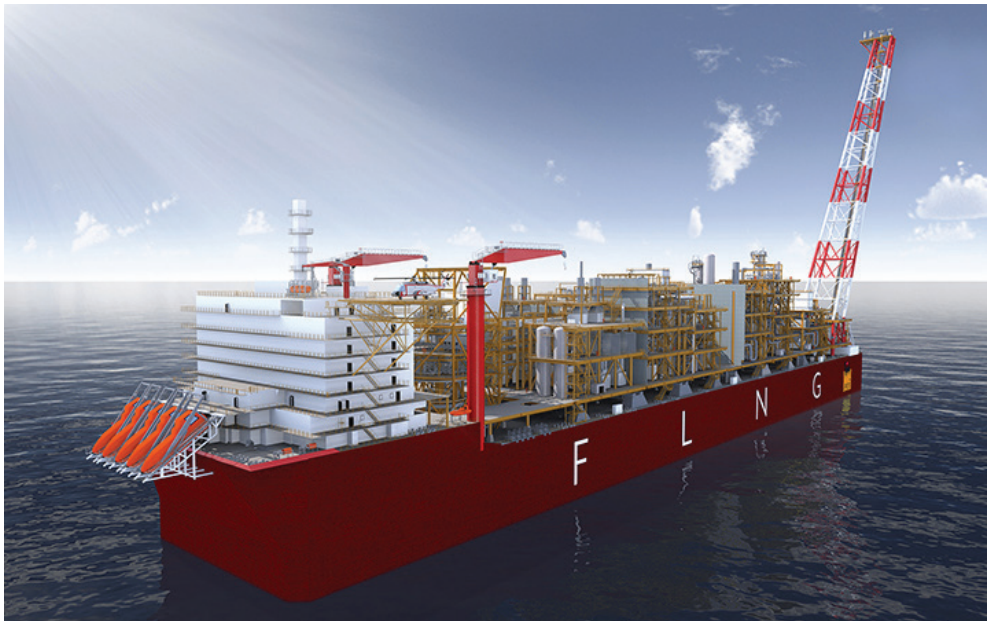




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GOVERNMENT REVENUES FROM CORAL FLNG

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EXECUTIVE SUMMARY

Discoveries of natural gas in the Rovuma Basin hold the potential to transform Mozambique. There is no shortage of natural gas, the challenge is to mobilize the investments that are needed to bring the gas to market. The construction of the liquid natural gas (LNG) facilities needed for export will cost tens of billions of dollars.

Thus far, only one of the proposed projects is currently under development. The project is led by the Italian oil company Eni and is known as Coral South Floating LNG. The production of gas and the conversion of that gas into LNG will take place offshore. The facility is designed to produce nearly 3.4 million tons of LNG per year with first exports expected in late 2022.

Previous revenue projections generated by the International Monetary Fund (IMF), the World Bank-funded Gas Master Plan, and the Standard Bank analysis commissioned by Anadarko have suggested very substantial government revenues from LNG by the early to mid 2020s. These forecasts assumed early first exports, rapid expansion of production capacity and very high LNG prices.

The prospects for government revenues from FLNG are ever more important given the challenges of external debt and declining donor support. As the contractual terms for Area 1 and Area 4 are comparable, the findings of this analysis also provide some insights into potential revenues from the onshore projects as well.

Eni has indicated that the government can expect to generate around \$16 billion in revenue over the life of the Coral South FLNG project. Two very different revenue forecasts have emerged from the government. In a report targeted at creditors, the Ministry of Finance suggests that the Coral South FLNG could generate around \$11.5 billion in revenue. In contrast, the Minister of Mineral Resources and Energy is reported to have suggested that the project could generate as much as \$24.5 billion.

This report provides an independent government revenue forecast for Coral South FLNG. The analysis is based on information in the public domain as of August 2019. Importantly, the 2006 Exploration and Production Concession Contracts (EPCCs) for the Rovuma Basin have been disclosed by the Government. Other terms are drawn from the 2014 Decree Law. Coral FLNG production will be sold to BP based on a twenty-year Gas Sales Agreement. While the agreement remains confidential, the basic terms have been reported. Input assumptions on production volumes and project costs are drawn from company filings to their investors and from a natural gas revenue projection prepared by the Ministry of Economy and Finance for creditors in 2018.

The oil companies have created a unique commercial structure for the development of Coral FLNG. Since the Decree Law of 2014, it has been clear that the FLNG facilities will be developed inside the legal structure of the 2006 EPCC. This approach will

allow the companies to be repaid for their investment in the FLNG vessel through what is known as “cost gas.” In order to secure financing for the floating vessel, the companies have created a Mozambican company to own and operate the vessel with billions of dollars in financing routed through Dubai. The Mozambican company will be compensated for producing LNG through a tolling fee.

The revenue forecast is generated through an industry-standard discounted cash flow model. The model analyzes the economics of the project, year-by-year, by integrating data on anticipated production volumes and production costs, varying LNG price scenarios, and the fiscal terms that determine how revenues will be allocated between costs, government revenue and company profit. The model itself is publicly accessible and therefore open to independent verification to ensure that the underlying logic and calculations generate reliable results. It is also a tool that can be updated over time to take into account new information, particularly related to project costs and LNG price.

Our base case analysis assumes an oil price in 2022 of \$70 per barrel. Under this assumption, we forecast government revenues over the life-cycle of the project of around \$11.6 billion. This finding is consistent with the Ministry of Finance note to creditors and much lower than forecasts from Eni or the Minister of Mineral Resources and Energy. As would be expected, government revenues are highly sensitive to oil price. At \$85 dollars per barrel we estimate government revenues of \$19 billion, while at \$55 dollars per barrel revenues would fall to \$5.5 billion.

Two factors are particularly important when analyzing the fiscal terms contained in oil contracts: the share of after-cost revenues that flow to the government as opposed to the companies (known as the “government take”) and the timing in the project lifecycle when the government revenue arrives. Our analysis suggests that the government share of revenues, around 49%, falls below what could be expected even for a country which signed contracts had signed contracts before major petroleum discoveries. More important than the share of overall revenues, however, is their timing. Government revenue under the 2006 EPCC is heavily rear-loaded. Until the late 2020s, the government can expect revenues of less than 6% of the overall value of Coral FLNG production, or less than \$100 million per year.

This study examines only the first of a series of LNG projects that will be developed for the Rovuma Basin. The findings however have wider applicability. Rovuma natural gas holds incredible promise for Mozambique. However, securing multi-billion-dollar investments always takes more time than expected, particularly in a low-price environment. The rear-loaded nature of the 2006 EPCCs, that apply to both Area 4 and Area 1, means that government revenues are likely to be very modest in the early years of production. If there are cost over-runs, or if prices remain low, the start of significant government revenues will be pushed back even further. The revenue logic contained in the 2006 EPCC should be taken into account in considerations of debt repayment and future budget planning. Revenues from Rovuma natural gas can be an economic game-changer for Mozambique, but this will not happen until sometime in the 2030s.

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Acronyms and Definitions

AETR – Average effective tax rate
CNPC – China National Petroleum Corporation
ENH – Empresa Nacional de Hidrocarbonetos
EPCC – Exploration and production concession contract
ERR – Effective royalty rate
FEED – Front end engineering and design
FID – Final investment decision
FLNG – Floating liquefied natural gas
IRPC – Corporate income tax
IRR – Internal rate of return
KOGAS – Korean Gas Corporation
LNG – Liquefied natural gas
MMBTU – Million British thermal units
MMscf – Million standard cubic feet
MTPA – Million metric tons per annum
NPV – Net present value
PPT – Petroleum production tax
SPE – Special purpose entity (Mozambique)
SPV – Special purpose vehicle (UAE)
TCF – Trillion cubic feet
UAE – United Arab Emirates

GLOSSARY

Capital costs: Costs incurred after a decision has been taken to develop a project, including the costs of constructing the site, installing equipment and purchasing machinery (sometimes “capex”).

Cash flow analysis: A year-by-year analysis of money generated by a project (cash inflows) and money spent on a project (cash outflows).

Corporate income tax: A tax assessed as a percentage of the net profits of a company after deducting allowable expenses (in Mozambique: IRPC).

Cost oil: The portion of oil production that is allocated to the company to reimburse past and current costs (exploration, development, operating etc.)

Cost recovery limit: A maximum percentage, set in an oil contract, limiting the proportion of annual production that can be allocated to cover costs (“cost oil”).

Cost recovery: The process of recouping costs of producing a commodity, usually established in the fiscal regime.

Development costs: Costs incurred after a decision has been taken to develop a field, including the costs of drilling, platforms, pipelines, and other equipment (called “capex”).

Double taxation agreement (DTA): Treaties that seek to avoid taxation of the same income in both the host and home countries.

Exploration costs: Money spent at the start of an oil project searching for oil, including seismic testing (sub-surface imaging) and drilling exploratory wells.

Final investment decision: The formal decision by the company (or joint venture) to shift from the exploration phase to the development phase of a project (also called “project sanction”).

Fiscal instruments: Policy tools that enable governments to generate revenues, including bonuses, taxes, royalties, dividends, and production entitlement, amongst others (sometimes “fiscal terms”).

Fiscal regime: The set of terms, agreements, laws, and regulations that together determine how the revenues from extractive projects are shared between company and government.

Government revenue: Money received by the government from an oil project through various sources, including taxes and a share of petroleum production.

Gross revenues: Total of all revenues collected from commodity sales (production x sales price) without any deductions for costs or taxes (sometimes “project revenues”).

International oil company (IOC): A private sector oil company with operations in many countries, including companies such as Tullow, Africa Oil, Shell, BP, and Exxon.

Investment incentives: A range of policy options that governments employ in order to attract investors, including but not limited to full or partial deferral of taxes, capital investment credits and accelerated depreciation (sometimes “tax incentives”).

Long-term sales agreements: Contracts between two separate or related entities that stipulate the price, or the formula for how the price will be determined, for future sales of a commodity.

Midstream: The oil and gas industry is normally divided into these sectors: upstream, midstream and downstream. The midstream sector involves processing, storage and transportation of petroleum resources, including pipelines and LNG facilities.

National oil company (NOC): An oil company owned (fully or at least majority) by a national government, and operating largely on the basis of market principles (e.g. ENH).

Net revenues: Income after expenses, according to the appropriate accounting rules (sometimes “net income” or “profit”).

Oil block: A specific geographical area awarded to a company through an oil contract (PSC), providing the right to explore, develop, produce, and sell any oil found (also known as “concession”).

Operating costs: The day-to-day costs incurred producing oil, including salaries, maintenance, materials and supplies, leasing of equipment, and insurance (called “opex”).

Operator: Company (e.g. Eni) that manages the assets, including well, field, licence, or transportation facilities on behalf of joint venture participants.

Production sharing contract (PSC) or agreement (PSA): The principal contract between a government and a private oil company, setting terms for oil exploration and future production (in Mozambique, Exploration and Production Concession Contracts – EPCC).

Production sharing: A system where the oil produced (“profit oil”) is divided between the oil company and the government after the company has recovered its costs (“cost oil”).

Profit oil: The portion of oil production that is split between government and company after cost oil has been deducted and allocated to the company.

Progressive fiscal regime: A set of tax terms that allow the government to capture a larger share of revenues for more profitable projects.

Revenue projections: A forecast of potential government revenues generated by applying contract fiscal terms to scenarios of production, price, and costs.

Ring-fencing: Establishing an economic perimeter around a project, often at the level of the contract or concession, so that the company cannot offset the income inside the fenced area with losses from other projects outside the fenced area.

Royalty: A fiscal tool commonly applied to resource extraction, often based on the value of the commodity extracted (in Mozambique, Petroleum Production Tax – PPT).

Scenario analysis: The creation of plausible futures based on assumptions about timelines and volumes of production, oil price, and the costs of oil production.

Slope: Used in oil-indexed LNG contracts. The slope is a measure of how much the gas price changes relative to a change in the oil price.

Stabilization clause: A contractual provision assuring investors (and their lenders) of the durability of the initial terms, particularly related to taxation.

State participation: Where a government holds an equity stake in an oil project, either directly through the Treasury or through a national oil company (e.g. ENH).

Tax base: The revenue against which tax rates are applied; the method of calculation is set out in contract or tax laws.

Tax exemptions: The waiving of specific taxes that would normally apply, such as a value added tax, or customs and excise duties.

Tax holiday: An incentive designed to stimulate investment that reduces or eliminates corporate taxation for a defined period of time.

Thin capitalization: The financing of an extractive sector project through a high level of debt, with financing often provided by an affiliated company at high interest rates.

Tolling fee: The fee per million British thermal units (mmbtu) paid by the upstream partners to the midstream LNG facility for processing, liquefaction, and storage.

Upstream: The oil and gas industry is normally divided into these sectors: upstream, midstream and downstream. The upstream sector involves exploration and production of petroleum resources.

Withholding tax: A tax levied on payments to non-residents, often applied to payments to non-resident subcontractors as well as the foreign interest and dividend payments.

1.0 INTRODUCTION

Liquefied natural gas (LNG) has a potentially important role to play in supporting development in Mozambique. Mozambique has massive offshore natural gas resources. According to Empresa Nacional de Hidrocarbonetos (ENH), the Rovuma Basin contains resources of around 165 trillion cubic feet (TCF) of natural gas.¹

The contribution that natural gas can make to the development of Mozambique is not limited by the amount of gas available. Rather, it is limited by the difficulty in getting international oil companies to develop the fields and finance the LNG facilities.

The gas finds in the Rovuma Basin are divided between two different concessions or Blocks: Area 1 (75 TCF) led by Anadarko and Area 4 (90 TCF) led by Eni. In both cases, large onshore LNG facilities are planned. Neither of these projects, however, has entered the development or construction stage.

The only project under construction is the Coral floating LNG (FLNG) project in Area 4 led by Eni. Work began on the FLNG unit in late 2018, and offshore drilling is expected to begin by the middle of 2019.² First gas exports are scheduled for late 2022.

The Government of Mozambique has long hailed LNG revenues as an economic game-changer for Mozambique.³ LNG has the potential to provide substantial revenues for the government. At the same time, however, LNG is a highly unpredictable commodity. Estimates of potential government revenues require a realistic understanding of project economics as well as the fiscal terms contained in the Exploration and Production Concession Contracts (EPCC).

Previous revenue projections generated by the International Monetary Fund (IMF), the World Bank-funded Gas Master Plan, and the Standard Bank analysis commissioned by Anadarko have suggested very substantial government revenues from LNG by the early to mid 2020s.⁴ These forecasts all assumed early first exports, rapid expansion of production capacity and very high LNG prices.

The early optimism around a windfall revenue before the end of this decade has given way to a realization that exports will not begin before 2022 at the earliest, and substantial government revenues will probably not arise until later in the 2020s.⁵

¹Financing LNG projects with shorter term and different pricing mechanism, ENH, 2018.

²Steel and coral off Mozambique, Eniday, 2018.

³See Natural Gas Master Plan, Republic of Mozambique, 2014.

⁴ See Alistair Watson, Ricardo Varsano, Charles McPherson, Cesar Santa Gadea, and Ejona Fuli, Reforming the Fiscal Regimes for Mining and Petroleum, IMF, 2012, The Future of Natural Gas in Mozambique: Towards a Natural Gas Master Plan, ICF, 2013 and Mozambique LNG: Macroeconomic Study, Standard Bank, 2014.

⁵See Projected government revenues from gas projects, Ministry of Finance, Government of Mozambique, 2018. See also the recent debate on on potential revenues from LNG between former-Minister of Finance Magid Osman and the Chairman of INP Carlos Zacarias. Carlos Zacarias: Abdul Magid Osman adverte que colcha de bilhões de USD no gás do Rovuma é uma miragem and Mozambique expects to raise US\$30.9 billion from LNG exploitation in Golfinho-Atum.

The timing of potential government revenues from LNG has become even more significant in the face of Mozambique's debt crisis. Understanding realistic timelines and the potential scale of government revenue is, therefore, more important than ever.

This study focuses specifically on potential government revenues from Coral South FLNG. Eni has indicated that the government can expect to generate around \$16 billion in revenue over the life of this project.⁶ Two very different revenue forecasts have emerged from the government. In a report targeted at creditors, the Ministry of Finance suggests that the Coral South FLNG could generate around \$11.5 billion in revenue.⁷ In contrast, the Minister of Mineral Resources and Energy is reported to have suggested that the project could generate as much as \$24.5 billion.⁸

This report, and the accompanying public domain economic model, provides an independent government revenue forecast for Coral South FLNG based on information available as of August 2019.⁹ In addition to analysing the first LNG project in detail, the findings will also provide important insights into the scale and timing of the onshore LNG projects that are expected to follow.

The data required for an assessment of potential government revenues from Coral FLNG includes the fiscal terms that will apply to the project, cost estimates for development, production and financing, and details about the commercial structure that will be adopted by the oil companies.

Most of the fiscal terms that will govern the project are available in the public domain. The core document is the 2006 EPCC for Area 4.¹⁰ The broader legal framework includes Mozambican petroleum and tax legislation. The terms of the Gas Sales Agreement signed with BP in 2016 remain confidential, though some details are publicly available.

The principal sources of information on the project itself are stock exchange disclosures by Eni and Galp.¹¹ Company disclosures are also the principal source for understanding the commercial structure including the separation of upstream gas production and midstream LNG production. Other inputs are drawn from a Government revenue projection prepared by the Ministry of Finance for creditors in June 2018.¹²

An industry-standard discounted cash flow model is used to generate Government of Mozambique revenue forecasts. The model itself is publicly accessible and therefore open to independent verification to ensure that the underlying logic and calculations generate reliable results. It is also a tool that can be updated over time to take into account new information, particularly related to project costs and LNG price.

⁶ The Jewel of the Indian Ocean, Eni, n.d.

⁷ Projected government revenues from gas projects, Ministry of Finance, Government of Mozambique, 2018, p. 6.

⁸ Govt expects over 77 billion dollars in taxes over the life span of two LNG projects – Mozambique, Club of Mozambique, 17 May 2018.

⁹ The model is available at [Oxfam to add weblink] and at <http://www.res4dev.com/moz-flng/>.

¹⁰ Area 4 EPCC, December 2006. A Supplemental Agreement to the original EPCC, however, is not in the public domain.

¹¹ Eni SpA 2017 Annual Report, p. F-74.

¹² Projected government revenues from gas projects, Ministry of Finance, 2018.

The report begins with an overview of the Coral FLNG project. This is followed by a description of the fiscal terms that will apply to LNG projects in Area 4, including the Coral FLNG project. Section 4 sets out the modelling inputs and assumptions including production profiles and cost estimates, as well as the rationale for the different oil price forecasts used. The following section contains the economic analysis including revenue forecasts for the government of Mozambique and an assessment of the economics from the perspective of the oil companies. The final section sets out the overall conclusions and recommendations.

2.0 CORAL FLNG

The Rovuma Blocks were allocated through Mozambique’s Second Licensing Round launched in 2005 (see Figure 2 and Figure 1).¹³ Eni secured the rights to Area 4 and signed an EPCC in late 2006. Fifteen wells were drilled between 2011 and 2014, resulting in the discovery of two separate fields, Mamba in the north and Coral in the south.¹⁴ The Mamba field is to be developed through onshore LNG led by joint venture partner ExxonMobil.

The Coral gasfield is situated in the southern half of Area 4. The discovery was based on four exploration and appraisal wells drilled between 2012 and 2014. Eni estimates that the overall resource in the Coral field is 15.65 TCF.¹⁵

Eni proposed to develop the Coral gasfield through floating LNG facilities. They argued that the field was far from the Mozambican coast and that a seabed canyon 13 kilometres wide and 300 metres deep “makes it difficult to lay pipes to transport the gas to the shore.”¹⁶ Although the government was initially opposed to the floating concept, they eventually relented and approved the Development Plan for Coral FLNG in early 2016. The current proposal is to develop the Coral field in two phases with two separate FLNG vessels. This analysis focuses only on the first phase: Coral South FLNG.

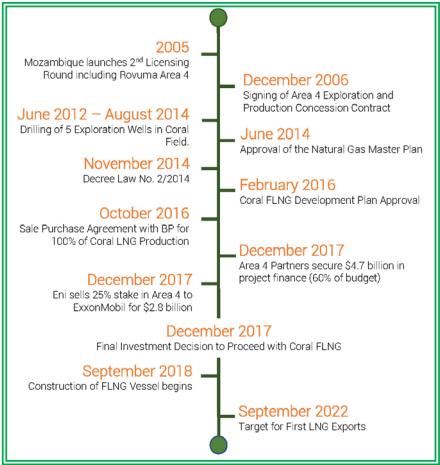


Figure 1: Area 4 Timeline

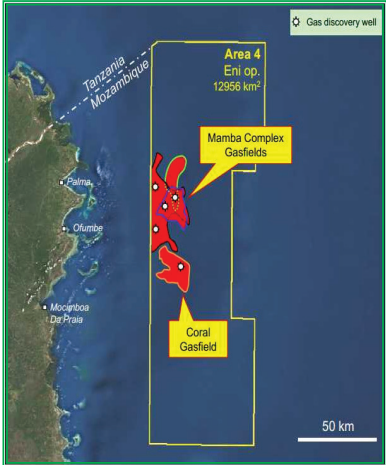


Figure 2: Coral Gasfield in Area 4

¹³ 2nd Licensing Round (Rovuma Basin).

¹⁴ History of Petroleum Exploration in Mozambique.

¹⁵ Mozambique, Eni, 2016, p. 4.

¹⁶ The Jewel of the Indian Ocean, Eni, n.d.

2.1 Project Description

Coral South FLNG seeks to exploit around 5 TCF, about one-third of the gas Eni says is available.¹⁷ The FLNG unit will be the world's first ultra-deepwater FLNG, operating in a water depth of around 2,000 m. It has been designed to produce just under 3.4 million tons of LNG per year (MTPA). The FLNG vessel will be about 430 m long and 66 m wide and will weigh about 210,000 tons. It has a design lifespan of 25 years.¹⁸ Capital costs for gas production and the FLNG facility are estimated at around \$8 billion.¹⁹

An Emerging Technology: Existing FLNG Projects

When exploring for petroleum, no one hopes to find natural gas. Oil, already in a liquid form, is easy to process and transport. Natural gas, in contrast, can be transported to markets only through pipelines or liquefaction, both of which require substantial capital investments. As a result, in the past when gas was found alongside oil it was often simply burned off (flared).

The production of LNG requires processing, liquefaction, storage and offloading. When natural gas has been found in remote locations offshore, it is normally transported to onshore LNG processing facilities (known as "trains") through undersea pipelines.

FLNG involves the construction of the processing facility on a floating vessel that can be permanently moored directly over the gasfield. FLNG avoids the need for deep-sea pipelines. It also allows the contractor to avoid potentially complicated issues related to the acquisition of land onshore.

Currently there are only three FLNG facilities in operation: Malaysia, Australia, and Cameroon. Comparative information on these three projects, and the Coral FLNG project, are set out below.

	Satu	Prelude	Hilli Episeyo	Coral
Country	Malaysia	Australia	Cameroon	Mozambique
Operator	Petronas	Shell	Golar LNG	Eni
First Gas	2017	2018	2018	2022 (est.)
Capacity (MTPA)	1.2	5.3	1.2	3.4
Water Depth (m)	70–200	200–250	20–50	1700–2100
Distance to Shore (km)	180	200	14	70
Capital Costs (USD billions)	10	10.8	1.2	8
Length (m)	365	488	294	430

Other potential FLNG projects in Africa that have not yet secured FID include Tortue (Mauritania and Senegal), Etinde and Sanga Sud (Cameroon), and Fortuna (Equatorial Guinea).

¹⁷ Mozambique, Eni, 2016, p. 4.

¹⁸ <https://www.lr.org/en/latest-news/lr-supports-coral-south-flng-project-in-mozambique/>.

¹⁹ See, Standard Bank and ICBC financing Eni's Coral South FLNG, LNG World News, 22 January 2018.

The basic development concept for Coral FLNG is set out in Figure 3 below. The feedstock will be produced by seven deep-sea wells connected to the FLNG vessel by flexible risers. The upstream (feedstock) component of the project will be responsible for the sub-surface wells, and subsea flowlines and risers. The midstream (FLNG vessel) component of the project will be responsible for gas processing, liquefaction, storage and offloading of the LNG and condensate.

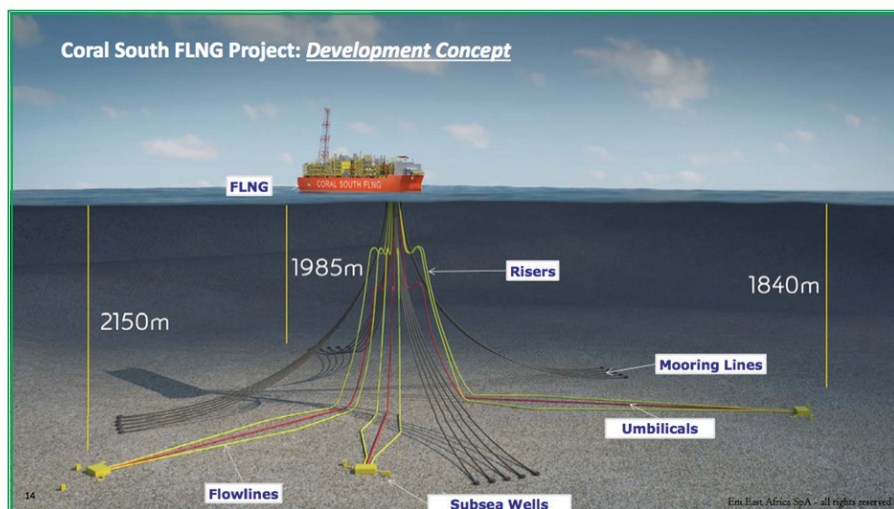


Figure 3: The Coral FLNG Development Concept ²⁰

2.2 Ownership and Commercial Structure

The original rights to Area 4 were granted to Eni. The company owned the rights through an Italian subsidiary called Eni East Africa SpA. The EPCC also granted Mozambique's national oil company, Empresa Nacional de Hidrocarbonetos (ENH), the right to acquire a 10% stake in the project if exploration efforts were successful. As is common in the petroleum sector, Eni sought to bring in other partners in order to spread the exploration risk. In April 2007, Galp Energy acquired a 10% stake in the project. In September 2008, Korean Gas Corporation (KOGAS) also acquired a 10% stake in Area 4.

In March 2013, China National Petroleum Corporation (CNPC) acquired a 20% stake in Area 4 for \$4.2 billion. The transaction was completed when CNPC secured a 28.75% stake in Eni East Africa. In March 2016, ExxonMobil acquired a 25% stake in Area 4 for \$2.8 billion. The transaction was completed when ExxonMobil secured a 35.7% stake in Eni East Africa. Following ExxonMobil's acquisition, Eni East Africa was renamed Mozambique Rovuma.

²⁰ Eni East Africa SpA – Mozambican Branch Contracts and Procurement Department, 8 November 2017, p. 14.

Venture. The current ownership structure, an unincorporated joint venture, for upstream Area 4 is set out in Table 1.

The 2006 EPCC did not specifically envisage the possibility of LNG production. Advice from the IMF, among others, was to ensure that the LNG production facilities operated outside of the EPCC framework. They also highlighted the importance of carefully monitoring the tolling fee for LNG production to avoid profit shifting from the high-tax upstream to the low-tax midstream.²¹

These terms governing LNG production from the Rovuma Basin (Area 1 and Area 4) were set out in the Decree Law of 2014. Going against the IMF advice, the law confirmed that both the upstream (natural gas production) and the midstream (LNG production) would operate under the terms of the 2006 EPCC.²² This decision allows the companies to recover both upstream and midstream costs through an allocation of production known as “cost gas” (See Section 3).

The upstream partners decided to create a separate company to own and operate the FLNG vessel. The company, a Special Purpose Entity (SPE) under the terms of the Decree Law of 2014 approved by Mozambique, is registered in the country as Coral FLNG SA. This midstream company will charge a tolling fee to the upstream partners as compensation for processing, liquefaction, storage, and offloading of gas (details in Section 4.3).

Area 4 Partners (Upstream)	Coral FLNG SA (Midstream)
70% Mozambique Rovuma Venture SpA	25% Eni Mozambique LNG Holding BV
Eni SpA (25%)	25% ExxonMobil Development Africa BV
ExxonMobil Development Africa BV (25%)	20% CNODC Mozambique BV
CNODC Dutch Cooperatief UA (20%)	10% ENH FLNG UM, SA
10% Galp Energia Rovuma BV	10% Galp Energia Rovuma BV
10% KG Mozambique Ltd	10% KG Mozambique Ltd
10% Empresa Nacional de Hidrocarbonetos EP	

Table 1: Upstream and Midstream Ownership Structure

In October 2016, the Area 4 partners signed a Gas Sales Agreement with BP. Under the terms of the Agreement, BP will purchase all of the Coral FLNG for a period of at least 20 years from first production (details in Section 4.2). An overview of the commercial structure for Coral is set out in Figure 4.

In order to facilitate third-party debt financing of the construction of the FLNG vessel, the Area 4 partners also created a separate company, known as a Special Purpose Vehicle (SPV), in the United Arab Emirates (UAE). Approval for this financing structure was granted by the Council of Ministers in 2017. The legal name of the company is Coral South FLNG DMCC.

²¹ Reforming the Fiscal Regimes for Mining and Petroleum, IMF, 2012, pp. 64–68.

²² See “ONGC and partners to invest US\$24 billion in Mozambique gas field,” Economic Times of India, 2015. “The decree law essentially means that the cost of bringing the gas field to production as well as building the liquefaction plant will be cost recoverable, i.e. all investments will be recouped from sale of gas first, before profits are shared with the Mozambican government.”

²³ Conselho De Ministros: Decreto Nº. 13/2017. SA (Sociedade Anónima) is the designation for a public limited company in Mozambique.

According to ENI, no shareholder financing will be routed through the UAE SPV.²⁴ It is registered in the Dubai Multi Commodities Centre (DMCC) Free Trade Zone. It is likely that the company is registered in the UAE not only to take advantage of the tax benefits associated with the Free Trade Zone, but also to benefit from exemptions on withholding taxes on dividend and interest payments in the Mozambique UAE Double Taxation Treaty.²⁵ Coral South FLNG DMCC secured financing for \$4.7 billion, covering an estimated 65% midstream development costs.²⁶

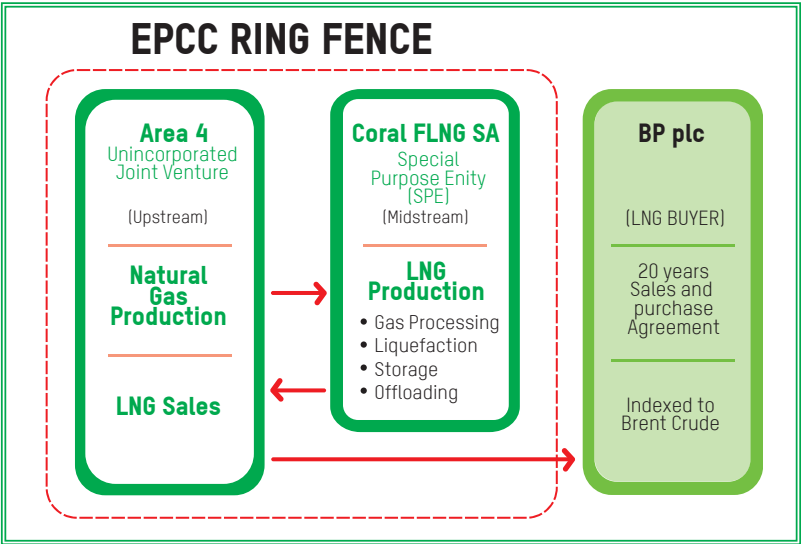


Figure 4: Commercial Structure for Coral FLNG

²⁴ In response to a shareholder question, Eni indicated that “The Coral South FLNG DMCC vehicle is used exclusively for third-party financing of the Coral South FLNG project. There will be no shareholder financing through the UAE vehicle.” See Questions and Answers before the Shareholders Meeting 2019, p. 88.

²⁵ See Double Taxation Treaty Mozambique – United Arab Emirates.

²⁶ Lenders include: BPI Export Credit Agency Covered Loan; KEXIM Export Credit Agency Covered Loan; Ksure Export Credit Agency Covered Loan; Sace Export Credit Agency Covered Loan; Sinasure Export Credit Agency Covered Loan; Commercial Bank Direct Loan; and KEXIM Direct Loan. Eni SpA 2017 Annual Report, p. F-73.

3.0 ROVUMA AREA 4 FISCAL TERMS

The core fiscal terms that will determine the allocation of revenues between the contractor and the government are set out in an EPCC signed by the Government of Mozambique, Eni East Africa, and ENH in December 2006. The EPCC is embedded within a wider set of laws that were in place when the contract was signed, including the Petroleum Law, the Code of Fiscal Benefits, and the corporate tax law (IRPC).

The Decree Law of 2014 provides additional clarity on the legal framework that would apply to LNG projects from Rovuma Area 1 and Area 4, including Coral FLNG. In 2016, the contractor and the government signed the Coral South Supplemental Agreement to the original EPCC, though there does not appear to be any public domain information on the contents of this agreement.²⁷ In 2016, ENH and the contractor signed a 20-year gas sales agreement with BP, the terms of which are confidential.²⁸

Table 2 provides a list of the legislative and contractual sources that set out the fiscal terms for Coral FLNG.

Legislation/Decrees	Contracts
Petroleum Law 3/2001	Area 4 EPCC 2006
Code of Fiscal Benefits, Decree 16/2002	Coral South Supplemental Agreement 2016*
IRPC, Decree 21/2002	Gas Sales Agreement 2016*
Decree Law 2/2014 (LNG Facilities)	
Decree 13/2017 (FLNG Financing)	

* Not in the public domain.

Table 2: Sources of Fiscal Terms for Coral FLNG

Mozambique's fiscal regime for the petroleum sector is a "hybrid" production sharing system. The core of the fiscal regime is a production sharing system with the contractor compensated for expenditures through cost recovery and the remaining production divided between the government and the contractor. The fiscal regime also includes a royalty (Production Tax), and corporate income tax (IRPC), and the right to an equity stake for ENH.²⁹

In summary, there are four main sources of government revenue in the Area 4 EPCC:

1. Production Tax
2. Profit Oil
3. Corporate Income Tax
4. State Participation

²⁷ Conselho De Ministros: Decreto N°. 74/2016.

²⁸ In a response to questions from shareholders, Eni indicated that "The Coral South Supplemental Agreement (CSSA) and the BP SPA are both subject to confidentiality clauses. The government of Mozambique may choose to publish the CSSA, but Eni cannot disclose it unilaterally. The LNG Sale & Purchase Agreement (LNG SPA) is a commercial agreement not included in the EITI disclosure provisions, also for the purpose of complying with the competition rules." See Questions and Answers before the Shareholders Meeting 2019, p. 90.

²⁹ While the broad framework is the same for the EPCCs for Area 1 and Area 4, there are differences including the cost recovery limit, the profit gas sharing, and the state's equity share.

The sequence for allocating production between the Mozambican government and international oil companies, drawn from the signed EPCC for Area 4, is set out in Figure 5.

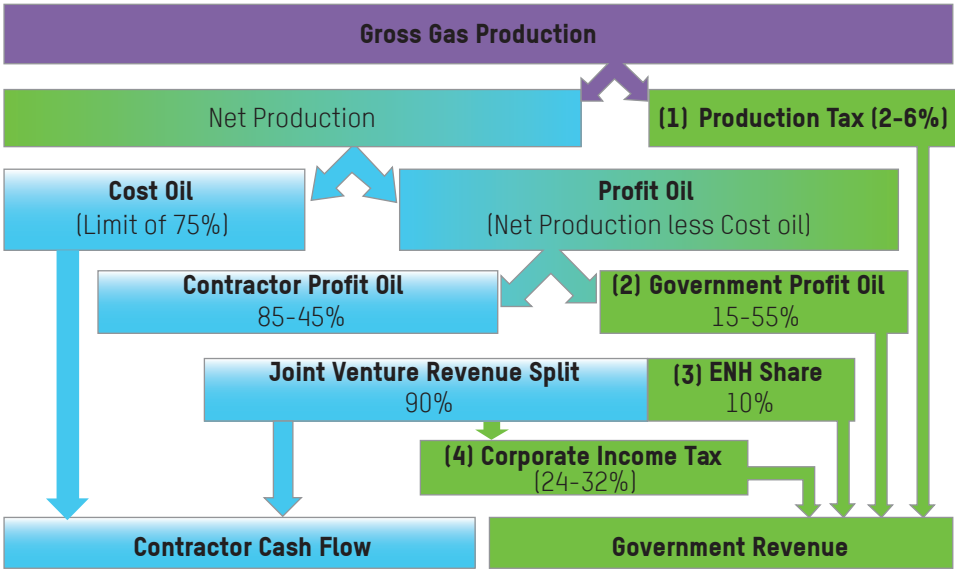


Figure 5: Annual Allocation of Production – Area 4 EPCC

Attempts are often made to compare fiscal regimes by listing the different fiscal instruments and the percentages associated with them. This approach suggests that there is an appropriate range of a royalty or a cost recovery limit. However, a basic principle of fiscal regime analysis is that terms can only be understood as a package. Generous terms in one area can be offset by more stringent terms in another area. It is only when the terms are analysed against plausible projects (existing, planned, or even hypothetical) that it is possible to make meaningful comparisons.³⁰

3.1 Production Tax

For most fiscal regimes, the payment of a royalty is the first step in the calculation of government revenue. In Mozambique, the royalty is called a Production Tax. Royalties are a payment to government calculated as a percentage of the value of production and are paid from the start of production.

Royalty payments in the extractive sector have traditionally been viewed as compensation to the government for the depletion of a non-renewable resource. But royalties are now more commonly viewed as a way to guarantee government revenue in the early years of production before profit-based taxes come on-stream.

³⁰ See Don Hubert, You don't know what you've got until it is modeled, OpenOil, 2014.

The Production Tax rate under the 2006 EPCC is based on water depth. For water deeper than 500 metres, the rate is 2% for gas and 3% for condensate.³¹ In 2008, the government replaced the depth-sensitive Production Tax rate with a flat rate of 6%.³² This rate also applied to the EPCC for Rovuma Area 3 and Area 6 signed by Petronas in 2008. However, the previous lower rates continue to apply to Area 1 and Area 4.

According to the Decree Law (2014), the contract terms will be re-opened for renegotiation after 10 years, and then again after 20 years, following the start of production. If the parties do not agree to new terms, the Decree Law (2014) specifies that the Production Tax rate will increase by 2% after 10 years and another 2% after 20 years.³³ We assume that there will be no change to contract terms and that the Production Tax will increase in year 11 and year 21.

3.2 Production Sharing

The second source of government revenue in the Mozambican fiscal system is a share of the gas produced. There are two steps in the allocation of gas: the recovery of costs by the contractor and the division of the remaining gas between the contractor and the government.³⁴

Production sharing systems allow the contractor to recover its costs through an allocation of an initial amount of production, termed “cost gas.” Recoverable costs include exploration, development, and operating, and they may include financing costs.³⁵ The cost recoverability of financing costs provides compensation to the contractor for the time lag between expenditures and cost recovery.³⁶ For Coral FLNG, financing costs are recoverable and applied to development costs for both upstream and midstream.³⁷

In the first years of production, accumulated exploration and development costs far exceed the value of total production. Many production sharing systems place a limit on the proportion of overall production that can be devoted to cost gas. This is done in order to ensure that at least some “profit gas” is available to be split between the contractor and the government at early stages in the project when total contractor costs to be recovered exceed total project revenues. The cost recovery limit for the Area 4 EPCC is 75%.³⁸

³¹ Article 11.5(iv). Condensates are liquids that are separated from natural gas during the liquefaction process. Condensates are normally treated as the equivalent of oil for fiscal calculations.

³² Petroleum Production Tax Regulations (Decree 4/2008, of 9 April 2008)

³³ 2014 Decree Law Article 26.10.

³⁴ Cost recovery limits and R-factor profit gas splits were biddable elements in the 2006 contracts and therefore differ between the EPCCs for Area 4 and Area 1.

³⁵ Development costs are depreciated at 25% per annum.

³⁶ There are three different approaches: no compensation, compensation through an “uplift” on capital expenditures, and the cost recoverability of interest. Cost recoverable interest is the option most vulnerable to company profit shifting.

³⁷ Projected government revenues, Footnote, p. 6.

³⁸ EPCC Article 9.5.

Once costs have been recovered, the remaining gas production, known as “profit gas,” is split between the contractor and the government. The division is normally based on some kind of sliding scale. Traditionally, the percentage of profit gas flowing to the government has increased with the volume of production (normally measured in daily production or cumulative project production). An alternative is to base the profit oil split on some measure of profitability. One option is the use of a measure of cumulative project revenues to cumulative project costs: a ratio known as an “R-factor.”

The 2006 EPCC allocates profit gas based on an R-factor (see Table 3). Under this system, the allocation of profit gas remains in the first tranche until the contractor has been paid back their initial investment. Once they have achieved payback, R will equal one and the profit gas allocation will move to the second tranche.

According to the EPCC, cost gas and profit gas are to be calculated at the level of the contract area.³⁹ This means that there is a “ring-fence” around Area 4. The development of onshore LNG can be expected, in due course, to affect cost gas and profit gas allocations. The impact of future developments on government revenue is difficult to predict. Substantial capital expenditures for additional LNG capacity, well in advance of actual production, could potentially result in a drop in the R-factor and therefore a reduction in government revenue. Under high oil prices, once onshore production begins it could result in a more rapid movement through the R-factor tranches.

R-factor	Government	Contractor
Less than 1	15%	85%
Between 1 and 2	25%	75%
Between 2 and 3	35%	65%
Between 3 and 4	45%	55%
Above 4	55%	45%

Table 3: Profit Gas Allocation

3.3 Corporate Income Tax (IRPC)

It is common for countries employing a production sharing system to also impose an IRPC. According to the IRPC in place when the contracts were signed, the tax rate was 32%.⁴⁰ However, the 2006 EPCC also contain a tax holiday, with corporate income tax assessed at 24% for the first 8 years of production before rising to the standard 32%. The fiscal framework at the time of the signing of the 2006 EPCC also allows the Petroleum Production Tax payment to be an eligible deduction in the calculation of taxable income.⁴¹

³⁹ Article 9.4(a).

⁴⁰ Decree No 21/2002.

⁴¹ Mozambique: Reforming Fiscal Regimes for Mining and Petroleum, Fiscal Affairs Department of the IMF, 2012, p. 49. This report was disclosed by the Mozambique Ministry of Finance as part of public consultations on the 2014 Petroleum and Mining Fiscal Laws.

Income tax is assessed on “net” or taxable income, calculated as gross income less eligible expenses. Most expenses are claimed in the year in which they were incurred. Capital expenditures, however, are “depreciated” over time.⁴² According to the Accounting Procedure, deductions for the calculation of taxable income will be broader than those allowed for cost recovery.⁴³ Some terms related to the assessment of IRPC have also been changed, as is the case with the removal of debt to equity limits (known as “thin capitalization”) in the Decree Law of 2014.⁴⁴

3.4 Withholding Taxes

Previous revenue forecasts have indicated that withholding taxes on dividend and interest payments could be a significant source of government revenue, particularly in the early years of the project.⁴⁵ Mozambican tax law includes withholding taxes on the repatriation of funds to other countries, including the dividend payments, interest payments, and sub-contractor payments. The Government Revenue Projection identifies “withholding tax on dividends and interest” as a fifth source of government revenue.⁴⁶ Indeed, guidance to governments from various international actors is normally to maintain these taxes (particularly on interest) as a way to counter potential profit shifting.⁴⁷

Potential revenues from withholding taxes, however, are highly vulnerable to corporate tax optimization strategies. For example, the Double Taxation Agreement between Mozambique and the UAE establishes a withholding tax of 0% for both interest and dividends.⁴⁸ Financing for the Coral FLNG vessel, accounting for the majority of the costs of the Coral project, is being routed through a subsidiary in the UAE and would therefore not be subject to withholding taxes.

According to a revenue forecast contained in a Presentation to Creditors by the Mozambican government in March 2018, no withholding taxes on interest or dividends are expected from Area 4.⁴⁹ Withholding taxes have therefore been excluded from this analysis.

⁴² Development costs are depreciated at 25% per annum.

⁴³ Section 3.4.

⁴⁴ Article 3.1 [e], Decree Law, 2014.

⁴⁵ For example, the IMF analysis shows withholding taxes as the principal source of government revenue in the first years of production. See Giovanni Melina and Yi Xiong, *Natural Gas, Public Investment and Debt Sustainability in Mozambique*, IMF, 2013, p. 8. According to Standard Bank, the various withholding taxes could amount to as much as 5% of total government revenue. *Rovuma LNG Project: Macroeconomic Study*, Standard Bank, 2019, p. 54.

⁴⁶ Projected government revenues from gas projects, p. 2.

⁴⁷ See, for example, OECD Base Erosion and Profit Shifting Action 4.

⁴⁸ See Convention Between The Republic Of Mozambique And The Government Of The United Arab Emirates For The Avoidance Of Double Taxation With Respect To Taxes On Income And On Capital (2004).

⁴⁹ Presentation to Creditors, March 20th, 2018, p. 12.

3.5 State Participation

The Mozambican state, through its national oil and gas company, ENH, has the right to hold an equity stake in Area 4. Specifically, ENH holds the right to “back-in” to the projects at the start of the development phase with a 10% stake. The rationale for state participation is not only economic. Other reasons why governments might seek an equity stake include the development of a skilled workforce, the possibility of linking to downstream enterprises (i.e. refineries), and the commercial knowledge that could be gained from being on the “inside” of the project.

The 2006 EPCC provides ENH with what is known as a “partial carry.” The companies take all of the exploration risk while ENH is provided with the opportunity to take up its 10% share when the project moves to the development phase. From that point forward, according to the EPCC, ENH would be required to fund its share of development costs. From the start of production, ENH will be required to repay its share of exploration costs with interest.⁵⁰ This kind of partial carry is common among frontier countries where the risks associated with petroleum exploration are deemed to be high.

The challenge for ENH is to fund its share of substantial development costs long before production, and the associated revenues, begin. As ENH is unable to cover its share of development costs, they have negotiated two separate loans from the upstream partners: one for up to \$500 million to cover capital expenses and another for up to \$640 million to cover the ENH share of debt service.⁵¹ The revenue benefits stemming from the government’s equity stake in the project are highly uncertain.

First, it is assumed that ENH cash flow, after the repayment of the exploration carry, will be allocated to the servicing of these two loans. According to the Government Revenue Projection, ENH “is not expected to generate any dividend to the government during the first years of the projects’ lifetime.”⁵² Initial ENH revenues from the gas projects would serve primarily to reimburse the company’s debt in relation to the equity carry financing during the exploration and construction phase.” We assume that ENH cash flow will be allocated to repayment of the exploration carry and then the development loan.

Second, while ENH hopes to refinance the development carry at lower interest rates once production begins, these funds are likely to be needed to cover ENH’s massive funding commitments for their stakes in onshore LNG in both Area 4 and Area 1. For example, ENH currently estimates that its share of capital costs for Area 1 onshore LNG will be \$1.5 billion.⁵³

⁵⁰ EPCC 9.13(f).

⁵¹ Eni SpA 2017 Annual Report, p. F-74.

⁵² Projected government revenues, p. 3.

⁵³ Financing LNG projects with shorter term and different pricing mechanism, ENH, 2018.

3.6 Stabilization

Production sharing agreements establish terms that could govern a project for many decades. Companies seek to ensure that the core economic terms under which they make their investment decisions are retained throughout the life of the contract through what are known as “stabilization” clauses.⁵⁴ While there has been a move in recent years to eliminate, or at least carefully circumscribe, the provisions that are to be stabilized, this kind of incentive remains common in many developing countries.

The 2006 EPCC contains a common stabilization formulation known as an “economic equilibrium” clause. It indicates that, in the event that changes in the laws and regulations of Mozambique create an “adverse effect of a material nature on the economic value derived from the Petroleum Operations,” the government will make “changes to this EPCC which will ensure that the Concessionaire obtains from the Petroleum Operations, following such changes, the same economic benefits as it would have obtained if the change in the law had not been effected.”⁵⁵

The issue of stabilization was raised again during the Parliamentary debate on the Decree Law in June of 2014. The draft Decree Law offered the companies stabilization for a period of 30 years. MPs initially balked at the inclusion of this provision. Ultimately, the contractor’s right to legal and fiscal stability for 30 years following the approval of a Development Plan was included in the Decree Law of 2014.⁵⁶ The price for this commitment was the agreement to review the fiscal terms at ten-year intervals from the start of production. In the absence of an agreement, the royalty rate would increase by 2% in year 11 and another 2% in year 21.

⁵⁴ Oil Contracts: How to Read and Understand Them, Open Oil, pp. 187–191.

⁵⁵ Article 11.9.

⁵⁶ Article 26.

4.0 CORAL FLNG INPUTS AND ASSUMPTIONS

The following paragraphs set out the base case assumptions used in this revenue analysis.

4.1 LNG Production

The volume of natural gas available in the Coral field significantly exceeds the capacity of the Coral South FLNG vessel over the proposed lifespan of the project. We assume therefore that production volumes will be determined by the capacity of the FLNG vessel.

The terms of the EPCC (Article 3.9) state that the contract lifespan is 30 years from the approval of the Development Plan. As the Coral project is estimated to take 5 years to come on-stream, we assume that production will last for 25 years.

Based on information disclosed by Eni, we assume first exports in the last quarter of 2022. This is an ambitious target, and it is possible that timelines will be pushed back.

The “nameplate” capacity of the proposed Coral FLNG vessel is 3.37 MTPA.⁵⁷ Production therefore is expected to remain at 3.37 MTPA throughout the 25-year lifespan of the project. Coral South is also expected to generate a modest amount of condensate, a liquid by-product produced during gas processing. As Rovuma Basin gas is comparatively dry, condensate production is expected to be limited to around 3,300 barrels per day.⁵⁸ We assume that the condensate will be sold at an equivalent price to Brent crude.

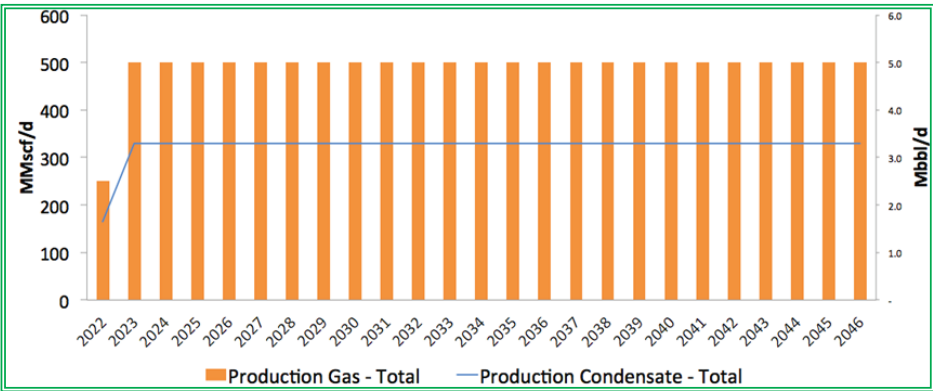


Figure 6: Production Profile – 3.37 MTPA (500 MMscf/day)

⁵⁷ “The FLNG plant is designed to treat approximately 3.37 million tons per year of LNG.” Eni SpA 2017 Annual Report, p. F-73–74. This requires c. 500 million standard cubic feet (MMscf) per day of feedstock gas.

⁵⁸ Projected government revenues, p. 4.

4.2 LNG Sale Price

Government revenues will be highly sensitive to the LNG sale price. Previous projections of government revenue from Rovuma LNG assumed very high LNG prices due to both high oil prices and a high demand in Japan following the shutdown of the country's nuclear reactors.⁵⁹

LNG has historically been sold under long-term sales agreements, with Asia being the principal market. There is a growing "spot" market for LNG where shipments are sold as they are produced. The price available in the spot market, however, is highly unpredictable. For projects seeking to borrow to finance project development, long-term sales agreements are essential in order to give the lender confidence that they will be repaid.

Production from Coral FLNG will be sold to a single purchaser. In October 2016 the upstream partners negotiated a 20-year Sale and Purchase Agreement with BP. "The LNG will be supplied to BP under a long-term LNG sale and purchase agreement with a take-or-pay clause and a twenty-year term, providing an option of extending the duration for up to ten consecutive years."⁶⁰ Long-term LNG sales contracts are commonly indexed to crude oil. Sales to Asian markets have traditionally been linked to a price for oil imported into Japan.⁶¹ As BP will decide the final destination for Coral LNG, the sales agreement is indexed to Brent crude (see Figure 6).

Plausible estimates of future oil prices are therefore required for estimating future government revenue. It is widely accepted that even the best oil price forecasts are little better than educated guesses. According to former BP CEO Lord John Browne, the future oil price is "inherently unpredictable." As it is impossible to predict future prices, the alternative is to conduct the analysis under differing price scenarios: normally a base case price and then a lower and higher price. For our base case analysis, we use \$70 per barrel in 2022. We also run scenarios at a low price of \$55 per barrel and a high price of \$85 per barrel. While there is no "right" price to use, these prices would be considered reasonable within industry analyses.

The relationship between the price of oil and the price of gas is determined by a percentage (known as the "slope"). When the slope is around 16.7, the LNG price is equal to crude oil in energy terms. Slopes less than 16.7 mean that LNG is sold at a discount to crude oil. Previous revenue forecasts from the IMF and the Gas Master Plan, for example, assumed a slope of 14 or more.⁶³ In recent years, however, the slope in sales contracts has often been less than 12. The Gas Sales Agreement with BP is confidential, the Government Revenue Projection implies a slope of around 11, and we used this for our analysis.⁶⁴

⁵⁹ World LNG Report, International Gas Union, 2018, p. 16-18.

⁶⁰ Eni 2017 Annual Report, p. F-74.

⁶¹ Known as Japanese Custom Cleared crude or JCC.

⁶² World Bank Commodities Price Forecast (April 24th 2018) indicates a Crude (average) price of \$64/bbl (long term price in 2022) in constant 2018 \$. World Bank (WB) crude price forecasts are based "average price of Brent, Dubai and West Texas Intermediate, equally weighed." The current differentials of these crudes (based on their prices quoted in October 24th 2018) indicated an adjustment of +\$6.01/bbl between WB crude average price and Brent. We therefore use \$70 /bbl Brent as our base case price.

⁶³ See Giovanni Melina and Yi Xiong, Natural Gas, Public Investment and Debt Sustainability in Mozambique, IMF, 2013, p. 6; and The Future of Natural Gas in Mozambique: Towards a Natural Gas Master Plan, ICF, 2013, pp. 5-28.

⁶⁴ The price is Free on Board (FOB) and therefore excludes shipping costs that will be incurred by BP.

It is likely that the slope will change at lower and higher oil prices. ⁶⁵ The relationship between Brent price per barrel and LNG price per mmbtu, assuming a slope of 11, is shown in Figure 6. Under our base case assumption of \$70 per barrel, the price per mmbtu is \$7.70.

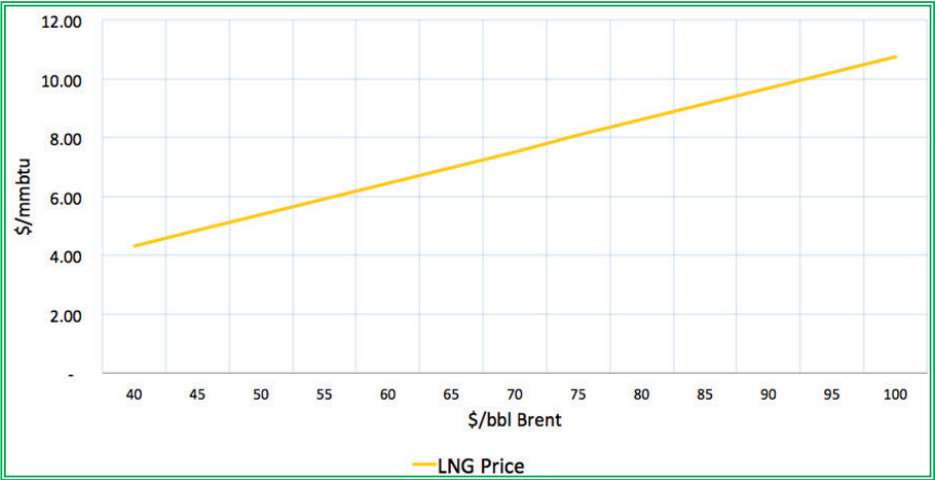


Figure 7: LNG Indexed to Brent Crude (Slope of 11.15)

4.3 Project Costs

Only four exploration and appraisal wells were drilled in the Coral field. However, as cost recovery is ring-fenced at the level of the Block, all exploration costs incurred for Area 4, including both the Coral and Mamba fields (a total of 15 wells), can be recovered against Coral FLNG revenues. While allocating all past costs to Coral FLNG reduces potential government revenues, this is accepted industry practice. Based on a report from the Tribunal Administrativo, costs for Area 4 through the end of 2017 are \$3.2 billion. ⁶⁶

Based on the commercial structure described in Section 2.2, development, operating, and financing costs need to be divided into upstream (gas production) and midstream (LNG production). The assumptions used in our analysis are set out in Table 4. Full details are provided in Annex I: Coral FLNG Modelling Inputs and Assumptions.

⁶⁵ "It should be noted that final off-take agreements (which remain confidential) could include mechanisms that reduce possible upside in the event of a very high increase of Brent market prices (in parallel, such mechanism could also prevent from very low selling prices in case of a very high reduction of market prices)" Projected government revenues, p. 5.

⁶⁶ Section V: Extractive Industries, Annual Report, Tribunal Administrativo, 2018

	Upstream	Midstream	TOTAL
Exploration	3.2 billion		3.2 billion
Capital	1.5 billion	7.3 billion	8.8 billion
Operating	1.7 billion	7.3 billion	9 billion
Financing	0.8 billion	4.3 billion	5.1 billion
TOTAL	7.2 billion	18.9 billion	26.1 billion

Table 4: Upstream and Midstream Costs (USD Billions)

We assume that these are the minimum costs associated with the Coral FLNG project. It is rare for petroleum mega-projects to hold to original cost estimates.⁶⁷ Further increases in costs should be expected. As cost increases will result in reduced government revenues, it is important for the government to carefully review work plans and budgets and to audit cost recovery statements and income tax returns.⁶⁸

Midstream costs are used within the model to establish the tolling fee that Coral FLNG SA will charge to the upstream. We assume that the tolling fee will be based on midstream capital, operating, and financing costs. Where affiliated companies provide goods and services within the framework of a production sharing contract these are normally governed by the principle of “no profit, no loss.”⁶⁹ As a result, we assume that Coral FLNG SA will operate, essentially, at cost.⁷⁰

We assume that the tolling fee will be structured to allow Coral FLNG SA to maintain a positive cash flow (See Annex I for details). In our base case analysis, the tolling fee per million British thermal units (mmbtu) in 2022 prices is \$3.6/mmbtu.

⁶⁷ See Spotlight on oil and gas megaprojects, Ernst and Young, 2014. LNG projects in Australia are all at least 40% over budget. Exxon's project in Papua New Guinea was initially estimated to cost \$11 billion, yet the final costs were \$19 billion. Initial estimates for Angola LNG were around \$4 billion, while final costs were closer to \$10 billion. For a discussion of LNG plant costs see Brian Songhurst, LNG Plant Cost Escalation, Oxford Institute for Energy Studies, 2014.

⁶⁸ See Examining the Crude Details: Government Audits of Oil & Gas Project Costs to Maximize Revenue Collection, Oxfam, 2018.

⁶⁹ The Accounting Procedure of the 2006 EPCC for Area 4 indicates that affiliated services must be based on “actual costs.” AP 3.1(d)(ii).

⁷⁰ In response to a shareholder question, Eni indicated that “all costs incurred by the CORAL FLNG company will be debited to the EPCC without application of any mark-up fee.” See Questions and Answers before the Shareholders Meeting 2019, p. 89.

5.0 REVENUE FORECAST – BASE CASE ASSUMPTIONS

The results from economic modelling are not a reliable projection of actual government revenues, particularly for projects that have only just entered the development stage. Rather, they provide insights into potential government revenue under specific sets of assumptions related to production volumes, oil price and field costs. As with any projection, forecasts of future government revenues from economic modelling are inherently susceptible to uncertainty and changes in circumstances.

5.1 Metrics for Analysing Fiscal Terms

For the government, we focus on three key metrics: government take, the timing of government revenue and how government revenues respond to increases in profitability (progressivity).

1. **Government Take:** The government take is the share of divisible (after-cost) revenue allocated to the government, as compared to the contractor, over the lifecycle of the project.⁷¹
2. **Timing:** It is important to understand when in the project lifecycle the government receives the bulk of its revenue. As companies can normally recover their investments quickly, the bulk of government revenue can often become significant only after the project has been producing for several years.
3. **Progressivity:** Ideally, the government's share of net benefits should increase for more profitable projects. As many fiscal regimes do not have a progressive tax, the government would not capture a higher share when commodity prices skyrocket.

For the contractor, we also focus on three key metrics measured from the time of the FID: net present value (NPV), internal rate of return (IRR) and payback.

1. The NPV is the value in today's money of future cash flows discounted to take into account the cost of capital (discount rate). For the base case analysis, we assume an industry-standard discount rate of 10%.
2. The IRR is the discount rate that would generate an NPV of zero. It provides an indication of the contractor's return on their investment.
3. Payback is the number of years from the start of production after which the contractor has recovered its initial investment. Our analysis of payback is based on discounted cash flows.

⁷¹The government take statistic normally does not include revenues flowing from state participation.

5.2 Government Revenues and Government Take

Under base case assumptions, we forecast that total revenue to the government from Coral South FLNG, including cash flow to ENH, would amount to approximately \$11.6 billion over the lifecycle of the project. This is similar to the revenue forecast provided by the Ministry of Economy and Finance to creditors (\$11.5 billion) but less than Eni (\$16 billion) or the Minister of of Mineral Resources and Energy (\$24.5 billion).

The most common statistic used to compare potential government revenue between different contracts and across different jurisdictions is the government take. The starting point for the calculation is the notion of divisible income. Government take is the portion of revenue it receives, as compared to the contractor, after costs have been deducted. The government take statistic does not include the contribution to government revenues that might come from state participation.

According to the IMF, petroleum-producing countries could expect a government take of 65–85%.⁷² The lower end of this spectrum would be expected for contracts signed before a country has experienced a commercial petroleum discovery.

Our analysis of the Coral FLNG project, under our base case assumptions (\$70 per barrel), suggests the government take is around 49%.

	Base Case Price \$70/bbl	High Price \$85/bbl	Low Price \$55/bbl
Production Tax	1,903	2,310	1,495
Profit Oil	5,950	10,508	2,118
IRPC	3,742	5,307	1,944
ENH	33	907	(44)
Gov't Cash Flow	11,629	19,035	5,516
Undiscounted			
Government Take	49.1%	56.1%	41.1%

Table 5: Government Revenues at Different LNG Prices (USD millions)

Government revenues are obviously highly sensitive to the LNG price. Table 5 above indicates that under a higher-price scenario total government revenue could double to more than \$19 billion, while under a lower price scenario they could plummet to around \$5.5 billion.

The use of the R-factor in the allocation of government profit oil ensures that the fiscal regime is progressive, meaning that the share allocated to the government increases as project profitability increases. Overall government take increases to 56% under the high-price scenario and drops to just over 41% under the low-price scenario.

⁷² "A suitable tax structure and a target range of AETRs [average effective tax rates] result from this analysis. These simulations, and those of other sources, suggest reasonably achievable ranges of discounted AETRs will be 40–60 percent for mining and 65–85 percent for petroleum." Fiscal Regimes for Extractive Industries: Design and Implementation, IMF 2012, p. 29.

ENH revenues over the lifecycle of the project are only about 33 million under the base case price, rising to more than 900 million under the high-price scenario. Due to repayment of the exploration carry and development loan, ENH revenue begin only in the latter years of the project.

Government revenues over the lifecycle of the project, under the three different oil price scenarios, are shown in Figure 8.

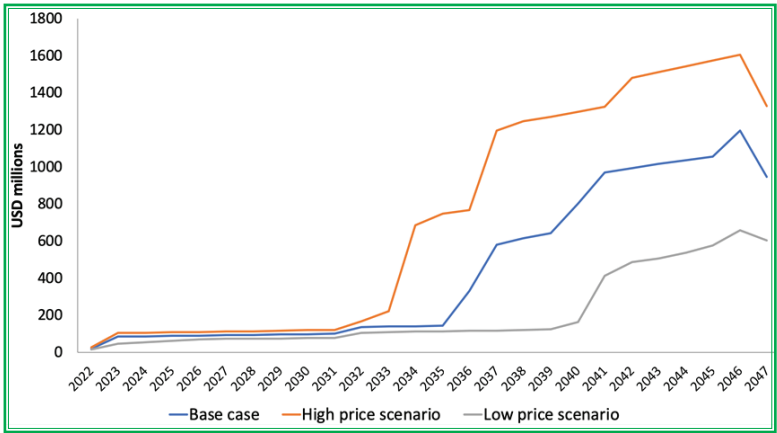


Figure 8: Government Revenues under different oil price scenarios

5.3 The Timing of Government Revenues

It is common for the fiscal terms in a production sharing agreement to reward companies early in the lifecycle of the project, with the bulk of government revenue coming on-stream somewhat later in the project lifecycle. Even so, the Area 4 2006 EPCC is heavily rear-loaded. (Figure 8). Government revenues are less than \$100 million per year for the first nine years (until 2031). This is the result of a comparatively low Production Tax rate for gas (2% for the first 10 years) and a low minimum share of government profit oil (15%).

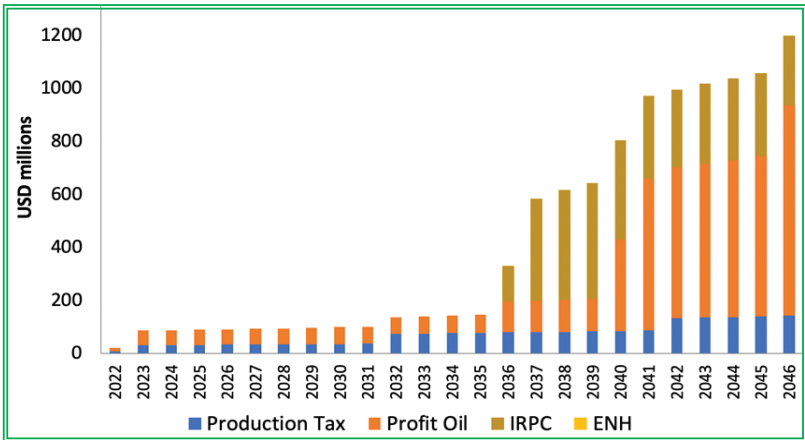


Figure 9: Government Revenues: Base Case Assumptions

One way to measure the timing of government revenues is the “effective royalty rate” (ERR). The ERR represents the minimum share of gross revenues that a government will receive over the course of a single year, taking into account maximum allowable expenses. In the early years of production, partners are not yet profitable and thus no IRPC is generated. And as ENH is still repaying its debt to the other partners, it will not be a source of government revenue. Thus, there are only two components to the ERR: royalty payments (Production Tax) and the government’s minimum share of profit oil.⁷³ According to the 2006 EPCC for Area 4, the ERR for Area 4 is 5.7% of gross production: the production tax (2%) and minimum government profit gas (3.7%).

According to a leading analyst, the global average ERR for production sharing contracts is around 23%.⁷⁴ These expectations are consistent with petroleum contracts signed in a similar period in southern and eastern Africa: Uganda (33%), Kenya (20%), and Tanzania (13.5%).⁷⁵

5.4 Contractor Economics

Strong revenues for the government are one basis for assessing a fiscal regime. The terms, however, must also be sufficiently good for the contractor in order to make it an attractive investment. Table 6 shows the results for contractor economics under the three different price scenarios.

	Base Case Price	High Price	Low Price
Total Cash Flow	12,039	14,874	7,912
Net Present Value (10%)	646	1,985	(959)
Internal Rate of Return	11.6%	15.1%	7.8%
Payback Years	14	11	17

Table 6: Government Revenues at Different LNG Prices (USD millions)

Due to the combination of high costs and significant declines in LNG price, contractor economics are not strong as might be expected. Under the base case scenario, the NPV is slightly positive and the company rate of return is on the lower end of a viable project. Costs are fully recovered only very late in the project life-cycle. Not surprisingly, the project looks much better for the contractor under higher price scenarios, with an NPV of almost \$2 billion and a rate of return of more than 15%. The companies achieve payback (undiscounted) in year 11. Under the low-price scenario, the rate of return falls well short of a company’s minimum expectations.

⁷³ The ERR is defined as the minimum share of revenue (or production) that the host government might expect to receive in any given accounting period from royalties and its share of profit oil. See Silvana Tordo, *Fiscal Systems for Hydrocarbons*, World Bank, 2007, p. 20.

⁷⁴ Daniel Johnston, *International Petroleum Fiscal Systems Data Base*, PennWell, 2001.

⁷⁵ Calculations based on fiscal terms in signed production sharing contracts, Resources for Development Consulting, 2019.

6.0 CONCLUSIONS

Coral FLNG was the first of the Rovuma projects to achieve FID. Barring significant project delays, it will be the first project to export LNG from Mozambique in late 2022 or 2023. Coral FLNG will produce much less LNG than the proposed onshore facilities. Nevertheless, with capital costs estimated at more than \$8 billion, it represents one of the largest investments in sub-Saharan Africa. The project economics and their implications for government revenues are important in their own right. Coral FLNG also provides some important insights into the challenges of bringing an LNG project on-stream and into the implications of the fiscal terms contained in the EPCC governing both Area 4 and Area 1, and in the 2014 Decree Law.

6.1 Disclosure of Fiscal Terms

Mozambique's disclosure of extractive sector contracts in 2013 is consistent with recommendations from the Extractive Industries Transparency Initiative (EITI) and the broader movement against secret deals.⁷⁶ The analysis contained in this report is only possible because the 2006 EPCC for Area 4 is available in the public domain. According to the EITI Standard, "Implementing countries are encouraged to publicly disclose any contracts and licenses that provide the terms attached to the exploitation of oil, gas and minerals." This includes amendments to the original contract. Mozambique, therefore, should disclose the Coral South Supplemental Agreement to the Area 4 EPCC. Finally, given the importance of the LNG sale price for government revenues, details of the BP Gas Sale and Purchase Agreement should also be disclosed.

6.2 Government Revenues from Coral FLNG

When exports begin, the project can be expected to generate overall revenue of around \$1.5 billion per year. We forecast that total revenue to the government would amount to around \$11.6 billion over the lifecycle of the project. This is similar to the revenue forecast provided by the Ministry of Economy and Finance to creditors (\$11.5 billion) but much less than Eni (\$16 billion) or the Minister of Mineral Resources and Energy (\$24.5 billion).

As would be expected, government revenues are highly sensitive to oil price. At \$85 dollars per barrel we estimate government revenues of \$19 billion, while at \$55 dollars per barrel revenues would fall to \$5.5 billion.

The 2006 EPCC provides very favourable terms for the international oil companies. Our analysis for Coral South suggests that the share of divisible revenues flowing to the government in our base case (\$70/bbl) is only around 49%. Although Coral South is a comparatively small project with high costs, the overall government take is relatively low compared with other countries in the region. This conclusion seems to be confirmed by other industry analysts.⁷⁷

⁷⁶ See Don Hubert and Rob Pitman, *Past the Tipping Point? Contract Disclosure within EITI*, NRGI, 2017.

⁷⁷ According to a different source, the government take for Mozambique falls below 55% and is significantly less than Tanzania, Kenya, Uganda, Ethiopia, or Sudan. See *East Africa Fiscal Regime Comparison*, Palantir, 2014.

Given the scale of Mozambique's natural gas resources, the precise share of after cost revenues is less important than the time in the lifecycle of the project when those revenues will arrive. The Area 4 EPCC is heavily rear-loaded. The Production Tax rate of 2% for the first ten years is comparatively low. The government share of profit oil in the early years is also unusually low due to a relatively high cost recovery limit (75%) and a very modest share of profit gas when R is less than 1 (15%). The ERR for the Area 4 contract is only 5.7%. In the early years of the project, therefore, more than 94% of production will flow to the contractor through the allocation of cost gas and profit gas.

Our forecasts suggest that annual revenue for the government from Coral FLNG will remain under \$100 million per year from project start-up in 2022 through 2030 and will exceed \$500 million per year only in 2037. Government revenues would grow much more quickly if oil prices were higher. Under this scenario government revenues would remain under \$200 million through 2032 and then begin to grow, exceeding \$600 million by 2034.

A series of decisions since the signing of the EPCC in 2006 have increased the economic benefits to the contractor at the expense of government revenue. Prominent examples include the decision to allow the cost of LNG facilities to be recoverable within the EPCC framework, removing restrictions on debt financing in the 2014 Decree Law, and allowing the financing arm of the FLNG vessel to be located in the Double Taxation Treaty jurisdiction of the UAE. The collective result is that the government share is modest, and it comes late in the project lifecycle.

Large-scale onshore LNG production could potentially begin production in the middle of the 2020s. Revenues from these projects, however, can be expected to have a similar profile, with the companies recovering their costs quickly and government revenues coming later in the lifecycle. Irrespective of the number of LNG facilities constructed, truly game-changing government revenues are unlikely before the middle of the 2030s.

There is growing recognition that government revenues from the 2006 EPCC comes unusually late.⁷⁸ The full impact of this conclusion, however, is not widely understood. LNG revenues are seen as the solution to the debt crisis and the way to offset declining support from donors.

Contracts that allocate a disproportionate share of project revenues to foreign companies can be hard to sustain. Consideration should be given to revisiting fiscal terms with the companies in order to allow Mozambique to secure a greater share of revenues during the early years following the start of LNG production.

⁷⁸ Alan Roe, Extractive industries and development: Lessons from international experience for Mozambique, Working Paper 2018/56, UNUWIDER, 2018.

6.3 LNG Revenues and Debt Repayment

Options for the repayment of the Mozambican public debt incurred by EMATUM, MAM, and Proindicus has been closely linked to LNG revenues. The restructuring of EMATUM bonds in 2016 was based on the assumption that they would be repaid in full in 2023 (known as a bullet bond).⁷⁹ This approach was clearly based on a fundamental misunderstanding of the timing of government LNG revenues. Only Coral FLNG has the potential to be producing by that time, and annual revenues are expected to be less than \$100 million per year for at least the first nine years.

The government's approach to creditors has changed dramatically in recent months. In March 2018, Finance Minister Maleiane indicated to creditors that "significant revenues derived from corporate income tax should kick in late 2020s / early 2030s under a best case scenario."⁸⁰ Much more detail was provided in a Ministry of Finance publication shared with creditors in June 2018.⁸¹ A government proposal in late 2018 suggested that a new Eurobond would be used to pay interest on the loans, repayment of the principal would begin only in 2029, and that creditors would also receive 5% of LNG revenues through to 2033 up to a maximum of \$500 million.⁸² The idea of allocating some gas revenues to creditors met with strong opposition and has been dropped from the latest proposal for debt repayment.⁸³

As this analysis has demonstrated, Coral FLNG is likely to generate only a fraction of the revenue required to repay the loans. Under our base case assumptions, Coral FLNG will generate around 760 million dollars in government revenue through to 2030. Significant revenues can also be expected from the much larger onshore LNG projects.

6.4 Realistic Expectations for the LNG Sector

Unrealistic expectations on the early arrival of substantial natural resources revenues can have detrimental effects on a nation's economy. The "presource curse" is a label given to resource-rich developing countries that under-perform economically even before petroleum production begins due to "elevated expectations" including embarking on risky borrowing.⁸⁴ Mozambique is identified as an example.

One prominent cause of the presource curse is thought to be "persistent over-forecasting." There is a clear risk that companies, government and donors all focus more on the upside possibilities than the downside risks.

High expectations surrounding potential government revenues from natural gas in the Rovuma Basin have tended to focus on the volume of gas available. Reports from the oil companies and the government indicate that there is far more natural gas available than would be required for the currently proposed LNG facilities offshore and onshore.

⁷⁹ Bondholders agree to Ematum exchange offer, Reuters, 24 March 2016.

⁸⁰ Adriano Maleiane, Presentation to Creditors, 20 March 2018, p. 12.

⁸¹ Projected government revenues.

⁸² Communiqué, Ministry of Finance, Government of Mozambique, 6 November 2018.

⁸³ See, Mozambique Eurobond creditor group GGBM to participate in government debt swap, Reuters, 27 August 2019.

⁸⁴ James Cust and David Mihalyi, Evidence for a Presource Curse? Oil Discoveries, Elevated Expectations, and Growth Disappointments,

The availability of gas, however, is only the first step. The resource itself has no value unless a buyer can be found for the gas and an investor can be found to develop the fields and finance the LNG facilities. Numerous reports assessing Rovuma Basin natural gas forecast LNG exports from Mozambique already in 2018 or 2019. For example, the Gas Master Plan LNG scenario, prepared in 2012, assumed 10 million tons of exports in 2018.⁸⁵ An IMF simulation, also prepared in 2012, assumed 10 million tons of exports beginning in 2019.⁸⁶ It is unlikely that FLNG exports will begin before 2023, with larger onshore volumes not expected until at least 2024. The expectation that the Rovuma gas could be monetized quickly was highly optimistic. For a country with limited experience of petroleum production, putting in place the legal and regulatory frameworks to support an investment of tens of billions of dollars was going to be time-consuming.

Early revenue forecasts also assumed high LNG prices. In part, these forecasts were driven by high international oil prices in advance of the collapse in 2014. The Gas Master Plan analysis assumed an oil price of \$88-126 per barrel at first LNG exports, while the IMF assumed \$100 per barrel. Current forecasts commonly assume a future oil price of \$60-70 per barrel.⁸⁷ Importantly, these early revenue forecasts also assumed a tight correlation between oil and LNG prices with a slope (percentage) to crude oil of 14.5 for the Gas Master Plan and 14 for the IMF.⁸⁸ It is now expected that gas sales agreements for LNG from Rovuma will have a slope of around 11.

Forecasts for production volumes and LNG prices have a profound impact on potential government revenues. The Gas Master Plan forecast government LNG revenues of \$6-8 billion per year, with revenues from a two-train 10 million ton per year project generating more than 1.3 billion per year by 2022.⁸⁹ The early IMF simulation was much more optimistic suggesting government revenues from a two-train 10 million ton project of more than \$3.5 billion per year from 2024.⁹⁰ The findings of this FLNG analysis suggest that annual government revenues from LNG by 2024 are likely to be less than \$200 million.

A note of caution is clear in more recent revenue forecasts from the Mozambique government. The report to creditors from June 2018 suggested that significant government revenues were not expected to materialize until the latter 2020s, or even later. The government analysis adopts cautious forecasts for production volumes and LNG prices, and takes into account the rear-loaded nature of the contracts. Other analysts, however, continue to focus on rapid expansion of additional LNG facilities, under the assumption that the better part of Mozambique's vast gas reserves will be economically viable to exploit and will quickly translate into lucrative commercial exports. This assessment may still be overly optimistic.

⁸⁵ The Future of Natural Gas in Mozambique: Towards a Natural Gas Master Plan, ICF, 2013, p. 6-7.

⁸⁶ Reforming the Fiscal Regimes for Mining and Petroleum, IMF, 2012, p. 71. IMF, p. 71.

⁸⁷ Gas Master Plan p. ES-26 and IMF p. 71.

⁸⁸ "Given the market situation, it will be possible for Mozambique to secure deals with oil linked prices with slopes of around or higher than 14.5%." Gas Master Plan, p. 5-28 and IMF p. 71.

⁸⁹ Gas Master Plan pp. 6-52 and 6-39

⁹⁰ IMF p. 71.

There are now approved development plans for five LNG trains: 2 trains onshore Area 1, two trains onshore Area 4 and Coral South FLNG. Further investment decisions to develop Rovuma Basin natural gas will depend on the uncertain LNG price outlook and on the progress of the first phase projects.⁹¹ For Mozambique, the timing of revenues matters as much as the overall scale.

This study is of a more limited scope than the broader Rovuma-basin analyses mentioned above, but it has provided a careful economic analysis of Coral South FLNG, the first of the LNG projects to reach the development phase. It is the smallest of the proposed projects and as such can be expected to generate modest government revenues in comparison. There has been important progress in recent months, including a final investment decision for Area 1 and the approval of the development plan for Area 4. There is a risk, however, that the transition to the development phase for the larger onshore projects will once again boost expectations that large government revenues are on the horizon.

Rovuma natural gas holds incredible promise for Mozambique. There are now approved development plans for five LNG trains – FLNG and two train facilities onshore in both Area 1 and Area 4. Any further expansion is, at this stage, speculative. Cost over-runs are common on mega-projects and would push back government revenues. LNG prices have recovered somewhat in recent years but remain comparatively low and are not currently expected to rise substantially. Finally, the rear-loaded nature of the 2006 EPCCs means that government revenues are very modest in the first years of production. The revenue logic contained in the 2006 EPCCs should be taken into account in considerations of debt repayment and future budget planning. Revenues from Rovuma natural gas can be an economic game-changer for Mozambique, but this is unlikely to arrive before sometime in the 2030s.

⁹¹ For example, in 2018 the IMF study of revenues forecast for Mozambique states: "LNG plants totaling 13 onshore LNG manufacturing units ("trains") and 4 floating trains (FLNG), are assumed to be under construction from late 2017 through 2027." Based on these assumptions, "the total fiscal revenues from the LNG project throughout the entire project period until 2045 could reach about \$500

billion." Macroeconomic and Fiscal Implications of Natural Gas Project, IMF, 2016, p. 5.

7.0 RECOMMENDATIONS

For the Government of Mozambique:

1. Publish the Supplemental Agreements to the Area 4 EPCC and the terms of the BP Gas Sales Agreement.
2. Assess the scale and timing of potential government revenues from the proposed LNG projects. Clarify when government revenues are expected to be received in public statements.
3. Explain how the timing of potential revenues from LNG are related to the potential for the repayment of foreign debt.
4. Evaluate the impact on government revenues of fiscal revisions made since the signing of the 2006 EPCCs, including the decision to allow the LNG facilities to be cost recoverable and the removal of limits on the recoverability and deductibility of debt financing.
5. Assess the impact of Mozambique's Double Taxation Agreements on government revenues from withholding taxes, including the generous provisions in the Agreement with the UAE.
6. Begin preparations for the renegotiation of fiscal terms, as provided for in the 2014 Decree Law and agreed in good faith by the oil companies, once production has begun in order to ensure an appropriate balance of economic benefits between Mozambique and the oil companies.
7. Strengthen government capacity to monitor and audit costs⁹⁴ in order to protect government revenues from offshore and onshore projects in Area 4 and Area 1.

For Eni:

1. Adopt a comprehensive contract disclosure policy as has already been done by industry leaders such as Kosmos, Total and Tullow.⁹⁵
2. Encourage the Government of Mozambique to publish the Supplemental Agreements to the 2006 Area 4 EPCC and to disclose the terms of the BP Gas Sales Agreement.
3. Commit to responsible tax practices, such as those other industry players have adopted (e.g. Shell and Repsol joining the B Team's Responsible Tax Principles), and implement them globally.
4. Explain the revenue implications for the government of Mozambique of the use of the special purpose vehicle (SPV) Coral South FLNG DMCC based in the UAE for financing for the FLNG vessel in the context of the Double Taxation Treaty with the UAE.

⁹⁴ For more detail about concerns related to the framework for monitoring and auditing petroleum project costs, see *Examining the Crude Details* (2018), Oxfam.

⁹⁵ See *Contract Disclosure Survey 2018*, Oxfam.

ANNEX I: CORAL FLNG MODELLING INPUTS AND ASSUMPTIONS

INPUTS AND ASSUMPTIONS		
Component	Input / Assumption	Description / Source
Project Overview		
Concession / Operator	Area 4 / Eni SpA	
Project Lifespan	25 years	EPCC provides for a Development and Production period of 30 years (Article 3.9).
Final Investment Decision	November 2017	Eni SpA 2017 Annual Report
Construction Period	5 years	Eni Press Release.
Production		
First LNG Exports	Q4 2022	Eni Press Release.
Annual LNG Production	3.37 MTPA	"The FLNG plant is designed to treat approximately 3.37 million tons per year of LNG." Eni SpA 2017 Annual Report, p. F-73–74.
Condensate Production	3,300 bbl/d	Projected government revenues from gas projects, p. 4.
Project Costs		
Exploration Costs	\$3,235 million	Section V: Extractive Industries, Annual Report, Tribunal Administrativo, 2018
Upstream Costs (Feedstock Production)		
Development Costs	\$1,405 million	Data from INP, 4 March 2019 (cost in 2016 money inflated to 2018 money).
Development Phasing	7 Wells: 1 (19), 2 (20), 2 (21) and 2 (22)	SAIPEM 12000 Contract. Single drill ship preference suggests spread of capex from 2019 through to 2022.

Operating Costs	\$42 million	Annual cost in 2018 money calculated as 3% of CAPEX. Floating Liquefaction (FLNG): Potential for Wider Deployment
Financing Costs	90% debt to equity Affiliate finance 8% interest	Cost of interests (8%) on shareholder loans during the development phase.
Midstream Costs (FLNG Vessel)		
Development Costs	\$6,950 million	Data from INP, 4 March 2019 (cost in 2016 money inflated to 2018 money).
Financing Costs	65% (\$4,518) million project finance 25% (1,738) affiliate finance 8% interest	65% project finance to SPV in UAE (Source) at assumed 8% interest. 25% shareholder loans from upstream partners at 8% interest.
Operating Costs	\$208 million	Annual cost in 2018 money calculated as 3% of CAPEX. Floating Liquefaction (FLNG): Potential for Wider Deployment
Inflation Rate	2%	
Tolling fee	Covers: Amortization, Debt service, and Operating costs	Tolling fee is calculated in the model from the midstream input assumptions. It is assumed that the tolling fee will be structured to allow Coral FLNG SA to maintain a zero cumulative cash flow over project life, with each year of post start-up cashflows being zero or slightly positive in order to offset the negative cash-flows during the investment phase. We assume that the Tolling Fee is made up of the following components: amortization component for capital expenditure paid from equity funds (10 year Amortization is assumed consistent with loan repayment schedules); debt service component covers interest payments and principal repayments for third party and affiliate loans; and operating costs component covers operating costs. We assume that as an affiliated company, midstream operates on the principle of no-profit no-loss and therefore does not secure a rate of return. Midstream cost through the tolling fee are recovered within cost recovery for upstream as operating costs.

LNG Sales	Inputs/Assumptions	Description /Source
Sale and Purchase Agreement	20 years, with provision for extension. Indexed to Brent	BP Press Release.
Brent Crude \$/bbl (2022)	\$70, \$55, \$85	World Bank Commodities Price Forecast (April 24th 2018) indicates a Crude (average) price of \$64/bbl (long term price in 2022) in constant 2018 \$. World Bank (WB) crude price forecasts are based "average price of Brent, Dubai and West Texas Intermediate, equally weighed." The current differentials of these crudes (based on their prices quoted in October 24th 2018) indicated an adjustment of +\$6.01/bbl between WB crude average price and Brent. We therefore use \$70 / bbl Brent as our base case price.
MTPA = billion mmbtu conversion	1 mtpa = 53.4 Bbtu	International Gas Union, Natural Gas Conversion Pocketbook , p. 22
Slope	11%	Based on latest LNG SPA prices trend.
Condensate \$/bbl	Equal to Brent	Projected government revenues from gas projects, p. 5.

FISCAL TERMS: AREA 4 EPCC (2006)			
Component	Assumption	Source	
Production Tax			
Rate Gas	2%	Article 11.5(iv). The Production Tax rate is 2% due to water depth greater than 500 metres.	
Rate Condensate	3%	Article 11.5(iv) 2006 EPCC. The Production Tax rate for liquids is 3% due to water depth greater than 500 metres.	
Production Tax Increases	Gas Rates Year 11 – 4% Year 21 – 6% Condensate Rates Year 11 – 5% Year 21 – 7%	Production Tax rate to increase by 2% at the start of year 11 and by another 2% at the start of year 21 (these rate increases would apply to both gas and condensate). Decree Law Article 26.10.	
	Production Sharing		
Cost Recovery Limit	75%	Article 9.5 2006 EPCC	
Capital Depreciation	25% straight-line	Article 9.7 2006 EPCC	
Financing Costs	Recoverable	Article 3.2, Annex C, 2006 EPCC	
Profit Gas	15–55%	Article 9.10 2006 EPCC	
		R-factor	Government
		Less than 1	15% 85%
		Between 1 and 2	25% 75%

		Between 2 and 3	35%	65%
		Between 3 and 4	45%	55%
		Greater than 4	55%	45%
Corporate Income Tax (IRPC) – Terms Apply to Both Upstream Stakeholders and Midstream Incorporate Joint Venture				
IRPC Rate	24–32%	Article 11.4(a) 2006 EPCC. Standard rate is 32%. Clause (i) provides for a 25% reduction in corporate tax over the first 8 years from the start of first production in the Block.		
Production Tax	Deductible	Production Tax is a deduction in the calculation of IRPC.		
Capital Depreciation	25% straight line	Article 11.4 (a)(iii).		
Withholding Taxes	N/A	According to <u>Presentation to Creditors</u> (March 20 th , 2018, p. 12) no withholding taxes on interest or dividends are expected from Area 4.		
State Participation				
ENH Equity Stake	10%	Article 3.2(b).		
Carried Exploration	Repaid at Libor + 1 % Paid from cost oil.	Article 9.13(d). State carried until the approval of a Development Plan. From start of production, exploration expenses are repaid with interest (LIBOR + 1 %) from the date that the costs were incurred. Article 9.13(f).		
Development Loan	8% interest Paid from available cashflow.	According to the EPCC, the State is responsible for paying its share of development costs. Upstream partners have loaned ENH funds to cover their costs during the development phase (100% of ENH share of upstream costs and 100% of ENH share of midstream Equity funding after project financing is taken into account) to be repaid from available ENH cash flow.		

ANNEX II: UNITS OF MEASURE

Measuring Reserves: Oil is normally measured in barrels (42 US gallons or 158.978 litres) while natural gas is measured in cubic feet or cubic meters: billion cubic feet (BCF) or trillion cubic feet (TCF) are the most commonly used. Barrels of oil equivalent (BOE) allows for gas to be included in overall reserve estimates and is based on the amount of heat released through burning: 6,000 cubic feet of gas equals one barrel of oil.

Measuring Production: Natural gas production is normally measured in cubic feet per day (cf/d) and is commonly seen as mmcf/d (millions) and bcf/d (billions). LNG production is commonly measured in millions of tons per year or annum (MTPA). For example, an LNG processing facility, known as a “train,” could have an annual production capacity of 5 MTPA.

Sale: Whether liquefied or not, natural gas sales are normally measured by units of energy. Traditionally, the unit of measure was the “British thermal unit” (btu): a unit of energy defined as the quantity of heat necessary to raise the temperature of one pound of water one degree Fahrenheit. The normal measure is million btus (mmbtu). The metric equivalent is the gigajoule (GJ): an international unit of energy defined as the energy produced from one watt flowing for one second.

Conversion factor of 53.4 mmbtu/tonne. International Gas Union, Natural Gas Conversion Pocketbook, p. 22

