG Project (10 mmtpa, 12 tcf gas resources)					
Summary results Nominal	Discount:		0%	10%	15%
Pre tax project	US$ mn		130.0	12.5	2.9
Upstream	US$ mn		107.6	13.4	4.9
Downstream	US$ mn		22.4	(0.9)	(2.0)
Government upstream	US$ mn		79.7	11.2	5.0
Government Downstream	US$ mn		9.5	0.2	(0.2)
Total Government	US$ mn		89.1	11.4	4.7
Share of pre tax Upstream	%		74%	84%	101%
Share of pre tax Downstream	%		42%	-23%	12%
Share of pre tax aggregate	%		69%	92%	161%
B. Illustrative Four-Train LNG Project (20 mmtpa, 24 tcf gas resources)					
Summary results Nominal	Discount:		0%	10%	15%
Pre tax project	US$ mn		291.8	20.7	4.5
Upstream	US$ mn		237.5	21.1	6.7
Downstream	US$ mn		54.3	(0.3)	(2.2)
Government upstream	US$ mn		181.9	18.3	7.2
Government Downstream	US$ mn		27.7	1.1	(0.0)
Total Government	US$ mn		209.6	19.4	7.2
Share of pre tax Upstream	%		77%	87%	108%
Share of pre tax Downstream	%		51%	-335%	1%
Share of pre tax aggregate	%		72%	94%	162%

Source: IMFstaff simulations using the IMF Fiscal Affairs Department LNG Model

The fiscal benefits of holding government equity in a project will depend on the financing modality and may be higher if this is centered on the upstream segment. If the government takes equity on a fully-funded basis in the project, there will initially be negative cash flows as the government contributes to the development of the project. On the other hand, under a carried interest the investor will finance the government's share of development cost with some future revenue being used to repay the carry. It is unlikely that government equity in the downstream (e.g., in an LNG plant) can be financed on a carried interest basis as this would likely weigh heavily on the project feasibility for the investor. Moreover, if the downstream segment of the project will be regulated as a utility, the fiscal benefits of holding equity in the downstream will be modest compared to the cost of the government financing its share of development. In contrast, the fiscal benefits to the government are much higher from holding equity in the upstream where the profits will be higher; it may also be more feasible to have this financed on a carried interest basis as is envisaged in most PSAs.

MANAGING THE GAS REVENUE

The revenue flow from a large scale gas project is likely to be substantial, although it will only materialize a decade or so after the decision to develop the project. The scale of the initial investment would outweigh any previous project in Tanzania. The key macro-fiscal challenges will therefore be both to manage the investment impact during the development phase and the subsequent revenue flow after production commences.

A. Potential Investment Impact of an LNG Project

The investment requirement of a large-scale LNG project will be significant. Estimates depend on the scale and final design of any project and are therefore uncertain at this stage. The simulations should be updated as information on actual project design and cost eventually becomes available.

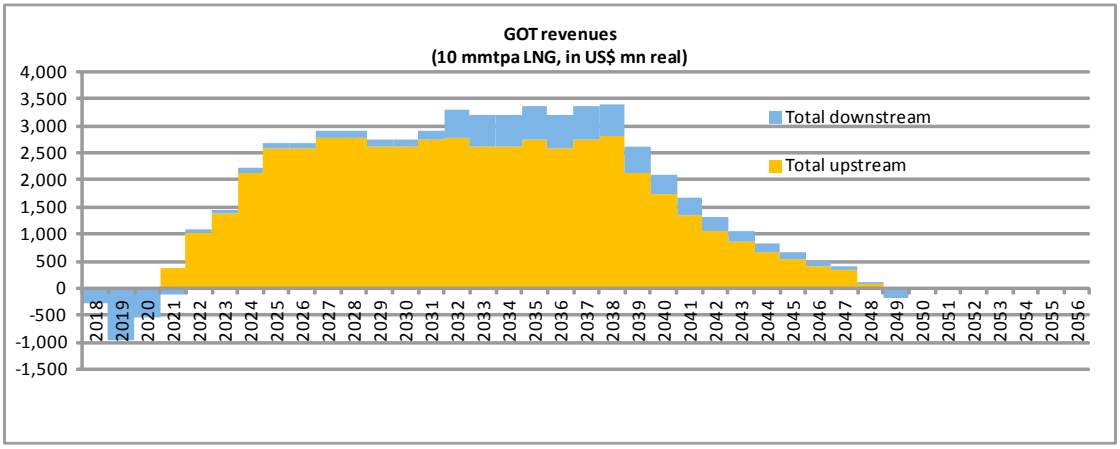
The investment impact of a two-train LNG project

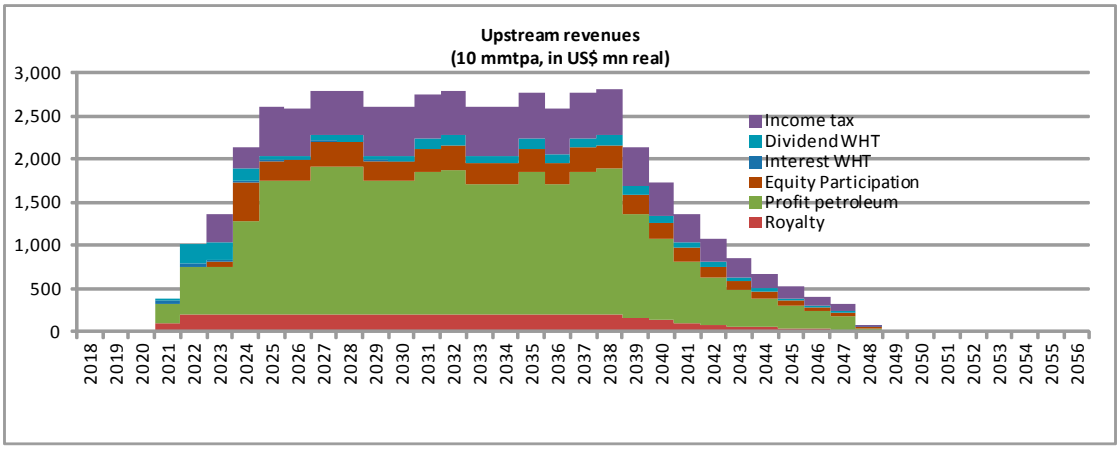
A two-train LNG project is estimated to have total development spending in the upstream and downstream of about US$ 20 billion (in 2012 prices) over five years. As simulated, the bulk of this spending would be incurred in 2018-21. At the peak of the development phase, the annual investment would amount to 19 percent of GDP (Figure 4).[10] A significant part of the development costs are incurred on the pipelines and LNG facility. This should have some bearing on the decision by the government whether to participate as an equity holder in all parts of an LNG project or rather to concentrate government equity participation in the upstream where the potential fiscal benefits are higher.

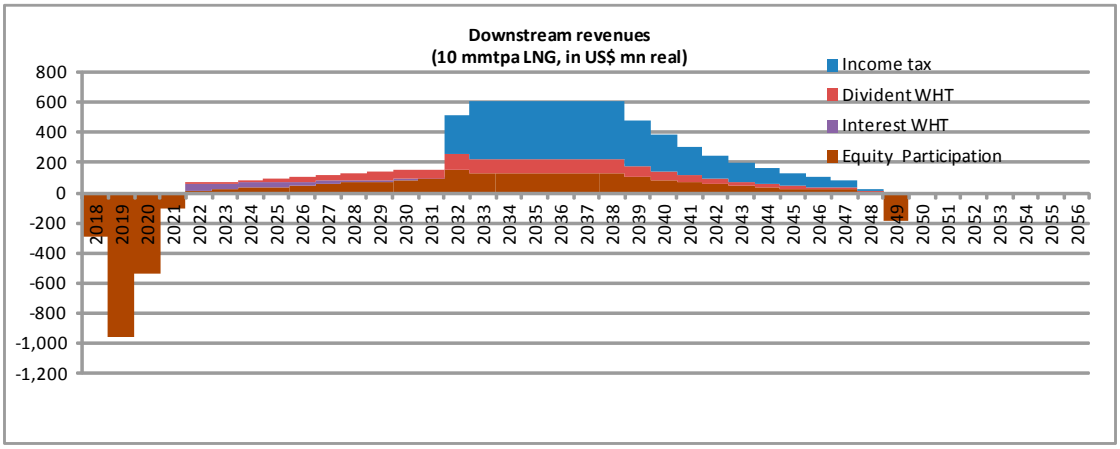
During the development phase, there will be a significant widening of the current account deficit (given the high import intensity). The fiscal impact during the development phase could range from relatively negligible to very significant depending on policy decisions regarding government equity participation. The government is likely to seek to have equity in the upstream segment of a project on a carried basis; on the other hand, this probably is not feasible in the downstream given the significant investment costs. Hence, equity participation in the downstream may require the government to borrow several billion dollars to finance its share of development costs.

[10] All references to GDP exclude the impact of the gas sector, so it is equivalent to non-gas GDP.

Figure 2. Tanzania: LNG Fiscal Simulations (Two-Train Project)
(In US$ million real)



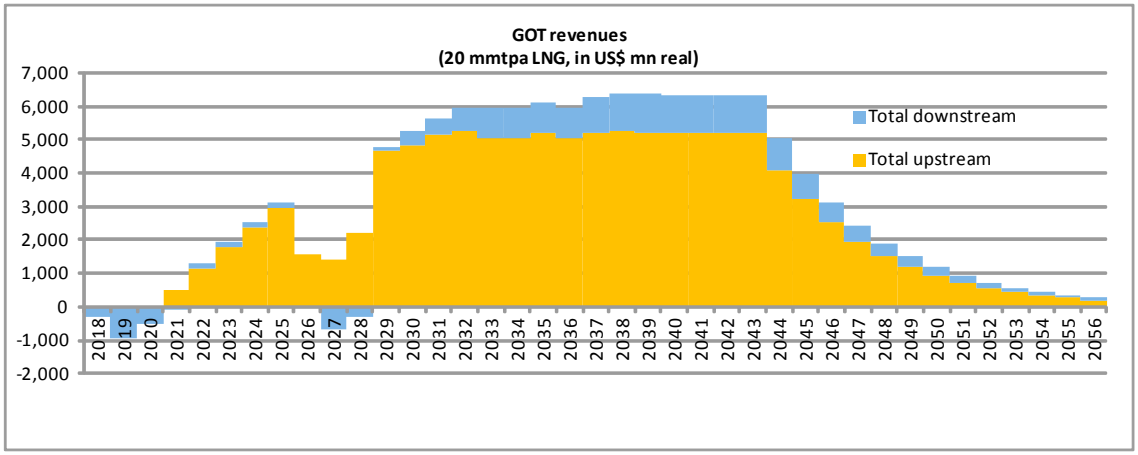


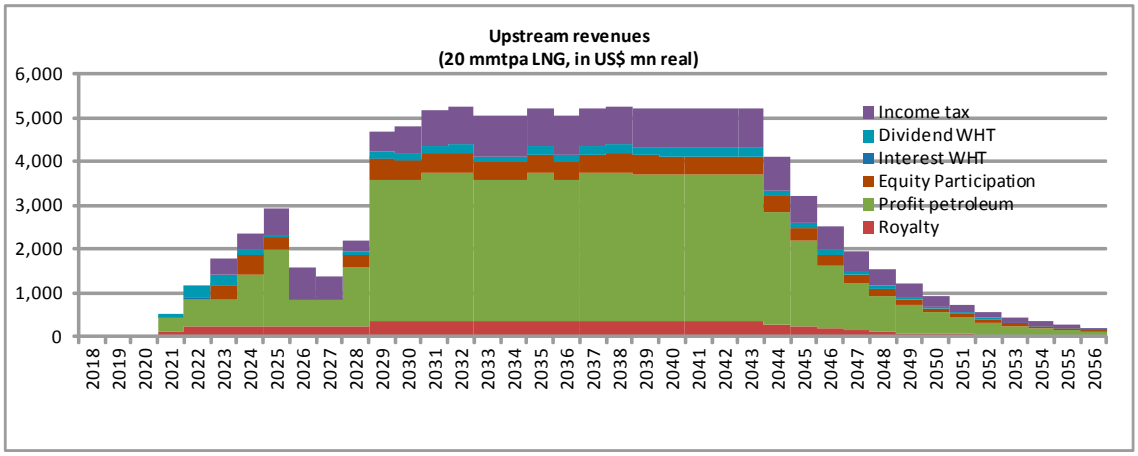


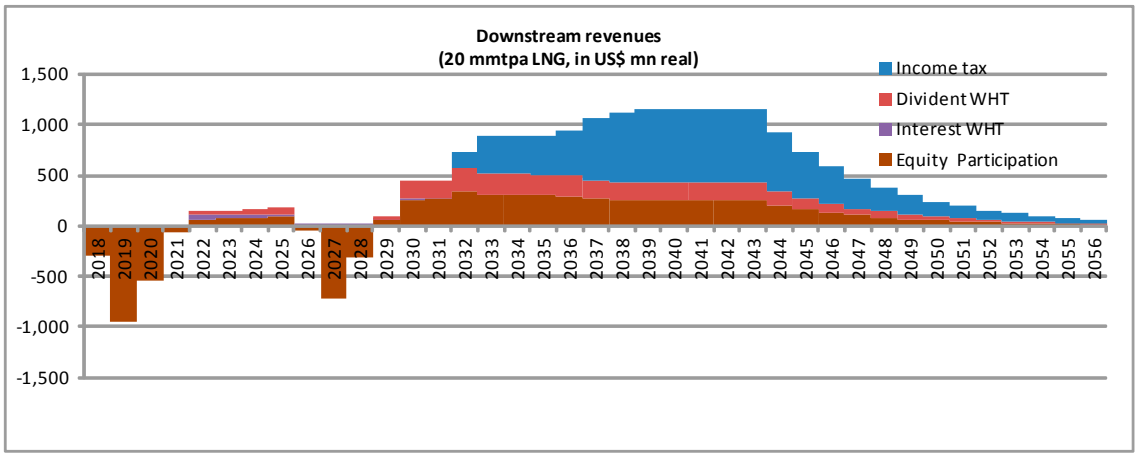
Source: IMF staff estimates

Note: The simulations assume a two-train LNG plant with annual production capacity of 10 mmtpa using total gas reserves of 12 tcf. Total capital cost (including exploration and development) amounts to US$24 billion. Revenue is projected at natural gas price in real terms of US11/MBtu.

Figure 3. Tanzania: LNG Fiscal Simulations (Four-Train Project (In US$ million real)



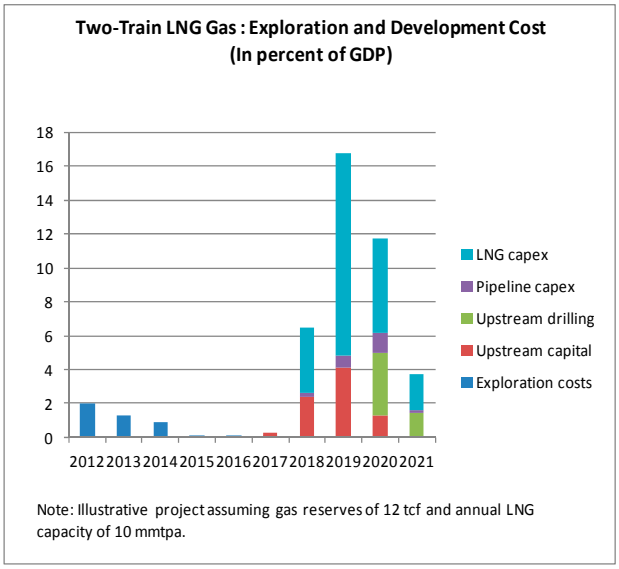


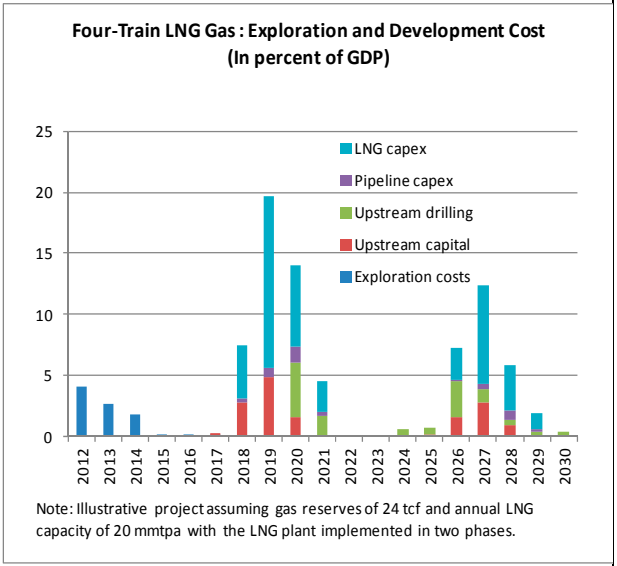


Source: IMF staff estimates

Note: The simulations assume a four-train LNG plant implemented in two phases with annual production capacity of 20 mmtpa using total gas reserves of 24 tcf. Total capital cost (including exploration and development) amounts to US$46 billion. Revenue is projected at natural gas price in real terms of US11/MBtu.

Figure 4. Tanzania: Potential Exploration and Development Cost of an LNG Project





Source: IMF staff estimates

The investment impact of a four-train LNG plant

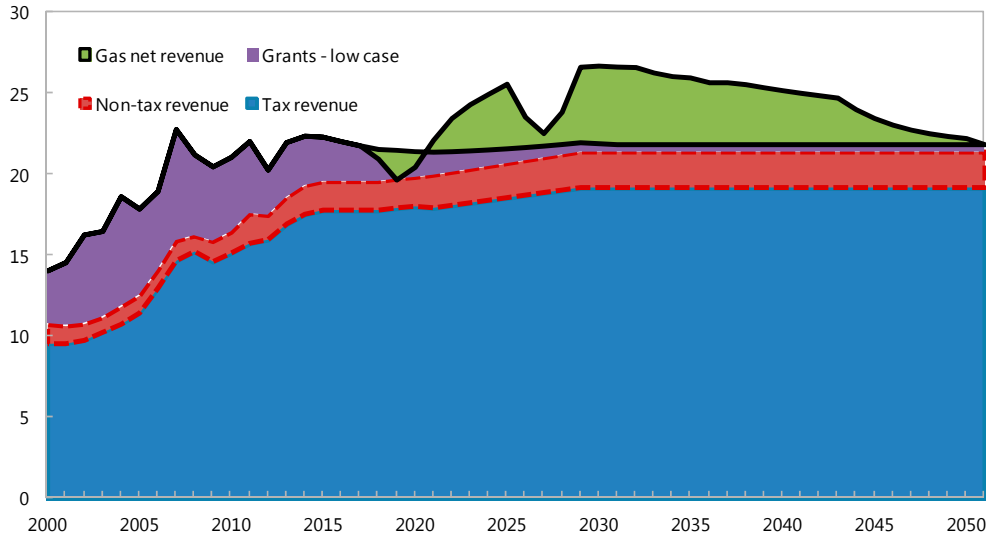
Given the encouraging exploration results, it is possible that a larger joint LNG facility can be developed using gas from several fields. A simulation assuming that 24 tcf in gas resources is available suggests that possibly a four-train LNG facility could be developed. As a crude approximation, it is assumed that the project is phased in starting off initially with a two-train LNG plant, which is subsequently doubled in size. This will imply total development costs of about US$40 billion with the development phase extending over a decade.

B. Gas revenue profile

Aggregate revenue impact of a potential LNG project

The project simulations indicate that a major gas project could increase government revenue collections by several percentage points of GDP at peak production (Figure 5). Although revenue from natural gas will not become so large as to dominate the budget, it will likely play a critical role offsetting a possible long term decline in grants and concessional loans. Given the exhaustibility of the natural gas reserves, the boost to revenue collections will be temporary. Any long term simulations are of course sensitive to underlying assumptions made regarding GDP growth, inflation and other revenue.

Figure 5. Tanzania: Long-Term Revenue Simulations of Large-Scale Gas Project (In percent of non-petroleum GDP)



Source: IMF staff simulations

Note: The revenue estimates are based on a simulated four-train LNG project implemented in two phases. Other fiscal projections are consistent with the long-term debt sustainability assessment.

C. Illustrative Macro-Fiscal Policy Rules

The most significant benefits are likely to be fiscal in nature.[11] The critical challenge for the government is therefore to make sure that the fiscal revenue flow is managed in a way that genuinely benefits the country and its citizens (both current and future generations). Given the characteristics of the expected natural gas revenue—significant in scale but temporary—and that the economy has large development needs (capital scarcity), the macro-fiscal framework should achieve multiple objectives: preserve macro-fiscal stability, save some revenue for future generations, and finance scaling-up of development spending. This can be fostered by implementing a fiscal policy framework that ensures (i) scaling up of growth-enhancing expenditure, which may need to be gradual if absorption and institutional capacity constraints are large; and (ii) adequate accumulation of financial assets for stabilization and/or savings purposes, while preserving macro-fiscal stability. Finally, the fiscal framework has to be operationally simple to implement.

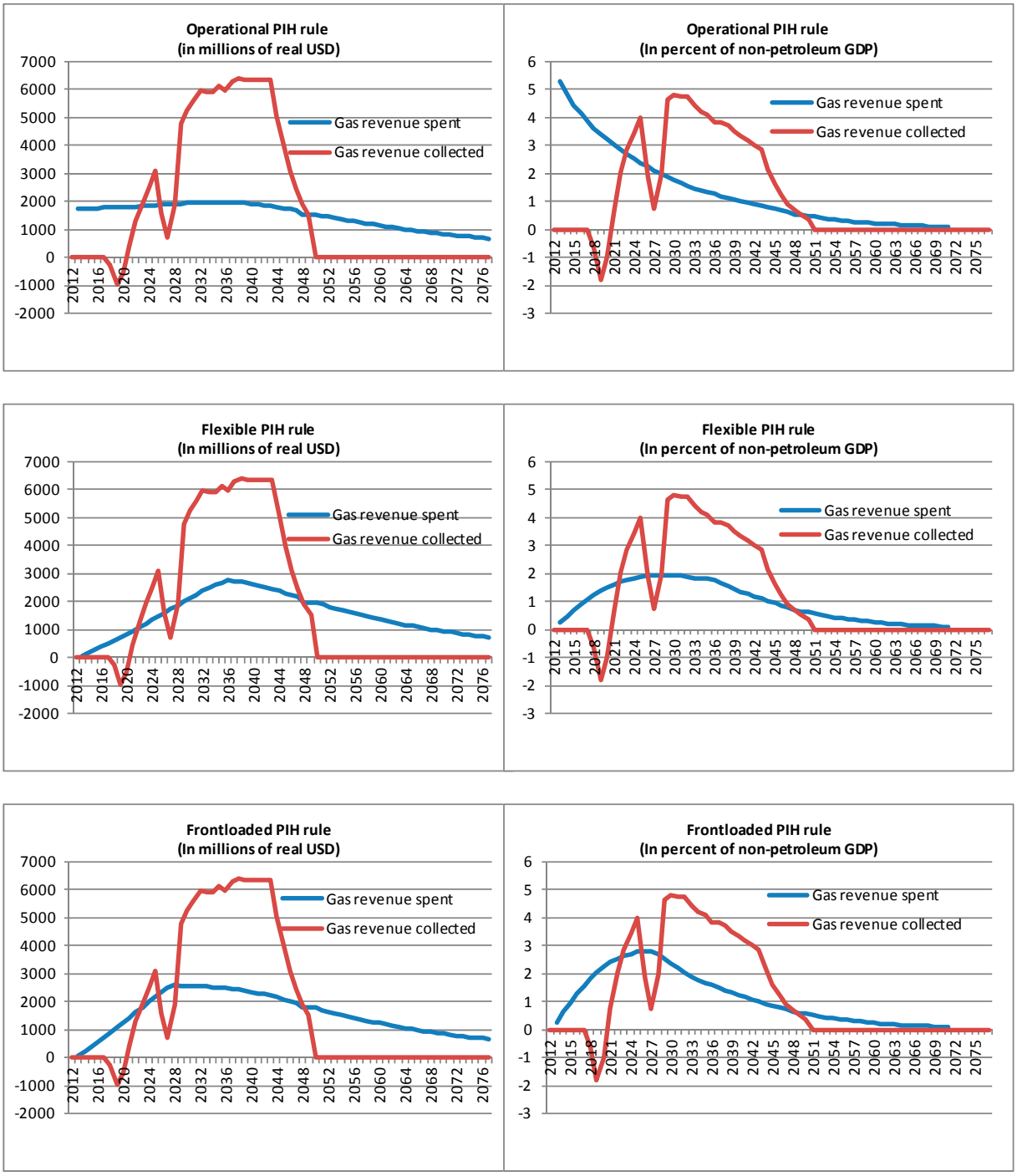
[11] The direct employment creation even by a large-scale project will likely be relatively modest—at most a couple of thousands jobs during construction and a few hundred during operations—given the capital intensive nature of the industry (Oxford Policy Management, 2013). More opportunities will arise from local businesses developing the capacity to supply goods and services during the construction and operation phases (local content).

A macro-fiscal policy framework would contain several elements: (i) indicators to assess the fiscal stance; (ii) a benchmark for assessing long-term fiscal sustainability; and (iii) a rule that anchors the short- to medium-term fiscal policy path (see Appendix 1 for further detail). The fiscal policy rule could be grounded in the permanent income hypothesis (PIH) but with flexibility to frontload investment spending (in physical and human capital). Such a fiscal rule would respect the intertemporal budget constraint by requiring that any frontloaded spending of gas revenue will be offset by lower spending in the future. The rule would be flexible by incorporating new information about gas revenue (e.g., if additional gas discoveries lead to higher estimates of future gas revenue) and being operationally integrated into the annual budget process (Box 1).

The PIH benchmark for fiscal sustainability will smoothen the spending over time (Figure 6).[12] Under this rule, the government will start borrowing against future revenue to finance an immediate scaling-up of spending, followed by a period during gas production when significant financial assets are accumulated, which in turn will finance continued spending in the future. The PIH calculation provides a useful benchmark, but it does not provide a feasible fiscal policy rule for Tanzania. Given large unmet development needs, there is instead a case for some front-loading of investment spending on infrastructure and other priority areas such as health and education. However, in the face of absorptive constraints, it is likely to be efficient to scale up spending and investment gradually. Reforms over time can then in parallel improve public investment management and reduce supply bottlenecks in the economy. This will also reduce the risk of borrowing against uncertain future revenue that may not fully materialize as anticipated.

[12] A theoretical PIH benchmark would have constant real spending in perpetuity.

Figure 6. Illustrative Fiscal Policy Rules for Natural Gas



Source: IMF staff simulations

Box 1: Operationalizing the Fiscal Rule

The first step is to calculate the total wealth derived from natural gas. This combines savings of natural gas revenue that have been converted into financial assets and the value today of future gas revenue (the wealth from gas in the ground). This measure of gas-related wealth will be recalculated annually to reflect new information about expected future gas revenue (which would go up if new gas discoveries are confirmed or down if gas prices or reserve estimates decline) but also to capture the impact of decisions on how gas revenue collections in any year are allocated between saving and investment spending.

The second step is to derive how much investment spending to finance in the current fiscal year from the natural gas revenue. The PIH benchmark calculation sets each year's spending financed by natural gas revenue equal to the return on natural gas wealth. This is a notional measure as it includes both the stock of financial assets and the value of gas in the ground (the sum of discounted future gas revenue in real terms). If the policy decision is to front-load spending of gas revenue, the build-up today in financial assets will be correspondingly lower. In the next period, applying the fiscal rule to the lower net wealth in turn will reduce future spending financed by gas revenue. In other words, the intertemporal budget constraint is respected –more gas revenue spent today implies less gas revenue is available to finance future spending.

A more flexible fiscal policy rule can accommodate a gradual scaling-up of investment while preserving fiscal sustainability. Under a flexible application of the operational PIH rule, investment spending financed by natural gas revenue is gradually increased until the peak is reached by 2036 in real terms and a few years earlier if scaled by non-petroleum GDP. The earlier spending of gas revenue will be automatically reflected in lower spending in the future, while the gradual scaling-up of spending will imply a less aggressive borrowing profile in pre-production years. The fiscal policy rule can easily accommodate differences in the pace of scaling-up under a more front-loaded PIH rule. This envisages that the peak of gas-financed spending is reached in 2025. Given the choice to still scale up spending gradually, this does imply higher pre-production borrowing (albeit still less than in the benchmark PIH illustration).

Several factors determine how rapidly expenditure should be scaled up. The higher the absorption constraints and the lower public investment efficiency, the more gradual should be the scaling-up. Model-based simulations can provide an analytical basis for determining the desirable pace of scaling-up.[13] At the same time, deciding the long term fiscal path is likely to require a significant amount of judgment. Complementary reforms to enhance the efficiency of government spending and the capacity for public investment management will underpin a faster scaling-up of

[13] For example, the DSGE model developed by Berg and others (2012) provides analytical answers to determine the desirable magnitude and pace of scaling-up public investment and the appropriate accumulation of financial assets for stabilization purposes.

growth-enhancing government spending. Likewise, investment to overcome infrastructure constraints and measures to enhance the labor force skills will also reduce absorption constraints enabling a faster scaling-up. Consideration should also be given to the fiscal implications from higher operations and maintenance to sustain the capital stock.

One question that will attract interest is whether to scale up spending before the gas revenue starts flowing. The theoretical reasoning supports that some borrowing against future gas revenue is justified to smooth expenditure. It is also possible that financing terms will become more attractive as more certainty materializes about the impact of future gas revenue on Tanzania's debt sustainability.[14] Even so, a more gradual increase in borrowing likely will support more favorable financing terms, whereas a sharp upward increase in borrowing may raise concern about debt sustainability, which in turn would lead to higher risk premia in the financing terms available. It could also be argued that with the accelerating issuance in recent years of new debt to finance infrastructure spending, *de facto* Tanzania has already started borrowing against future gas revenue.

The simulated policy rules need to be integrated into the fiscal policy path. Given the still favorable interest-growth differential, the sustainable long term fiscal position is consistent with a primary deficit of about 2 percent of GDP (from the debt sustainability assessment). Adding natural gas revenue would initially have a negative impact during the development phase under the assumption that the government would hold equity participation (albeit this is a final decision that has not yet been made). This would be followed by fiscal surpluses as gas revenue is partially saved by accumulating financial assets. Both the flexible and the front-loaded PIH rules allow an initial scaling-up of the non-gas primary deficit followed by a gradual consolidation back to the long-run sustainable position. It is an added attractive feature of the flexible and front-loaded PIH rules that they avoid disruptive sharp changes in government expenditure and the underlying fiscal stance.

CONCLUDING THOUGHTS

The outlook for natural gas in Tanzania is positive, albeit still highly uncertain. In the event that major revenues are obtained and put to fruitful use, they could have a transformational impact on the economy. At the same time, expectations need to be tempered by the remaining uncertainty about the eventual size of the gas resources; no company has yet made a final investment decision involving the deep offshore gas reserves. This uncertainty will hopefully diminish in the next few years.

A significant amount of work is needed to put in place an appropriate policy and regulatory framework. The recent natural gas policy issued by the government provides a starting point;

[14] It may be prudent to factor the fiscal impact of natural gas into the debt sustainability assessment only after it is know with reasonable certainty that a large-scale investment in a gas project will proceed.

further steps are needed to operationalize the policy, including in the fiscal area. While progress can be made on fostering linkages to the non-gas economy (through employment, skills transfer and domestic supply channels), the most substantive benefits to the country will arise through the fiscal channel.

Encouragingly, the existing upstream fiscal regime provides a good starting point with a favorable fiscal share to government. Refinements are nonetheless needed to the fiscal regime to make this function for a large-scale gas project. This partly reflects that the original petroleum fiscal regime was designed with a more direct focus on oil rather than gas. It is important to clarify the interaction between the tax and production sharing regimes, and the fiscal treatment of different segments of a large-scale gas project. As a guiding principle, the revenue to government would be maximized by ensuring that most economic value remains in the upstream segment, where the tax share is larger, while treating the downstream similarly to a regulated utility.

Transparency is critical, not the least for the public to gain confidence that any agreements are fair. A good starting point would be to disclose the terms of signed PSAs. Companies are likely to welcome this, at least as long as disclosure is applied across all companies on a level playing field. More generally, the government needs to step up to the challenge of providing credible information that is accessible to the ordinary citizen.

If a large-scale gas project goes ahead, the potential fiscal revenue would be substantial, and would facilitate government spending on priority investment. Careful attention is needed to design a fiscal policy framework that provides both macro-fiscal stability while ensuring an adequate balance between saving and investment spending. Although substantial revenue is not likely to flow for at least another decade, preparing for how to manage the eventual revenue flow should start now. The present challenge is to move forward with the design and implementation of policy and regulatory reforms to unlock the potential of natural gas to transform the economy in a manner that benefits all Tanzanian members of both current and future generations.

Appendix: Key Principles Underpinning a Macro-Fiscal Policy Framework

A macro-fiscal policy framework can guide the allocation of natural gas revenue between saving and investment spending. This should balance financial savings, including on a precautionary basis to manage revenue volatility, with scaling up of investment expenditure**.** Given that the fiscal revenue impact of a large scale gas project is likely to be significant but temporary, the fiscal policy framework should achieve two objectives: (1) reduce transmission of revenue volatility to the budget; and (2) an appropriate balance between spending and saving revenue to the benefit of future generations. The framework should also accommodate a gradual scaling-up of growth enhancing spending that bolsters the physical and human capital stock in the economy.

Indicators of the fiscal stance

A key part of the fiscal framework is an indicator of the fiscal policy stance – i.e., a measure of whether fiscal policy is expansionary, neutral or contractionary.

- The *non-resource primary balance* (the primary balance minus (net) resource revenue, preferably scaled to non-resource GDP) measures the underlying fiscal policy stance and government domestic demand and can be compared against a benchmark for long-term fiscal sustainability. Setting fiscal policy on the basis of this indicator can help delink policy from the volatility of resource revenue.

- The *overall (or primary) balance* can present a misleading measure of the fiscal policy stance in resource dependent countries: with rising resource revenues, a fiscal expansion (increase in spending) can be masked by an improving overall balance. Still, the overall balance does provide an indication of the change in net financial assets and related fiscal vulnerabilities and gross financing needs in the event of declines in resource revenue.

A benchmark for assessing long-run fiscal sustainability

The macro-fiscal framework should be guided by an assessment of long-term fiscal sustainability. For resource-rich countries, such an assessment needs to take into account the exhaustibility of the resource revenue. The permanent income hypothesis (PIH) has commonly been used to assess fiscal sustainability for resource rich countries –this calculates the benchmark for the non-resource primary deficit that can be financed in perpetuity by converting finite resources in the ground into financial assets. But the PIH has been criticized for providing a fiscal benchmark that is too tight for

developing countries.[15] Capital scarcity and financing constraints in developing countries implies that the rate of return to capital investment is likely to be high. Investing resource revenues domestically could therefore raise non-resource growth and provide increased fiscal space.

The sustainability assessment should focus on net wealth, by taking into consideration natural resource assets in the ground (the present value of the future resource revenue) in addition to net financial assets. In countries that are scaling up investment in physical and human capital, a more "dynamic" assessment could incorporate the effect of growth-enhancing expenditure on the non-resource growth path. Through the higher growth path, the scaled-up investment could in turn lead to more non-resource revenue, although this will be partially offset by higher operation and maintenance costs.

A fiscal anchor or rule for the short to medium term

The fiscal policy framework could be reinforced by the formulation of fiscal policy rules. For countries with a temporary resource revenue horizon, the fiscal policy rule preferably would be linked to fiscal sustainability considerations. It should be flexible to enable the potential incorporation of scaling-up of expenditure (investment), but should adjust the future fiscal path downwards when current spending is scaled up to preserve fiscal sustainability. Moreover, the fiscal rule should also adjust to changes in the resource outlook to accommodate new resource discoveries, changes in natural resource project cost and gas prices etc. Moreover, the fiscal rule should be simple to understand and implement.

Fiscal anchors can take the form of either non-resource balance rules or resource price-based rules.[16] Both sets of rules deal well with the fiscal management of short- to medium-term demand. The non-resource primary balance rule offers the added attraction of directly tying the short/medium-term to the long-term sustainability benchmark. More rigid rules can also be applied by allocating resource revenue inflows between spending and saving by fixed percentages.

Rules for the non-resource primary balance, based on the PIH, provide an explicit link to the exhaustibility of resource revenue. This is relevant for countries with a relatively short reserve horizon for resources. While the standard PIH may be inadequate for LICs, a modified version of the PIH can be designed to accommodate scaling-up of capital expenditure. This should allow a more front-loaded spending path "financed" by resource revenue that may be offset by lower spending in

[15] Barnett and Ossowski (2003) provide a comprehensive operational framework for applying the PIH to guide fiscal policy for resource-rich countries. Recent papers argue that earlt scaling-up domestic investment can be more advantageous for credit-constrained, capital-scarce economies (Collier et al, 2010; Venables, 2010; van der Ploeg and Venables, 2011). Taking into account the impact of public investment efficiencies and absorptive capacity constraints, Berg et al (2012) advocate a combination of higher public investment and financial savings.

[16] Price-based rules are less relevant to the case of a temporary gas resource boom, and hence are not considered here. However, a brief discussion of these rules can be found in Baunsgaard et al (2012).

the future. Such a *modified PIH* approach needs a transparent procedure to approve scaled-up capital expenditure if economically justified. The expenditure path would no longer be smoothed, but fiscal policy would remain anchored within an estimate of the long-term sustainable use of resource revenue.

Other institutional features

The revenue from natural gas should be integrated into the fiscal policy and budget framework. All spending of natural gas revenue should go through the budget, and be subject to the same scrutiny and accountability, including by parliamentary oversight, as any other public spending. There should be no separate institution with the authority to spend gas revenue. This also implies that all revenue collected on natural gas, including the production share, should be submitted to the Treasury.

The fiscal policy framework could be reinforced by the creation of a resource fund, including to transparently account for the gas revenue receipts. This could simply be an account kept in the central bank. The resource fund should be fully integrated into the fiscal policy framework and any spending should be carried out through the normal budget process. Withdrawal and deposit rules for the resource fund should be consistent with the overarching fiscal policy rule. The best approach would be to use the resource fund as a financing fund for the budget deficit determined in accordance with the macro-fiscal policy framework and rule. To prepare institutionally for this, reforms should be introduced to strengthen the budget design, implementation, and accountability practices to enhance the effectiveness and transparency of all public spending, rather than only focus on a segment of spending financed by natural gas.

Implementing a credible fiscal policy rule will also require strengthening the medium term orientation to the budget. The capacity to forecast revenue from natural gas, including under uncertainty, could be enhanced by developing a framework for forecasting natural resource revenue based on project-specific models that are appropriately aggregated across all projects, and provide the scope to run alternative forecasts under different assumptions. This should go hand in hand with efforts to introduce a forward-looking orientation to the budget through a medium term fiscal policy framework and a credible medium term expenditure framework to guide the annual budget formulation.

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