Surplus or Shortage? The Challenge of Setting a Domestic Supply Obligation for Tanzania's Offshore Gas

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Contents

Key messages

- The Tanzanian government wants a larger share of gas from the offshore project to prevent further energy shortages. This is in the form of a domestic supply obligation (DSO), currently agreed at around 8.5 percent of reserves.
- The landing zone for a new deal is narrow, and domestic and regional demand may be lower than the government expects. The potential costs of a DSO of 20 percent are vast. Combined, they are almost twice Tanzania's health budget. A DSO at that level could:
  - Make an already financially precarious project less viable.
  - Require tax incentives, resulting in 14 percent lower government revenue from the project.
  - Risk a gas surplus, hitting the government with take-or-pay penalties equivalent to 11 percent of government revenue from the project.
- To avoid such costs the government could:
  - Expand the country's energy mix to include more renewable energy, using some gas to manage power intermittency, for cooking and to supply industry, and exporting the rest.
  - Negotiate a variable DSO to better fit the country's likely demand in the future, using a revised Natural Gas Utilisation Master Plan to guide companies in redesigning the project.
  - Limit the DSO to below 20 percent, given the risks to the project's viability and the public finances.
  - Support this policy by changing the public narrative from one in which Tanzania's future is driven by gas, to one in which Tanzanians enjoy the full energy wealth of the country.
  - Make the project more competitive by working with companies to reduce project costs and emissions.

Summary

The amount of gas that Tanzania's government will take from the country's first offshore gas project is a key issue between the government and companies negotiating over the project. This amount is contractually defined as the domestic supply obligation (DSO). It determines the proportion of extracted gas that the Tanzanian government should take to sell on to Tanzanians and neighboring countries. The joint venture (JV) partners will export the remainder as liquefied natural gas (LNG), probably mainly to Asia. We believe the DSOs in the contracts signed with an Equinor-led JV and a Shell-led JV before the companies started exploring for gas are, when combined, equivalent to around 8.5 percent of reserves, and provide a relatively fixed volume across the project's lifetime. The government now seeks to increase the DSO, given the desperate need for accessible and reliable power for homes and businesses, clean technologies for cooking, and fuel for an industrial expansion in the country. The basis for the government's negotiation is the 2016 Natural Gas Utilisation Master Plan, which implies a DSO of 45 percent.[1] But much has changed since then, and the government is revising the plan.

A revised Natural Gas Utilization Master Plan (NGUMP) could clearly and realistically state what DSO it wants, to help all parties find solutions to delivering the gas. The revision could correct the potential over-estimation of domestic and regional demand for offshore gas. There are five reasons for these over-estimations. First, NGUMP's projected gas demand is much larger than projections by organizations like the International Energy Agency (IEA).[2] Second, the government projections rely on increasing Tanzania's gas-fired generation capacity by 650 percent by 2044. In contrast, the government is envisaging wind and solar energy contributing only 6 percent of power by 2044, despite their potential in Tanzania and falling costs.[3] Third, NGUMP assumes that industries such as fertilizer and gas-to-liquid plants will use the gas, but the gas is likely to be unaffordable without subsidies. Fourth, there could be substantial delays in building infrastructure to deliver gas across Tanzania, limiting how much gas the country can take. Fifth, Kenya is the largest potential market for regional exports. The necessary infrastructure is soon to be developed, with the Tanzanian and Kenyan governments recently announcing a plan to build a gas pipeline between the two countries.[4] But given Kenya's renewables plan and independent assessments of gas demand, the country might take much less gas than NGUMP projects.

Modeling more realistic scenarios to analyse the uncertainty of energy demand and supply could help the government understand the risks Tanzania faces. We developed two scenarios. These scenarios include the supply of onshore gas given this will also impact demand for offshore gas.

1 Government of Tanzania, *Natural Gas Utilisation Master Plan, Final Draft* (2016), www.resourcedata.org/dataset/tanzania-natural-gas-utilisation-master-plan-2016-2045.
2 IEA, *Africa Energy Outlook 2019, Tanzania* (2019), www.iea.org/articles/tanzania-energy-outlook.
3 Table 3-31 in Ministry of Energy, *Power System Master Plan, 2020 update* (2020), www.resourcedata.org/dataset/tanzania-power-system-master-plan-2020-update.
4 Aggrey Mutambo, "Kenya, Tanzania agree on gas pipeline plans," *The East African*, 4 May 2021, www.theeastafrican.co.ke/tea/news/east-africa/kenya-tanzania-gas-pipeline-3387670.

"NGUMP demand-low onshore supply"	"IEA demand-high onshore supply"
• Domestic demand is as high as NGUMP predicts • Tanzania supplies its neighbors with the amount of gas assumed by NGUMP • Onshore gas supply only from current projects	• Domestic demand is only as high as IEA STEPS predicts • Tanzania supplies Kenya to satisfy the demand assumed by IEA STEPS • Onshore gas supply from current projects and Tanzania's other onshore reserves

A mismatch between the agreed DSO and actual gas demand creates either gas shortages or surpluses—both significant concerns. A shortage without having developed other energy sources would exacerbate energy poverty and frequent blackouts in Tanzania. A surplus would mean the government may be unable to take all the gas off the project. This "offtake risk" means companies cannot quickly sell the gas to keep the project profitable. To partially insure against this risk, companies will likely require a take-or-pay arrangement which penalises the government for not taking the entire amount of gas it is obligated to. Even with a DSO of 20 percent, we estimate that penalties for the government could amount to 11 percent of total gas revenues.

Developing Tanzania's entire energy resource—including wind and solar—would help the government avoid gas shortages and surpluses. Figure 1 shows that even in the "IEA demand-high onshore gas scenario," there is eventually a gas shortage. This means that even a 20 percent DSO would not deliver the gas that Tanzania would need to meet the energy needs the IEA projects by the 2040s. The solution, we suggest, is to make the most of Tanzania's entire energy wealth—including solar and wind, and onshore gas reserves—reducing the need to consume the offshore gas domestically. Because overseas export of energy from these other sources is prohibitively expensive and difficult, if the government does not use these resources to supply the domestic market, they will not be used at all. Instead, by developing these other energy sources, Tanzanians would benefit both from revenues from exporting offshore gas and energy from these alternatives.

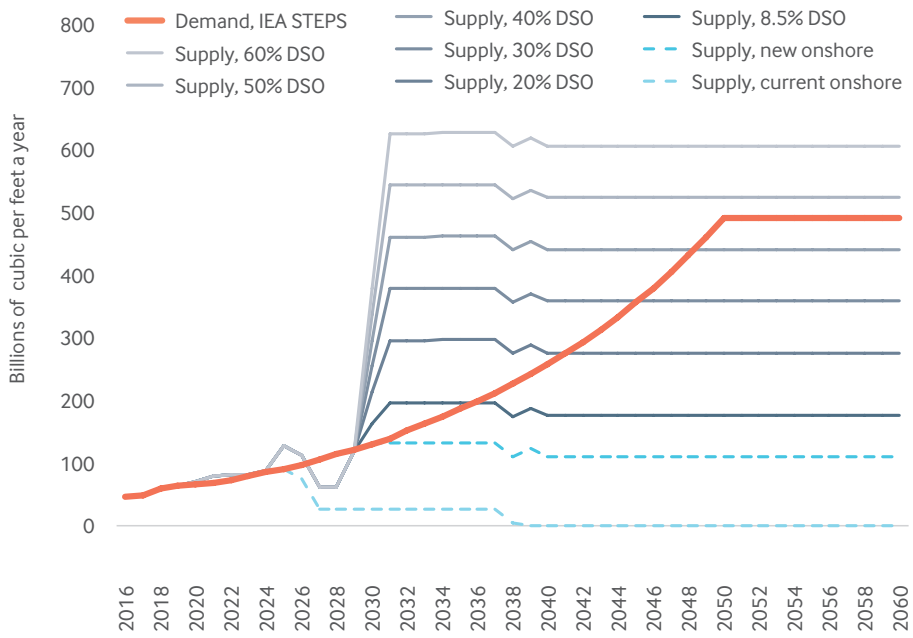


Figure 1. IEA demand-high onshore supply and different DSOs

Raising the DSO is risky, because even with the existing DSO, the project may not be viable. We estimate that for the companies to earn the minimum return they need to invest in Tanzania, the long-term LNG price at the point of delivery in Asia must be at least USD 9 per million British thermal unit (mmBtu). In contrast, Rystad Energy forecasts an Asian LNG price of around $8 per mmBtu in the long term. Wood Mackenzie thinks that the Asian price would be lower if the world meets the goals established in the Paris Agreement on climate change. In its 2020 scenario, it suggests that the Asian gas price could reach $8-9 per mmBtu by 2040 but will be lower from then onwards.[5] In its 2019 scenario, it suggested that the price could be less than $5 per mmBtu by 2040.[6] The landing zone for a deal is therefore narrow. However, the government could work with companies to reduce the carbon and methane emissions from the project, to make it more competitive for when export markets impose stricter emissions standards and carbon prices.

Given the offtake risk, increasing the DSO further reduces the project's viability for companies. In our "NGUMP demand-low onshore supply scenario," increasing the DSO does not significantly alter the return to the joint venture partners, because there is sufficient demand for Tanzanians and neighboring countries to purchase the extra gas. Conversely, in our "IEA demand-high onshore supply scenario," a larger DSO reduces project returns, as the government cannot take all the gas it contracted on schedule. Companies will have built an LNG plant only large enough to liquefy the gas initially intended for export. They must leave the untaken DSO gas in the ground until later, delaying sales revenues and the recoup of project costs. Figure 2 shows that the higher the DSO, the larger the drop in returns if domestic and regional demand are not high enough.

5 Wood Mackenzie, *Reversal of Fortune: oil and gas prices in a 2-degree world* (2021), www.woodmac.com/horizons/reversal-of-fortune-oil-and-gas-prices-in-a-2-degree-world?promo_name=horizonsapril21&promo_creative=roadblock.

6 Wood Mackenzie, *Accelerated energy transition 2-degree scenario (2019): what happens to the gas industry?* (2020), www.woodmac.com/reports/gas-markets-accelerated-energy-transition-2-degree-scenario-2019-what-happens-to-the-gas-industry-450213/.

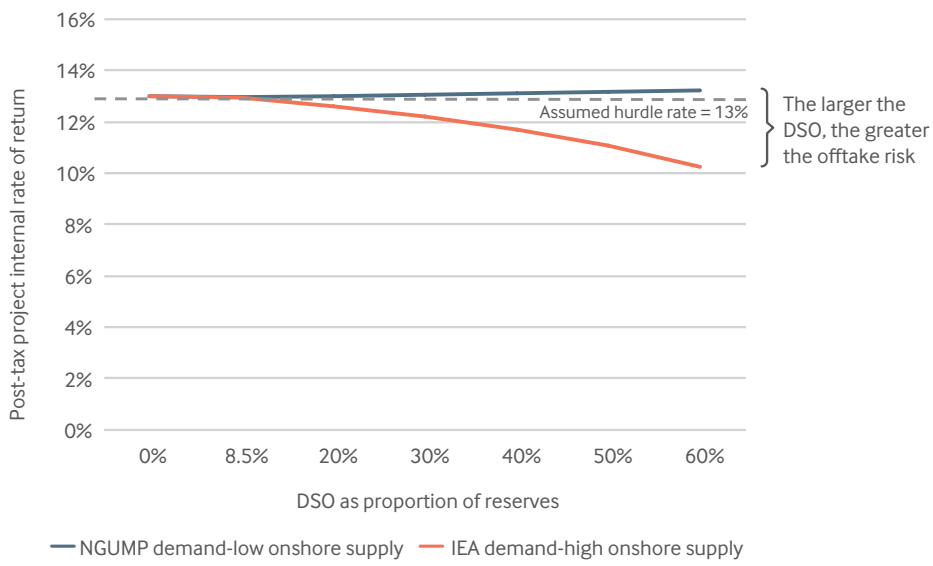


Figure 2. Project returns with different DSO volumes, given an LNG price of USD 9 per mmBtu and a DSO price of USD 4 per mmBtu

Note: We assume the DSO gas is sold at the cost-plus price at the exit of the processing plant, estimated to be $4 per mmBtu.

Rather than a fixed-rate DSO, the government could negotiate a DSO that varies with its stated demand schedule. If the government provides a clear and realistic demand schedule, it may be technically and economically possible to construct the project to deliver an increasing amount of gas to Tanzania. This would better fit the country's likely demand over the next decades, and reduce the offtake risk and penalties. However, the government would need to carefully consider the trade-offs in taking this approach, such as the need to pay for any spare capacity.

Companies are likely to push for tax incentives to make the project viable with a large DSO, however it is structured. With LNG exports likely to generate larger revenues than DSO sales, a larger DSO is likely to result in lower government revenues. Tax incentives will reduce government revenues further. We estimate government revenues would be 14 percent lower with a DSO of 20 percent than the DSO currently agreed.

If the government still wants a larger DSO, it should consider limiting it to below 20 percent. This would make it easier for Tanzania to tolerate the disadvantages, illustrated in Figure 3. With the double hit of take-or-pay penalties and lower government revenues, even a 20 percent DSO could cost the government the equivalent of 26 percent of revenue from the offshore project, or almost twice Tanzania's health budget.[7]

7 We estimate that, with a DSO of 20 percent, the take-or-pay penalty could be $631 million and government revenues from the project could be $974 million lower. Tanzania's health budget in 2017-2018 was TZS 2.2 trillion or about $946 million. Government of Tanzania and Unicef, *Health Budget Brief 2018* (2019), www.unicef.org/esa/media/2331/file/UNICEF-Tanzania-Mainland-2018-Health-Budget-Brief-revised.pdf.

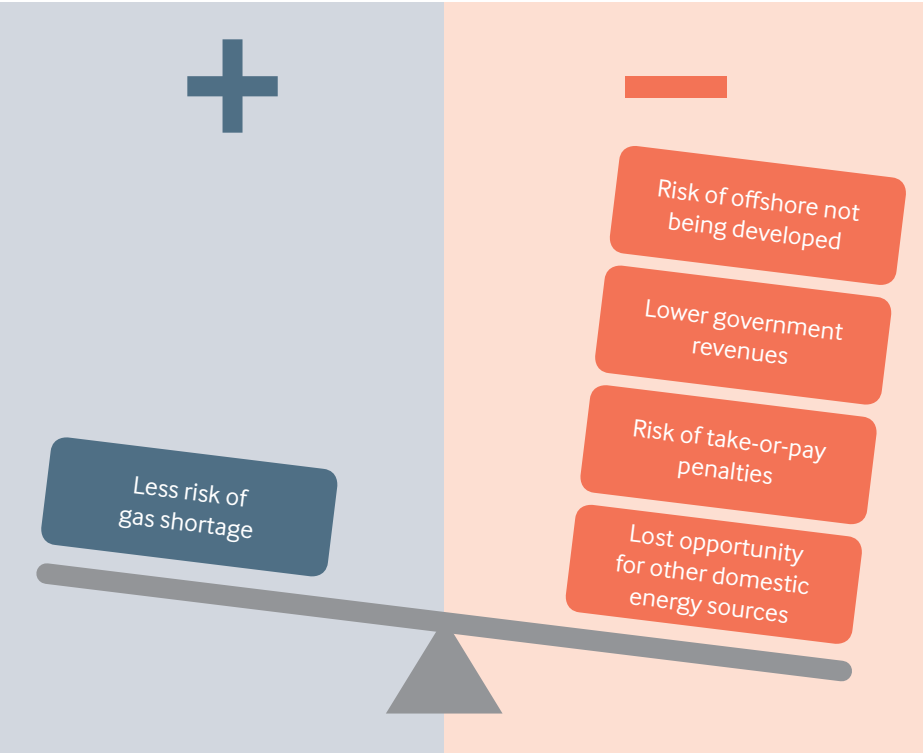


Figure 3. The advantages and disadvantages of a large DSO

The public may support a lower DSO to gain more government revenues if the government changes the narrative. The government has created a narrative that Tanzania will become a gas-fuelled society, but the trade-offs of such a vision—described in this report—also hurt the public. Public surveys suggest the public is evenly split between using the gas to earn money for government programmes and generating power.[8] If the public is concerned with power, emphasising the role that other energy sources can play may help the government negotiate a DSO that makes the project viable and achieves its higher energy goals.

Tanzania's new president has made negotiating a way forward on the offshore project one of her early priorities.[9] We hope that our proposals for determining the right DSO for Tanzania help the president to achieve her goal.

8 See, for example, Question 5 in Twaweza, *Great Expectations: Citizens' views about the gas sector, September 2015* (2015), twaweza.org//wp-content/uploads/2021/02/NaturalResources-FINAL-EN-1.pdf.

9 Rosemary Mirondo, "President Samia directs speeding up of stalled LNG project," *The Citizen*, 6 April 2021, www.thecitizen.co.tz/tanzania/news/president-samia-directs-speeding-up-of-stalled-lng-project--3351746.

Introduction

Most Tanzanians do not have access to power and very few use clean fuels to cook with.[10] Businesses also suffer. A survey in 2013 suggested that power cuts lost firms in Tanzania the equivalent of 15 percent of their sales each year.[11] Tanzanians will need more energy in the future, due to a growing economy and population. No one knows how much, but projections by the International Energy Agency (IEA) suggest that in 2040, Tanzania will use at least double the energy the country uses today.[12] This amount is still equivalent to only a fifth of what the average person in the world consumes now, so a greater energy supply is drastically needed in Tanzania.[13]

Paradoxically, Tanzania has a lot of energy resources. Its hydro resources have the potential to generate 66 Terawatt-hours (TWh) of power a year, compared to around 3 TWh currently.[14] It has the necessary space and climate to generate power from solar, wind and geothermal sources,[15] and could have up to 5 billion tons of coal reserves.[16] There is possibly also 7.1 trillion cubic feet (tcf) of recoverable natural gas remaining onshore, and another 33.3 tcf 100 kilometres offshore.[17] However, there are challenges with using each of these forms of energy. This report focuses on one of the greatest: using the offshore gas.

A Domestic Supply Obligation will determine how much offshore gas is supplied to Tanzanians and their neighbors

The government and companies—comprising a Equinor-led joint venture (JV) and a Shell-led JV—are currently negotiating over the regulatory framework for the offshore project involving Blocks 1, 2 and 4.[18] Part of this negotiation is determining the domestic supply obligation (DSO), a contractual provision setting out how much of the gas from the offshore reserves will be used by the government to supply Tanzania and possibly its neighbors.

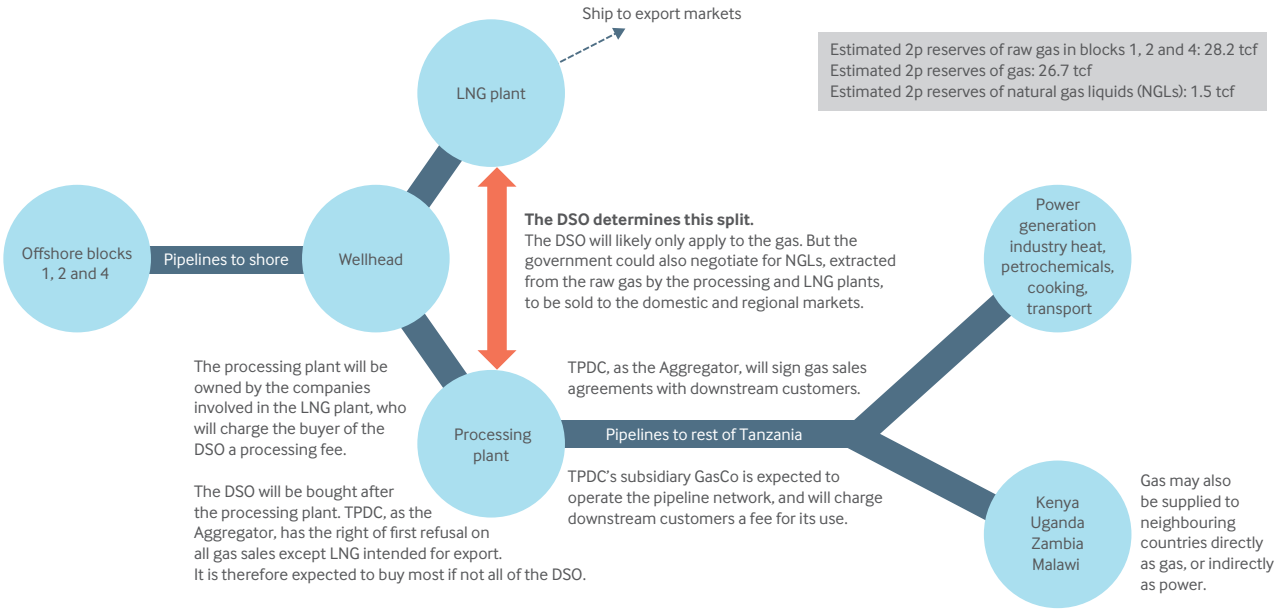
DSOs are an increasingly common component of gas projects.[19] The Tanzania DSO,

10 36 percent of the population has access to power for some of each day, and only 2 percent cooks with clean fuels. World Bank, "Access to electricity (% of population) – Tanzania," last updated 2018, data.worldbank.org/indicator/EG.ELC.ACCS.ZS?locations=TZ.
11 Ben Garside and Davida Wood, *Improving Tanzania's power quality: can data help?* (International Institute for Environment and Development, 2018), www.iied.org/improving-tanzanias-power-quality-can-data-help.
12 Primary energy demand in the IEA's Africa Energy Outlook 2019 Stated Policies Scenario. IEA, *Africa Energy Outlook 2019, Tanzania.*
13 World Bank, "Energy use (kg of oil equivalent per capita)," last updated 2014, data.worldbank.org/indicator/EG.USE.PCAP.KG.OE.
14 Ministry of Energy, *Power System Master Plan, 2020 update.*
15 AfDB, *Renewable Energy in Africa: Tanzania Country Profile* (2015), www.afdb.org/fileadmin/uploads/afdb/Documents/Generic-Documents/Renewable_Energy_in_Africa_-_Tanzania.pdf; World Bank, *Tanzania: Solar and Wind Potential Could Help Meet Future Power Generation Goals* (2015), www.worldbank.org/en/news/feature/2015/06/09/tanzania-solar-and-wind-potential-could-help-meet-future-power-generation-goals.
16 U.S. Department of Commerce, "Tanzania – Energy," last updated January 2019, www.export.gov/apex/article2?id=Tanzania-Energy.
17 Estimates by Tanzania Petroleum Development Corporation (TPDC), the national oil company, of gas initially in place in 2019, adjusted for the government's assumption that around 70 percent is recoverable. National Audit Office, *Report of the Controller and Auditor General on the Consolidated and Separate Financial Statements of Tanzania Petroleum Development Corporation for the Year Ended 30 June 2018* (2019), www.tpdc.co.tz/pdfstuff/FINANCIAL%20REPORT%20JUNE2018.pdf.
18 The Shell JV holds the license for Blocks 1 and 4, and the Equinor JV holds the Block 2 license.
19 See examples of DSOs in other countries in: U.S. Department of Energy and United States Energy Association, *Understanding Natural Gas and LNG Options* (2016), 49-50, www.energy.gov/sites/prod/

as currently envisaged, will determine how much gas is sent to a DSO processing plant and then purchased by the state-owned Tanzania Petroleum Development Corporation (TPDC) to supply the domestic and neighboring markets. The remainder will be processed by a liquefaction plant and exported as LNG on ships.

Figure 4. Tanzania's offshore project and the DSO[20]

Notes: Authors' depiction based on discussions with government and company officials.



Tanzania's government is seeking a larger DSO

Each block in the planned offshore project is regulated by an existing production sharing agreement (PSA), which will be complemented by a Host Government Agreement (HGA) being negotiated for the LNG plant to form the overall regulatory framework. The PSAs already contain a DSO. The government and companies have not disclosed the PSAs, so we have a limited understanding of their content. However, Equinor, the operator of Block 2, has disclosed that it has a DSO of 10 percent of reserves. As discussed in Box 1, the leaked addendum to Block 2's PSA implies that this DSO will be fixed across the project's lifetime. We understand that the DSO for Blocks 1 and 4, operated by Shell, is between 6 and 8 percent and is also fixed. Assuming a DSO of 7 percent for Blocks 1 and 4, the weighted average DSO across the project is 8.5 percent (based on Rystad Energy's proved and probable (2P) reserve estimates).

files/2016/12/f34/Understanding%20Natural%20Gas%20and%20LNG%20Options.pdf; and in Tomás Lanardonne, *Domestic Gas Supply Obligation Schemes and Gas Exports: A Catch-22 Situation?* (2015), www.ogel.org/article.asp?key=3521. Several contracts on ResourceContracts.org also contain a DSO. Natural Resource Governance Institute, "Resource Contracts," last accessed 26 April 2021, www.resourcecontracts.org/.

20 Estimated 2P reserves from Rystad Energy UCube.

Box 1. Mechanics of the DSO

The Petroleum Act 2015 requires both TPDC and the companies to contribute to the DSO. This contribution will be proportional to their share of production and made from their share of profit gas.

The Petroleum Act 2015 does not cover the structure of the DSO. Our understanding of the currently agreed structure is therefore based on the leaked addendum to Block 2's PSA. This states that the DSO shall "not exceed 10% of the Proven Reserves and shall not exceed 10% of the projected production rate unless otherwise mutually agreed by the Parties."[21] If the government and companies agree a DSO of 10 percent of reserves, the ceiling of 10 percent of production at any given time implies the DSO will be a fixed volume at the production plateau. For example, if TPDC were to take only 5 percent of production in one year, it could not take 15 percent in the following year to obtain the 10 percent share of reserves overall. This structure would be similar, for example, to that recently agreed for Mozambique's Area 1 project.[22] The arrangement is likely to still allow the volume that TPDC takes to vary within a defined range across a given year. However, as we discuss in Section 3, the government and companies could agree to a DSO with even more variability under certain conditions.

We are not certain what pricing arrangement the PSAs specify, but discussions with the companies suggest it could be the LNG netback price—the LNG price minus the cost of liquefying the gas and transporting it to market. However, the government has suggested it intends to buy the DSO gas at the "cost-plus" price, and that TPDC will purchase this gas at the exit of the domestic market processing plant. Therefore, the "cost" will comprise the cost of producing and processing the gas. The "plus" will be a defined profit margin. The Natural Gas Pricing Regulations 2016 outline a methodology for calculating this price, although both the approach to calculating costs and the definition of a "reasonable" profit margin will likely be negotiated. A price could either be agreed for the lifetime of the project, the duration of its financing term or set annually. How much the companies resist changes to any existing pricing arrangements therefore depends on these details.

Each DSO is likely to include a take-or-pay clause that stipulates that if TPDC does not take and pay for a specified portion of the DSO, it must still pay for it. It is unclear whether the parties have agreed whether the untaken DSO can be "banked," which means TPDC would have the right to later take the gas paid for. When TPDC can take any banked gas will depend on the physical capacity of the project's infrastructure.

21 Article 8 of *Addendum to Existing Production Sharing Agreement between Government of United Republic of Tanzania and Tanzania Petroleum Development Corporation and Statoil Tanzania AS and ExxonMobil Exploration and Production Tanzania Limited Block 2* (2012), www.resourcecontracts.org/contract/ocds-591adf-8344502322/view#/pdf.

22 Moçambique Ministério da Economia e Finanças, *Projected government revenues from gas projects* (2018), 4, www.inp.gov.mz/pt/content/download/1372/9256/version/1/file/Republic+of+Mozambique_Government+Revenues+from+Gas+Projects.pdf.

The government is now asking for a larger DSO. It has not indicated the size or structure it is aiming for, but government documents may provide a clue. The main government document, written in 2016, is the Natural Gas Utilisation Master Plan (NGUMP). This contains two scenarios of gas consumed in Tanzania and the region over the next 25 years: a base case and a high case. The base case scenario envisions the country consuming the equivalent of 45 percent of all offshore reserves (as well as the estimated 7.1 tcf of recoverable onshore reserves) from 2016 to 2045.[23] In other words, a DSO of 45 percent is required if the NGUMP base case estimate turns out to be correct. NGUMP provides one possible target for the government. Another is the Petroleum Act 2015, which provides for a DSO up to the amount of profit gas. Using our economic model of the offshore project, we estimate this provision could mean a DSO of around 60 percent of reserves.

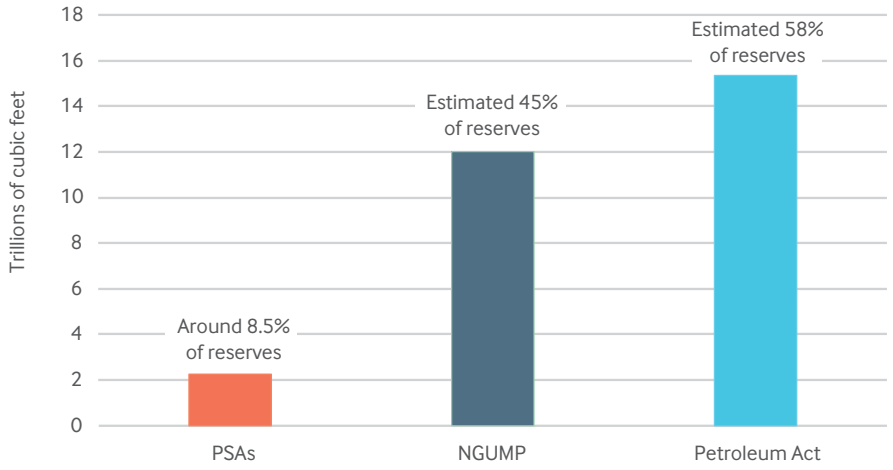


Figure 5. The DSO implied by different sources

Notes: This is based on reserves excluding natural gas liquids. The implied DSO in the PSAs of 8.5 percent is based on a DSO of 10 percent in the Block 2 PSA and an assumed DSO of 7 percent in the Block 1 and 4 PSAs. However, we understand that the latter DSO may be as low as 6 percent. NGUMP's implied DSO is based on expected gas consumption in its base case, net of onshore reserves. The Petroleum Act implies the DSO could be total profit gas. We used our economic model of the project to estimate the volume that this DSO could entail in our baseline scenario.

Three key questions

To inform the government's approach to negotiating a DSO that is optimal for Tanzania, we analyzed three key questions, which form the three main sections of this report:

1. How much gas might Tanzania and its neighbors need in the future?
2. How concerned should the government be about a shortage or surplus of gas?
3. What are the implications of a larger DSO for the offshore project and government revenues?

The fourth section of the report proposes a way forward for the Tanzanian government.

23 Based on reserves excluding natural gas liquids.

1. Gas demand for Tanzania and its neighbors is uncertain

Setting the DSO is difficult because no one knows for sure how much gas Tanzania or its neighbors will need in the future. Nor do they know when Tanzanians will need the gas, or what price people will be willing to pay for it. In the 2016 NGUMP, the government has projected the country's gas needs up to 2045, and these form the basis for its negotiations with the companies.[24] However, much has changed since 2016. Not only is the global shift away from fossil fuel investments potentially accelerating, but the costs of solar and wind technologies that compete against gas in power markets are falling. Given these changes, the government is currently reviewing this plan. However, all projections, particularly those stretching decades into the future, include a great deal of uncertainty. When faced with such uncertainty, it can be useful to test policies by applying multiple realistic scenarios and understanding the implications of the plan in the case that one of these scenarios occurs. This section reviews different scenarios. In the rest of the report, we further develop these scenarios and use them to analyse the DSO question.

Projections for Tanzanian domestic gas demand vary widely

In lieu of the government's revision of NGUMP, we have assembled a set of forecasts and scenarios that show a wide range of potential futures for Tanzanian gas demand. As these projections were made at different times, with different assumptions, we had to calibrate them to be comparable. The appendix explains our methodology.

These forecasts and scenarios come from three sources:

1. **National Gas Utilisation Master Plan 2016 (NGUMP).** This is from the NGUMP base case scenario.[25] NGUMP provides a high-case scenario, but no low case. We therefore focus on the base case. NGUMP includes an assumed demand from regional neighbors in east and southern Africa, but the other scenarios do not. We separate out domestic demand here to make it comparable to the other scenarios, and discuss the regional demand projection later in the section.
2. **Potential for Regional Use of East Africa's Natural Gas (" Demierre et al.")** This scenario is for domestic demand, taken from the research paper by Demierre et al. in 2014.[26]

24 Government of Tanzania, *Natural Gas Utilisation Master Plan.*
25 Government of Tanzania, *Natural Gas Utilisation Master Plan.*
26 Jonathan Demierre, Morgan Bazilian, Jonathan Carbajal, Shaky Sherpa and Vijay Modi, *Potential for Regional Use of East Africa's Natural Gas*, (Sustainable Development Solutions Network, 2014), 28, www.energypolicy.columbia.edu/sites/default/files/Potential-for-Regional-Use-of-East-Africas-Natural-Gas-SEL-SDSN.pdf.

3 **International Energy Agency (IEA).** The IEA publishes a range of scenarios. The two most relevant that we could use to calculate domestic demand are:

a. **IEA STEPS.** This scenario is based on the IEA's Stated Policies Scenario in the *Africa Energy Outlook* in 2019.[27]

b. **IEA SDS.** This scenario is based on the IEA's Sustainable Development Scenario in 2020.[28] This scenario is consistent with a fast enough energy transition to limit the growth in global temperature to below two degrees Celsius.

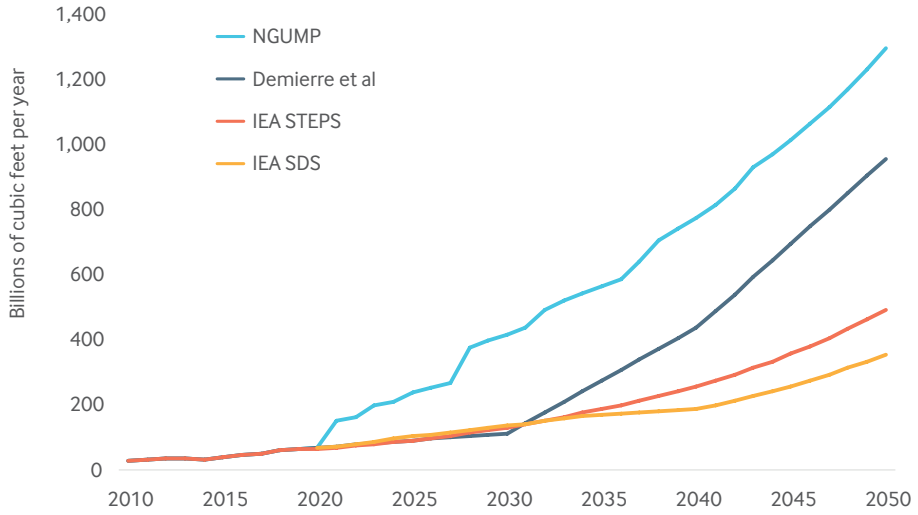


Figure 6. A range of potential gas demand in Tanzania

Notes: See appendix for further details on how we configured these scenarios.

Comparing these scenarios suggests a very wide range of consumption. The NGUMP scenario is the most optimistic. We could not find a third-party forecast that was more optimistic. However, there are several reasons to doubt NGUMP's projections.

27 IEA, *Africa Energy Outlook 2019, Tanzania.*
28 IEA, *World Energy Outlook 2020* (2020), www.iea.org/reports/world-energy-outlook-2020.

Renewable energy could be more viable than the government expects

Tanzania already has two producing onshore gas projects: Songo Songo and Mnazi Bay. The country uses most of this gas to generate half its power: 51 percent of power was generated using gas between 2015, when production ramped up, and 2018. The next largest power source—hydro—contributed 26 percent of power during this period.[29]

The government plans to continue deriving most of Tanzania's power from gas. Its Power System Master Plan 2020-2044 (PSMP) identifies gas as the largest source of power in the mix, comprising 36 percent or 42 TWh of generation by 2044.[30] To achieve this, it aims for a 650 percent increase in gas-fired generation capacity over the plan's period.[31] This involves the construction or expansion of 16 power plants in 25 years. Reflecting this ambition, NGUMP proposes the country will use 46 percent of domestic gas supply to generate power, equivalent to 8.8 tcf over 30 years.

However, there are several reasons why Tanzania may need less gas for power than projected in NGUMP and PSMP. These include the shifting role of its hydroelectric dams, which are now working as baseload providers, requiring gas plants to act as "peaker" plants.[32,33] This is due to rainfall becoming less reliable in Tanzania. Existing gas plants are therefore not always operating at full capacity and are consuming less gas. For example, unusually heavy rainfall resulted in larger hydropower generation in 2019. With this power needing to be used or there being a risk of the dams overflowing, gas demand was reduced. Mnazi Bay therefore had to produce gas below capacity.[34] As the government brings more hydroelectric dams, such as Stiegler's Gorge, online, this peaker role for gas will only increase—particularly if the government's need to generate a return on its investment in Stiegler's Gorge means this hydroelectric dam takes precedent over other power sources.

29 IEA, *Africa Energy Outlook 2019, Tanzania.*
30 Table 3-31 in Ministry of Energy, *Power System Master Plan, 2020 update.*
31 The PSMP reports 893 MW of installed capacity in 2020 and aims for 6,700 MW in 2044.
32 Peaker plants generally only generate power during periods of high demand.
33 Giacomo Falchetta, David E. H. J. Gernaat, Julian Hunt and Sebastian Sterl, *Hydropower dependency and climate change in sub-Saharan Africa: A nexus framework and evidence-based review,* (Journal of Cleaner Production, 2019), www.sciencedirect.com/science/article/abs/pii/S0959652619317998.
34 Wentworth Resources PLC, *Annual Report and Financial Statements 2019* (2020), wp-wentworth-2020.s3.eu-west-2.amazonaws.com/media/2020/11/19100910/Web-version-Wentworth-Resources-Annual-Report-and-Financial-Statements-2019.pdf.

In its NGUMP and PSMP, the government might also have underestimated the contribution that solar and wind power can make. In the PSMP, updated in 2020, the government planned for only 6 percent of its power or 7 TWh to derive from wind and solar sources by 2044. Yet Tanzania has significant potential for both these types of power generation, as the World Bank and African Development Bank (AfDB) have noted.[35] The IEA thinks wind and solar has the potential to contribute up to 33 TWh by 2040.[36]

Part of the reason for the relatively small role for wind and solar power in PSMP may be concerns about their cost. Government estimates in 2012 suggested these sources are more expensive than gas and hydropower.[37] However, as shown in Figures 7 and 8, global average costs for solar and wind power have fallen significantly since 2012. Comparing the levelized cost of electricity (LCOE) estimates for Tanzania taken in 2012 with global costs in 2010 suggests that Tanzania's solar costs were relatively low in 2012.[38] The global average cost has fallen significantly since then, so Tanzanian costs may be even lower now.[39] For wind, the 2012 estimates are higher than the global average in 2010. However, they are also likely to have fallen since global costs have fallen too.

Solar and wind power costs are expected to continue falling.[40] This is likely to make them increasingly competitive against gas power plants in Tanzania. Even now, the global average cost for power from solar and wind sources is similar to or lower than power from the lowest cost fossil fuel plants.[41]

35 World Bank, *Tanzania: Solar and Wind Potential Could Help Meet Future Power Generation Goals; AfDB, Renewable Energy in Africa: Tanzania Country Profile.*
36 In the Africa case in IEA, *Africa Energy Outlook 2019, Tanzania.*
37 Ministry of Energy and Minerals, *Scaling-up renewable energy programme: Investment plan.*
38 IRENA, "Global Trends," last updated 2020, www.irena.org/Statistics/View-Data-by-Topic/Costs/Global-Trends.
39 Measured as the levelized cost of electricity. This measures purely the cost of bringing a kilowatt hour onto a grid, and not wider system costs related to managing grid variability.
40 IEA, *Renewables 2020* (2020), www.iea.org/reports/renewables-2020.
41 IRENA, "Global Trends."

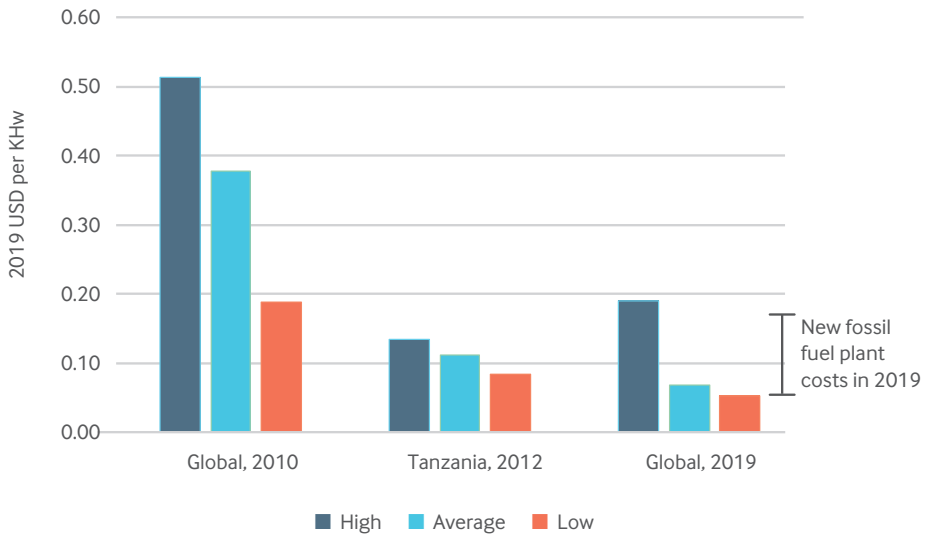


Figure 7. Solar photo-voltaic, levelized cost of electricity (global and Tanzania)[42]

Notes: Levelized cost of electricity for newly commissioned utility-scale power generation technologies across the world in 2010 and 2019. The high costs represent the 95th percentile and the low costs represent the 5th percentile.

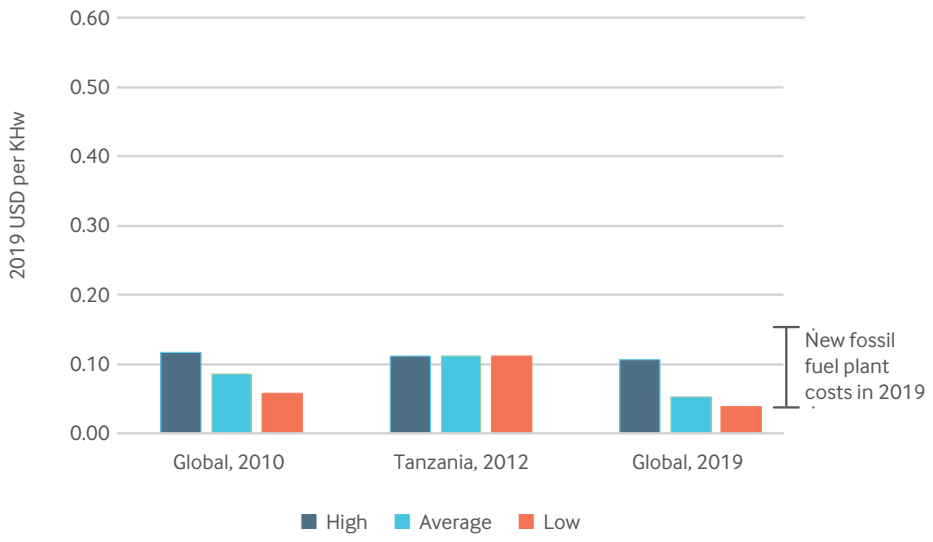


Figure 8. Onshore wind, levelized cost of electricity (global and Tanzania)[43]

Notes: Levelized cost of electricity for newly commissioned utility-scale power generation technologies across the world in 2010 and 2019. The high costs represent the 95th percentile and the low costs represent the 5th percentile.

42 Global costs from IRENA, "Global Trends;" Tanzania costs from Ministry of Energy and Minerals, *Scaling-up renewable energy programme: Investment plan.*

43 Global costs from IRENA, "Global Trends;" Tanzania costs from Ministry of Energy and Minerals, *Scaling-up renewable energy programme: Investment plan.*

As with many energy planners, the government also appears to be concerned about the intermittency of solar and wind. However, this does not preclude renewable energy taking a large share of the energy mix, for two reasons:

1. **A diversified energy mix guards against the collapse of any one power source.** Variation in any individual source is very unlikely to be correlated with any other source. This includes wind versus solar power—where there appears to be some negative correlation between the two sources—as well as hydro versus solar, as the government noted in its 2013 renewable energy plan.[44]

2. **Gas and other energy sources can be used as peakers.** Tanzania is already using gas to provide power when hydro-generation drops, or demand is high. Instead of building combined-cycle gas turbines (as planned in PSMP), more open-cycle gas turbines could be built, which are more efficient in playing the role of peaker plants. In this role, gas plants need less fuel than when providing baseload power.

Nevertheless, the intermittency of solar and wind will make it even more important that the government strengthens the transmission and distribution system within Tanzania and interconnectors with neighboring countries. Time-varying tariffs would also help address intermittency challenges and enable a larger role for renewables.[45]

44 Ministry of Energy and Minerals, *Scaling-up renewable energy programme: Investment plan.*
45 CDC Group, *Decarbonising Africa's Grid Electricity Generation* (2021), assets.cdcgroup.com/wp-content/uploads/2021/05/25111607/Decarbonising-Africas-grid-electricity.pdf.

Anticipated petrochemical and gas-to-liquid plants may not be viable

NGUMP assumes 32 percent of domestic gas supply will be consumed by industries not yet established in Tanzania (see Figure 9). There are several reasons to doubt whether these industries would be able to afford gas without government subsidies.

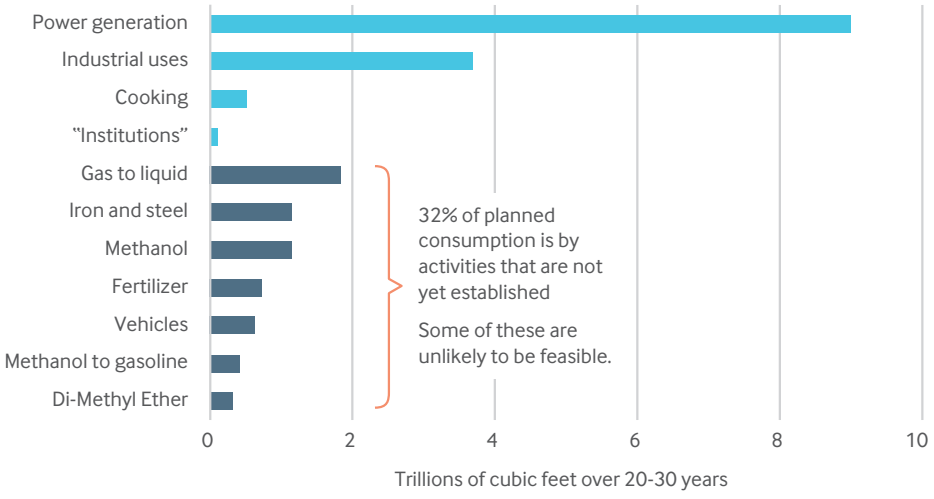


Figure 9. Gas uses, NGUMP base case scenario[46]

The final price that the government and other consumers have paid over the last five years for onshore gas is around $4 per mmBtu—an amount that makes many of these new industries unviable. The DSO gas from the offshore project is likely to cost at least $4 per mmBtu. Using our economic model of the project, we estimate that a cost-plus price at the exit of the processing plant could be around $4 per mmBtu. This price comprises of a wellhead price of around $3 per mmBtu and a processing tariff of up to $1 per mmBtu.[47] TPDC will then need to add transport and marketing costs to this price.

In contrast, Tanzania's Petroleum Regulatory Upstream Authority has noted that a proposed fertilizer plant in Mtwara would not be viable buying gas above $2.6 per mmBtu.[48] This is unsurprising, as both the global and Tanzanian fertilizer markets are highly competitive, so Tanzanian farmers have access to cheaper fertilizer. Other countries, such as Trinidad and Tobago, have been able to displace foreign fertilizer imports, but principally because domestic producers used associated gas available at a lower cost than in Tanzania.[49] Gas-to-Liquids (GTL) plants need an even

46 Government of Tanzania, *Natural Gas Utilisation Master Plan.*
47 We have assumed a "plus" of around 13 percent (after adjusting for assumed inflation of 2 percent). This is based on Wood Mackenzie's "State of the Upstream Industry" company surveys in 2017 and 2018 that found an expected real return of 13 percent to be the most common hurdle rate used for LNG projects across the globe in recent years.
48 *The Citizen,* "Why Mtwara fertilizer plant project has been delayed," 2 December 2020. www.thecitizen.co.tz/tanzania/news/-why-mtwara-fertiliser-plant-project-has-been-delayed-3235536.
49 For example, ammonia producers paid around $1.3 per mmBtu for gas in 2014. Poten & Partners. T*rinidad & Tobago Gas Master Plan.* 2015. www.energy.gov.tt/wp-content/uploads/2020/01/Trinidad-and-Tobago-gas-master-plan-2015.pdf.

lower gas price, often less than $1 per mmBtu, to be viable.[50] They also commonly use associated gas as a result. Highlighting the challenge of making downstream projects such as these a reality, Mozambique's plans for a GTL plant and a fertilizer plant have both been shelved.[51] This is despite Mozambique having cheaper gas than Tanzania.[52]

The government might be tempted to subsidize gas to encourage the development of these industries. The Natural Gas Pricing Regulations already allow the government to subsidize the wellhead price by up to 35 percent for "strategic industry." The definition of a strategic industry is broad: "an industry that the government considers to have significant multiplier effects on the growth of the country's economy, including power generation, fertilizer manufacturing and petrochemicals."

However, downstream investors are likely be cautious about any subsidy commitments, particularly given the unpredictability of the government's wider policy framework. Subsidies are costly and raise tremendous political and financial challenges for the government, meaning they may fail to materialize as promised.

Infrastructure to supply gas across Tanzania could be delayed

Coordinating the construction of a vast array of infrastructure required to move offshore gas to power plants, homes and businesses is also an immense challenge. Not only will the new infrastructure cost a great deal. It involves coordinating the physical construction, as well as ensuring that the state energy companies and other entities are able to spend the large amounts necessary to guarantee construction, and subsequent deals are completed on time.

Ghana's experience provides a warning. The government intended to start taking gas from the Jubilee project in 2013. However, completion of the necessary pipelines and processing plant was delayed, partly due to the state entities involved being saddled with debt. The government was not able to take any gas until the end of 2014.[53] It then agreed to purchase more gas from the Offshore Cape Three Points project starting in 2018. However, despite this gas being in the southwest of the country, the government had constructed the power plants that would use it in the east. It therefore needed to reverse the flow of the existing West Africa Gas Pipeline, as well as construct additional pipelines.[54] The timetable for this work also slipped, preventing the government from taking gas until 2019.

50 See, for example: Ekwueme Stanley Toochukwu, Izuwa Nkemakolam Chinedu, Obibuike Ubanozie Julian, Kerunwa Anthony, Ohia Nnaemeka Princewill, Odo Jude Emeka and Obah Boniface. *Economics of Gas-to Liquids (GTL) Plants*. Petroleum Science and Engineering, 2019. www.researchgate.net/profile/Anthony-Kerunwa/publication/338987326_Economics_of_Gas-to-Liquids_GTL_Plants/links/5e3703e7299bf1cdb9083a42/Economics-of-Gas-to-Liquids-GTL-Plants.pdf.

51 Petroleum Economist. "Mozambique's Ambitious Northern Gas Plans Head South," 27 November 2020. www.world-energy.org/article/14130.html.

52 Rystad Energy UCube.

53 Monica Skaten, *Ghana's Oil Industry: Steady growth in a challenging environment* (The Oxford Institute for Energy Studies, 2018), www.oxfordenergy.org/wpcms/wp-content/uploads/2018/04/Ghanas-Oil-Industry-Steady-growth-in-a-challenging-environment-WPM-77.pdf.

54 ACEP, *ACEP's comments on the OCTP gas utilization challenges* (2019), acep.africa/aceps_comments_on_the_octp_gas_utilization_challenges/.

Tanzania will also face challenges. The 2016 NGUMP assumes the development of gas infrastructure across Tanzania. Currently, a gas pipeline runs only to Dar es Salaam from the gas fields in the south. The PSMP forecasts that the city will consume around 40 percent of the country's total power by 2030. NGUMP therefore plans to connect other cities by pipeline in the future (such as Mwanza and Arusha, accounting for 11 percent of power demand by 2030).[55] If this infrastructure is delayed, then TPDC will not be able to reach new markets in time to sell the DSO gas across Tanzania as expected in NGUMP. The government has already experienced such infrastructure challenges in the power sector. It targeted power generation capacity of 5,536 MW by 2020 in its earlier PSMP 2016-2040, but capacity is currently only 1,602 MW.[56]

There is further potential for delay in transporting the gas to Dar es Salaam. Currently the gas pipeline that runs from the southern village of Madimba to Dar es Salaam, through which the offshore gas is expected to be transported, has a capacity of 750 million cubic feet per day (mmcfd).[57] At its maximum, the NGUMP base case assumes that the country will be consuming 3,948 mmcfd. If much of this demand is in Dar es Salaam and further north, as expected, another four similarly sized pipelines would be needed just to get the gas to Dar es Salaam.

Some of these challenges might be alleviated by developing a "virtual pipeline." This involves transporting the gas as LNG by road or rail and then reconverting the LNG using small-scale regassification terminals in places to which it would be too expensive to pipe gas.[58] However, delays are still a distinct possibility.

Tanzania's neighbors may need less gas than the government expects

NGUMP estimates that in addition to supply to the domestic market, three tcf, or 400 million cubic feet per day (mmcfd), will be exported to the regional market by 2045. However, it is uncertain whether Tanzania's neighbors will buy its gas, either directly via pipelines or indirectly as power, or whether they will buy from Mozambique, or develop their own abundant energy sources.

Kenya is the largest potential market for regional exports. The necessary infrastructure is soon to be developed, with the Tanzanian and Kenyan governments recently announcing a plan to build a gas pipeline between the two countries.[59] According to the Tanzanian government, Kenya has requested 400 mmcfd.[60] But there is reason to doubt whether Kenya will require this much. The

55 Ministry of Energy, *Power System Master Plan, 2020 update.*
56 Ministry of Energy and Mine*rals, Power System Master Plan, 2016 update* (2016), www.resourcedata.org/dataset/tanzania-power-system-master-plan-2016-update.; Ministry of Energy, *Power System Master Plan, 2020 update.*
57 Wood Mackenzie, *Tanzania Upstream Summary September 2016* (2016).
58 There have been continued discussions on establishing a virtual LNG pipeline. For example, the Japan International Cooperation Agency held a domestic gas symposium on this proposal in January 2020. Presentation by the Ministry of Energy, "Highlights of NGUMP," Symposium on Domestic Natural Gas Promotion Plan, 17 January 2020.
59 Aggrey Mutambo, "Kenya, Tanzania agree on gas pipeline plans."
60 Presentation by the Ministry of Energy, "Highlights of NGUMP."

country already has a sizable share of power from wind and solar sources, and plans to develop much more.[61] It could therefore benefit from installing more gas turbines to manage the resulting intermittency.[62] However, in such a case, it would still require a more limited amount of gas. Kenya is also quickly developing geothermal energy, with a third of its power already coming from this source[63] This means that Kenya is unlikely to need gas to derive most of its power. This is backed up by IEA's projections. Compared with the 400 mmcfd expected by the government, the IEA projects that Kenya will consume only 71 mmcfd by 2040.[64]

It is not clear that other countries in the region will need so much gas either. The Tanzanian government has also signed a (non-legally binding) memorandum of understanding with Uganda for the supply of 160 mmcfd.[65] However, again this amount is doubtful. A recent Ugandan government plan does not mention gas for power, only for gas to be used by industry for heat.[66] Any gas used for power would also be competing against the coal Uganda plans to import from Tanzania.[67] The IEA does not project gas consumption for Uganda, but if it is only projecting 71 mmcfd for Kenya, a much larger economy, then it seems unlikely, given this projection, that Uganda would be consuming 160 mmcfd.

Tanzania is also considering Zambia and Malawi as potential customers. Exporting the gas as power may be an option, particularly given the Southern Africa Power Pool. However, Tanzania will be competing with Mozambique for these gas and power markets.[68] It has yet to undertake feasibility studies for any of these supply options other than Kenya. As a result, there is a significant question over the certainty and scale of regional supply opportunities.

61 USAID, "Kenya: Power Africa Fact Sheet."
62 Mark Thurber and Todd Moss, *12 reasons why natural gas should be part of Africa's clean energy future*, (Energy for Growth Hub, 2020), www.energyforgrowth.org/op-ed/12-reasons-why-natural-gas-should-be-part-of-africas-clean-energy-future/.
63 USAID, "Kenya: Power Africa Fact Sheet."
64 IEA, *Africa Energy Outlook 2019, Kenya* (2019), www.iea.org/articles/kenya-energy-outlook.
65 Presentation by Ministry of Energy, "Highlights of NGUMP."
66 Uganda's new draft National Energy Policy does not reference natural gas being used for power. Uganda Ministry of Energy and Mineral Development, *Draft National Energy Policy* (2019), www.energyandminerals.go.ug/site/assets/files/1081/draft_revised_energy_policy_-_11_10_2019-1_1.pdf.
67 National Resistance Movement, *2021-2026 Manifesto: Securing Your Future* (2020), www.nrm.ug/NRM_Manifesto_2021-2026.pdf.
68 While Mozambique's LNG projects are facing delays due to the domestic security situation, most analysts believe they will still go ahead. See, for example: Rystad Energy, *Global LNG market faces supply deficit, higher prices from decade-long impact of Mozambique delays* (2021), www.rystadenergy.com/newsevents/news/press-releases/global-lng-market-faces-supply-deficit-higher-prices-from-decade-long-impact-of-Mozambique-delays/.

2. Tanzania's government should be concerned about both gas shortages and surpluses

The government faces a problem. In Section 1 we argued that NGUMP may have overestimated how much offshore gas Tanzania will need. However, the domestic supply obligation (DSO) must be negotiated years before anyone will know what the actual demand will be. Negotiating a DSO that is either too small or too large results in gas shortages or surpluses. A gas shortage is an obvious problem—if Tanzanians have not tapped other energy sources, a gas shortage contributes to the already high energy poverty. Yet a gas surplus is as severe a concern, which could cost the government dearly. In this section, we analyze the risks of surpluses and shortages by comparing two demand scenarios that represent high and low demand for DSO gas and a range of DSOs from 0 to 60 percent.

Scenarios of demand and supply of DSO gas

We differentiate the scenarios in three ways: different levels of domestic demand; whether Tanzania's neighbors demand gas; and whether the government develops more of the country's onshore gas reserves to meet some of this demand. The supply scenarios comprise DSOs of 0 to 60 percent.

"NGUMP demand-low onshore supply"

- Domestic demand is as high as NGUMP predicts
- Tanzania supplies its neighbors with the amount of gas assumed by NGUMP
- Onshore gas supply only from current projects

"IEA demand-high onshore supply"

- Domestic demand is only as high as IEA STEPS predicts
- Tanzania supplies Kenya to satisfy the demand assumed by IEA STEPS
- Onshore gas supply from current projects and Tanzania's other onshore reserves

DSO supply

- DSOs of 0 to 60 percent, at intervals of 10 percentage points. We apply the same DSO to Blocks 1 and 4, and to Block 2.
- We also look at the DSOs we assume are currently in the PSAs: 7 percent DSO for Blocks 1 and 4, and 10 percent DSO for Block 2. We refer to this as a DSO of 8.5 percent, given this is their weighted average.
- We convert the share of offshore reserves to a fixed volume of gas for every year of the offshore project's production plateau.

Low demand could result in significant gas surpluses

Figures 10 and 11 show the interaction of these demand and supply scenarios. The supply lines are stacked, so the top line represents the total supply available.[69]

In the NGUMP demand-low onshore supply scenario, a gas shortage arises during this decade. DSO gas from the offshore project starting up in 2030 fails to address this shortage. Given how high NGUMP expects demand to be, there is a gas shortage even with a 60 percent DSO.

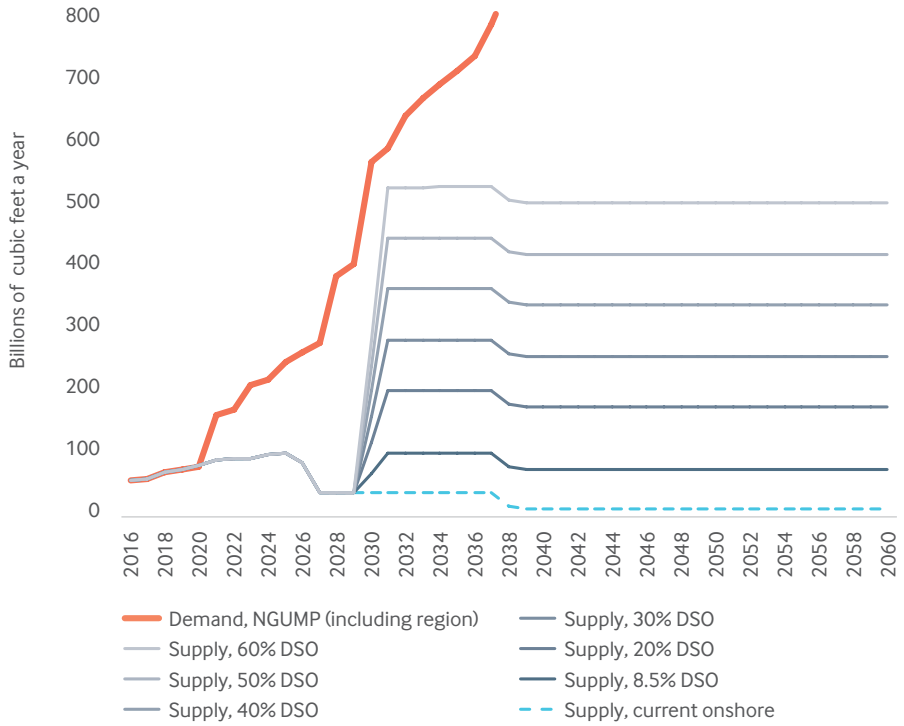


Figure 10. NGUMP demand-low onshore supply

Notes: See appendix for how we modeled gas supply.

In the IEA demand-high onshore supply scenario, a gas shortage still eventually emerges when there is a DSO of up to 40 percent. However, this is preceded by a surplus. The larger the DSO, the larger and longer lasting the surplus. With a DSO of 50 percent and more, this surplus remains throughout the lifetime of the offshore project.

69 We do not model gas prices, so do not model how demand would adjust to a change in gas supply. A price change might moderate demand given the supply. However, it is likely that gas prices in Tanzania will be set by the state's Energy and Water Utilities Regulatory Authority, rather than determined in a free market. More research on this could be useful. We explain how we modeled gas supply in the appendix.

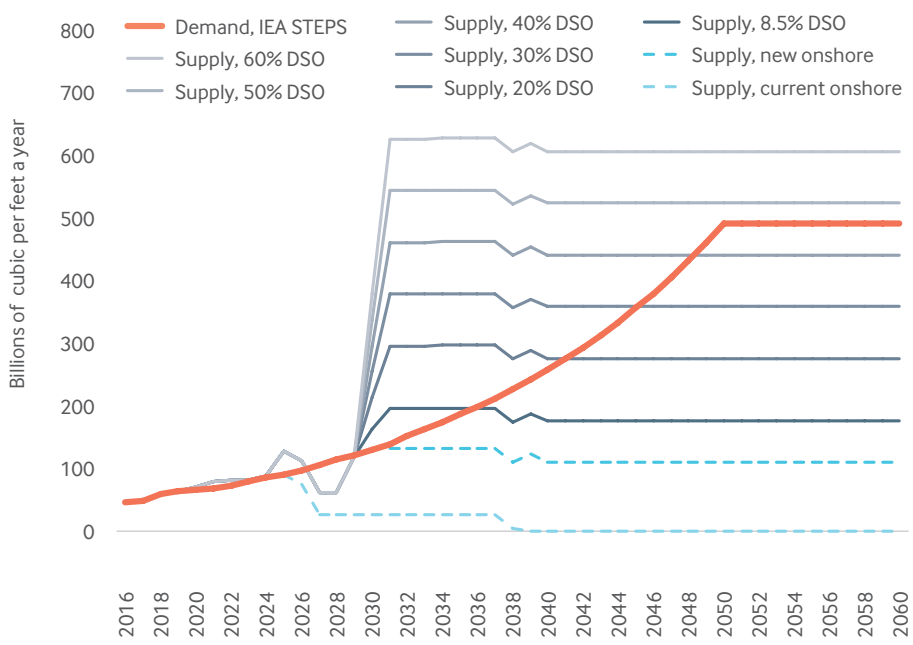


Figure 11. IEA demand-high onshore supply

Notes: See appendix for how we modeled gas supply.

These two charts show two things. First, in all cases, except for with a DSO of at least 50 percent in the IEA demand scenario, there is an eventual gas shortage. Therefore, Tanzania will likely require other energy sources. Second, there is a substantial risk of a gas surplus in the early years of the project, which, as we explain next, could cost Tanzanians dearly.

Gas surpluses could result in large take-or-pay penalties for Tanzania

Gas surpluses are dangerous for Tanzania because companies will likely insist on protecting themselves by signing a take-or-pay agreement for gas with the government. These agreements are common practice for gas project developments, and created a fiscal crisis for Ghana.

Box 2. Take-or-pay penalties for gas pitched Ghana into a grave financial situation

The Ghanaian government entered a take-or-pay arrangement in 2018 to buy the gas from the Offshore Cape Three Points (OCTP) project. But, as noted in Section 1, it struggled to develop the infrastructure needed to transport the gas across the country. It also over-estimated demand. Since the gas started flowing, Ghana has failed to take all the gas and faced significant penalties. In 2019, the government said these penalties "pose[d] grave financial risks to the whole economy" and that by 2020 they could be as large as $850 million.[70] The IMF's 2019 debt sustainability analysis explicitly mentions the gas sector and the OCTP take-or-pay agreement as a fiscal risk to the country.[71] The government could not initially afford to pay the penalty, but the parties found a compromise. They negotiated a lower sales price, thus hurting company profits, and the companies deducted the government's debts from tax obligations, thus hurting the government.[72] Despite these changes, the government still had to pay $168 million on top of the tax costs in 2019, equivalent to over 1 percent of total government expenditure.[73]

Similarly, Tanzania could face large penalties. We calculated the possible penalty by multiplying the quantity of surplus gas and the assumed DSO price of $4 per mmBtu. Tables 1 and 2 show the results for DSOs of 8.5 percent, 20 percent and 40 percent, with high and low demand.

In the best-case scenario—with NGUMP demand and low onshore supply—there is no surplus gas and no penalties. But if demand is low, onshore supply is high and the DSO is 20 percent, the government pays penalties equivalent to 11 percent of all revenue it will earn from the offshore project—equivalent to two-thirds of Tanzania's annual health budget. With a DSO of 40 percent, penalties are equivalent to 37 percent of government revenue from the offshore project, or Tanzania's annual education budget.[74]

	8.5% DSO	20% DSO	40% DSO
NGUMP demand-low onshore supply	0	0	0
IEA demand-high onshore supply	85	631	2,000

Table 1. Present value of Tanzania's possible take-or-pay penalty (USD millions, 10% discount rate)

70 Government of Ghana, *Mid-year Fiscal Policy Review of the 2019 Budget Statement and Economic Policy* (2019), 31, www.mofep.gov.gh/sites/default/files/news/2019-Mid-Year-Budget-Statement.pdf.
71 IMF, *Ghana: Seventh and Eighth Reviews under the Extended Credit Facility Arrangement* (2019), www.imf.org/~/media/Files/Publications/CR/2019/1GHAEA2019001.ashx.
72 ACEP, *ACEP's comments on the OCTP gas utilization challenges.*
73 Based on a penalty of around $168 million, total government expenditure of GHc 75,707 million and an exchange rate of $1:GHc5.2. Bretton Woods Project, *Ghana's Sankofa gas project – backed by World Bank – brings fiscal pain* (2020), www.brettonwoodsproject.org/2020/04/ghanas-sankofa-gas-project-backed-by-world-bank-brings-fiscal-pain/; IMF, *Ghana: Request for Disbursement under the Rapid Credit Facility* (2020), www.imf.org/-/media/Files/Publications/CR/2020/English/1GHAEA2020001.ashx.
74 Penalties estimated in the IEA demand-high onshore supply scenario with a DSO of 20 percent equal $631 million. The country's health budget in 2017-2018 was TZS 2.2 trillion or about $946 million. Penalties estimated in this scenario with a DSO of 40 percent equal $2 billion. The country's education budget in 2017-2018 was TZS 4.7 trillion or about $2 billion. Government of Tanzania and Unicef, *Health Budget Brief 2018; Government of Tanzania and Unicef, Education Budget Brief 2018* (2019), www.unicef.org/esa/media/2321/file/UNICEF-Tanzania-Mainland-2018-Education-Budget-Brief-revised.pdf.

	8.5% DSO	20% DSO	40% DSO
NGUMP demand-low onshore supply	0%	0%	0%
IEA demand-high onshore supply	1%	11%	37%

Table 2. Take-or-pay penalty as proportion of government revenues from offshore project

This situation could be even worse for the government for a given DSO, with the gas surplus even larger than we estimate. This could result from lower demand—for example, in line with IEA SDS rather than IEA STEPS. Or it could result from greater supply, if, for example, the government develops other gas and energy projects to address shortfalls before the offshore project starts in 2030.

Avoiding a gas surplus by subsidizing gas use would also be expensive

The government could subsidize consumer gas prices to stimulate demand and reduce the DSO surplus. But subsidies are expensive.

We calculated the possible cost by assuming that the government subsidizes all domestic gas sales by the offshore project and new onshore developments by $1 per mmBtu for the first 10 years of offshore production. Given that our estimated wellhead price for the offshore gas is around $3, this would be roughly equivalent to the 35 percent subsidization of the wellhead price provided for in the Natural Gas Pricing Regulations 2016. Tables 3 and 4 show the cost of this subsidy for DSOs of 8.5 percent, 20 percent and 40 percent, with high and low demand.

In the best-case scenario—with NGUMP demand and low onshore supply—there is no surplus gas, and therefore no need for the government to provide subsidies. But if demand is low, onshore supply is high and the DSO is 20 percent, the government pays a subsidy equivalent to 12 percent of all revenue it earns from the offshore project. With a DSO of 40 percent, the subsidy is equivalent to 19 percent of government revenue from the project.

	8.5% DSO	20% DSO	40% DSO
NGUMP demand-low onshore supply	0	0	0
IEA demand-high onshore supply	435	595	920

Table 3. Present value of price subsidy of $1 per mmBtu for first 10 years of offshore production (USD millions, 10% discount rate)

	8.5% DSO	20% DSO	40% DSO
NGUMP demand-low onshore supply	0%	0%	0%
IEA demand-high onshore supply	7%	12%	19%

Table 4. Price subsidy of $1 per mmBtu for first 10 years of offshore production as a proportion of government revenues from offshore project

Not only would the surplus be expensive for the government, but experience suggests removing energy subsidies is politically difficult.

Box 3. The challenges of subsidizing gas use in gas-producing countries

Malaysia, Indonesia and Argentina all initially faced a similar problem to Tanzania. All had abundant gas, but its extraction costs meant it was too expensive for the domestic market. The governments resorted to subsidizing the gas. These subsidies were so successful in spurring demand that the domestic market not only consumed the entire production of each country but also required imports. The cost of the subsidies ballooned, leading the three governments to since try to reduce energy subsidies and increase prices. However, they are facing challenges, as these subsidies are now so embedded in society.[75] There are countless examples from across the world of political and social upheaval triggered by government attempts to remove energy subsidies, resulting in these attempts failing.[76]

A more diversified energy mix would reduce the risk of a gas shortage—and provide other benefits

If the government agrees a smaller DSO to reduce the likelihood of a gas surplus, it increases the risk of a gas shortage. One way it could manage this risk is to develop other energy sources. Power makes up nearly half of projected domestic demand in the NGUMP. Yet, as discussed in Section 1, Tanzania has access to large amounts of alternative sources of power. The government could therefore follow other countries and develop a more diversified power mix.

A diversified mix would have two other benefits. It provides optionality in the face of uncertainty and maximizes overall use of Tanzania's energy resources.

Optionality. Tanzania's future power needs are, like its future gas needs, uncertain. This uncertainty is difficult to manage with the offshore gas. Even if the DSO agreement has some flexibility built in (as we suggest in Section 3), the fact that it is coming from one project will still mean deciding on one large lump of gas supply years before the government knows what demand will be. Nor does the government have much freedom to change the deal afterwards.

Alternatively, the government could set a lower DSO and develop other power sources, including more of Tanzania's onshore gas reserves, to create "optionality." To burn all the gas that NGUMP proposes Tanzania take from the offshore project would require an additional 4.8 Gigawatts (GW) of gas-fired power capacity. PSMP calculates this requiring 13 new or expanded gas-fired power plants.[77] In committing to take this volume of gas over the life of the project, the government is effectively committing to building all these power plants as well. In comparison, Tanzania could theoretically develop the same 4.8 GW of capacity by building 48 wind and solar plants.[78] These plants do not rely on any feedstock such as gas,

75 Ieda Gomes, *The dilemma of gas importing and exporting countries* (The Oxford Institute for Energy Studies, 2020), www.oxfordenergy.org/wpcms/wp-content/uploads/2020/08/The-dilemma-of-gas-importing-and-exporting-countries-NG-161.pdf.

76 Jakob Skovgaard and Harro van Asselt (editors), *The Politics of Fossil Fuel Subsidies and their Reform,* (Cambridge University Press, 2018), www.cambridge.org/core/books/politics-of-fossil-fuel-subsidies-and-their-reform.

77 Based on offshore gas accounting for 83 percent of Tanzania's reserves as reported by NGUMP, and PSMP aiming for 5.8 GW of additional capacity by 2044. Government of Tanzania, *Natural Gas Utilisation Master Plan*; Ministry of Energy, *Power System Master Plan, 2020 update.*

78 Assuming the average capacity of each plant is 100 MW. This is about correct when looking at capacities stated in PSMP for Njombe Wind (100 MW), Singida Wind (100 MW), Monyoni Solar (100 MW) and Dodoma Solar (55 MW).

meaning the country would not need to commit to developing the entire set. The government could order developments piecemeal, as near-term demand becomes more certain. If demand follows the NGUMP projection, the government can develop more of these projects, choosing from a menu of alternatives to fit the emerging demand profile. If demand turns out to be much less than NGUMP projects, the government can delay or cancel these projects. Rather than forecasting decades in advance, the government need only forecast a few years in advance. It would be able to sequence their installation as the future reveals itself and increase supply in time with demand.

Maximal use of Tanzania's energy sources. A huge role for gas in the power mix is likely to mean alternative power sources are not developed to their full potential. Tanzania's power sources are not fungible. This is because power is expensive to export. So the power from hydro, wind and solar plants can only be used in Tanzania, or to a small extent, neighboring markets.[79] In contrast, energy in the form of gas can be exported as LNG to overseas markets, generating government revenue. Therefore, each unit of offshore gas the government uses to generate power has a double opportunity cost: less government revenue and less likelihood of Tanzania's wind, solar and hydro resources being fully used.

With a large DSO, these lost opportunities could be locked in for decades. The government would be forced to use the offshore gas over other energy sources to avoid penalties, and to build large amounts of infrastructure—the distribution network and the power plants—needed to use the gas in the first place. This infrastructure will likely only be cost-effective if it operates for 20-30 years. Tanzania therefore risks locking itself into continuing to use the gas infrastructure and missing out on developing alternative power that could be significantly cheaper.

Developing more of Tanzania's onshore gas reserves would also help reduce the risk of a gas shortage

The government estimates that there is still nearly 7.1 tcf of recoverable gas onshore in Tanzania. This makes the country's potential supply of onshore gas equivalent to an offshore DSO of around 27 percent. Given the risk of infrastructure lock-in, the government needs to also be cautious in significantly increasing the amount of Tanzania's onshore gas that it uses. However, if it is worried about a gas shortage even with a more diversified energy mix, developing more of the onshore reserves, rather than negotiating a larger offshore DSO, would be beneficial.

The multiple potential onshore projects, which are smaller and can be developed more quickly than the offshore gas, provide more optionality. They are also more suited to meet domestic needs. Onshore gas is more difficult to export overseas than the offshore gas—requiring the development of an extra LNG train and significant coordination between the projects. It is also likely to be more affordable to Tanzanians than the offshore gas. As noted in Section 1, the final price that the government and other consumers have paid over the last five years for onshore gas is around $4 per mmBtu. We estimate that the offshore gas will cost around $4 per mmBtu before adding marketing and transport costs. Leaving the onshore gas in the ground and negotiating a larger DSO would therefore be another lost opportunity for the country.

79 In the future, it might be commercially viable to transform power into hydrogen and export hydrogen overseas, but currently this option is highly uncertain.

3. A large domestic supply obligation threatens Tanzania's offshore project and government revenue

In negotiating the DSO, the government also needs to consider the economics of the offshore project across the possible demand scenarios discussed in Sections 1 and 2. We used our economic model of the project (described in the annex) to analyze how the DSO alters the viability of the project and the government revenue it could generate.

The offshore project's economics and the energy transition mean a narrow landing zone for a new deal

It is 10 years since Tanzania's first offshore gas discovery. Production was initially expected by 2020.[80] Some optimism still reigned even in 2019, when the government expected construction to start by 2022.[81] But based on company announcements, a Final Investment Decision (FID) is unlikely before 2025 and production will not start before 2030.[82]

As discussed in Box 4, there is significant uncertainty surrounding the future of gas in the accelerating global energy transition. Further delays mean production occurs further ahead in the future, when the state of the gas market is less certain. This risks the project never happening.

In our baseline scenario ("NRGI baseline project design" in Figure 12), based on company plans, the LNG plant has a combined capacity of 14.5 million tonnes per annum (mmtpa). Shell has an LNG train of 7 mmtpa and Equinor a train of 7.5 mmtpa.[83] In this case, and with the DSOs currently in the PSAs, our modeling suggests the project is viable for companies only if the long-term LNG price at the

80 John Daly, "Fast growing Tanzania Looks To Begin LNG Production By 2020," *Oil Price*, 30 April 2014, oilprice.com/Energy/Natural-Gas/Fast-Growing-Tanzania-Looks-To-Begin-LNG-Production-By-2020.html.

81 Fumbuka Ng'wanakilala and Nuzulack Dausen, "Tanzania says construction of LNG plant to start in 2022," *Reuters*, 28 May 2019, af.reuters.com/article/commoditiesNews/idAFL8N23459P.

82 This FID estimate is based on key terms being agreed around the end of 2021, and Equinor and Shell's suggestions of 3 and at least 3.5 years from then until FID, respectively. We therefore think the government's recent suggestion that FID could be reached in 2023 is optimistic. Equinor, *Block 2 Tanzania* (2018), 6-7, www.equinor.com/content/dam/statoil/documents/where-we-are/equinor-block-2-project-121018.pdf; Shell, T*anzania LNG: Our Vision* (2018), www.shell.co.tz/about-us/reports/_jcr_content/par/list_751c.stream/1562315752269/02dae9d0db9c8e7162ef597421d4267886622ebd/tanzania-lng-brochure-english.pdf; Fumbuka Ng'wanakilala, "Tanzania May Start Building $30 Billion LNG Project in 2023," *Bloomberg*, 4 June 2021, www.bloombergquint.com/business/tanzania-aims-for-lng-project-construction-to-begin-mid-2023.

83 Equinor states this capacity in its publication on the project, while discussions with Shell suggest it envisages the overall LNG plant being similar in size to its Canadian LNG project. https://www.equinor.com/content/dam/statoil/documents/where-we-are/equinor-block-2-project-121018.pdf; https://www.bloomberg.com/news/articles/2018-10-02/shell-partners-announce-31-billion-lng-canada-investment.

point of delivery in Asia is at least $9 per mmBtu (the "breakeven price"). At this price, the project earns companies a 13 percent return (in real terms), equal to the "hurdle rate" companies tend to require before sanctioning LNG projects.[84]

Are LNG prices likely to be this high? Rystad Energy forecasts an Asian LNG price of around $8 per mmBtu in the long term. Wood Mackenzie thinks that the Asian price would be lower if the world acts to limit global warming to less than two degrees Celsius by 2100 in line with the Paris agreement. In its 2020 scenario, it suggests that the Asian gas price could reach $8-9 per mmBtu by 2040 but will be lower from then onwards.[85] In its 2019 scenario, it suggested that the price could be less than $5 per mmBtu by 2040 (as a result of it being less optimistic about, for example, the development of carbon capture and storage).[86] In other words, further in the future, high gas prices might only be consistent with dangerous climate breakdown. While our breakeven price estimate is lower than stated in our previous report (the reasons for which are discussed in the appendix), the implications for the project remain the same: Given our assumptions, the likelihood that LNG prices will be high enough to support the project in its current form is slim.[87]

However, could our baseline scenario be too pessimistic for the project? The hurdle rate companies use might be lower. Rystad Energy's global hurdle rate across oil and gas projects is 7.5 percent.[88] If investors in the project use a 7.5 percent rate, the breakeven price is slightly less than $7 per mmBtu. However, given an LNG project is likely to be riskier than, for example, a typical offshore oil project, this generic rate is probably low for the Tanzania project. And as companies grow more worried about the global transition away from gas, hurdle rates may increase.[89]

Costs could also be lower. Costs in the oil and gas industry tend to rise and fall with oil prices.[90] If global gas activity reduces, perhaps due to the energy transition, suppliers will be forced to offer cheaper machinery and services as they compete for remaining business.

The companies might also find more efficient ways to develop the gas. Figure 12 shows the estimated returns from two alternative project designs in our baseline scenario. The government suggested an LNG plant ("Government project design" in Figure 12) with a capacity of 10 mmtpa in 2019. We assume this entails each JV having a train of 5 mmtpa.[91] This design did not align with company proposals at the time, and our modeling suggests it would have a slightly higher breakeven price. But as the prospects of global gas demand worsen, the companies may now consider a smaller plant. It would require less financing and smaller gas sales agreements

84 Based on Wood Mackenzie's "State of the Upstream Industry" company surveys in 2017 and 2018.
85 Wood Mackenzie, *Reversal of Fortune: oil and gas prices in a 2-degree world.*
86 Wood Mackenzie, *Accelerated energy transition 2-degree scenario (2019): what happens to the gas industry?.*
87 Thomas Scurfield and David Manley, *How Tanzania Can Secure a Good Deal for its Offshore Gas,* (Natural Resource Governance Institute, 2019), resourcegovernance.org/analysis-tools/publications/tanzania-good-deal-offshore-gas.
88 Rystad assumes a hurdle rate in nominal terms of 10 percent and an inflation rate of 2.5 percent.
89 An Oxford Institute of Energy Studies company survey in 2019 found that hurdle rates for fossil fuel projects are already starting to increase. https://www.oxfordenergy.org/wpcms/wp-content/uploads/2019/01/Energy-Transition-Uncertainty-and-the-Implications-of-Change-in-the-Risk-Preferences-of-Fossil-Fuel-Investors-Insight-45.pdf.
90 This study measured the change in costs in the oil and gas industry after a change in global oil prices. It did not specifically consider gas prices. Toews, G., and Naumov, A. (2015). The Relationship Between Oil Price and Costs in the Oil and Gas Industry (OxCarre Research Paper 152).
91 Ng'wanakilala and Dausen, "Tanzania says construction of LNG plant to start in 2022." https://www.reuters.com/article/us-tanzania-lng/tanzania-says-construction-of-lng-plant-to-start-in-2022-idUSKCN1SY1TU.

to proceed. Rystad Energy has also revised its estimates (shown as "Rystad project design"). It expects an LNG plant capacity of 10 mmtpa initially, with Shell JV adding another 5 mmtpa, and the Equinor JV another 3 mmtpa, 10 years after first gas.[92] With this configuration, we estimate that companies would also require a slightly higher price to break even than they would in our baseline scenario, and must wait much longer to recover their investment. However, they may still consider it, given the advantage of less financing and smaller sales agreements initially.

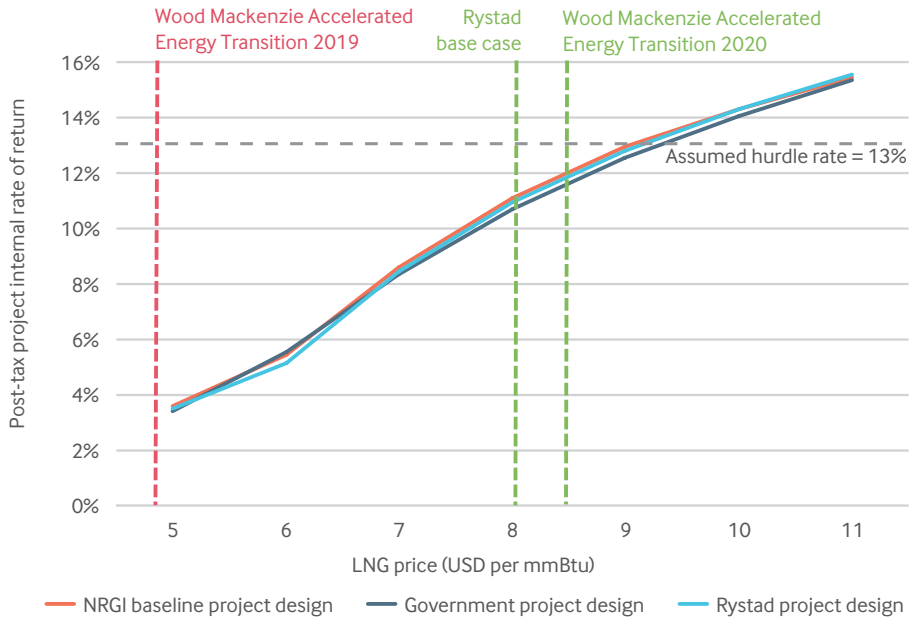


Figure 12. Project returns across LNG plant configurations and projections of Asian LNG price in 2040[93]

Notes: The JV projects will likely generate different returns. The return from the overall project is reported here for simplicity. See our economic model for the disaggregated results. Wood Mackenzie's Accelerated Energy Transition 2020 scenario assumes prices fall after 2040.

We therefore still think that the project could go ahead, but the landing zone for a deal is narrow. Indeed, Equinor reduced the value of this project on its balance sheet in January 2021, stating that it was "at this time, not competitive."[94] Critical to the companies' decision is the energy transition. Box 4 discusses the future of natural gas use across the world. We then look at how much a larger DSO changes the project's prospects.

92 Rystad Energy UCube.
93 Sources for Asian LNG prices: Wood Mackenzie, *Accelerated energy transition 2-degree scenario*; Rystad Energy UCube.
94 Equinor, *Impairment at Tanzania LNG Project* (2021) www.equinor.com/en/news/20210129-impairment-tanzania-lng.html.

Box 4. Strong headwinds for Tanzania's LNG

The offshore project is likely to start in 2030 at the earliest, meaning the project will operate in a future that is increasingly uncertain. For example, if the world limits global warming to less than two degrees Celsius by 2100, Wood Mackenzie expects LNG demand to remain strong until 2050. While if the world limits global warming to one and a half Celsius, the IEA suggests no new gas projects would be needed. However, some aspects of global gas demand and supply trends are becoming clearer.

Although LNG demand from Africa is growing, it is likely to be small relative to other markets.[95] Instead, Asia is the largest and fastest growing LNG market. This is driven by China switching from coal to gas, with plans to quadruple regasification capacity along its coast. India is also starting to limit the role of coal in its energy mix, though much more slowly. The country grew LNG imports by 16 percent in 2018, but that is a small fraction of China's LNG demand.[96]

However, while Asia might be the most important market for Tanzania's gas, Tanzania faces competition from other forms of gas and energy. Asian countries can choose between domestic gas, LNG and piped gas from places like Russia and Central Asia.[97] In turn, Tanzania's LNG must compete with LNG from Mozambique, Australia, Indonesia and Qatar. All have developed LNG projects faster than Tanzania. By the time Tanzania's project comes online, demand may have grown significantly, but other gas, wind and solar projects are all being developed and will be competing with Tanzania's gas.

LNG and gas more broadly compete with solar and wind power. These energy sources have two advantages. First, they are becoming cheaper than gas on a pure levelized cost of electricity basis.[98]

Second, China, South Korea and Japan have all pledged to become carbon-neutral by mid-century. Natural gas is more frequently being called "fossil gas" to show that it is still environmentally damaging. The methane leaks from the global natural gas industry are equivalent to the entire carbon emissions of the EU. The liquefaction and transportation of Tanzania's gas increases the environmental impact. With at least 10 percent of the gas arriving at a plant often combusted during this process, there are significant emissions before the LNG has even left the project site.[99]

95 ACTING, *State of Play: African Gas 2021* (2021), actingas.org/blog-page/ACTING-Launches-African-Gas-2021-Report.html; Christopher Le Bec, "Mozambique to Benin: Total sees a booming African LNG market," *The Africa Report*, 14 October 2020, www.theafricareport.com/45893/mozambique-to-benin-total-sees-a-booming-african-lng-market/.

96 For a broad survey of LNG demand in Asia, and the prospects for East African LNG see: Etienne Romsom and Kathryn McPhail, *The energy transition in Asia: The role of liquefied natural gas and implications for East African producers* (UNU-WIDER, 2020), www.wider.unu.edu/publication/energy-transition-asia-0; and Etienne Romsom and Kathryn McPhail, *The energy transition in Asia: Country priorities, fuel types, and energy decisions*, (UNU-WIDER, 2020), www.wider.unu.edu/publication/energy-transition-asia.

97 Akos Losz, Tim Boersma and Tatiana Mitrova, A Changing Global Gas Order 3.0 (Columbia Center on Global Energy Policy, 2019), www.energypolicy.columbia.edu/research/commentary/changing-global-gas-order-30.

98 International Energy Agency, "Project Costs of Generating Electricity 2020" (2020), www.iea.org/reports/projected-costs-of-generating-electricity-2020; IEA, *World Energy Outlook 2020*.

99 Jonathan Stern, Challenges to the Future of LNG: decarbonization, affordability and profitability (The Oxford Institute for Energy Studies, 2019), www.oxfordenergy.org/wpcms/wp-content/uploads/2019/10/Challenges-to-the-Future-of-LNG-NG-152.pdf.

If domestic and regional demand is lower than the government predicts, a larger DSO is not feasible

The uncertainty of Tanzania's future gas needs, as explained in Section 1, makes designing the offshore project extremely challenging. In theory, there are multiple potential designs—from a project that only supplies Tanzania and the region, to one that liquefies all the gas into LNG for export. However, the offshore gas is costly to extract, requiring significant investment. In order to minimize costs, including debt costs, investors will look to avoid unnecessary capacity in the project's infrastructure and earn revenue as early as possible.

To analyze how the DSO alters the viability of the project, we used the two demand scenarios set out in Section 2 and considered a range of DSO volumes between 0 and 60 percent. We set out the results of our economic modeling below.

Given our assumptions, the project is only economically viable with a large DSO volume in the NGUMP demand-low onshore supply scenario. As Figure 13 shows, with an LNG price of $9 per mmBtu and a DSO price of $4 per mmBtu, the project's returns exceed our assumed hurdle rate of 13 percent up to a DSO rate of 60 percent.

However, this is not the case if domestic and regional demand is as predicted by IEA STEPS and onshore supply is high. In this scenario, a DSO volume significantly larger than that currently in the PSAs fails to generate project returns above the hurdle rate. For even lower demand—in line with IEA SDS—returns are lower still.

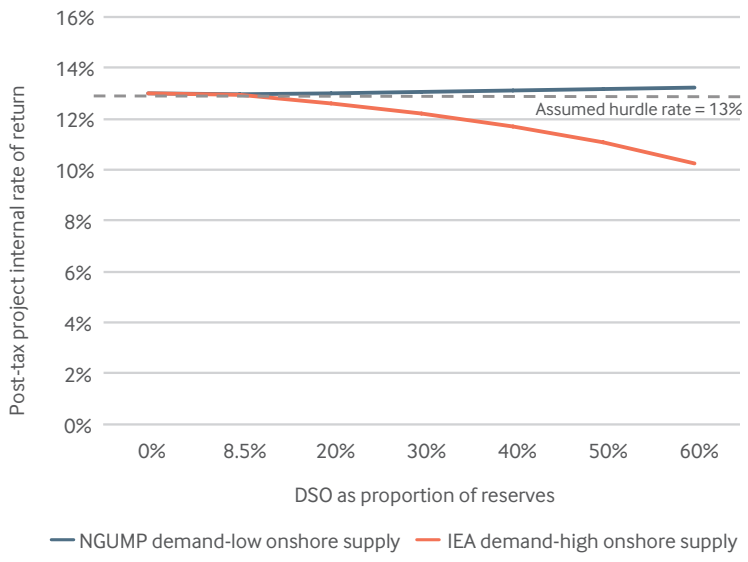


Figure 13. Project returns with different DSO volumes, given an LNG price of USD 9 per mmBtu and a DSO price of USD 4 per mmBtu

One of the driving factors is the timing of gas sales in Tanzania. With IEA demand and high onshore supply, the country would have a gas surplus for at least the first few years of the project. The companies will have built the infrastructure necessary to deliver the agreed DSO, but would only sell a portion of it. With limited field, pipeline and DSO processing capacity during the production plateau, the companies are unable to then deliver the untaken DSO to TPDC until much later.[100] DSO revenues are therefore generated later with low domestic and regional demand. While this does not reduce project return significantly with a modest DSO, such as that currently in the PSAs, the return falls much more as the DSO increases and counts for a larger proportion of sales.

An LNG price higher than the DSO price is another driving factor. With an LNG price of $9 per mmBtu and a DSO price of $4 per mmBtu, LNG exports generate more revenue for the project than DSO sales, even after accounting for the higher processing and transport costs for LNG. In other words, LNG exports have a higher netback price.[101] As Figure 14 shows, we estimate that with an LNG price of $9 per mmBtu, the DSO would only generate similar revenue if it was sold at a price of around $6.5 per mmBtu.

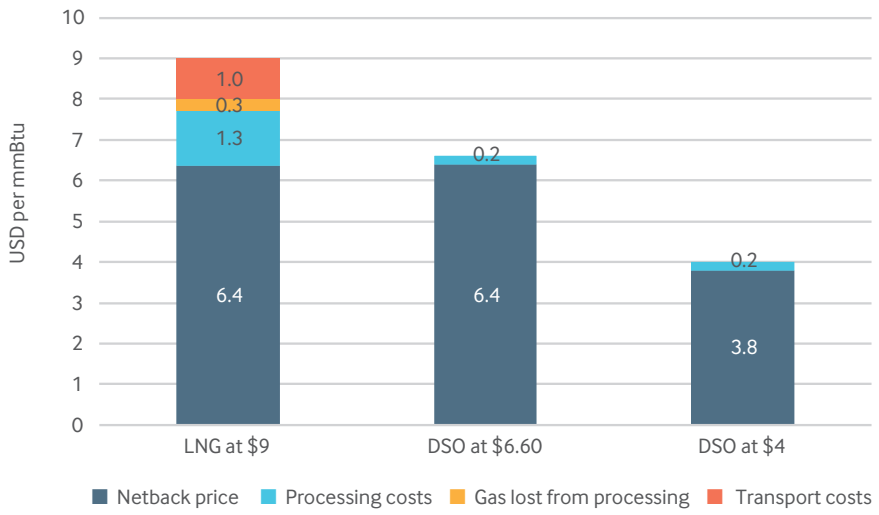


Figure 14. LNG and DSO netback prices in baseline scenario

Notes: The cost estimates used to estimate the netback prices do not include any return to investors (such as through the LNG plant tolling fee) or any payments to government. Gas lost from processing is valued at the estimated wellhead price. These estimates are the average costs across the two JVs. For other assumptions, see appendix.

100 TPDC will either have to wait until towards the end of planned production to take the gas or negotiate with the companies for some of the production and pipeline capacity allocated to the LNG plant to be diverted to the DSO. However, scope for the latter is limited by the size of the DSO processing plant and the economic and operational challenges arising from spare capacity in the LNG plant.

101 The netback price is the sales price minus the cost of processing the gas and transporting it to market. The cost of processing will change with a different allocation of gas between the two markets, given that this would mean different sized plants, but possibly not significantly.

High prices would make a large DSO more feasible—but are unlikely

Prices might be higher than our baseline scenario. Figure 15 shows estimated project returns given a range of LNG and DSO prices. Areas of green show combinations of DSO shares, DSO prices and LNG export prices that result in project returns that clear the companies' assumed hurdle rate. Yellow areas show combinations that result in returns that are close to clearing the hurdle rate, and red areas show combinations that do not. The figure shows that with an LNG price of at least $10 per mmBtu, the project generates sufficient LNG revenues to compensate for lower revenues from low domestic and regional demand up to a DSO of 40 percent. However, as we have noted, several forecasters think $10 per mmBtu is unlikely.

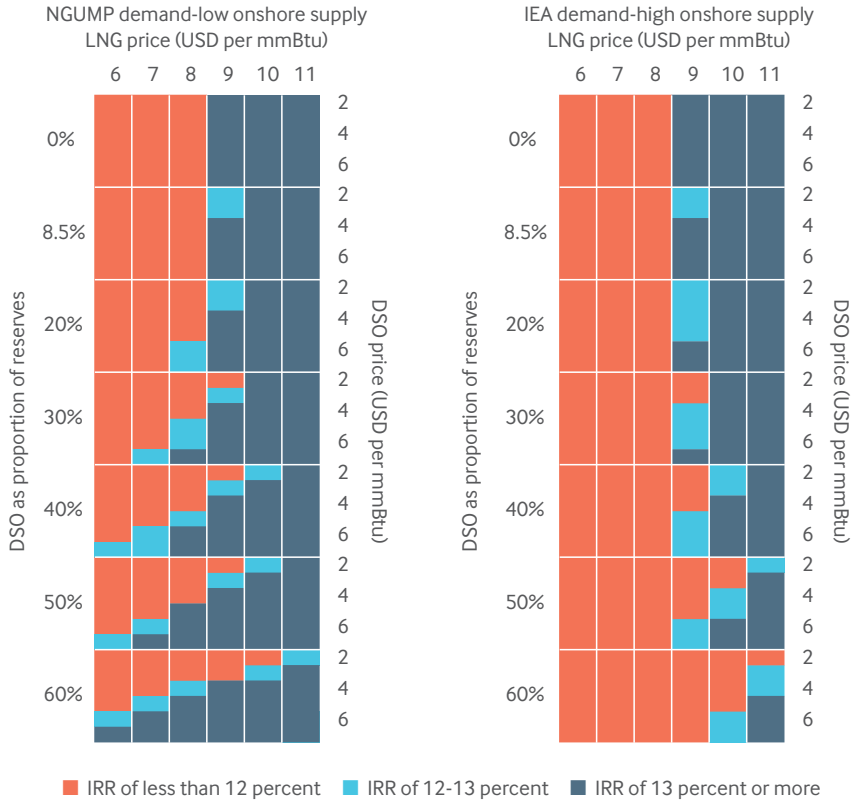


Figure 15. Project returns with different DSO volumes and a range of LNG and DSO prices

Agreement by the government and companies to a higher DSO price also makes a larger DSO volume more feasible. However, even a DSO price of $4 per mmBtu seems optimistic. Our modeling suggests $4 would be the cost-plus price at the exit of the processing plant. It is also the average final onshore price over the past five years. We did not model the domestic market for gas, but it is likely that for a given level of gas demand, greater gas supply to the domestic market would result in under-consumption of the DSO volume. There is no free market price for gas in Tanzania. The Energy and Water Utilities Regulatory Authority (EWURA) controls the price. To balance supply and demand, EWURA would have to reduce gas prices. This would require subsidizing the price paid by the final consumer or reducing the price paid to the companies.

With an LNG price higher than $9 per mmBtu unlikely, whether the companies will agree to a larger DSO volume will depend on whether they believe the government will actually take and pay for that volume, and the agreed price at which the government will buy this gas. For example, as Figure 15 shows, if the companies think that IEA demand and high onshore supply is likely, increasing the DSO volume to as much as 20 percent would be difficult even with a DSO price of $5 per mmBtu.

A high DSO creates offtake risk for the companies

The companies can sell LNG to any buyer in the world, so the project is practically guaranteed to sell the LNG it produces, particularly with the LNG spot market continuing to grow. In contrast, given the uncertainty about Tanzania's gas needs, the government cannot guarantee that it will buy all the DSO gas it agrees to take off the companies. This is a common concern for gas sellers, often described as the "domestic offtake risk."

The parties could negotiate a DSO schedule that assumes high domestic and regional demand. However, if the government fails to take the gas off the project when planned, project returns fall substantially, as Figure 16 shows. The difference between the returns generated under the two scenarios is the offtake risk. The larger the DSO volume, the larger the risk.

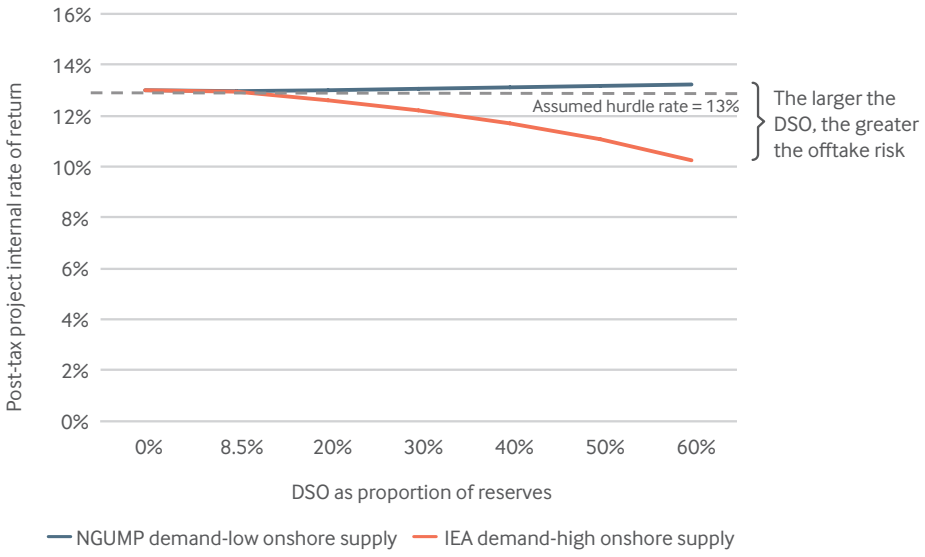


Figure 16. Project returns with different DSO volumes, given an LNG price of USD 9 per mmBtu and a DSO price of USD 4 per mmBtu

The companies will insure against offtake risk by arranging a take-or-pay agreement, as noted in Section 2. However, as the Ghana experience discussed in Box 2 shows, a take-or-pay agreement not only risks huge damage to public finances, but is also not perfect insurance for companies, as the government may not be able to pay. The companies in Tanzania will expect that a similar non-payment situation will arise in Tanzania if the government negotiates a large DSO, and will account for that in their calculation of expected return. To illustrate, we replicated the Ghana experience by modeling the government failing to pay any penalty incurred in the first two years

and then renegotiating the price down by 19 percent from $4 per mmBtu to $3.2 per mmBtu. In this scenario, the project still failed to clear the hurdle rate with a DSO of 20 percent or more.

Negotiating a variable rather than a fixed DSO could help

Tanzania is unlikely to suddenly have the large gas demand that would support a fixed DSO. This will result in heavy take-or-pay penalties for the government and offtake risk for the companies for the period until demand reaches the DSO level. However, the DSO need not be fixed. A variable DSO could be designed to better match the government's stated demand schedule—for instance, one with a lower volume in the earlier years of the project and a larger volume later.

For a variable DSO to work, the government needs to be clear on the volume of gas it will buy and when. With such clarity, the parties can then optimize the infrastructure for the planned flow of gas, and agree on managing the trade-offs (discussed further below). As we have explained, it is difficult to accurately forecast Tanzanian gas demand, but stating a realistic demand schedule could allow companies to design a system to fit. This will require leadership from government, innovation from companies and negotiations from both to manage trade-offs.

The companies are likely to have three main ways to physically vary the volume of gas for the DSO.

Option 1. Both JVs build spare capacity into the infrastructure initially. The JVs will schedule well drilling and can build the processing plant in modules to fit the government's stated demand schedule. However, some elements of the project—for example, the subsea distribution centers and the pipelines to the shore—are only built once, and must have capacity that is large enough to accommodate the maximum production rate from the other project elements. This initial spare capacity creates a cost for the project, which the government will be expected to pay. This might be through additional financing of the project from TPDC or by reducing taxes on the project. The government could also attempt to persuade large downstream customers to cover this cost, though in doing so, it might have to provide other incentives in return.

Option 2. Both JVs split their projects into two phases, with each phase a separate bankable asset. The assets in the first phase have low production rates and a low DSO—with the attendant financing raised given this schedule. The second phase is developed with a higher production rate. The companies could build the capacity required for this increase at the start of either the first or the second phase, depending on the optimal configuration. This design is similar to that assumed by Rystad. But instead of a set plan to construct second LNG trains to consume all the additional gas, the government could have the option of taking at least some of it as part of a larger DSO.

The first phase would establish the main infrastructure and supply chains for subsequent developments, and effectively test the entire system, including Tanzania's ability to take the gas. The companies, the government and other entities could learn from this experience to adapt their approach. The government will by that time have a better idea of domestic and regional demand for the next phase. This reduces the offtake and operational risks for the second phase, which might allow the government to negotiate better terms, including a higher DSO if still desired. This approach is not without risks. The second phase will be exposed to a greater risk of low prices, as the energy transition continues, which might make financing it more difficult.

With both options one and two, there are still physical constraints on providing an increase in production beside the size of the infrastructure in any given project. This increase is limited by three characteristics of gas reservoirs. First, there is a maximum gas flow that a reservoir can produce before damaging its structure and impairing how much more gas can be extracted. Second, reservoir pressure falls as gas is extracted, reducing the maximum gas flow. Third, each reservoir has a different pressure and therefore maximum gas flow. Projects tend to extract gas from higher pressure reservoirs first to delay spending on a compressor to raise the pressure of gas through the system. However, even with a compressor, declining reservoir pressure will limit a lengthy increase in production after a certain stage of a project. Given these three constraints, a large expansion in production may only be feasible if additional recoverable reserves are discovered during the first phase, or if production, and therefore the LNG plant, is smaller initially, as this will delay the fall in reservoir pressure. But this smaller LNG plant would likely mean lower returns—as we found with the government and Rystad project designs, which both include a 10 mmtpa plant initially.

Option 3. To avoid these physical constraints, the two JV projects can be developed sequentially. Countries such as Papua New Guinea have successfully implemented this sequencing strategy. However, this approach may reduce returns from each project if it means they miss out on some of the cost-saving synergies from being developed together. It may also be difficult to negotiate—the government must convince one of the JVs to go second.

In all three options, delayed production—as a result of any of these approaches—increases price risk, as more production is scheduled further into the future, when the energy transition may be even further along.

With a large DSO, companies will push for tax incentives to make the project viable

With a take-or-pay arrangement not fully mitigating offtake risk, and a more flexible approach to the DSO not a silver bullet, significantly increasing the DSO from its current size probably makes the project unviable. The government may therefore have to offer incentives to the companies if it wishes to significantly increase the DSO from PSA levels. This will most likely involve reducing taxes.

As Table 5 shows, the larger the DSO volume, the lower taxes must be. To illustrate, we continued to model the impact of a fixed DSO. Though as noted above, a variable DSO may result in lower project returns and therefore require even lower taxes than a fixed DSO. With a fixed DSO of 20 percent, if the companies assume that demand will be low and the government will not fully meet its take-or-pay commitments, they may push the government to reduce its tax take by around 7 percent to ensure the project still meets the companies' hurdle rate. With a fixed DSO of 40 percent, this would mean reducing tax take by 15 percent.[102]

	0% DSO	8.5% DSO	20% DSO	30% DSO	40% DSO	50% DSO	60% DSO
NGUMP demand	0%	0%	0%	0%	0%	0%	0%
IEA demand	0%	0%	-8%	-16%	-27%	-42%	-69%
IEA demand with renegotiated take-or-pay	0%	0%	-7%	-11%	-15%	-19%	-24%

Table 5. Tax reduction that companies will likely push for at different DSO volumes

Notes: The LNG price is set at $9 per mmBtu and the DSO price at $4 per mmBtu. Government take is measured as the average effective tax rate. The change in government take needed is based on increasing the project's return to our assumed hurdle rate of 13 percent.

Tax incentives worsen the trade-off between government revenues and the DSO

With LNG exports generating larger net revenues than DSO sales with an LNG price higher than $6.5 per mmBtu and a DSO price of $4 per mmBtu, larger DSOs are likely to result in lower government revenues.

Tax incentives reduce government revenues further. To illustrate, we assume the government reduces taxes to compensate for the possibility of later renegotiating the take-or-pay agreement in the way we described above. We estimate that government revenues would be 33 percent lower with a fixed DSO of 40 percent than with the DSOs currently in the PSAs. They would be 14 percent lower with a fixed DSO of 20 percent. If the companies believe that Tanzanian consumption will be even lower than IEA STEPS—for example, in line with IEA SDS—they will negotiate for even more tax concessions. A larger DSO will therefore have an even greater hit on government revenues.

102 Given the project would generate larger returns if domestic and regional demand is high, a flexible regime is even more critical—that is, one that applies low taxes when profits are low, but high taxes if profits are high.

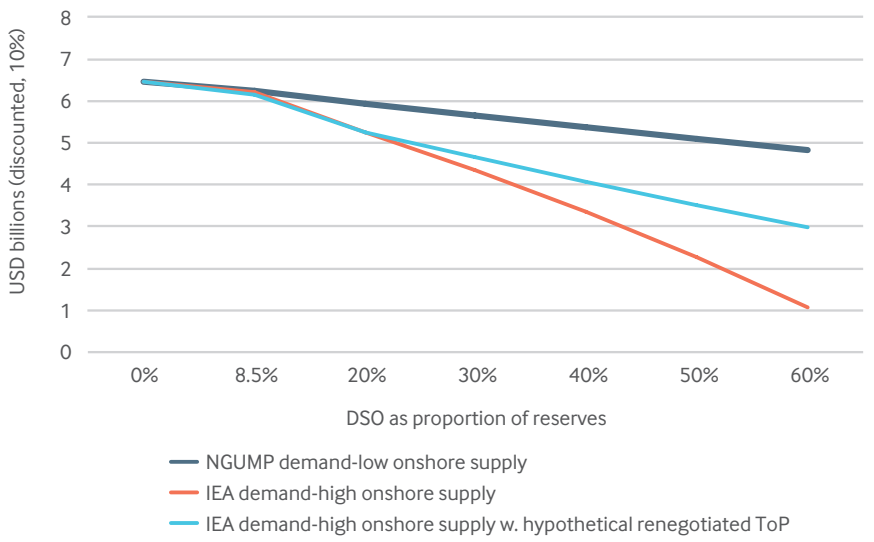


Figure 17. Government revenues after tax concessions with different DSO volumes, given an LNG price of USD 9 per mmBtu and a DSO price of USD 4 per mmBtu

However, these tax incentives may still be insufficient to persuade companies to accept a large DSO. A key requirement for investors is to be able to benefit if reserves are larger or prices higher than expected. This possibility will be particularly important for a marginal project like the Tanzania offshore project. A larger DSO volume limits companies benefiting from this upside. Unless DSO prices are sufficiently high so that DSO sales generate more revenue than LNG exports—which is unlikely. This makes a larger DSO volume even more damaging for the project.

4. Policy recommendation: A moderate and variable domestic supply obligation

Tanzania needs a lot more energy. A large DSO for the offshore project could help provide this. However, as this report has argued, it involves several trade-offs for the country, including the risk of missing the narrow landing zone for a deal and ending up with no offshore gas at all. The following five recommendations could help Tanzania's government find a solution.

1. Create a more diversified energy mix and use a revised NGUMP to communicate gas demand clearly and credibly to companies

We understand that the government is currently in the process of reviewing NGUMP. As part of this review, it could revisit its plans for the country's energy mix. As we argue in Sections 1 and 2, a more diverse mix with a smaller role for gas is both feasible and beneficial to Tanzania. Wind and solar technologies have become far more competitive, including in emerging economies, since the last edition of NGUMP. The government could also revise its plans for gas-to-liquid and petrochemical plants. Gas consumed in these sectors could be much lower than the 2016 NGUMP forecasts.

The revision of NGUMP could also make plans to develop Tanzania's large onshore reserves more concrete. Some onshore exploration is currently taking place.[103] However, the government could further incentivize onshore activity, given that it is more suited to meet domestic needs than offshore gas.

With more realistic consideration of energy policy and gas demand, this revision could provide companies with a clear demand schedule for offshore gas. As we have explained, it is difficult to accurately forecast Tanzanian gas demand. However, providing a realistic demand schedule at least enables the companies to design options that optimize the gas reserves and infrastructure for the planned flow of gas.

2. Consider a variable DSO and decide what trade-offs to accept

The demand schedule that the government develops is likely to have demand increasing from a low level. As a result, a fixed DSO that is significantly larger than currently set out in the PSAs risks heavy take-or-pay penalties. There are two ways that the government could negotiate some protection against these penalties. It could give companies the option to buy back gas later in the project that TPDC has

103 Oil & Gas Journal, "APT to begin seismic work in Ruvuma PSA, Tanzania," 23 November 2020, www.ogj.com/exploration-development/article/14187891/apt-to-begin-seismic-work-in-ruvuma-psa-tanzania?oly_enc_id=5879D2281056E9Z.

paid for but left in the ground, or allow untaken gas to be treated as contingency gas.[104] Nevertheless, penalties could still be significant. Instead, the parties could agree on a variable DSO to fit the likely rising demand in Tanzania and the region.

While the feasibility of different project designs depends on the size of reserves and the characteristics of the reservoirs, the companies are likely to have three ways to physically vary the volume of gas for the DSO, as described in Section 3: Building spare capacity into the infrastructure initially, to allow for a production increase when needed; planning a second, larger phase, or developing the two JV projects sequentially. However, a variable DSO also has trade-offs for the country. Therefore, while the government should not necessarily accept the current fixed DSO, deciding what type of DSO it pursues, and therefore the depletion policy for the project, requires deciding what trade-offs to accept.

Table 6. Trade-offs between a fixed DSO and a variable DSO

Type of DSO	Project design	Benefits for government	Costs for government
Fixed DSO	One long production plateau	Avoids unnecessary infrastructure, so less need for tax incentives. Earlier production, so less exposed to energy transition risks.	Higher risk of large take-or-pay penalties.
Variable DSO	Initial spare capacity for flexible increase in production	Less risk of large take-or-pay penalties.	Payment for spare capacity through direct financing or tax incentives. Later production more exposed to energy transition risks.
	A second phase with increased production	Less risk of large take-or-pay penalties.	Smaller LNG plant may be needed in first phase, so more tax incentives possibly required. Later production more exposed to energy transition risks.
	Sequential JV projects	Less risk of large take-or-pay penalties.	Foregone cost savings from co-development, so more tax incentives required. Difficult to negotiate which JV goes second. Later production more exposed to energy transition risks.

104 Giving the companies the option to buy back untaken gas: This would not prevent the penalty being paid initially. TPDC would also probably have to sell the gas at a discount, given that the companies will not be able to process it into LNG until the end of planned production. However, it would mean some of the penalty could be recouped later if TPDC still cannot take it. Allowing untaken gas to be treated as contingency gas: A project is typically required to drill contingency wells to bring online if producing wells run into problems. If TPDC realizes it will not be able to take some of the DSO for a certain period, the wells used to produce the DSO gas could be treated as contingency wells instead. This would enable the companies to delay drilling additional wells, deferring their costs, and would reduce the take-or-pay penalty that TPDC would have to pay.

3. If the government still wants to pursue a larger DSO, limit it to below 20 percent

No DSO structure offers a silver bullet for the government's pursuit of a large DSO. To avoid paying heavy take-or-pay penalties early in the project, the government will likely have to pay for spare capacity or offer tax incentives to facilitate a later increase in production. The government could consider these as merely teething problems, which it is willing to absorb, but the financial and political damage could be severe. As argued in Sections 2 and 3, there are also two longer-term drawbacks to a large DSO. First, it reduces the chance that the project goes ahead, unless the government substantially reduces taxes to make it viable. Second, given that there are abundant energy sources already within Tanzania, a larger DSO increases the opportunity cost of consuming the gas in Tanzania, rather than using other energy sources for domestic power and selling the offshore gas abroad and earning higher revenue for government.

A large DSO reduces the risk of a gas shortage, and the constraint this could place on economic development if other energy resources are not developed should not be downplayed. The government therefore needs to decide whether these advantages outweigh the disadvantages. We think they do not, as illustrated in Figure 18. Therefore, if the government does pursue a larger DSO, we think it should be below 20 percent. With the double hit of take-or-pay penalties and lower government revenues, even a 20 percent DSO could cost the government the equivalent of 26 percent of revenue from the offshore project, or almost twice Tanzania's health budget.[105]

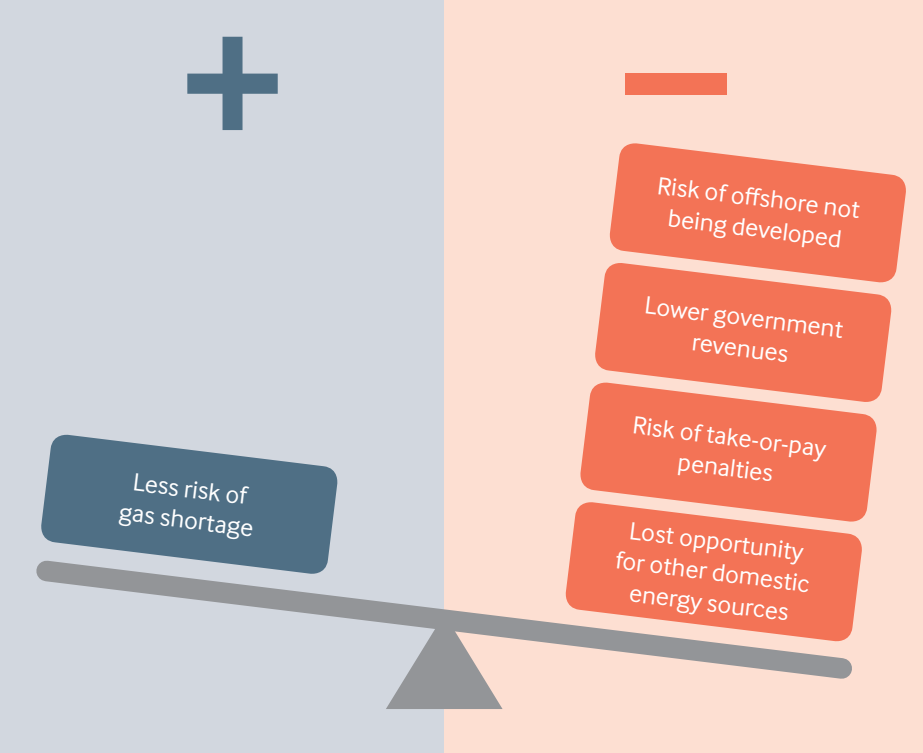


Figure 18. The advantages and disadvantages of a large DSO

105 As discussed in Section 2, we estimate that the take-or-pay penalty could be $631 million with a DSO of 20 percent. As set out in Section 3, we estimate that government revenues could be 14 percent or $974 million lower with a DSO of 20 percent. Tanzania's health budget in 2017-2018 was TZS 2.2 trillion or about $946 million. Government of Tanzania and Unicef, *Health Budget Brief 2018*.

4. Change the public narrative from a "gas-driven society" to "using Tanzania's entire energy resources"

Changing the narrative around gas would ease some of the pressure on the government to negotiate a large DSO. The government has developed a narrative of Tanzania becoming a gas-led industrialized country. This is supported by the high estimates of future gas consumption in NGUMP and the anticipation of the offshore project bringing supply. This has encouraged public expectation of a gas bonanza. It has possibly also meant a focus on the means rather than the end, with a focus on gas rather than the power that most of the gas will be used for.

Publishing the revised NGUMP is a good opportunity to temper expectations of a gas bonanza. Concurrently, the government could change from talking about Tanzania being a "gas-driven society" to being an "energy-driven society." The story could be about the government "developing all the natural resources that Tanzania is blessed with, to provide affordable and clean energy for all." Alternatively, it could be about building the state's capacity in industries of the future.

Tanzania could look to its neighbors for ideas on how to reframe the narrative. For example, Kenya has focused on becoming a "global powerhouse in geothermal energy" and is now turning its attention to other renewable energy sources.[106]

A different narrative, coupled with more public consultation, could increase the space that the government has to negotiate a moderate, less risky DSO and take a more holistic approach to powering the country's industrialization. Some evidence, including that shown in Figure 19, suggests that Tanzanians may be more open to exporting offshore gas than the government assumes.[107][108]

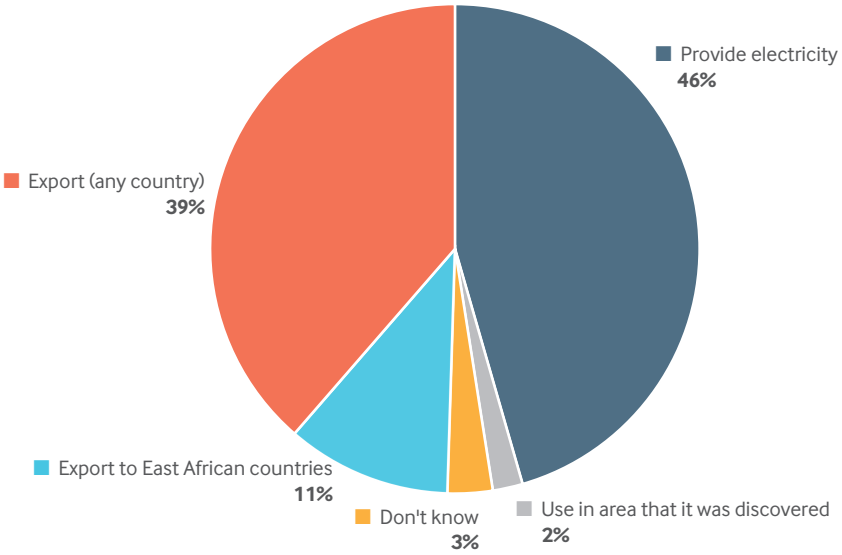


Figure 19. Citizens' views on how Tanzania's offshore gas should be used[108]

106 President of Kenya, Kenya On Track To Achieve Full Transition To Renewable Energy By 2020, President Kenyatta (2018), www.president.go.ke/2018/12/04/kenya-on-track-to-achieve-full-transition-to-renewable-energy-by-2020-president-kenyatta/.

107 Justin Sandefur, Nancy Birdsall, James Fishkin and Mujobu Moyo, Deliberative Democracy and the Resource Curse: A Nationwide Experiment in Tanzania (Center for Global Development, 2020), www.cgdev.org/sites/default/files/deliberative-democracy-resource-curse-nationwide-experiment-tanzania.pdf.

108 Twaweza, *Great Expectations: Citizens' views about the gas sector.*

5. Work with companies to reduce project costs and carbon emissions

Regardless of the size and type of DSO that the government aims for, the offshore project needs to be made more competitive if it is to have a reasonable chance of going ahead. The government could work with the companies to find ways to lower costs, such as by revisiting the decision to have an onshore rather than a floating LNG plant.

The government could also explore ways to reduce carbon emissions from the project. Minimizing emissions from gas projects is becoming critical, as discussed in Box 4. While this presents further challenges to Tanzania's project, it is also an opportunity for Tanzania to differentiate itself from its competitors. Shell suggests Tanzania's gas is already low carbon intensity, containing less than 0.2 percent CO2 (compared to, for example, Australia's gas, which can contain up to 17 percent).[109] The government could work with the companies to limit methane leaks and use renewable energy to supply power to the LNG plant. These steps would make Tanzania's gas even more attractive to buyers and make more gas available for export (given less gas will be used for powering the LNG plant).

The government could also work to make its policy more predictable, which investors have questioned since new laws were passed for the extractives sector in 2017. The Arbitration Act 2020, which largely removes the restriction on using international arbitration to resolve disputes, was introduced in 2017 and should ease some concerns. However, the government could clarify other areas, as set out in our initial guidance on these laws.[110] It could also be more transparent. A good first step—and one already required by law—would be to disclose the PSAs now and the HGA document once concluded. This will be critical for improving trust between companies and Tanzanians, and therefore for reducing the likelihood of further regulatory changes. These steps would not only increase the prospect of the offshore project going ahead, but also of new onshore projects and the large downstream investments that the government is hoping for.

Determining the right DSO for Tanzania is a challenging task for the government. However, Tanzania's new president has made negotiating a way forward on the offshore project one of her early priorities, generating fresh optimism that a solution can be found.[111] We hope that our proposals for navigating this decision help the president to achieve her goal.

109 Reuters, "Q+A: How do emissions from LNG and coal compare?" 10 May 2011, www.reuters.com/article/australia-lng-emissions/qa-how-do-emissions-from-lng-and-coal-compare-idUSL3E7FS0HG20110510.

110 Nicola Woodroffe, Matt Genasci and Thomas Scurfield. T*anzania's New Natural Resources Legislation: What Will Change?* (Natural Resource Governance Institute, 2017), www.resourcegovernance.org/analysis-tools/publications/tanzanianew-natural-resources-legislation-what-will-change.

111 Rosemary Mirondo, "President Samia directs speeding up of stalled LNG project."

Appendix

Our economic model of the offshore project

We developed an economic model of Tanzania's offshore project to inform our analysis. Like all models, the results depend crucially on the assumptions used. There are varying degrees of uncertainty around key inputs into the model—including the project's design, costs and regulatory framework—any of which may have a significant impact on our estimates. Indeed, we adjusted several assumptions made for our analysis in 2019, resulting in changes to our estimates.[112]

Our main assumptions are presented in Table 7 and discussed further below. Other assumptions can be found in the model.

Table 7. Baseline assumptions for the offshore project (2020 USD)

Element	Assumption
Final investment decision	2025
Production start	2030
Blocks involved	Blocks 1, 2 and 4
Recoverable reserves of raw gasof which gas of which natural gas liquids (NGLs)	Blocks 1 and 4: 15.02 tcf Block 2: 13.15 tcf Blocks 1 and 4: 13.53 tcf Block 2: 13.15 tcf Blocks 1 and 4: 1.48 tcf Block 2: 0 tcf
Well drilling schedule	Drilling every 10 years
Well production capacity	150 mmcf per day
Total production capacity	Blocks 1 and 4: 470 bcf per year Block 2: 463 bcf per year
LNG plant size	Blocks 1 and 4: 7 mmtpa Block 2: 7.5 mmtpa
LNG plant processing loss	10% of gas supplied
Domestic supply obligation (DSO)	Blocks 1 and 4: 7% of reserves Block 2: 10% of reserves Converted to fixed volume at production plateau Production capacity allocated to LNG plant can be diverted to allow supply of previously untaken DSO after 20 years
DSO processing plant size	Blocks 1 and 4: 31 bcf Block 2: 38 bcf
DSO plant processing loss	0% of gas supplied
Project structure	Segmented: Upstream and midstream (LNG plant and DSO processing plant) are separate entities for regulatory and tax purposes
LNG tolling fee	Provides LNG plant a 13% post-tax return
DSO processing tariff	Provides DSO processing plant a 13% post-tax return

112 Scurfield and Manley, *How Tanzania Can Secure a Good Deal for its Offshore Gas,* (Natural Resource Governance Institute, 2019), resourcegovernance.org/analysis-tools/publications/tanzania-good-deal-offshore-gas.

Element	Assumption
Exploration expenditure	Blocks 1 and 4: $1.8 billion Block 2: $1.5 billion
Upstream development expenditure	Blocks 1 and 4: $8.9 billion Block 2: $8.5 billion
LNG plant development expenditure	Blocks 1 and 4: $7 billion Block 2: $7.5 billion
DSO plant development expenditure	Blocks 1 and 4: $0.09 billion Block 2: $0.1 billion
Upstream replacement capital expenditure	Blocks 1 and 4: $1.5 billion Block 2: $1.5 billion
LNG plant replacement capital expenditure	Blocks 1 and 4: $2.5 billion Block 2: $2.4 billion
DSO plant replacement capital expenditure	Blocks 1 and 4: $0.03 billion Block 2: 0.04 billion
Upstream operating expenditure	Blocks 1 and 4: $0.6 per mmBtu Block 2: $0.6 mmBtu
LNG plant operating expenditure	Blocks 1 and 4: $0.5 mmBtu Block 2: $0.5 mmBtu
DSO plant operating expenditure	Blocks 1 and 4: $0.1 mmBtu Block 2: $0.1 mmBtu
LNG shipment cost	$1 per mmBtu
Domestic demand	Based on IEA STEPS projection
Regional demand	From Kenya; Based on IEA STEPS projection
Onshore gas supply	Only production from existing projects
DSO price at processing plant exit	$4 per mmBtu
NGL price	$5 per mmBtu
Upstream fiscal regime	Based on Block 2 PSA addendum
Midstream fiscal regime	Based on general legislation
Minimum return required by companies to trigger investment	13%

Timeline. The government and companies must at least agree on key terms of the HGA before companies can conduct feasibility studies (what the industry calls "preliminary front end engineering design" or pre-FEED), while more advanced project planning (called "front end engineering design", or FEED) will not take place until parties have signed the HGA. Only once these two planning stages are complete will companies make a final decision on whether to invest. Given Tanzania's new president has made the offshore project an early priority and the government is targeting an acceleration in negotiations, key terms may be agreed in 2021.[113] Equinor and Shell suggest that once they have, it will take three to

113 *The Guardian*, "Govt readies LNG talks with investors," 7 May 2021. www.ippmedia.com/en/news/govt-readies-lng-talks-investors.

three and a half years to get to FID.[114] We therefore think the government's recent suggestion that FID could be reached in 2023 is optimistic, and are more cautious.[115] Construction of the project is expected to take four to five years. We therefore assumed that, if investment does go ahead in 2025, production will commence in 2030. This timeline is three years later than our assumption in earlier analyses of the project.

Reserves. We used Rystad's estimates of raw gas production by the three blocks. The estimate for Blocks 1 and 4 of 15.02 tcf is lower than Wood Mackenzie's 2016 estimate of 2P reserves of 16.64 tcf, which we had used previously. The estimate for Block 2 of 13.15 tcf is higher than Wood Mackenzie's 2016 estimate of 10.01 tcf. We disaggregated between gas and NGLs, which we did not do previously.

Production capacity. Our production capacity estimates are based on the production required for the blocks to supply the amount of gas that the LNG plant requires to operate at full capacity and to meet their DSO obligations. Discussions with the companies suggest it will be difficult to obtain financing for a larger project initially. We assumed that each well has a production capacity of 150 mmcf per day, given that Mozambique's Area 1 project is expected to have wells with a capacity of 100-200 mmcf per day.

Supply allocation. We assumed most gas is processed and exported as LNG in our baseline scenario, though the impact of changing this assumption is the focus of this analysis. We assumed Block 2 has an LNG train with a capacity of 7.5 mmtpa, based on Equinor's publication on the project.[116] Discussions with Shell suggest it may have an LNG train with a capacity of 7 mmtpa, given it is envisaged that the overall LNG plant would be similar in size to its Canadian LNG project.[117]

Any offshore gas not exported as LNG is used to satisfy the DSO. The government and companies have not disclosed the PSAs, but Equinor, the operator of Block 2, has disclosed that it has a DSO of 10 percent of reserves. The leaked addendum to Block 2's PSA implies that this DSO will be fixed across the project's lifetime, as domestic supply shall not exceed "10 percent of projected production."[118] We had previously been informed that the DSO for Blocks 1 and 4 is 8 percent. However, we now understand that it may be lower, around 6 percent. We have therefore assumed that it is 7 percent, and also fixed. We assumed that the size of the DSO processing plant, with a train for Blocks 1 and 4 and a train for Block 2, will be based on these DSO volumes.

When we looked at the impact of different DSOs, we varied the size of the LNG plant too, as set out in Table 8. We based its size on it processing as much gas as the fields can produce, net of the DSO.

114 Equinor, B*lock 2 Tanzania; Shell, Tanzania LNG: Our Vision.*
115 Fumbuka Ng'wanakilala, "Tanzania May Start Building $30 Billion LNG Project in 2023."
116 Equinor, *Block 2 Tanzania.*
117 Natalie Obiko Pearson, Stephen Stapczynski, Elffie Chew, and Kelly Gilblom, "Shell, Partners Announce $31 Billion LNG Canada Investment," Bloomberg, 2 October 2018, www.bloomberg.com/news/articles/2018-10-02/shell-partners-announce-31-billion-lng-canada-investment.
118 Article 8 of *Addendum to Existing Production Sharing Agreement.*

Table 8. Modeled relationship between size of DSO and size of LNG plant

	DSO as proportion of reserves					
	0%	20%	30%	40%	50%	60%
Blocks 1 and 4 LNG train (mmtpa)	7.5	6.8	6.0	5.3	4.6	3.8
Block 2 LNG train (mmtpa)	8.2	7.5	6.8	6.1	5.3	4.6

The government could use the DSO gas to supply the domestic or regional markets, or both. We assumed it supplies both markets, but prioritizes the domestic market if the DSO volume is too small to satisfy domestic and regional demand.

As discussed in this analysis, current projections of potential domestic demand from different sources vary widely. We use the most recent projection, which is from the IEA's Africa Energy Outlook Stated Policies Scenario (STEPS) in 2019.[119] However, we made four modifications. First, the IEA does not provide annual amounts, so we inferred these from the data points given using linear extrapolation. Second, we adjusted it to reflect slightly lower expected demand for Africa in the longer term in the IEA's 2020 projections—around 5 percent less in 2035 and 13 percent less in 2040, as a result of larger expansion of renewables.[120] (The 2020 projections are not disaggregated to the country level.) Third, the IEA assumed a lower gas consumption in years prior to 2020 than actually occurred, and assumed a lower gas consumption up to 2023 than Tanzania was actually consuming in 2019. We therefore brought forward the projection by four years. The original 2024 consumption becomes the 2020 consumption. Fourth, the IEA projection then runs until 2036. We therefore assumed that consumption grows until 2050 by the average rate that the IEA expects in 2020-2036. The IEA expects even lower gas demand across Africa in its Sustainable Development Scenario. Nevertheless, gas demand in the projection we used is still significantly lower than in the government's NGUMP.[121] It is also slightly lower than in Demierre et al, which we had used previously, but is now six years old.[122]

We based our projection of regional demand on the IEA's Africa Energy Outlook STEPS for Kenya. Tanzania is also considering supplying other countries in the region. However, it has yet to undertake feasibility studies for these other supply options, and there is significant uncertainty about them. We assumed that a pipeline to supply gas to Kenya is operational by the time offshore production starts in 2030. As with the IEA STEPS projection for Tanzanian demand, we made several modifications to the projection of Kenyan demand. First, we have inferred annual amounts from the data points given, using linear extrapolation. Second, we have adjusted it to reflect slightly lower expected demand for Africa in the longer term in the IEA's 2020 projections.[123] Third, the IEA projection runs until 2040. We therefore assumed that consumption grows until 2050 by the average rate that the IEA expects in 2020-2040.

119 IEA, *Africa Energy Outlook 2019, Tanzania.*
120 IEA, *World Energy Outlook 2020.*
121 Government of Tanzania, *Natural Gas Utilisation Master Plan.*
122 Demierre et al, *Potential for Regional Use of East Africa's Natural Gas.*
123 IEA, *World Energy Outlook 2020.*

Domestic and regional demand for offshore gas will be affected by the amount of onshore gas production. We were conservative and only considered onshore reserves for which there are currently development plans: Reserves in the Songo Songo and Mnazi Bay blocks. We used the production projections provided in the Orca 2019 annual report for Songo Songo, and assumed Mnazi Bay's future production will be similar to 2019 levels.[124] We estimate that these reserves will run out in 2038. However, as Table 9 sets out, government estimates suggest Songo Songo and Mnazi Bay contain significant additional reserves, as do other blocks.

Block	Status	Gas Initially in Place (tcf)	Recoverable (tcf)
Songo Songo	Operating		0.39
Mnazi Bay	Operating		0.47
Songo Songo	Extra undeveloped reserves	2.5	1.8
Mnazi Bay	Extra undeveloped reserves	5.0	3.5
Mkuranga	Undeveloped	0.2	0.1
Nyuni	Undeveloped	0.1	0.0
Ruvuma	Undeveloped	0.2	0.1
Ruvu	Undeveloped	2.2	1.5
Total		10.1	7.1

Table 9. Tanzania's estimated onshore reserves in its Power System Master Plan, adjusted to account for the government's suggested recoverability rate of 70 percent[125]

Costs. There continues to be significant uncertainty around capital expenditure requirements for the

offshore project—both the total amount and the time profile. We used Rystad's unit costs for development expenditure on the offshore facilities and wells. We assumed that wells are drilled every 10 years, with the Blocks 1 and 4 drilling program and the Block 2 program each using two rigs at a time.

We assumed that the LNG plant will cost $1 billion per mmtpa.[126] We based our cost assumption for the DSO processing plant on Tanzania's existing processing plants, which we calculated cost $2,737 per mmcf of capacity. In total, this results in development expenditure for the offshore project of $32 billion, which is slightly higher than the assumption of $30 billion in our previous analysis. However, we have now assumed around $3 billion less replacement capital expenditure, due to a change in our methodology.

124 Orca, Focused on growing a sustainable integrated gas business for Africa: Annual Report & Accounts 2019 (2020), orcaenergygroup.com/wp-content/uploads/2020/05/Orca-Exploration-Annual-Report-2019.pdf

125 Ministry of Energy and Minerals, *Power System Master Plan, 2016 update*.

126 According to recent analysis of LNG plant costs across the globe, a unit cost of $1 billion per mmtpa would be relatively cheap, given that Tanzania's LNG plant is greenfield, will process wet gas and is in a remote location. However, company officials suggest having fewer, larger trains should generate cost efficiencies that enable them to achieve a unit cost of around $1 billion. This is slightly higher than estimated by Rystad. Brian Songhurst, *LNG Plant Cost Reduction for 2014-18* (The Oxford Institute for Energy Studies, 2018), 7, www.oxfordenergy.org/wpcms/wp-content/uploads/2018/10/LNG-Plant-Cost-Reduction-2014%E2%80%9318-NG137.pdf.

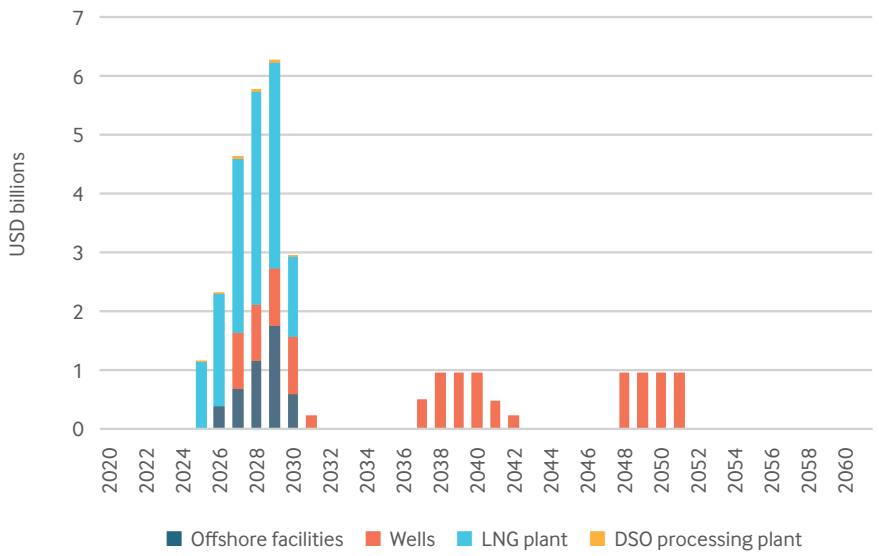


Figure 20. Assumed development costs

For operating expenditure, we used Rystad's estimates for the upstream entities, which align with our previous assumption. Our assumption for the LNG plant is based on the industry norm of annual operating expenditure (excluding fuel) being 2.5 percent of total capital expenditure. Operating expenditure for the DSO processing plant is based on the same approach, but we assumed annual operating expenditure is 3.5 percent of total capital expenditure, because we do not exclude fuel.

Sales prices. The target markets for Tanzanian LNG exports are expected to be in Asia, for which Japanese prices are a reliable metric. Given the inherent unpredictability, we did not assume an LNG price in our baseline. Instead, we looked at the long-term price required at different investor hurdle rates.

We assumed the government buys DSO gas at the exit of the processing plant at the cost-plus price. We estimated this price using our baseline assumptions.

We followed Rystad's approach of assuming that the NGL price is 65 percent of the Brent oil price. We assumed that the oil price will be $50 per barrel over the long term. This results in a NGL price of around $5 per mmBtu. However, the government could negotiate a price that is more reflective of the cost-plus price of around $4 per mmBtu.

Segmentation of the project value chain. We understand that all parties are likely to agree to a segmented value chain, and so assume this structure in our baseline. We therefore assumed four project entities are in operation: Blocks 1 and 4; Block 2; the LNG and DSO processing trains for Blocks 1 and 4, and the LNG and DSO processing trains for Block 2.

Fiscal regime. In a segmented structure, we expect the fiscal regimes provided in the current PSAs to be levied on the upstream entities, but a different fiscal regime to be agreed and levied on the midstream entities. The main components of these assumed regimes are presented in Table 10.

Table 10. Main components of baseline fiscal regimes for upstream and midstream entities

Fiscal term	Upstream	Midstream
Royalty	5%	None
Cost gas limit	70%	None
Government share of profit gas	30-50%	None
Royalty paid from government profit gas?	Yes	No
Income tax	30%	30%
Royalty deductible from taxable income?	Yes	No
Depreciation of capital expenditure	20% per year across five years	20% per year across five years
Loss carry forward	Unlimited	Losses can be carried forward indefinitely, but used against maximum of 70% of income per year
Additional profit tax	None	None
Dividend and interest withholding taxes	10%[127]	10%
State equity share	10%; Carried and repaid through TPDC's share of cost gas	10%; Carried and repaid through TPDC's share of revenues

Because the government and companies have not disclosed the PSAs, we derived our baseline fiscal terms from the contents of the leaked addendum to the Block 2 PSA, government statements in 2014 and an assumption that the terms approximate the model PSAs that the government has developed for the sector.[128] We therefore assumed that the fiscal regimes in the PSAs for Blocks 1 and 4 are not significantly different from that in the Block 2 PSA. However, until they are disclosed, we will have a limited understanding of their contents. We assumed that the midstream entities are taxed as a normal business entity, under the standard income tax regime, but subject to the rules set out in the Finance Act 2016 and Written Laws (Miscellaneous Amendments) Act 2017 for oil and gas projects. We assumed that TPDC also has 10 percent carried interest in the midstream entities, so that incentives for TPDC and companies are aligned across the value chain.

Pricing between project entities. In a segmented structure, any gas bought and sold between the upstream and midstream entities will need to be priced, as will any services provided between these components. We assumed that the upstream entities will pay a fee to the midstream entities. Rather than selling their gas to the LNG and DSO processing plants, they will pay the midstream entities a fee for processing the gas, and then sell the LNG or DSO itself. We assumed that this fee will be regulated through capping the rate of post-tax return of the midstream entities at 13 percent.

127 Depending on the multinational structure of a company, double taxation treaties between Tanzania and other jurisdictions may significantly reduce the effective rates of withholding taxes. However, the treaties we have viewed allow for the current rates of withholding tax on interest and dividends. Tanzania Revenue Authority, "Double Taxation Agreements," accessed 3 July 2019, www.tra.go.tz/index.php/double-taxation-agreements.

128 David Manley and Thomas Lassourd, *Tanzania and Statoil: What Does the Leaked Agreement Mean for Citizens?* (Natural Resource Governance Institute, 2014), www.resourcegovernance.org/sites/default/files/Tanzania_Statoil_20140808.pdf.

Project hurdle rate. We assumed a hurdle rate of return of 13 percent (in real terms). Wood Mackenzie company surveys have found that the most common hurdle rate used for LNG projects across the globe is 13 percent (after adjusting for assumed inflation of 2 percent).[129] However, as discussed in our analysis, the hurdle rate for Tanzania's project could be higher or lower.

Configuration of gas supply and demand scenarios

Gas domestic demand. We assembled four scenarios on potential future domestic demand for Tanzania's gas from external sources. However, they all required further calibration.

1. *NGUMP.* This scenario is taken from the government's NGUMP, which was produced in 2016 and projects demand from 2016 to 2045.[130] We picked the three-train scenario as the one most closely matching likely LNG plant capacity. We picked the base case scenario, rather than NGUMP's high case, because even this lower base case is still the most optimistic of the scenarios we found. NGUMP expects a significant expansion in gas demand at the start of offshore production, which was predicted to be in 2025. We assumed an offshore start of 2030, and therefore shifted the entire consumption profile back to start in 2021, not 2016.
2. *Demierre et al.* This scenario is taken from the research paper by Demierre et al. in 2014.[131] The paper does not show annual amounts, so we have inferred these from the data points given, using linear extrapolation.
3. *IEA STEPS.* As discussed in the previous section on the assumptions in our economic model, this scenario is based on the IEA's Stated Policies Scenario in the Africa Energy Outlook in 2019, but with some modifications.[132]
4. *IEA SDS.* This scenario is based on the IEA's Sustainable Development Scenario in 2020.[133] It is consistent with a fast enough energy transition to limit the growth in global temperature to below two degrees Celsius. The IEA only provides this scenario at the regional level. We therefore used the difference in regional demand between this scenario and the STEPS scenario to infer possible demand for Tanzania.

129 Wood Mackenzie's "State of the Upstream Industry" company surveys in 2017 and 2018.
130 Government of Tanzania, *Natural Gas Utilisation Master Plan.*
131 Demierre et al, *Potential for Regional Use of East Africa's Natural Gas.*
132 IEA, *Africa Energy Outlook 2019, Tanzania.*
133 IEA, *World Energy Outlook 2020.*

Gas regional demand. We assembled two scenarios on potential future regional demand for Tanzania's gas from NGUMP and IEA STEPS. We made the same modifications to them as we describe above for the domestic demand scenarios.

Gas supply. In modeling the total supply of gas to Tanzania, we assumed that the existing onshore projects, Songo Songo and Mnazi Bay, produce the reserves in their current development plans. As noted above, we used the projections provided in the Orca annual report 2019 for Songo Songo, and assumed Mnazi Bay's future production will be similar to 2019 levels.[134] We then assumed DSO gas is supplied when the offshore project starts in 2030. Finally, in our IEA demand-high onshore supply scenario, we assumed that further onshore gas is developed when the country needs it, from the estimated 7 tcf of recoverable onshore gas reserves, for which there are currently no development plans. We assumed these fields would be developed after there have been two years of surplus demand, and that they each operate for a minimum of 10 years and can produce at the same potential rate as Mnazi Bay—around 37 bcf a year—until the known reserves are depleted.[135] We did not include the possibility of new offshore gas discoveries.

Our modeling of gas supply makes two main simplifications. First, we did not model the effects of developing new sources of energy such as wind, solar and geothermal, nor the effects of a faster than anticipated development of Stiegler's Gorge hydroelectric plant. These alternative energy sources coming online earlier or at a larger scale than previously expected may deter further development of onshore reserves. Second, we did not factor in the price of gas in the Tanzanian economy. This is an important factor missing from the model, but a complex one to include. In theory, prices within the system should act to ration gas to some extent. However, most gas is expected to be sold at prices set by the authorities rather than determined by the market. Future research could investigate this further.

134 Orca, Focused on growing a sustainable integrated gas business for Africa; Wentworth, Annual Report and Financial Statements 2019.
135 Wentworth, *Annual Report and Financial Statements 2019.*

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