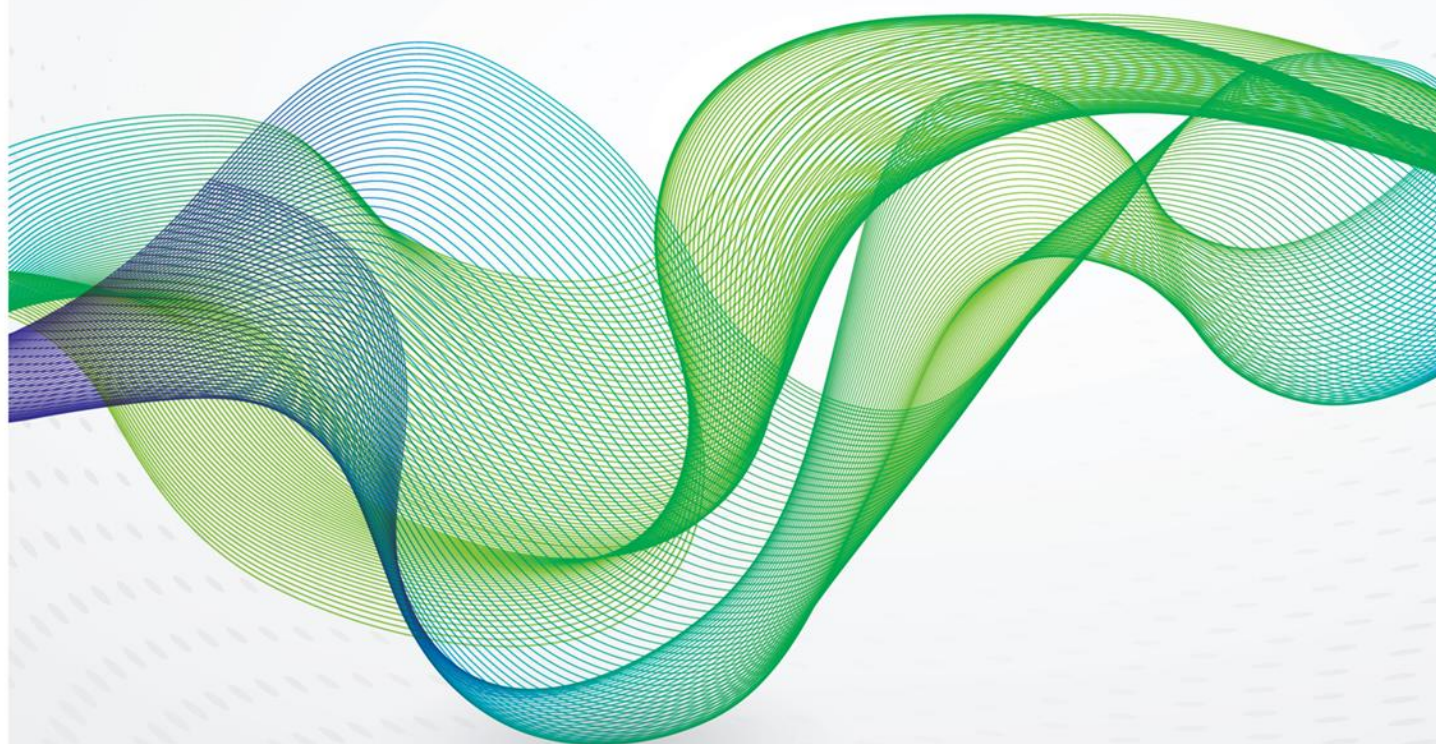


October 2020

# **Mauritania - Senegal: an emerging New African Gas Province – is it still possible?**





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## Contents

Contents .....	ii
Tables .....	ii
Preface .....	1
INTRODUCTION .....	3
NATURAL GAS POTENTIAL .....	3
Mauritania .....	3
Senegal .....	5
Upstream interests in Mauritania and Senegal .....	7
EXISTING AND POTENTIAL DOMESTIC GAS MARKETS .....	7
Context .....	7
Mauritania's potential gas use(s) .....	8
Non-power gas monetization .....	12
Senegal's potential gas use(s) .....	13
Summary of Mauritania and Senegal's total potential gas demand .....	18
GRAND TORTUE AHMEYIM LNG PROJECT and OTHER LNG HUBS .....	18
GTA project - Agreements .....	18
GTA project - Status .....	19
Planned other LNG hubs .....	20
Challenging planned LNG capacity .....	21
LNG EXPORT CHALLENGES .....	21
Cost competitiveness challenges .....	21
Delivered costs and potential price movements .....	22
CONCLUSIONS .....	25

## Tables

Table 1: Mauritania's Natural Gas Potential – Summary .....	5
Table 2: Senegal's Natural Gas Potential – Summary .....	6
Table 3: Mauritania and Senegal – Companies Equity Interests .....	7
Table 4: Mauritania and Senegal's Population and Economic Data (2018) .....	8
Table 5: Outline of gas infrastructure development plan as of December 2018 .....	17
Table 6: Summary of Potential Gas Demand of Mauritania and Senegal – 2030 (Bcm) .....	18

## Figures

Figure 1: Mauritania - 2019 Net Electricity Production Shares (excluding mining) .....	10
Figure 2: Senegal's Planned Evolution of Installed Power Capacity (MW): 2018–2023 .....	16
Figure 3: Simplified GTA Project Structure – Phase 1 .....	19
Figure 4: Scenario 1 - GTA LNG delivered cost to Europe (averages 2025–2030, \$ per MMBtu) .....	23
Figure 5: Scenario 2 - GTA LNG delivered cost to Europe (averages 2025–2030, \$ per MMBtu) .....	23
Figure 6: Scenario 1 - GTA LNG delivered cost to Asia (averages 2025–2030, \$ per MMBtu) .....	24
Figure 7: Scenario 2 - GTA LNG delivered cost to Asia (averages 2025–2030, \$ per MMBtu) .....	24



## Preface

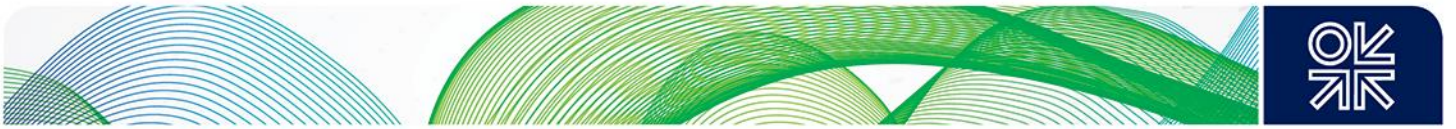
When significant gas discoveries are made in new regions the gas industry has historically got excited, as any expansion into new areas promises growth and opportunity. For the countries involved, the potential for a new gas-field offers a new source of energy for the domestic market, the possibility of export revenues and a boost to the economy from the construction and ancillary work that will go along with the development are major attractions. As a result, the possibility that Mauritania and Senegal could be the location of a major new LNG scheme has created something of a stir, and in this paper Mostefa Ouki examines the current status of the project and its potential for success.

Clearly the current gas market environment, with demand crushed by the impact of the COVID-19 pandemic and supply plentiful as the latest wave of LNG projects ramps up, is hardly ideal. Nevertheless, BP, as the major project operator, and the governments of both countries have started to take steps along the road that could see gas supply at some point this decade. Indeed, the cooperation between the two countries has been one of the major successes to date, and points to their enthusiasm to establish the region as a source of LNG exports. It remains to be seen whether the other challenges of establishing such a major project in countries with little other hydrocarbon infrastructure can be met, and the paper details the key obstacles that will be faced. However, we hope that the paper will be useful to commercial and academic analysts of the industry alike as an example of the difficulties and opportunities that present themselves as a new gas province is opened up.

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## I. INTRODUCTION

Africa's MSGBC basin covers areas situated in five African countries: Mauritania, Senegal, Gambia, Guinea Bissau, and Guinea Conakry. Initial 'world class' discoveries<sup>1</sup> made in this geological basin, more specifically in Mauritania and Senegal, have resulted in an interest in these countries hydrocarbon potential. Until the early 2000s, international oil and gas companies (IOCs) mainly concentrated their African exploration activities in a limited number of countries in Northern Africa, West Africa's Gulf of Guinea and the Congo basin. Then, more exploration activities took place in these areas and in parts of Southern Africa resulting in significant hydrocarbon discoveries. Over the last five years, the MSGBC basin has started to attract increased interest from the IOCs. The Grand Tortue Ahmeyim (GTA) gas field development project, overlapping Mauritania and Senegal's offshore waters, is a key example. Exploration activities that led to the launching of the GTA gas project started in the mid-2010s. This project is a unique case of cooperation and partnership between two African countries and international oil and gas companies (BP and Kosmos Energy) in a potentially new African natural gas province.

Mauritania and Senegal, where separate other offshore natural gas discoveries have also been made, are expected to become potential new sources of African gas supply. A situation that will present them with a number of challenges, especially in a period of severe multiple crises (oil and gas price meltdowns and the COVID-19 health crisis). However, greatly needed new economic development opportunities and added export revenues for both countries could be forthcoming if commercially viable markets are identified enabling the development of these natural gas resources.

The focus of the GTA gas development project is a floating liquefied natural gas (FLNG) export project to enable the quick and phased monetization of the discovered gas resources. This would make available natural gas supplies not only for export, but also for the domestic energy markets of Mauritania and Senegal.

Due to the COVID-19 pandemic, the commissioning of the first phase of the GTA project, which was initially planned for 2022, has been delayed to 2023. The capacity of this Phase 1 FLNG project is about 2.5 mtpa<sup>2</sup>. Subsequent phases of this LNG export project, if and when approved, are expected to potentially expand the project's LNG export capacity to 10 mtpa. Furthermore, two other separate LNG projects with a 10 mtpa LNG capacity each are planned or under consideration in Mauritania and Senegal. This is a huge LNG export capacity for these two countries. Can these on-going and planned gas developments transform Mauritania and Senegal into a new emerging African gas province, especially under the current adverse international economic and energy market conditions?

In order to gain a better understanding of this crucial question; this paper will look at the following key aspects of gas developments in this potential new gas province.

- Mauritania and Senegal's natural gas potential to date;
- domestic gas demand prospects in Mauritania and Senegal;
- the GTA LNG project and other planned LNG hubs in Mauritania and Senegal; and,
- challenges of new LNG export projects in today's uncertain gas markets.

## II. NATURAL GAS POTENTIAL

### Mauritania

Oil was discovered in Mauritania in the 1960s, however, no hydrocarbon development took place until the discovery of the Chinguetti oil field in 2001 by Australia's oil and gas company, Woodside. This field's oil production started in 2006 at a rate of 75,000 barrels per day (bpd). But it declined very rapidly

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<sup>1</sup> Sayers, B. and Cooke, R. (2018). 'The MSGBC Basin', *GeoExpro*, (15) 5  
<https://www.geoexpro.com/articles/2018/12/the-msgbc-basin>

<sup>2</sup> Million tons per annum



to 15,000 bpd in 2007, 7,000 bpd in 2013 and to much lower volumes after that. Production stopped in 2017 and the field has now been abandoned.

In addition to the Chinguetti discovery, a number of hydrocarbon discoveries have been made offshore in Mauritania's coastal basin since the early 2000s. These include:

- Banda (2002, gas and liquid)
- Walata (2003, liquid)
- Pélican (2003, gas)
- Tevet (2004, liquid and gas)
- Labeidna (2005, liquid)
- Aigrette (2006, liquid).<sup>3</sup>

The Banda natural gas field was discovered by Woodside. In 2011, the UK independent Tullow Oil took over operatorship of the field. Due to its small recoverable reserve base of 1.2 trillion cubic feet (Tcf),<sup>4</sup> a gas export monetization option could not be considered. Therefore, it was decided that the Banda field would supply gas to power units to be sited near the capital Nouakchott. Electricity generated from these units was planned to supply domestic consumers, including large mining companies, and for potential electricity exports to the subregion. However, with the collapse of oil prices in 2014 and a severe drop in international demand for mining products, Tullow Oil abandoned the development of the field. The government commissioned studies to identify potential monetization options that could relaunch the field's development.<sup>5</sup> But in February 2020, Maersk Decom was awarded a contract to plug and abandon the Banda field.<sup>6</sup>

In 2015, the US independent Kosmos Energy made a major natural gas discovery, the Grand Tortue Ahmeyim (GTA), in an area located in the ultra-deep waters straddling Mauritania's block C8 and Senegal's Saint Louis Profond block. The GTA discovery is reported to have a total of 15 Tcf of recoverable gas reserves<sup>7</sup> from 25 Tcf of Gas Initially in Place (GIIP). In December 2016, Kosmos Energy farmed out 61 per cent of its GTA share to BP. The GTA field is being developed to supply an LNG export project and BP is the project's operator.

Four years after the GTA gas discovery, another major gas discovery was made in Mauritania's deep waters. In October 2019, Kosmos Energy and BP announced a gas discovery at the Orca 1 well in the Bir Allah area situated north of the GTA field in block C8. According to Kosmos Energy, the Orca prospect is estimated at 13 Tcf of GIIP<sup>8</sup>. Orca and Marsouin, another prospect discovered in 2015, both located in the same Bir Allah area, could have about 50 Tcf of GIIP.<sup>9</sup>

Mauritania's natural gas resource potential is about 63 Tcf of GIIP, as shown in the following table, of which 7.5 Tcf (Mauritania's share) have already been estimated as recoverable reserves for the GTA

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<sup>3</sup> Bechir, M. (2019). 'Developing the Oil & Gas Market. Mauritania as a destination for oil and gas majors', Direction Générale des Hydrocarbures, Ministère du Pétrole, de l'Energie et des Mines, Nouakchot, Mauritania  
<http://www.petrole.gov.mr/IMG/pdf/presentation-dgh-2019.pdf>

<sup>4</sup> Bechir, M. (2019). <http://www.petrole.gov.mr/IMG/pdf/presentation-dgh-2019.pdf>

<sup>5</sup> World Bank (2017). 'Supporting Gas Project Negotiations and Enhancing Institutional Capacities', Washington DC  
<https://projects.worldbank.org/en/projects-operations/project-detail/P163563>

<sup>6</sup> *Petroleum Africa* (2020). 'Maersk Decom Wins Mauritania Abandonment Contract', 28 February  
<https://www.petroleumafrika.com/maersk-decom-wins-mauritania-abandonment-contract/>

<sup>7</sup> Cockayne, J. (2018). 'Mauritania: BP Eyes Second Hub With Tortue Set For Take-Off', *Middle East Economic Survey* (61) 50  
<https://www.mees.com/2018/12/14/oil-gas/mauritania-bp-eyes-second-hub-with-tortue-set-for-take-off/94e6ec20-ffb9-11e8-ac74-cd23c7457c8d>

<sup>8</sup> Kosmos Energy (2019). 'Orca-1 Exploration Well Makes Major Gas Discovery Offshore Mauritania', News Release, 28 October. <http://investors.kosmosenergy.com/news-releases/news-release-details/orca-1-exploration-well-makes-major-gas-discovery-offshore>

<sup>9</sup> Kosmos Energy (2019). 3Q 2019 Results, 4 November. <http://investors.kosmosenergy.com/static-files/c9d6dc5b-2155-4fd4-88b5-23ef7715b4ab>



project. Assuming an average recovery rate of 60 per cent, this would result in about 38 Tcf of total recoverable reserves of natural gas in Mauritania. This is potentially much larger than Mauritania's domestic energy market could absorb.

**Table 1: Mauritania's Natural Gas Potential – Summary**

Field or Area	GIIP (Tcf)	Recoverable Reserves (Tcf)	Status
Grand Tortue/Ahmeyim (50%) <sup>10</sup>	12.5 (Mauritania's GTA share)	7.5 (Mauritania's GTA share)	Development
Bir Allah (Marsouin & Orca fields)	~ 50		Exploration
Banda field		1.2	Abandoned

Source: various press articles and company sources

## Senegal

Hydrocarbon exploration activities in Senegal started in the 1950s, but only a few, very small and non-commercial discoveries were made. Several small oil and gas fields were discovered in the early 1960s in the Diam Niadio onshore area, near the capital Dakar. In 1996, the Gadiaga gas and condensate field was discovered in the same region, north east of Diam Niadio. But these fields recoverable natural gas reserves were small. Gas production from Diam Niadio started in 1987 and stopped in 2000. The Gadiaga gas field is operated by the Houston-based Fortesa International. It started producing natural gas in 2002 reaching a peak production of about 1.5 Bcf in 2013.<sup>11</sup> But its gas output declined rapidly to reach an annual output of less than half a Bcf.<sup>12</sup>

From the late 1990s until the early 2000s, the Government of Senegal deployed a lot of effort to launch the exploration of its territory. As a result, between 2008 and 2017, exploration and production sharing contracts were signed for a total of ten blocks located in three main areas: Sangomar Offshore Profond, Cayar Offshore Profond, and Saint Louis Profond where part of the joint GTA gas field is located. Initially, these contracts included independent oil and gas companies from the UK (Cairn Energy), Australia (FAR) and the US (Kosmos Energy). More recently larger international oil and gas companies, such as BP and Total, have acquired interests in some of these blocks along with the national oil and gas company Société des Pétroles du Sénégal or Petrosen.

In addition to the Grand Tortue Ahmeyim field that Senegal shares with Mauritania, other natural gas discoveries have been made in Senegal in two deep water areas: Sangomar Offshore Profond and Cayar Offshore Profond.

### Sangomar Offshore Profond

The Sangomar Offshore Profond block includes the FAN oil field and the SNE oil and gas field. The SNE field was discovered in 2014 by Cairn Energy (through its local subsidiary Capricorn Senegal) and its partners (Woodside, FAR and Petrosen). In July 2020, Cairn Energy announced that it has entered into an agreement to sell its 40 per cent share in the Sangomar block (Rufisque Offshore, Sangomar Offshore and Sangomar Deep Offshore contract area) to Russia's Lukoil.<sup>13</sup> In this area, Woodside is the operator with a 35 per cent interest, the rest of the shares are distributed as follows: Cairn Energy,

<sup>10</sup> The GTA field is shared 50/50% between Mauritania and Senegal

<sup>11</sup> Petrosen (2018). 'Senegal Sedimentary Basin - Offshore Petroleum Potential & Discoveries', September. <http://www.energie.gouv.sn>

<sup>12</sup> Comité national de l'Initiative pour la Transparence dans les Industries Extractives du Sénégal (2019). 'Rapport de Conciliation 2018', December. <http://itie.sn>

<sup>13</sup> Cairn Energy (2020). 'Sale of Senegal interests and planned special dividend of at least US\$250 million', 27 July. <https://www.cairnenergy.com/news-media/news/2020/sale-of-senegal-interests-and-planned-special-dividend-of-at-least-us-250-million/#Tabundefined=1>





40 per cent; FAR, 15 per cent; and Petrosen, 10 per cent. In August 2020, Woodside announced that it is exercising its pre-emption right to match Lukoil's offer to buy Cairn's share.<sup>14</sup>

The Sangomar block is estimated to hold 563 million barrels of oil and 1.3 Tcf of technically recoverable associated and non-associated gas resources.<sup>15</sup> According to the Senegalese Ministry of Petroleum and Energy, all of Sangomar's gas production will be allocated to the domestic market. Between 60 and 100 MMscf/d is planned to be supplied from Sangomar to the electricity utility Senelec.<sup>16</sup>

The Final Investment Decision (FID) for the development of this oil and gas field was announced in January 2020.<sup>17</sup> Production of gas from Sangomar Profond is now planned for the end of 2024. However, financing of the project could be challenging in today's constrained financial environment.<sup>18</sup> In June 2020, it was reported that Senegal's national oil and gas company, Petrosen, may have to take over FAR's share of the project as FAR is facing difficulties in paying for its share of the project's development.<sup>19</sup>

### Cayar Offshore Profond

Two natural gas fields, Teranga and Yakaar, have been discovered in the Cayar Offshore Profond block. The Teranga 1 discovery was made in 2016. It was followed by the Yakaar 1 and Yakaar 2 discoveries in 2017 and 2019, respectively. These discoveries were made by the same upstream partners consisting of BP (60 per cent), Kosmos Energy (30 per cent) and Petrosen (10 per cent). The estimated total gas initially in place is about 25 Tcf. Gas to be produced from the Yakaar and Teranga fields would be allocated initially to the domestic Senegalese market.<sup>20</sup> As domestic gas demand is likely to be limited (see section on potential gas uses) relative to the Yakaar and Teranga fields gas potential, these fields have been designated as potential supply sources for an LNG hub.<sup>21</sup>

As presented in the table below, Senegal's natural gas resource potential is about 39 Tcf of GIIP. Based on an average recovery rate of 60 per cent, Senegal's recoverable gas reserves could be estimated at 23 Tcf. This is potentially much larger than Senegal's domestic market would need for its potential power and non-power gas uses, as explained in the following section.

**Table 2: Senegal's Natural Gas Potential – Summary**

Field or Area	GIIP (Tcf)	Recoverable Reserves (Tcf)	Status
Grand Tortue/Ahmeyim (50%)	12.5 (Senegal's GTA share)	7.5 (Senegal's GTA share)	Development
Cayar Profond (Yakaar & Teranga)	~ 25		Appraisal
Sangomar Profond (SNE)	1.3		FID in January 2020

Source: various press articles and company sources

<sup>14</sup> Paul, S. and Manekar, S. (2020). 'Australia's Woodside matches Russia's Lukoil offer for Senegal oil project', *Reuters*, 17 August. <https://www.reuters.com/article/us-cairn-energy-divestiture-nk-lukoil-wo/australias-woodside-matches-russias-lukoil-offer-for-senegal-oil-project-idUSKCN25D0L3>

<sup>15</sup> Petrosen (2018)

<sup>16</sup> Ministère du Pétrole et des Energies (2018). Stratégie 'Gas To Power' Le gaz naturel: instrument majeur pour l'atteinte de l'objectif d'électrification universelle à moindre coût! Dakar, December <http://www.energie.gouv.sn>

<sup>17</sup> *Ecofin* (2020). 'Sénégal : la décision finale d'investissement pour le projet pétrolier de Sangomar a été prise', 15 January <https://www.agenceecofin.com/production/1501-72826-senegal-la-decision-finale-d-investissement-pour-le-projet-petrolier-de-sangomar-a-ete-prise>

<sup>18</sup> *Energy-Pedia* (2020). 'FAR to sell all or part of its interest in the Sangomar development offshore Senegal', 01 May. <https://www.energy-pedia.com/news/senegal/far-to-sell-all-or-part-of-its-interest-in-the-sangomar-development-offshore-senegal-179464>

<sup>19</sup> Le Bec, C. (2020). 'Pétrole: le Sénégal prêt à tripler ses parts dans Sangomar', *Jeune Afrique*, 26 June <https://www.jeuneafrique.com/1006522/economie/senegal-petrosen-a-la-rescousse-du-projet-de-sangomar/>

<sup>20</sup> *Ecofin* (2019). 'Sénégal : la production de la nouvelle découverte de gaz sera essentiellement consacrée à la demande domestique', 27 September. <https://www.agenceecofin.com/gaz-naturel/2709-69617-senegal-la-production-de-la-nouvelle-decouverte-de-gaz-sera-essentiellement-consacree-a-la-demande-domestique>

<sup>21</sup> Kosmos Energy (2020). Kosmos presentation at Credit Suisse Annual Energy Summit, 2 March. <http://investors.kosmosenergy.com/news-releases/news-release-details/kosmos-energy-investor-presentation>



## Upstream interests in Mauritania and Senegal

At present, all upstream interests in Mauritania, Senegal and in the joint area between Mauritania and Senegal are held by two international oil and gas companies (BP and Kosmos Energy) together with national oil and gas companies (NOCs), Mauritania's Société Mauritanienne des Hydrocarbures et de Patrimoine Minier (SMHPM) and Senegal's Société des Pétroles du Sénégal (Petrosen). These interests cover blocks fully situated within each country's boundaries and in the joint Grand Tortue Ahmeyim (GTA) gas development. The interests of these companies are summarized below for each on-going gas development or planned gas development. The NOC of each country represents the state's interest.

**Table 3: Mauritania and Senegal – Companies Equity Interests**

	Mauritania	Senegal	GTA
BP	62%	60%	61%
Kosmos Energy <sup>22</sup>	28%	30%	29%
SMHPM	10%	NA	5%
Petrosen	NA	10%	5%

Source: Kosmos Energy, 2018<sup>23</sup>

## III. EXISTING AND POTENTIAL DOMESTIC GAS MARKETS

### Context

Mauritania and Senegal are endowed with natural gas resources estimated at 100 Tcf of gas initially in place and potentially recoverable gas reserves that could reach 60 Tcf. Even though domestic gas uses tend to be a priority for governments and their national policy makers, the development of all these gas resources into commercially recoverable reserves requires the availability of commercially viable monetization options and the necessary funding to implement them. These options include the utilization of the gas domestically, the ability to export the gas or both.

Given the differences in the sizes of their economies and populations (see table below), Mauritania and Senegal are likely to have different levels of natural gas use and domestic gas market development phases over time. It should be noted that there is a level of subregional energy integration and cooperation between these two countries, as well as with other neighbouring countries.

In 2018, the mining and fisheries sectors accounted each for about fifty per cent of Mauritania's export revenue.<sup>24</sup> In 2019, the share of the mining sector increased to about 60 per cent of total exports, whilst the share of fisheries went down to about a third of total export revenue.<sup>25</sup>

In Senegal, export revenues are more diversified and are generated by 'fisheries, phosphates, groundnuts, tourism and services. Senegal is also a subregional hub for banking, shipping and transportation' (World Bank, 2019).

<sup>22</sup> Kosmos Energy is planning to sell down some of its shares in Mauritania and Senegal.

<sup>23</sup> Kosmos Energy (2018). 'Kosmos Energy Announces Final Investment Decision for Phase 1 of the Greater Tortue Ahmeyim LNG Project', 21 December. <https://www.businesswire.com/news/home/20181221005209/en/Kosmos-Energy-Announces-Final-Investment-Decision-Phase>

<sup>24</sup> Office National de la Statistique (2020). 'Annuaire Statistique 2018', June. <http://www.ons.mr>

<sup>25</sup> World Bank (2020). 'Rapport sur la Situation Économique en Mauritanie', June. <https://www.banquemondiale.org/fr/country/mauritania/publication/improving-education-to-foster-social-cohesion>



**Table 4: Mauritania and Senegal's Population and Economic Data (2018)**

	<i>Mauritania</i>	<i>Senegal</i>
Population, total (millions)	4.4	15.85
Population density (people per sq. km of land area)	4.3	82
GDP (current US\$) (billions)	5.23	24.13
GDP per capita (current US\$)	1,189	1,522

Source: The World Bank Databank (2020)

## Mauritania's potential gas use(s)

### Economic and Energy Development Strategy

In 2017, the Government of Mauritania published its 2016 - 2030 economic development strategy entitled 'Accelerated Growth and Shared Prosperity Strategy', or SCAPP (Stratégie de Croissance Accélérée et de Prospérité Partagée) in French, with the following three objectives:

- promote robust, inclusive, and sustainable growth;
- develop human capital and access to basic social services; and,
- strengthen all dimensions of governance.<sup>26</sup>

One of the key aspects of this long-term strategy is to provide much wider access to electricity, especially in rural areas. As a result, the government's electricity sector development strategy revolves around the following four axes:<sup>27</sup>

- addition of new generation capacity drawing on local resources (mainly natural gas and hydro);
- development of transmission grid and interconnections with neighbouring countries;
- increase share of renewable energy sources in the energy mix; and
- implementation of solutions adaptable to communities in remote areas.

### Gas-to-power prospects

At present, there is no natural gas use in Mauritania and the power sector is the only segment of the economy that could be a potential gas user. The focus on gas-fired electricity generation started in the early 2000s, following the discovery of the Banda natural gas field. There were plans to utilize the gas to generate electricity from a new power plant to be sited in an area north of the capital Nouakchott. Natural gas was intended to substitute for the high cost petroleum products used by the power sector.

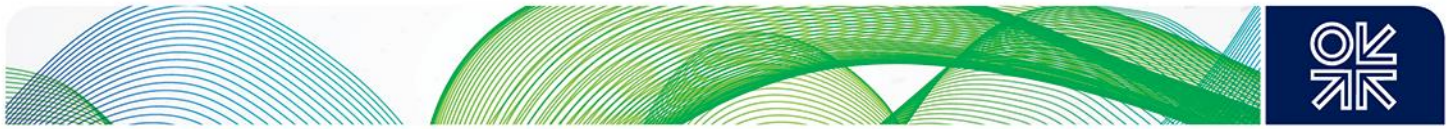
The planned World Bank-supported Banda gas-to-power project consisted of a 300 MW gas-fired power plant with a 180 MW dual-fired (heavy fuel oil and gas) unit and a 120 MW Combined Cycle Gas Turbine unit. About 60 per cent of the electricity output to be generated from this plant was to be exported to neighbouring countries (Senegal and Mali) and the rest allocated to Mauritania's mining companies and other local domestic consumers.<sup>28</sup> Unfortunately, the Banda natural gas project had to be abandoned, as explained in the previous section. Nevertheless, the first 180 MW dual-fuelled unit was built and is now operating and uses heavy fuel oil (HFO) as generating fuel. Therefore, whenever Mauritania's indigenous natural gas supplies become available, and provided that the required gas infrastructure is

<sup>26</sup> IMF (2018). 'Islamic Republic of Mauritania - Economic Development Documents', Washington, DC., May <https://www.imf.org/en/Publications/CR/Issues/2018/06/01/Islamic-Republic-of-Mauritania-Economic-Development-Documents-45918>

<sup>27</sup> Ministry of Petroleum, Energy and Mines (2016). 'Electricity Sector in Mauritania', December. <http://www.petrole.gov.mr/spip.php?article17>

<sup>28</sup> World Bank (2014). 'Project Appraisal Document for the Banda Gas to Power Project', 9 May. <http://documents.worldbank.org/curated/en/228311468113062659/pdf/830250PAD0P107010Box385211B00OUO090.pdf>





in place, this relatively large power plant<sup>29</sup> would be the immediate potential user of natural gas. This plant would consume the 35 MMscf/d of gas reserved by the first phase of the GTA project for the domestic Mauritanian market. A total of 70 MMscf/d of gas is to be reserved for Mauritania and Senegal's domestic markets in equal shares.

As part of the GTA project's domestic gas-monetization options, a new combined cycle gas turbine (CCGT) power plant was initially considered, to be developed jointly by Mauritania and Senegal, and joint committees were set up to study this project. The plant would be located not far from the GTA gas project's landing point near the town of Saint Louis in Senegal and would have a capacity of about 500 MW. The idea was to allocate both Mauritania and Senegal's Phase 1 domestic gas supply shares to fuel this large plant.<sup>30</sup> Given the delay that the GTA gas project is facing, market uncertainties, and the fact that the two countries may want to develop their own separate electricity generation expansion plans, it is unlikely that such a new joint-power plant project would materialize any time soon.

Assuming that the GTA project could expand beyond Phase 1, and considering the future potential development of the Bir Allah area gas discoveries, how much can the Mauritanian electricity sector absorb of the country's total indigenous gas potential? A brief overview of the main segments of Mauritania's power sector is presented below to provide a high level understanding of this potential domestic market for gas.

The bulk of the electricity generated in Mauritania is fuelled with imported petroleum products (HFO and diesel). Mauritania's installed electricity generation capacity is about 500 MW (excluding the mining companies power units).<sup>31</sup> Renewable energy (solar and wind) accounts for 20 per cent of this total installed capacity. In addition, a 100 MW wind farm sited in the Dakhlet Nouadhibou area is expected to be commissioned in 2021. Thus, electricity generation from renewable energy sources is expected to increase its share of Mauritania's energy mix.

The two main mining companies operating in Mauritania are the state controlled SNIM (Société Nationale Industrielle et Minière) and the Canadian gold mining company Kinross. SNIM has an installed power capacity of about 180 MW including less than 10 per cent renewable energy capacity. SNIM is the second largest producer of electricity in Mauritania after Somelec, the state-owned electricity utility. It generates electricity for its own mining operations in Zouerate and Nouadhibou and for sales to Somelec.

Kinross' thermal power units have a total installed power capacity of 42 MW (as of October 2019). This capacity meets its present electricity needs of 30 MW and provides redundancy capacity.<sup>32</sup> In the long-term, Kinross is planning the construction of two additional power units totalling 20 MW to meet the needs of future mining production. In 2019 Kinross stated that it did not envisage being connected to the national electricity grid, but that it could be an option for the future.<sup>33</sup> However, Kinross' Tasiast gold mine is expected to be linked to the grid through a new power transmission line (see below).

A third mining company, Mauritanian Copper Mines (MCM), a subsidiary of Canada's First Quantum Minerals, also has an installed power capacity of 20 MW for its own operations in the Guelb Moghrein area near the town of Akjoujt (north east of Nouakchott).

According to Somelec, a total of 1,179 GWh was produced in 2019. About 98 per cent of this electricity output was allocated to users connected to the Somelec electricity grid. The total electricity generated excludes electricity produced by the mining companies for their own uses. As shown in Figure 1, the

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<sup>29</sup> This plant accounts for more than a third of the country's present electricity generation capacity, excluding mining sector.

<sup>30</sup> Ministère du Pétrole et des Energies (2018). *Stratégie 'Gas To Power' Le gaz naturel: instrument majeur pour l'atteinte de l'objectif d'électrification universelle à moindre coût!*, Dakar, December. <http://www.energie.gouv.sn>

<sup>31</sup> Somelec (2020). [https://www.somelec.mr/spip.php?page=article&id\\_article=6](https://www.somelec.mr/spip.php?page=article&id_article=6)

<sup>32</sup> Kinross (2019). 'Tasiast Project – Mauritania, National Instrument 43-101 Technical Report', 31 October. [https://s2.q4cdn.com/496390694/files/doc\\_downloads/technical\\_reports/2019/Kinross-Tasiast-NI-43-101-Technical-Report-Oct-2019-FINAL.pdf](https://s2.q4cdn.com/496390694/files/doc_downloads/technical_reports/2019/Kinross-Tasiast-NI-43-101-Technical-Report-Oct-2019-FINAL.pdf)

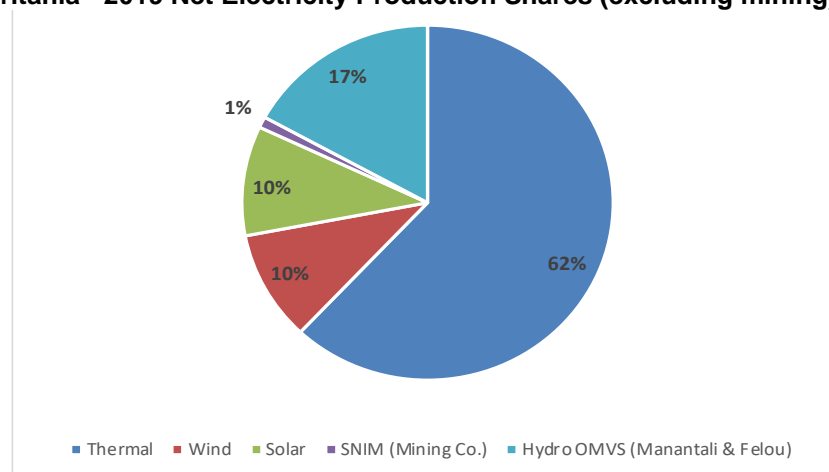
<sup>33</sup> Kinross, (2019). [https://s2.q4cdn.com/496390694/files/doc\\_downloads/technical\\_reports/2019/Kinross-Tasiast-NI-43-101-Technical-Report-Oct-2019-FINAL.pdf](https://s2.q4cdn.com/496390694/files/doc_downloads/technical_reports/2019/Kinross-Tasiast-NI-43-101-Technical-Report-Oct-2019-FINAL.pdf)





bulk of the electricity was produced by Somelec's thermal units. 17 per cent of the total electricity was produced by the OMVS (*Organisation pour la Mise en Valeur du fleuve Sénégal* (organization for the development of the Senegal river basin)) hydro-electric power units (jointly owned by Mauritania, Mali and Senegal) located in Mali (Manantali) and Senegal (Felou) and 20 per cent was generated by Somelec's solar and wind power units.

**Figure 1: Mauritania - 2019 Net Electricity Production Shares (excluding mining)**



Source: Somelec (2020)

Over the last two decades, electricity demand in Mauritania (excluding the mining sector) has grown very rapidly at an annual rate of about 10 per cent. For the next five years, the Ministry of Petroleum, Energy and Mines forecasted an annual growth of 6 per cent for non-mining demand and 12 per cent for all electricity consumers, including the mining sector.<sup>34</sup> It should be noted that these high growth rate projections were published in 2016 and to the best of our knowledge are the latest forecasts publicly available. Under the present much less favourable global and domestic economic conditions as a result of the COVID-19 pandemic, such growth forecasts could be revisited downwards.

In a June 2020 assessment of the economic situation, the World Bank indicated that Mauritania's economy will be severely affected by this global crisis, especially due to an economic slowdown in Europe and in China (Mauritania's main trade partners). This will result in a reduction of Mauritania's exports to these regions of the world. In 2019, two sectors accounted for 90 per cent of Mauritania's exports, about 60 per cent from mining and over 30 per cent from fisheries. Domestically, a slowdown of economic activity, due to the confinement measures, will also depress domestic demand in the short to medium term. A significant reduction of Mauritania's GDP by about 7 per cent is predicted for 2020. This economic situation is unlikely to change drastically over the next few years. A lower economic growth rate ranging between 2.7 per cent and 4.6 per cent is projected by the World Bank for 2021.<sup>35</sup> This is compared to a positive GDP growth rate of about 6 per cent achieved in 2019.

According to the United Nations, Mauritania is the only country among the less developed Arab economies that 'requires a significant acceleration in its efforts to make access to electricity universal'.<sup>36</sup> Because of the sparsely populated nature of Mauritania, rural areas are isolated from the power grids and have an extremely low level of access to electricity. In 2017, the levels of electrification were just over 80 per cent for urban areas and well below 10 per cent for rural areas. This is a major development challenge for the government of Mauritania given that about half of the country's population lives in

<sup>34</sup> Ministère du Pétrole, de l'Énergie et des Mines (2016). 'Le Secteur de l'Électricité en Mauritanie', October. <http://www.petrole.gov.mr>

<sup>35</sup> World Bank (2020).

<sup>36</sup> UN ESCWA (2019). 'Tracking SDG 7: Energy Progress Report 2019 Arab Region', Beirut, Lebanon. [https://www.unescwa.org/sites/www.unescwa.org/files/publications/files/energy-progress-report-arab-region-english\\_0.pdf](https://www.unescwa.org/sites/www.unescwa.org/files/publications/files/energy-progress-report-arab-region-english_0.pdf)



these rural areas. Furthermore, a large number of rural households will not be able to pay for electricity even if priced at low levels (UN ESCWA, 2019).

The mining companies are the country's largest electricity consumers and a key segment of the Mauritanian economy. However, they are not linked to the national grid and rely on off-grid power units. As indicated above, Mauritania's economy is highly dependent on export revenue from the mining industry. International price conditions for their mining output are likely to drive their demand for additional electricity supplies. Thus, potential gas-fired power capacity to supply the mining sector will be sensitive to the movements of international mineral product prices and potential demand for these products.

New power transmission lines will need to be installed to supply potential mining and non-mining electricity users. There are, at the moment, two power transmission projects to link key regions including mining centres. These are the:

- Nouakchott – Nouadhibou transmission line linking the capital, Nouakchott, to the country's second largest city and its major commercial centre, Nouadhibou. This power line is expected to be completed by the end of 2020 and will cover the Nouadhibou free zone and the gold mine of Tasiast operated by the Kinross gold corporation. It should be noted that the Kinross Tasiast mining plant has existing onsite power units totalling over 40 MW and there are on-going plans to expand this onsite HFO-fuelled power capacity to 65 MW. According to a Kinross October 2019 technical report, 'At this time, there are no plans to connect to the national electric grid, although that could be an option in the future'.<sup>37</sup>
- Nouakchott – Zouerate transmission line. This power line will cover the towns of Akjoujt, Atar and Zouerate in the northern region where iron ore mines are located. Its construction is planned to be completed in 2021.

Although Mauritania has 'surplus' power capacity relative to its current electricity use, the country's existing installed capacity will not be sufficient to supply all the above-mentioned regions once the grid is extended and new consumption points are connected. Additional generation capacity would be required to meet this potential new demand. Furthermore, the issue of the very low rural electrification rate may also, in the long-term, necessitate more generation and transmission capacity unless off-grid solutions are developed to provide electricity access to the rural communities.

However, it should be noted that these communities, especially in the rural areas, have very constrained financial resources with which to pay for new electricity supplies. In 2018, the average electricity tariff for residential users was estimated at about US\$0.09/kWh and about US\$0.12/kWh for industry.<sup>38</sup> These are relatively high tariffs for rural areas where a lot of households are living under the poverty line. According to the government's statistical office, in 2014 (latest data publicly available), 44 per cent of the rural population was classified as poor and 25 per cent as extremely poor.<sup>39</sup> Therefore, expanding grid-connected electricity to rural communities without heavy tariff subsidies would be difficult.

Nonetheless, if commercially viable, an expansion of exports of electricity to the subregion could potentially drive an increase in natural gas-fired electricity production. Mauritania has already had experience of subregional integration projects. It is a member of OMVS, set up in 1972.<sup>40</sup> The other members are Mali, Senegal and Guinea. The initial objective of OMVS was limited to the management of water resources for irrigation to ensure food security. Its role was later extended to the subregional

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<sup>37</sup> Kinross (2019). Tasiast Project, Mauritania, National Instrument 43-101 Technical Report, 31 October. [https://s2.q4cdn.com/496390694/files/doc\\_downloads/technical\\_reports/2019/Kinross-Tasiast-NI-43-101-Technical-Report-Oct-2019-FINAL.pdf](https://s2.q4cdn.com/496390694/files/doc_downloads/technical_reports/2019/Kinross-Tasiast-NI-43-101-Technical-Report-Oct-2019-FINAL.pdf)

<sup>38</sup> Enerdata (2020). 'Mauritania Energy Report', April. <https://estore.enerdata.net/energy-market/mauritania-energy-report-and-data.html>

<sup>39</sup> Office National de la Statistique (2020).

<sup>40</sup> <http://www.omvs.org>



trade of hydroelectricity (World Bank, 2014). This enabled the development of an interconnected sub-regional electricity transmission system.

Depending on its current condition and capacity, this cross-border power transmission infrastructure could be utilized to promote additional electricity exports from Mauritania. However, the key challenge for potential investors in gas-fired power projects targeting subregional exports is the lack of creditworthiness of potential off takers, which would be mainly the respective energy utility companies in each country. There are also some serious political and security risks in parts of this subregion that would need to be addressed before engaging in large energy cross-border power projects. Thus, in the short to medium term, potential natural gas use within Mauritania for domestic electricity consumption or for subregional electricity exports remains limited.

### Non-power gas monetization

Outside the power sector, the potential development of gas-based industrial projects, like fertilizers, has been proposed to monetize the GTA reserved gas volumes or the surplus volumes after meeting the needs of the power sector. A gas masterplan study funded by the World Bank<sup>41</sup> is currently under way or about to be commissioned. This masterplan is likely to include a detailed assessment of all power and non-power gas monetization options and consider all potential gas sources (GTA project and the Bir Allah prospect). Notwithstanding market, infrastructure and logistical challenges, *inter alia*, it should be pointed out, that the current 35 MMscf/d (about 0.4 Bcm pa) of gas reserved for Mauritania for potential power and non-power uses would be far too limited to consider commercially viable gas-based industries.

### Gas infrastructure issues

As indicated above, there is no gas use in Mauritania at the moment although studies have been undertaken or are about to be commissioned regarding the development of a domestic natural gas infrastructure for the potential utilization of the initial volume of natural gas reserved for the Mauritanian domestic market as part of the GTA gas project. Initially, the focus is likely to be on the gas infrastructure necessary to deliver the gas from the GTA gas landfall point at N'Diogo near the Senegalese border to the existing dual fuel power station around Nouakchott.

However, it is not clear yet how the potential development of this gas infrastructure would be funded. Given the state's constrained financial resources, it is unlikely that the government would finance gas infrastructure projects, or at least finance them fully. Multilateral or bilateral development agencies could be solicited and/or act as catalysts for potential private sector investment participation. This would be subject to energy sector reforms, including the enactment and/or strengthening of an adequate institutional and regulatory framework for the yet to be developed gas sector (including domestic gas pricing policy and regulation).

### Mauritania's potential total gas demand

Overall, Mauritania's potential natural gas demand by 2025 would be limited to the about **0.4 Bcm** reserved by the first phase of the GTA gas project for domestic gas use. This volume will most likely supply the existing 180 MW dual fuel plant in Nouakchott.

In the long-term, Mauritania's future domestic gas monetization prospects will depend on whether the next phases of the GTA project will be developed and the likelihood of developing the large natural gas potential of the Bir Allah area. If such upstream prospects are developed and additional power capacity of 120 MW, as initially planned under the now-abandoned Banda gas project, is implemented, Mauritania's total gas demand could increase to about **0.6 Bcm** by 2030.

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<sup>41</sup> The World Bank (2020). 'Supporting Gas Project Negotiations and Enhancing Institutional Capacities', 30 June. <https://projects.worldbank.org/en/projects-operations/project-detail/P163563>



## Senegal's potential gas use(s)

### Economic and energy development strategy

In 2014, the Government of Senegal issued a long-term economic and social development strategy entitled *Plan Sénégal Émergent* (PSE)<sup>42</sup> with the objective of transforming Senegal into an emerging middle-income economy by 2035. The PSE is based on the following three strategic pillars:

- structural transformation of the economic framework;
- promotion of human capital; and,
- good governance and rule of law.

Based on a fundamental part of the PSE on the need to ensure large and reliable access to affordable sources of energy, a gas-to-power strategy was formulated and issued by the government in December 2018.<sup>43</sup> This strategy's objectives are:

- energy independence by securing the supply of fuels to Senelec (national electricity utility);
- remove in a structured manner, the subsidy provided by the state;
- reduce the energy cost for households and companies; and,
- achieve universal access to energy by 2025 and the objective of clean energy for the whole country.

In August 2019, the Ministry of Petroleum and Energy issued the *Lettre de Politique de Développement du Secteur de l'Énergie (LPDSE) 2019 - 2023* defining the government's medium-term energy sector development policy. Reiterating the PSE's overall objective, the document states that this policy is intended to 'reinforce access to all to a least cost, sustainable and environmentally-friendly energy in sufficient quality and quantity'.<sup>44</sup> It emphasizes the use of the country's natural gas resources to generate electricity at costs lower than those of liquid fuels, and with less adverse environmental impact. The policy also includes the potential import of LNG supplies through a floating storage and regasification unit (FSRU) during a transition period until indigenous natural gas supplies become available.

Following the natural gas discovery in 2015 of the Grand Tortue Ahmeyim field straddling Mauritania and Senegal's deep offshore waters and the first discovery in Senegal's Cayar Profond area in 2016, the Government of Senegal set up a new committee, COS-PETROGAZ (Comité d'Orientation Stratégique Pétrole et du Gaz).<sup>45</sup> This committee, housed within the Office of the President and chaired by the president, is a strategic 'structure of steering, coordination and follow up of oil and gas projects in order to better assist the president and the government in the definition, supervision and implementation of the policy related to the management of these national energy resources'.<sup>46</sup> The decree that established COS-PETROGAZ also included the creation of an implementation unit, GES-PETROGAZ, within the Ministry of Petroleum and Energy. This unit implements all the decisions taken by the COS-PETROGAZ and assists the Minister of Petroleum and Energy.

In order to prepare for an expanded use of natural gas in the country and for the implementation of its gas-to-power strategy, the Ministry of Petroleum and Energy announced in December 2019 a proposed

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<sup>42</sup> Government of Senegal (2014). 'Plan Senegal Emergent'. [https://www.sec.gouv.sn/sites/default/files/Plan%20Senegal%20Emergent\\_0.pdf](https://www.sec.gouv.sn/sites/default/files/Plan%20Senegal%20Emergent_0.pdf)

<sup>43</sup> Ministère du Pétrole et des Énergies (2018). 'Stratégie 'Gas To Power' Le gaz naturel: instrument majeur pour l'atteinte de l'objectif d'électrification universelle à moindre coût', Dakar, December. <http://www.energie.gouv.sn>

<sup>44</sup> Ministère du Pétrole et des Énergies (2019). 'Lettre de Politique de Développement du Secteur de l'Énergie (LPDSE) 2019 – 2023', 20 August. <http://www.energie.gouv.sn>

<sup>45</sup> <http://www.cospetrogaz.sn>

<sup>46</sup> <http://www.cospetrogaz.sn/concertation/>





study for the formulation of a legal and regulatory framework for the development of Senegal's midstream and downstream natural gas activities.

### Gas-to-power prospects

Natural gas is used in Senegal, but in very small volumes. From 1987 to 2000 the now depleted Diam Niadio onshore oil and gas field supplied gas to Senegal's domestic market. Since the early 2000s, the Gadiaga onshore gas field has been supplying gas to local power and cement companies. Recently, the field's gas production decline has constrained this supply to less than half a Bcf per year, as indicated earlier.

The prospect of using natural gas domestically in Senegal is expected to be mainly for the generation of electricity. The key objective of the government's economic and energy policy strategies is to rapidly expand the rate of electrification, especially in the rural areas where over 50 per cent of Senegal's population lives. In 2018, the rural electrification rate was 42 per cent compared to about 94 per cent in urban areas. There are also pronounced differences in electricity access among regions with population centres close to the capital Dakar having the highest access rates.

Electricity consumption in Senegal continues to grow rapidly from 6 per cent in 2016, to 9 per cent in 2017 and over 10 per cent in 2018.<sup>47</sup> In 2018, about 3,987 GWh of electricity was produced. According to the World Bank, electricity sales could grow at about 7 per cent per year until 2030.<sup>48</sup> Therefore, the government is proceeding with plant expansion projects and the planning of new power units. Although, it is not known yet how the COVID-19 pandemic will affect future electricity demand growth and, thus, the implementation of this expansion program.

This expansion program is focused on providing least cost and clean generation sources based on natural gas and renewable energy. Electricity tariffs in Senegal are high and were estimated at an average of about \$0.18 to \$0.20 per kWh<sup>49</sup> between 2018 and 2019 compared to an international benchmark of \$0.10 per kWh. According to the World Bank, despite their high levels, the tariffs are set below costs and therefore result in heavy state subsidies.<sup>50</sup> The subsidy is provided through a costly compensation paid by the state to the national electricity utility Senelec. This situation is not financially sustainable for the country. Future reform of this subsidy system and a reduction of the size of the subsidy will have an impact on electricity consumption.

In order to reduce electricity costs and in line with its gas-to-power strategy, Senegal is preparing for the introduction of natural gas as a generating fuel. Some of the existing power units already have a dual fuel (liquid and natural gas) capability, others are planned to be converted to dual fuelling and new dual-fired plants are under construction or at a planning stage. In addition, in 2019, Senelec signed a 5.5 year contract with the Turkish provider of power barges, Karpowership, to deploy a 235 MW power ship that will initially be fuelled with liquid fuel.<sup>51</sup> It is then planned to be supplied with natural gas from a new LNG import FSRU until indigenous gas supplies become available although it is not clear when and how this temporary LNG import project would be implemented or what stage of planning/development it has reached.

In 2018, Senegal had an installed power capacity of about 1,100 MW (excluding the OMVS allocated capacity) and about 70 per cent of the population is connected to the electricity grid. Independent Power Producers (IPPs) account for 40 per cent of the country's total installed capacity. As shown in the Figure

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<sup>47</sup> Ministère du Pétrole et des Énergies (2019). 'Termes de référence pour le Recrutement d'un Cabinet pour l'élaboration d'un cadre légal et réglementaire pour les secteurs gaziers « midstream » et « downstream »', GES-PETROGAZ, Dakar, Senegal, December. <http://www.energie.gouv.sn/wp-content/uploads/2019/12/TDR-cadre-légal.pdf>

<sup>48</sup> World Bank (2019). 'Senegal - Third Multi-Sectoral Structural Reforms Development Policy Financing', November. <http://documents.worldbank.org/curated/en/331641576983717851/Senegal-Third-Multi-Sectoral-Structural-Reforms-Development-Policy-Financing>

<sup>49</sup> It should be noted that these tariffs are impacted by high oil prices through the liquid fuel prices. In 2018, the average Brent price was \$71 per bbl compared to much lower current oil prices.

<sup>50</sup> World Bank (2019).

<sup>51</sup> <http://www.karpowership.com/en/project-senegal>



below, Senegal's power plant mix is presently dominated by HFO-fuelled plants but renewable energy sources (solar and wind) are expected to play an increasing role in the energy generation mix. In February 2020, a new 159 MW wind power project was officially inaugurated (it started preliminary operation in December 2019). This wind project, located in the Taiba N'Diaye area (about 90 km north of Dakar), is the country's first large-scale wind energy project and is an essential element of the government's Plan Sénégal Émergent.<sup>52</sup>

By 2023, the share of renewable energy in Senegal's energy mix is planned to reach 17 per cent. When hydro is added, about a third of Senegal's power capacity would be based on three renewable energy sources (solar, wind and hydro). The impact of such a share of renewables in the mix will need to be managed in terms of grid stability and dispatch availability.

A new 125 MW coal-fired power plant, Sendou power project was constructed in the town of Bargny 35 km south-east of Dakar and started operating in 2018. The plant's operation stopped in July 2019 because of non-compliance with environmental and social policies.<sup>53</sup> A June 2020 monitoring report issued by the African Development Bank (AfDB), one of the project's lenders, concluded that 'there is non-compliance with the AfDB Policy on the Environment on several accounts' and other non-compliance issues are also identified in this monitoring report.<sup>54</sup> In December 2019, the government decided to convert this coal-fired plant to natural gas in order to comply with Senegal's COP 21 (Paris agreement) commitments.<sup>55</sup> Although it is not clear how and when this conversion would be carried out and whether this conversion is possible.

The share of natural gas-fuelled power plants is projected to rise significantly in the next three years. The installed capacity is planned to evolve from 24 MW to 584 MW by 2023 or 25 per cent of the total power plant mix. Furthermore, if the conversion to gas of the Sendou power project is technically and commercially feasible and it is implemented, the share of natural gas in Senegal's energy mix could exceed 30 per cent.

This steep rise in planned gas-fired power capacity reflects the initial expected availability from about 2022/2023 of natural gas supplies from the joint Mauritania-Senegal GTA gas project and from new indigenous gas sources in the Sangomar Profond and Cayar Profond blocks (including Yakaar and Teranga fields). However, with the delay in the development of the GTA project announced in April 2020 due to the COVID-19 pandemic and possible delays in the Sangomar and Cayar gas developments, the above gas-based power development plan is likely to be delayed by at least a year or two.

Natural gas is planned to be supplied to existing and new power plants. This would include the potential joint new CCGT plant, not far from the GTA landfall point in the Saint Louis area, mentioned in the Mauritania section and existing dual-fired and converted power units. As indicated previously, it is unlikely that the new joint-power plant would be built any time soon.

In 2019, a World Bank report presented an electricity forecast scenario assuming long-term financial sustainability of the energy sector, including the diversification of the energy mix and sector governance, reform and institutional strengthening. Under this scenario, electricity production would increase from about 4,000 GWh in 2018 to over 8,000 GWh in 2030 with the share of gas-fired generation output reaching 5,220 GWh by 2030.<sup>56</sup> As part of their World Energy Outlook, the International Energy Agency's (IEA) scenarios: *Stated Policies Scenario* and the *African Case* have estimates for the gas-

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<sup>52</sup> Parc Eolien Taiba N'Diaye (PETN). <http://www.taibaeolien.com/sn/home-sn/>

<sup>53</sup> FMO (2020). 'Update Sendou', 27 January. <https://www.fmo.nl/news-detail/694da753-7bbf-41db-a79a-e97fac99052e/update-sendou>

<sup>54</sup> African Development Bank (2020). 'Senegal - Construction of a 125 MW coal-fired Sendou power plant in the village of Bargny Minam – 1st Monitoring Report', June. <https://www.afdb.org/en/documents/senegal-construction-125-mw-coal-sendou-power-plant-village-bargny-minam-1st-monitoring-report>

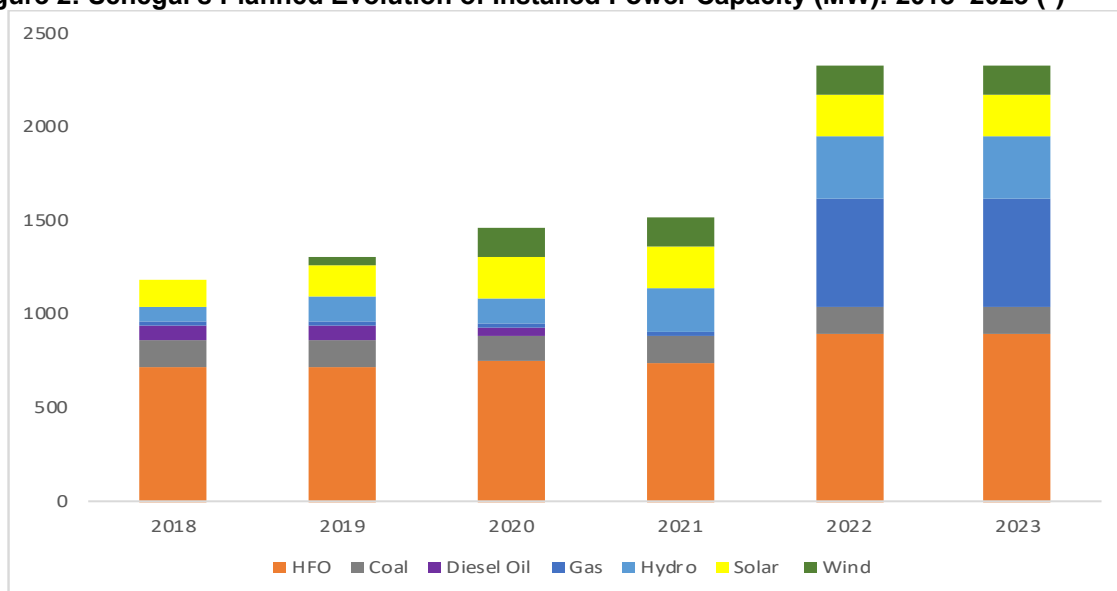
<sup>55</sup> Ecofin (2019). 'Sénégal : le gouvernement échange la centrale à charbon de Sendou contre une centrale à gaz', 12 December. <https://www.agenceecofin.com/centrale/1212-72073-senegal-le-gouvernement-echange-la-centrale-a-charbon-de-sendou-contre-une-centrale-a-gaz>

<sup>56</sup> World Bank (2019).



based electricity generation ranging between over 4,000 GWh and 7,000 GWh.<sup>57</sup> Considering the World Bank's estimate of 5,220 GWh which falls between the two IEA scenario estimates and assuming that gas is supplied to existing and new power units as indicated above, this would require just over 1 Bcm of natural gas by 2030.

**Figure 2: Senegal's Planned Evolution of Installed Power Capacity (MW): 2018–2023 (\*)**



Source: Ministère du Pétrole et des Énergies (2019)

(\*) Installed power capacities connected and planned to be connected to the grid. These include Senegal's allocated shares of regional hydropower capacity installed in neighbouring countries as part of the sub-regional OMVS scheme. It does not include small off-grid solar units and capacity fuelled with solid fuels (biomass).

### Non-power gas monetization

As for Mauritania, Senegal's gas supply share of the joint GTA project and potential gas supplies from indigenous offshore fields within Senegal have led to proposals to develop a gas-based fertilizer project. However, the market, infrastructure and logistical challenges of developing such a capital-intensive gas monetization option are similar to those highlighted in the Mauritania section.

If commercially viable, gas volumes could be supplied to cement kilns and industries located close to the planned expanded gas infrastructure. But the volumes needed for these potential non-power gas users would be limited to less than one 1 Bcm per annum.

### Planned gas infrastructure development

In order to supply power plants and potentially some non-power industries like cement, the government has presented in its gas-to-power strategy and plan<sup>58</sup> the development of a phased natural gas transportation network with three segments as outlined below. It should be noted though that this plan was issued in December 2018. In July 2019, it was announced that Senegal had awarded a contract to a team of British consultancies for a study of the initial phase of its gas-to-power plan, including its gas infrastructure development.<sup>59</sup> There has not been any announced update on the implementation status of this plan.

<sup>57</sup> International Energy Agency (2019). 'Senegal Energy Outlook 2019', <https://www.iea.org/articles/senegal-energy-outlook>

<sup>58</sup> Ministère du Pétrole et des Énergies (2018).

<sup>59</sup> Ecofin (2019). 'Sénégal: la phase initiale du projet de production d'électricité à partir du gaz, confiée à Penspen et MJMEnergy', 2 July. <https://www.agenceecofin.com/electricite/0207-67495-senegal-la-phase-initiale-du-projet-de-production-d-electricite-a-partir-du-gaz-confiee-a-penspen-et-mjmenergy>



As indicated below, this was a plan formulated about two years ago under significantly different economic and energy market conditions and international investment climate. The implementation of this plan or parts of it will depend on the stakeholders' new investment priorities and capabilities and international natural gas market prospects. Nonetheless, the existing and potential new gas consumption areas identified by the plan are unlikely to change much. If the plan is implemented, it is more the time that it will take to develop this gas infrastructure that is expected to change and possibly the gas supply sources and their volumes. This would have an impact on the sizing and routing of the gas pipeline infrastructure. It will depend also on the time required to convert existing power units to gas (including availability of funding) and the number of units that will be commercially viable to convert.

**Table 5: Outline of gas infrastructure development plan as of December 2018**

<b>Northern segment</b>
20 km offshore gas pipeline connecting the GTA field to a planned new gas-fired power station to be sited in the Saint Louis area, from 2022.
140 km onshore gas pipeline extension to connect, by 2024, the existing Tobene power plant north east of the capital Dakar.
<b>Dakar segment</b>
157 km gas pipeline to connect gas sources in the Sangomar Profond block to Senegal's main power plants around Dakar. Planned to be operational by 2023.
<b>Southern segment</b>
120 km gas pipeline to be constructed in parallel with the Dakar pipeline segment to connect, before 2023, the power plants located south of Dakar.

Source: Senegal Ministry of Petroleum & Energy, 2018.

In August 2020, the US Trade and Development Agency (USTDA) signed an agreement with Senegal's Sovereign Fund for Strategic Investments (FONSIS) for the provision of a grant of \$1.2 million.<sup>60</sup> This grant is to finance a feasibility study for the development of Réseau Gazier du Sénégal's (RGS) onshore natural gas network. RGS SA is a new company created in November 2019 by Petrosen, Senelec and FONSIS to 'transport gas from production sites to areas of consumption (power stations, industries, residential, etc.)'.<sup>61</sup> The findings of this feasibility study should provide an update or a revised version of the above-mentioned natural gas infrastructure plan.

Studies to plan for the potential significant expansion of natural gas use in Senegal are obviously necessary. But, it is critically important to focus on the funding aspect of this planned gas infrastructure. As outlined in the Mauritania section, it is unlikely that the government would finance gas infrastructure projects, or at least finance them fully. International development agencies could be involved and also act as catalysts to attract potential private sector investments. This would be subject to energy sector

<sup>60</sup> USTDA (2020). 'USTDA Supports Senegal's First Major Gas Pipeline', Press Release, 28 August. <https://ustda.gov/ustda-supports-senegals-first-major-gas-pipeline/>

<sup>61</sup> FONSIS (2020). 'FONSIS obtient une subvention de plus de 700 millions FCFA pour sa société Réseau Gazier du Sénégal', 28 August. <http://www.fonsis.org/fr/articles/28-08-2020/fonsis-obtient-une-subvention-de-plus-de-700-millions-fcfa-pour-sa-societe>





reforms, including the enactment and/or strengthening of an adequate institutional and regulatory framework for the gas sector (including domestic gas pricing policy and regulation).

### Senegal's potential total gas demand

Gas-fired electricity generation will continue to provide the main potential source of natural gas use in Senegal. The country's potential natural gas demand would range between **1.5** and **2.0 Bcm** by 2030. These volumes are very small by international market standards and could easily be supplied from Senegal's indigenous natural gas resources if they are all developed.

### Summary of Mauritania and Senegal's total potential gas demand

The previous sections show that Mauritania and Senegal's aggregated potential gas demand over the next ten years will remain very limited relative to these countries' potential natural gas resources.

The total potential natural gas demand for the two countries would be below 3 Bcm by 2030, as summarized in the table below.

**Table 6: Summary of Potential Gas Demand of Mauritania and Senegal – 2030 (Bcm)**

2030	
<b>Mauritania</b>	0.6
<b>Senegal</b>	1.5 – 2.0
<b>Total</b>	<b>2.1 – 2.6</b>

Source: Author's estimation

Consequently, in order to develop the large natural gas potential of this area of Africa's MSGBC geological basin, the LNG export monetization option, if commercially viable, is unavoidable. The next section looks at the Grand Tortue Ahmeyim (GTA) LNG project launched by the governments of Mauritania and Senegal and their international partners BP and Kosmos Energy along with the two planned or under consideration separate LNG projects in Mauritania and Senegal.

## IV. GRAND TORTUE AHMEYIM LNG PROJECT and OTHER LNG HUBS

### GTA project - Agreements

The Grand Tortue Ahmeyim (GTA) natural gas field was discovered by Kosmos Energy in April 2015 in an ultra-deep offshore area straddling Mauritania and Senegal. This major gas discovery led to the launching of an LNG export project through unique cooperation and partnership in a potentially new African gas province. In September 2015, while attending the United Nations General Assembly in New York, the Mauritanian and Senegalese heads of state met and decided to work together to develop the GTA natural gas field. A month later, at a meeting of the joint commission between Mauritania and Senegal, the two countries signed a memorandum of understanding on cooperation in upstream hydrocarbon activities.

In January 2016, a framework agreement on the delineation, evaluation, development and utilization of the GTA zone's joint hydrocarbon resources was signed between the Société des Pétroles du Sénégal (Petrosen); Société Mauritanienne des Hydrocarbures et de Patrimoine Minier (SMHPM); Kosmos Energy Senegal; and, Kosmos Energy Mauritania.<sup>62</sup> In December 2016, BP joined the project and is now the project's operator.

The above agreements culminated in the signature in February 2018 of an Inter-government Cooperation Agreement (ICA) that 'provides for development of the Tortue/Ahmeyim gas field through cross-border unitisation, with a 50-50% initial split of resources and revenues and a mechanism for

<sup>62</sup> *Journal Officiel du Senegal* (2018). 'Accord de Cooperation inter-Etats portant sur le developpement et l'exploitation des reservoirs du champ Grand Tortue/Ahmeyim entre Republique Islamique de Mauritanie et la la Republique du Senegal', No. 7119, 30 August. <http://itie.sn/wp-content/uploads/2019/01/Accord-de-coopération-sur-le-GTA.pdf>



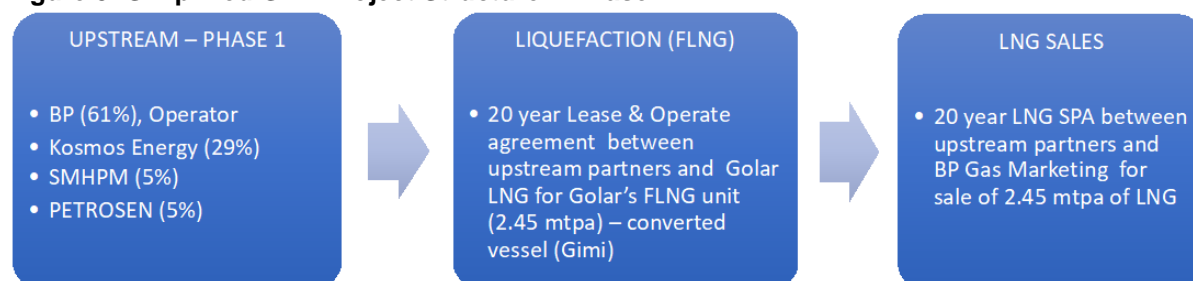
future equity redetermination based on actual production and other technical data'.<sup>63</sup> This was followed by the achievement of a key project milestone in December 2018, when BP and its GTA partners announced the Final Investment Decision (FID) for the first phase of the GTA LNG project.<sup>64</sup> The project's FID cleared the way for other critical decisions and agreements.

In February 2019, the GTA project partners (BP, Kosmos Energy, SMHPM and Petrosen) led by BP signed a 20-year Lease and Operate agreement with Golar LNG for the charter of a floating LNG unit, for the liquefaction segment of the Grand Tortue Ahmeyim project. The FLNG facility will have an average design capacity of 2.45 mtpa of LNG and will use the Black & Veatch 'PRICO' liquefaction process.<sup>65</sup> The FLNG facility is a conversion of an LNG carrier, Gimi, that will enable it to be dispatched quicker to the project, though it has a smaller capacity than new build FLNG units.

In early 2020, the GTA project partners signed a 20-year Sale and Purchase Agreement (SPA) with BP Gas Marketing Limited for the sale of 2.45 million tonnes per annum of liquefied natural gas to be produced from the project's Phase 1.<sup>66</sup>

A simplified diagram of the GTA project (Phase 1) tolling structure is presented below. It should be noted that Kosmos Energy has announced that it is planning to sell down some of its interests in Mauritania and Senegal, but it is not clear yet how this will affect the GTA project shareholding.<sup>67</sup> Also, Phase 1 of this GTA LNG project is 100 per cent equity financed. Whilst, it is reported that the next two phases of the GTA project, if implemented, would be project finance funded.

**Figure 3: Simplified GTA Project Structure – Phase 1**



Source: Companies press releases and trade press articles

## GTA project - Status

The GTA gas field located 120 km from the shoreline has two gas reservoirs 2,000 meters below the seabed and has 15 Tcf of potentially recoverable natural gas reserves. The unprocessed gas will be transported from the field to a Floating Production and Storage Offload (FPSO) vessel with a processing capacity of 500 MMscf/d and capable of handling condensate. Then the processed gas is sent from the FPSO to the FLNG facility moored to a new near-shore breakwater. As indicated above, the FLNG unit

<sup>63</sup> BP (2018a). 'Major milestone achieved for BP-operated Tortue/Ahmeyim gas project', press release, 12 February. <https://www.bp.com/en/global/corporate/media/press-releases/major-milestone-achieved-for-bp-operated-tortue-ahmeyim-gas-project.html>

<sup>64</sup> BP (2018b). 'BP announces Final Investment Decision for Phase 1 of the Greater Tortue Ahmeyim LNG development', press release, 21 December. <https://www.bp.com/en/global/corporate/news-and-insights/press-releases/bp-announces-final-investment-decision-for-phase-1-of-the-greater-tortue-ahmeyim-lng-development.html>

<sup>65</sup> Golar LNG (2019). 'Golar LNG enters into an agreement to supply a FLNG unit to BP for phase 1 of the Greater Tortue / Ahmeyim Project, West Africa', press release, 26 February. <https://www.golarlng.com/investors/press-releases/pr-story.aspx?ResultPageURL=https://www.globenewswire.com/HexMLItem/Content/FullText/Attachments/All/Identifier/1742531/language/en>

<sup>66</sup> Kosmos Energy (2020). 'Greater Tortue Ahmeyim Sale and Purchase Agreement Signed with BP Gas Marketing', press release, 12 February. <http://investors.kosmosenergy.com/news-releases/news-release-details/greater-tortue-ahmeyim-sale-and-purchase-agreement-signed-bp-gas>

<sup>67</sup> Kosmos Energy (2020). '1Q 2020 Results', 11 May. <http://investors.kosmosenergy.com/static-files/3bd3f0ef-3129-415d-94b8-841eb6938eca>



will have a design capacity of 2.45 mtpa or just over 3 Bcm per annum of gas to cover the project's Phase 1.<sup>68</sup>

Initially, the commissioning of Phase 1 of the Grand Tortue Ahmeyim gas project was scheduled to take place in 2022. In early April 2020, Golar LNG received notification of a force majeure claim from BP stating that 'due to the recent outbreak of the novel coronavirus (COVID-19) around the globe, BP is not able to be ready to receive the floating liquefied natural gas facility "GIMI" on the target connection date in 2022'.<sup>69</sup> In its 2020 second quarter results presentation on 4 August 2020, BP stated that 'GTA operations are severely affected by COVID-19 and the 2020 weather window for installation works can no longer be met resulting in a delay of around one year'.<sup>70</sup>

Furthermore, the final investment decisions for Phase 2 and Phase 3 of the GTA project which were planned for 2020 have been delayed as well. These phases FIDs will be considered after the commissioning of Phase 1 in 2023 and when it is 'up and running'.<sup>71</sup> Phase 2 and Phase 3 are each planned to have an LNG production capacity of 3.75 mtpa. In total the three phases of the GTA LNG project would form an 'LNG hub' of about 10 mtpa. Pre-front end engineering design work has already been carried out for the additional two phases.<sup>72</sup> Phase 2 and Phase 3, if implemented, would require an expansion of the project's FPSO capacity, as the existing 500 MMscf/d FPSO capacity is to cover Phase 1 only. Furthermore, instead of the FLNG option being developed for Phase 1, fixed platforms in shallow waters are considered for Phases 2 and 3 (KBR, 2019).

In a conference presentation in early September 2020, Kosmos Energy announced that total execution of Phase 1 of the GTA project was over 40 per cent complete and provided the following project status information for the project's four key work streams:<sup>73</sup>

- Subsea: about 32% complete - 251 km of the 308 km line pipe have been completed
- FPSO: about 43% complete - 291 of 387 Hull / Living Quarter blocks constructed
- FLNG: about 55% complete - major equipment packages delivered. Site workforce to ramp up through August
- Breakwater: about 36% complete - delivery of rock continues despite shutdown of caisson construction yard

### Planned other LNG hubs

In addition to the about 10 mtpa GTA 'LNG hub' with its three phases, two other LNG hubs were initially planned or considered to develop and monetize other natural gas resources discovered in Mauritania and Senegal. Yakaar/Teranga in Senegal and Bir Allah in Mauritania.

The Yakaar/Teranga 'LNG hub' would be supplied with gas from the Yakaar and Teranga gas fields in Senegal's Cayar Offshore Profond block (see section on natural gas potential). These fields have about 25 Tcf of gas initially in place (GIIP). This LNG project would have also an ultimate total LNG capacity of about 10 mtpa of LNG. According to Kosmos Energy, the project would use a 'fixed platform in

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<sup>68</sup> BP (2018). 'New Chapter for Africa's energy story', <https://www.bp.com/en/global/corporate/news-and-insights/bp-magazine/new-chapter-for-africa-energy-story.html>

<sup>69</sup> *GlobeNewswire* sourced from Golar LNG (2020). 'FLNG Gimi Force Majeure claim', 7 April. <https://www.globenewswire.com/news-release/2020/04/07/2012917/0/en/FLNG-Gimi-Force-Majeure-claim.html>

<sup>70</sup> BP (2020). 'BP p.l.c. Group results - Second quarter and half year 2020', 4 August. <https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/investors/bp-second-quarter-2020-results.pdf>

<sup>71</sup> Kosmos Energy (2020). '1Q 2020 Results', 11 May. <http://investors.kosmosenergy.com/static-files/3bd3f0ef-3129-415d-94b8-841eb6938eca>

<sup>72</sup> KBR (2019). 'KBR Awarded Pre-FEED Contract for Phases 2 and 3 of BP's Greater Tortue Ahmeyim Project', wire release, 09 April. <https://www.kbr.com/en/insights-events/press-release/kbr-awarded-pre-feed-contract-phases-2-and-3-bps-greater-tortue>

<sup>73</sup> Kosmos Energy (2020). Presentation at 'Barclays CEO Energy-Power Conference', September. <http://investors.kosmosenergy.com/static-files/2e81dc20-174a-4193-bce6-93f25a1a227b>





shallow water or an onshore plant' sited near Senegal's capital Dakar.<sup>74</sup> Although a phased development is envisaged, as in the GTA LNG project, the scale of this Senegal LNG hub remains challenging in today's uncertain gas market environment.

The second planned LNG hub would be located in the Bir Allah area in Mauritania's C8 block (see section on natural gas potential), which is estimated to hold about 50 Tcf of GIIP. This area holds a much bigger gas potential than the GTA field or the Yakaar\Teranga gas fields. As for the Senegalese LNG hub, this separate Mauritania LNG project would have also an ultimate LNG capacity of about 10 mtpa and would use a fixed platform. Its implementation would also face a challenging situation.

### Challenging planned LNG capacity

A total capacity of 30 mtpa of LNG is planned or considered over the next decade for the whole Mauritania and Senegal subregion. This is equivalent to about 40 per cent of Qatar's pre-expansion LNG capacity and more than twice the capacity of the initial phase of the Mozambique LNG project. It is a relatively large LNG capacity to develop in a new potential natural gas province in Africa over a period of significant economic and energy market uncertainties.

Moreover, according to BP's presentation of its second quarter results for 2020, BP announced that it is targeting an LNG portfolio of 30 mtpa by 2030.<sup>75</sup> Based on BP's current participation interests in the GTA project and in the upstream segments of the other planned LNG hub projects in Mauritania and Senegal, this would result in a total of 18 mtpa of equity LNG for BP's total share or the equivalent of 60 per cent of its newly announced LNG portfolio target for 2030. Notwithstanding the commercial viability of these planned LNG hubs, this potential share of Mauritanian and Senegalese LNG capacity could be quite high given BP's existing LNG portfolio of 15 mtpa; BP's forthcoming equity and merchant LNG positions in different regions of the world, including Africa; and, its objective of having a balance of equity and merchant LNG supplies in its portfolio.

In terms of natural gas resource potential, Mauritania and Senegal's combined total of 100 Tcf of gas initially in place could, in theory, support the total planned LNG export capacity of 30 mtpa. However, its development and implementation would present significant multifaceted challenges.

## V. LNG EXPORT CHALLENGES

### Cost competitiveness challenges

At present, only Phase 1 of the GTA LNG project is being developed. The relatively small LNG output (2.45 mtpa) of this first phase has already been sold and should not be an issue for the project. Of critical importance to the potential development of Mauritania and Senegal as a new African gas province are the development prospects of the next two phases of the GTA project and the planned separate LNG hubs in Mauritania and Senegal. These would account for 92 per cent of the above-mentioned total planned or considered LNG capacity of 30 mtpa for the two countries.

Before the COVID-19 outbreak, the task of developing such a large LNG capacity over the next ten years was already a challenge. This pandemic has worsened an already uncertain situation in international gas markets. As indicated recently by BP, can LNG produced from Mauritania and Senegal be 'competitive enough' and can it be 'low-cost and competitive' against Henry Hub-based LNG exports?<sup>76</sup> Furthermore and critically important, can the Mauritania and Senegal gas projects meet the

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<sup>74</sup> Lewis, I. (2019). 'Orca find boosts Mauritania LNG prospects - Kosmos makes the year's largest deepwater gas discovery', *Petroleum Economist*, October. <https://www.petroleum-economist.com/articles/midstream-downstream/lng/2019/orca-find-boosts-mauritania-lng-prospects>

<sup>75</sup> MarketScreener (2020). 'BP 2Q 2020 results: Webcast Q&A transcript', 4<sup>th</sup> August. <https://www.marketscreener.com/BP-PLC-9590188/news/bp-2Q-2020-results-Webcast-Q-A-transcript-31061980/>

<sup>76</sup> MarketScreener (2020).





conditions of BP's recently announced 'investment hurdles'?<sup>77</sup> According to Kosmos Energy, LNG from the GTA project has 'a breakeven FOB (free on board) price of less than \$5 per MMBtu'.<sup>78</sup> However, in a world where LNG exporters are likely to continue to be price takers, the first relevant factor is the level of gas prices that will prevail in international markets and how they will evolve over time relative to the GTA LNG delivered cost. Then the issue of how this delivered cost will rank against that of other LNG exporters will have to be considered.

LNG supplies from the GTA LNG project and potentially from other LNG projects in Mauritania and Senegal are planned for the period 2023/24 and beyond. Therefore, the critical question to address is how would gas prices move over the 2025 - 2030 period (and beyond) in gas export markets?

### **Delivered costs and potential price movements**

The following overview of natural gas price movements is based on a July 2020 market modelling analysis carried out by the Oxford Institute for Energy Studies (OIES) and presented in its Quarterly Gas Review.<sup>79</sup> Assumptions used, and other relevant information, are presented in this review of gas markets.

The multidimensional crisis situation (oil and gas price collapses and COVID-19 pandemic) is expected to have a long-lasting impact on the world's economies. Over the next five years, economic recovery could go through a W shaped pattern if the current concerns about a possible wider second wave of the pandemic are confirmed. On the demand side and after 2021, China, the Middle East and North America are expected to drive gas demand growth in volume terms. The rest of Asia-Pacific's demand growth will rank fourth after these regions. In Europe, it is only in 2025 that gas demand is predicted to return to its 2019 level. Over the period to 2025, total LNG imports are projected to rise by about 75 Bcm, but Europe's LNG imports are expected to be reduced by 34 Bcm. Imports from the Middle East and North Africa region and Americas rise by 10 Bcm, with the wider Asia region up by 100 Bcm (40 Bcm from China, zero from Japan, Korea and Taiwan, and the balance from other Asian markets).

Starting from 2021, the growth in LNG export capacity is expected to slow down with few new LNG projects being commissioned over the next three years, including Phase 1 of the GTA LNG project. As a result, the aforementioned return in gas demand growth post 2021 could push up spot prices (TTF and Japan spot) significantly until about the middle of this decade. But, except for 2024, when markets tighten, prices are not expected to rise much above \$6 per MMBtu. Between 2025 to 2030, Europe's gas price benchmark, TTF, is assumed to move around an average price level of \$6 per MMBtu. In Asia, the Japan spot price is assumed to get close to \$7 per MMBtu over the same period to 2030.

Can Mauritania and Senegal's potential LNG exports be 'cost competitive enough' to penetrate markets at these natural gas price levels? This is a complex question to address in today's unpredictable gas markets and the lack of clear visibility beyond the next year or so. On the supply side, there are no publicly available data on the cost structure of the GTA LNG project. Therefore, to provide some high-level indication of possible answers to the above critical question, two scenarios are assumed for the breakeven FOB price of the GTA LNG project.

In the first scenario, a breakeven FOB price of \$4.50 per MMBtu, or less than \$5 per MMBtu, is assumed, as indicated by Kosmos Energy. The second scenario assumes a breakeven FOB price of \$5.50 per MMBtu. Estimates of shipping and regasification costs, where applicable, are added to derive delivered gas costs ex-regas (Europe) or ex-ship (Asia). In the following four figures, these scenario-based delivered costs are presented against assumed gas market prices in Europe (TTF) and Asia

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<sup>77</sup> BP (2020).

<sup>78</sup> Kosmos Energy (2020). 'CEO Andrew Inglis on Q1 2020 Results - Earnings Call Transcript', 11 May.

<https://seekingalpha.com/article/4346265-kosmos-energy-ltd-kos-ceo-andrew-inglis-on-q1-2020-results-earnings-call-transcript>

<sup>79</sup> Oxford Institute for Energy Studies (2020). 'Quarterly Gas Review: Short and Medium Term Outlook for Gas Markets', July.

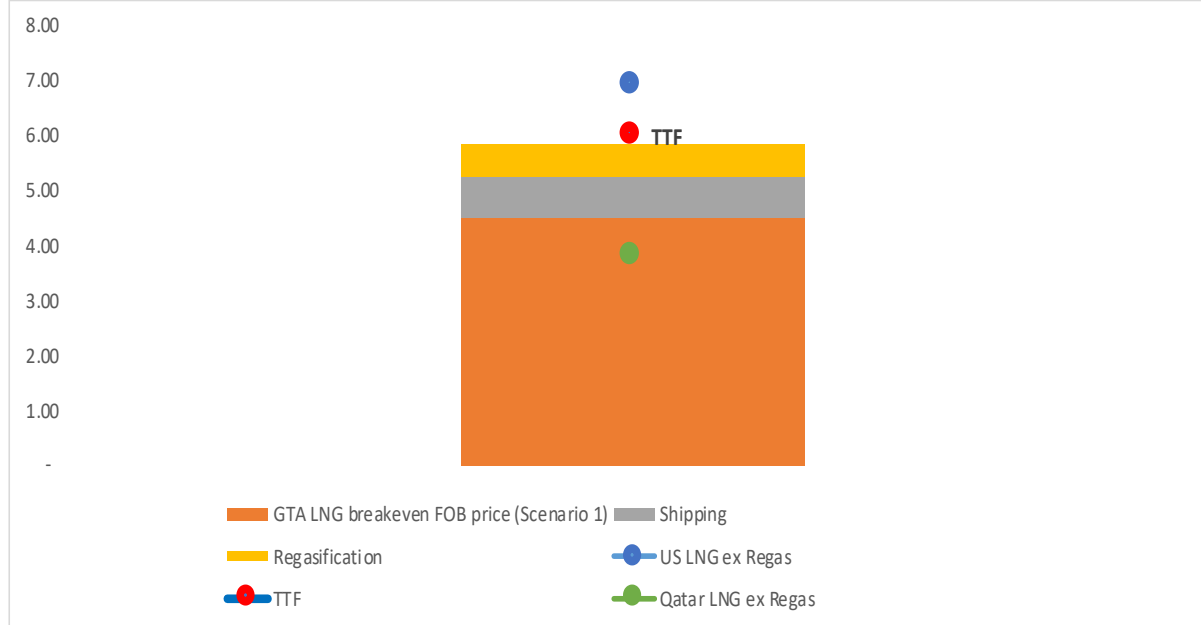
<https://www.oxfordenergy.org/wpcms/wp-content/uploads/2020/07/Quarterly-Gas-Review-Issue-10.pdf>



(Japan spot) along with an estimation of the delivered costs of some key LNG competitors, US Gulf Coast (US GC) and Qatar, to these two key LNG markets.

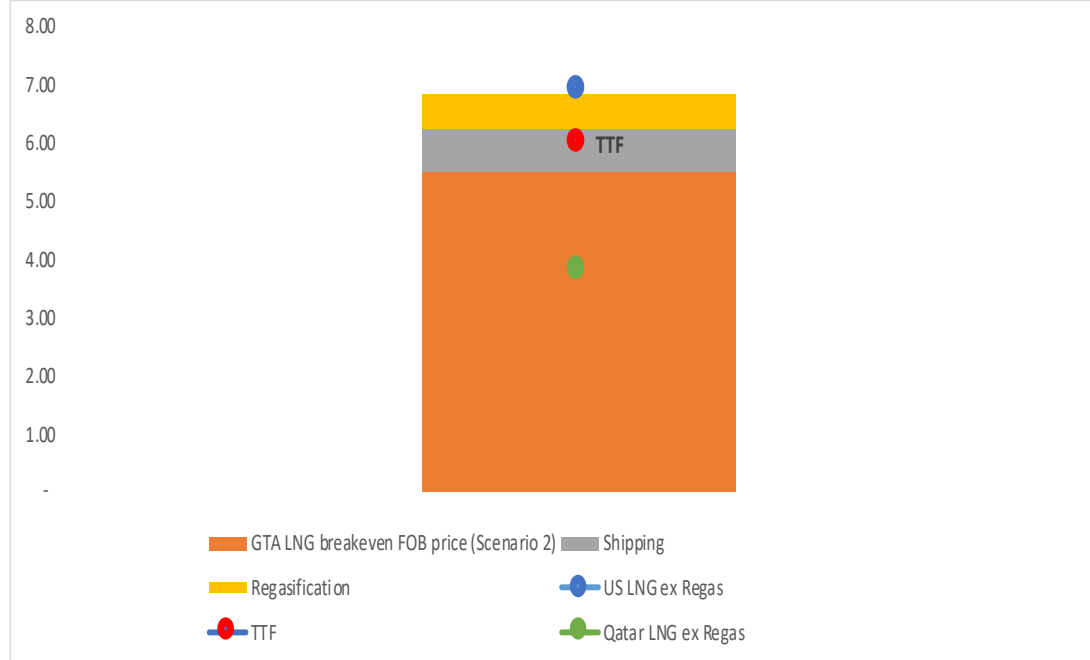
It should be stressed that Europe and Asia are not the only export markets that could be targeted by potential Mauritanian and Senegalese LNG exports. Latin America would also be a potential market and possibly some African countries. On the supply side, Qatar and the US are obviously not the only LNG competitors. In this paper, however, analysis is limited to a few key markets and LNG exporters.

**Figure 4: Scenario 1 - GTA LNG delivered cost to Europe (averages 2025–2030, \$ per MMBtu)**



Source: OIES estimates

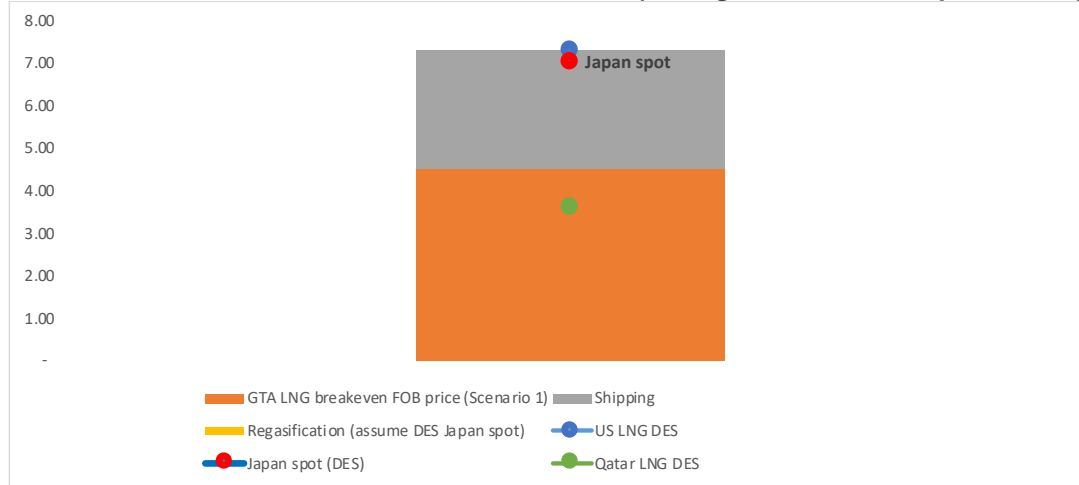
**Figure 5: Scenario 2 - GTA LNG delivered cost to Europe (averages 2025–2030, \$ per MMBtu)**



Source: OIES estimates

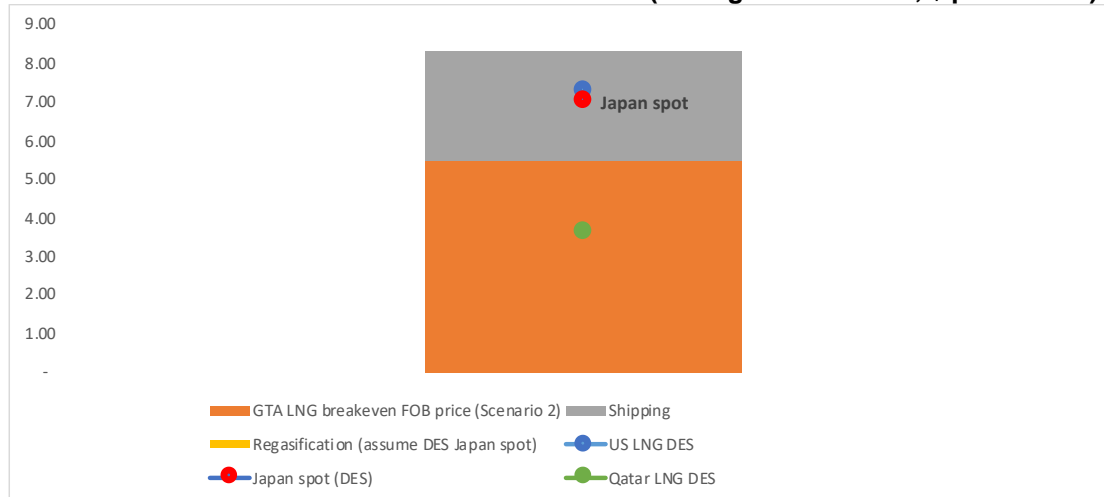


**Figure 6: Scenario 1 - GTA LNG delivered cost to Asia (averages 2025–2030, \$ per MMBtu)**



Source: OIES estimates

**Figure 7: Scenario 2 - GTA LNG delivered cost to Asia (averages 2025–2030, \$ per MMBtu)**



Source: OIES estimates

A review of the above scenario results shows the following:

- If the GTA LNG is produced at a breakeven FOB price below \$5 per MMBtu, as assumed in Scenario 1, GTA LNG could be delivered into Europe at a cost less than the assumed average TTF price of \$6 per MMBtu. In Asia (Japan), GTA LNG under this first scenario could be delivered at a cost just above the assumed average Japan spot price of \$7 per MMBtu. However, these European and Asian gas market prices if they persist over a long period of time would result in continued limited or very limited returns for the developers and investors of the GTA LNG project.
- Under the second scenario, with an assumed GTA LNG breakeven FOB price above the \$5 per MMBtu mark, GTA LNG would be priced out of both the European and Asian gas markets.
- As expected, Qatar is by far the lowest cost LNG supplier to both markets.
- Under the above-mentioned assumed gas market prices and for Scenario 1, GTA LNG exports to Europe are more cost competitive than US GC LNG exports and as cost competitive as US GC LNG supplies for the case of exports to Asia. For Scenario 2, GTA LNG exports to Europe are about as cost competitive as US GC LNG exports. However,



under this second scenario, GTA LNG exports to Asia are not cost competitive compared to the delivered cost of US GC LNG exports and their delivered cost is well above the assumed average Japan spot price of \$7 per MMBtu.

In the case of potential LNG exports from Mauritania-Senegal to Asia, the issue of shipping will need to be looked at as these LNG exports will require more ships than for supplies to Europe.

The emphasis here is that the above results reflect the cost assumptions used for the two scenarios and the assumed gas market prices in Europe (TTF) and Asia (Japan spot). Consideration should also be given to the fact that the addition of the next two phases of the GTA LNG project could produce LNG at lower breakeven costs given the pre-investments made during the project's first phase that Phases 2 and 3 will benefit from;<sup>80</sup> the use of fixed platforms as opposed to FLNG facilities, and the higher combined LNG output.

Given the resilience of US gas producers/LNG exporters and their ability to quickly adjust to market changes, the competitiveness of US LNG exports should be carefully considered. Moreover, the procurement of US LNG exports provides a lot more contractual flexibility than the rigid long-term contracts that have underpinned LNG exports from new LNG projects in West Africa. Thus, potential Mauritanian-Senegalese LNG exports may require the involvement of an aggregator such as BP Gas Marketing or another portfolio holder.<sup>81</sup> This aggregator or intermediary would put these LNG supplies in its portfolio and optimise it to maximize returns.

In conclusion to this section, there is definitely a need to continue to focus on cost reduction efforts if new Mauritania and Senegal LNG projects, like the GTA project, aspire to enter international markets at assumed market prices hovering between \$6 and \$7 per MMBtu over the second half of this decade. Furthermore, the challenge is not only to cut costs enough to meet these gas prices. It is also about generating project returns acceptable to LNG developers and investors, something that has eluded them in recent years and that could not be sustainable in the long term.

A corollary to this key conclusion is the fact that the development of the separate Mauritania and Senegal LNG projects could take longer to develop, especially the one in the Bir Allah area. The Yakaar-Teranga gas development in Senegal could find a local market for a portion of its potential gas output, before considering potential LNG exports. But the dilemma would be to find developers and investors willing to invest in selling gas to small size domestic markets, whilst waiting for the next favourable LNG export market opening.

In these uncertain and extraordinary times (to avoid using the now clichéd 'unprecedented times'), the possibility of a strong and sustained tightening of LNG supplies post-2025 to 2030 cannot be eliminated. This would coincide with the planned commissioning period of the above-mentioned LNG projects under consideration in both Mauritania and Senegal although decisions to invest in these projects would need to be taken in the next few years.

## VI. CONCLUSIONS

With a total of 100 Tcf of natural gas initially in place of which about 60 Tcf could be technically recoverable, Mauritania and Senegal have potentially the natural gas resources to become a new African gas province. However, the two countries will have to go through a protracted and challenging process to fully realize this objective. The full development of all these gas resources into recoverable gas reserves requires the securing of commercially viable and sustainable gas monetization options to attract all the necessary investment. These options include domestic utilization of the gas, gas exports or both. Although domestic monetization tends to be preferred by governments and their policy decision makers, the relevance of the gas export option will depend on the sizes of domestic gas markets.

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<sup>80</sup> Kosmos Energy, 2020.

<sup>81</sup> As indicated above, BP has put a cap on the size of its targeted LNG portfolio by 2030. Therefore, including more LNG supplies and from the same source in its portfolio could be difficult.





In the case of Mauritania and Senegal, first, there is a difference in potential gas market sizes between these two countries. Due to the different sizes of their populations and economies, the potential level of domestic gas utilization in Mauritania in 2030 is estimated at between 30 and 40 per cent of Senegal's potential domestic gas market. Together, Mauritania and Senegal could potentially consume between about 2.1 and 2.6 Bcm of gas by 2030. This is an extremely limited domestic gas market potential relative to the two countries' reported gas resource base. Therefore, the transformation of this area of Africa's MSGBC geological basin into a new natural gas province will undoubtedly need to be underpinned by commercially viable and sustainable LNG exports. In fact, this is what Mauritania and Senegal and their international partners, BP and Kosmos Energy, are focusing on to develop the province's natural gas potential.

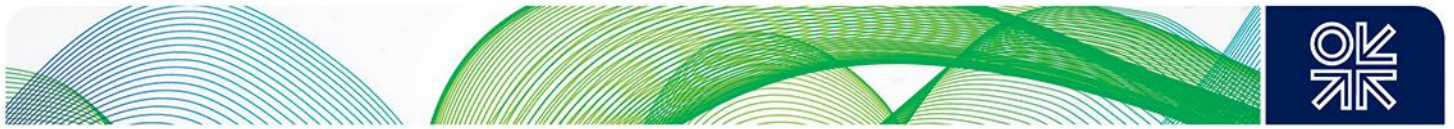
The first phase of a joint Mauritania-Senegal LNG export project, Grand Tortue Ahmeyim (GTA) LNG, is currently under development. The LNG output (2.45 mtpa) of this initial phase has already been sold on a long-term basis to a portfolio holder, BP Gas Marketing. In order to capture all the benefits of their complete gas resource potential, Mauritania and Senegal and their partners have planned a significant LNG export capacity expansion beyond the GTA project's Phase 1. This planned or under consideration expansion includes the next two phases of the GTA LNG project and two new 'LNG hubs', one in Senegal and another one in Mauritania. This would increase the two countries potential LNG export capacity from about 2.5 mtpa to about 30 mtpa. This is an ambitious and very challenging capacity to develop in today's highly uncertain natural gas markets.

Furthermore, based on BP's current participation interests in Mauritania and Senegal, sixty per cent of this planned LNG capacity or a total of 18 mtpa would be BP's equity LNG share. This could be quite high given BP's existing LNG portfolio of 15 mtpa and BP's objective of having a balance of equity and merchant LNG supplies in a portfolio capped at 30 mtpa by 2030. There is the possibility of new partners joining these LNG projects resulting in a redistribution of the size of the projects shares. However, the relevant fundamental question, regardless of shareholding structure and size, is the commercial viability of developing such a large LNG export capacity over the next ten years. More specifically, the levels of gas pricing that will prevail in gas export markets and how they will evolve over time relative to the delivered cost of LNG supplies from Mauritania and Senegal and how cost competitive these supplies would be.

A high level scenario analysis of the delivered costs of the GTA LNG project shows that if the GTA LNG is produced at a breakeven FOB price of \$4.50 per MMBtu, GTA LNG could be delivered into Europe at a cost less than an assumed average TTF price of \$6 per MMBtu by 2030. Assuming the same breakeven FOB price, GTA LNG could be delivered into Asia at a cost just above the assumed Japan spot price of \$7 per MMBtu by 2030. However, these assumed European and Asian gas market price levels if they persist over a long period would significantly squeeze the returns for developers and investors in Mauritania and Senegal's LNG export projects. These projects developers and investors will also have to consider the cost competitiveness of their LNG supplies vis-a-vis competing LNG exports such as those from the US Gulf Coast.

Therefore, if new Mauritania and Senegal LNG projects, like the GTA LNG project, are to enter international markets with market prices assumed to hover between \$6 and \$7 per MMBtu over the second half of this decade, cost optimization efforts will have to continue. In an era where gas exporters are likely to continue to find themselves in a price taker situation, all project stakeholders, including governments, national and international oil and gas companies will have to be mobilized and focused on these efforts and also adopt flexible contractual approaches. Moreover, the challenge is not only to reduce costs relative to international gas prices, it is also to ensure that LNG exports generate levels of project returns that are acceptable to LNG developers and investors. Recently, this has not been the case for most LNG exporters and is definitely not a sustainable situation in the long term.

Nevertheless, attention should be drawn to the highly uncertain nature of natural gas market dynamics and a look at the history of international natural gas markets shows the number of unexpected changes markets went through and continue to do so. Consequently, one possible scenario is where a strong and sustained tightening of LNG supplies takes place during the second part of this decade and beyond.



This would provide renewed opportunities and confidence for LNG export projects such as those planned or under consideration in Mauritania and Senegal.

However, to be ready to get access to and compete in these markets, investment and risk mitigation decisions would need to be taken during the next three years or indeed well before 2025. There is also the prospect that new players with different strategies and priorities could join the planned gas projects in Mauritania and Senegal, if some of the current project stakeholders reduce or sell down their interests in those projects. Kosmos Energy has already decided to sell down some of its Mauritania and Senegal interests.

Before attempting to answer the question posed at the beginning of this paper about whether it is still possible that Mauritania and Senegal can emerge as a new African gas province, it is important to underline two key achievements of the launching of the GTA gas development project. Achievements that are also considered as key incentives for future gas projects in this subregion. First, the high degree of cooperation and commitment between the Mauritanian and Senegalese governments to make the GTA project happen. Second, notwithstanding factors such as adverse gas market conditions and the COVID-19 health crisis, the ongoing implementation of Phase 1 of the GTA LNG project in partnership with two international oil and gas companies, including a major, has opened up this province to potential new gas investments, even if they are going to take some time to materialize. Finally, it is still too early to establish whether Mauritania and Senegal could become a new African gas province and how long it will take to reach this position. The jury is still out, but the journey has already started, and it is going to be a long and challenging one.