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LNG for Africa

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About KAPSARC

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Key Points

Though Africa is traditionally considered as an exporter of pipeline gas and liquefied natural gas (LNG), in future it could come to be seen as an LNG market. Until recently, financing issues, market conditions, price sensitivity and the small size of the individual gas markets were all strong deterrents to sellers looking at Africa as an LNG destination, even though the region's per capita energy consumption is very low and there are hundreds of millions without electricity and modern cooking facilities. But now the situation has fundamentally changed because, faced with the slowdown in Asian LNG demand and a global LNG oversupply, sellers are looking for new markets. At the same time, LNG has become more affordable, more flexible and is increasingly sold on a spot basis. So now, gas can be part of the solution to developing Africa's electricity generation, along with renewables.

Most African countries would need small initial volumes to feed the integrated LNG-to-power projects that sponsors are considering. This could lead to a further development of gas demand in other sectors as gas supply becomes available and infrastructure is developed.

The majority of countries are opting for floating storage and re-gasification units (FSRUs), enabling faster implementation.

The new markets could benefit from the proximity of existing African LNG suppliers, and future projects in Cameroon and Eastern Africa as suppliers optimize shipping distances.

The key issues of financing and the role of the state see investors looking for governments to provide regulatory and political clarity to prospective sellers, financial institutions to facilitate access to capital and LNG suppliers that will accept the risk of delivering to these new markets. The choice of pricing mechanism and contract commitment will be key for their viability.

The intended gas and power markets for these new LNG projects will only be developed if domestic gas and electricity buyers can secure their offtake liabilities and ability to pay for the energy to the satisfaction of lenders.

Summary

The idea that Africa could become an LNG destination is not new. It has been proposed for many years in countries as far apart as South Africa, Morocco and West Africa. Sellers' attention, though, was previously directed toward the more lucrative and larger Asian markets and traditional creditworthy buyers able to commit to a 20-year oil-indexed long-term contract. But over the past two years the global LNG market situation has radically changed. Global gas markets are currently oversupplied, and this glut could last until the middle of the next decade. Consequently, sellers are actively seeking new markets and offering innovative new models that may suit riskier new LNG buyers. LNG imports into Africa became a reality in 2015 with Egypt and many African countries are considering following suit, given the product's current affordability.

As the gas industry ponders how to bring an end to its new Dark Age (KAPSARC 2015), developing gas markets in Africa could be one solution. Gas is also an opportunity for Africa, so long as it remains affordable. Sub-Saharan Africa is starved of electricity. Despite many initiatives, power capacity is still lagging behind population growth and hampering gross domestic product (GDP) growth. Africa's future economic development is directly linked to its ability to develop its power sector, for which there is a range of different options depending on the country in question, its natural resources and existing power infrastructure – with both centralized and decentralized solutions available. Developing coal-fired generation looks more compromised since the resolutions of the 2015 Paris Climate Conference (COP21), while the development of capital-intensive nuclear capacity looks even more challenging. This leaves gas and renewable energies as the main options for extending access to electricity.

A key question for Africa, as for many developing countries, is whether customers will be willing to pay an environmental premium for power. For remote applications, though, renewable options may in fact be the cheaper option. Both Shell and Total recently highlighted how LNG could help bring power to Africa by creating an integrated LNG-to-power project (Smedley 2016). Indeed, most projects that have recently emerged are LNG-to-power projects, using power plants as anchor customers (see Table 1). Many international financial institutions tend to favor renewables against gas, but gas could provide opportunities as a source of baseload power in urban areas, as a complement to intermittent renewable generation and as a fuel source for the industrial sector.

Intraregional gas trade in Africa has remained limited so far. This leaves LNG imports as the main solution to empower resource poor African countries. As of late 2016, the list of potential LNG importers includes Morocco, Senegal, Côte d'Ivoire, Benin, Ghana, Kenya, Namibia, Sudan and South Africa. Only Ghana so far has a floating storage regasification unit (FSRU) on site, albeit not yet operational. Africa could be a growing LNG importer: while individual countries represent small volumes – all markets begin small (0.5-2 million metric tons per year, mtpa) – the aggregate could be significant in the medium term. A further development of demand in other sectors is also envisaged. The short shipping distances to neighboring producers could make these markets more attractive. By 2020, five Africa countries will export LNG, with Mozambique and Tanzania potentially joining them later.

The road to developing LNG imports may be a long one, though. The key issue is how to attract investors and reduce the risks, given the initial small size of markets, the countries' low credit ratings, low domestic energy prices and higher project risks. Most projects have opted for the more flexible FSRU, which can be put more rapidly into operation, has lower capital costs, and is often leased rather

than bought by the investor. This solution also gives the operator the option to remove the facility and redeploy it elsewhere, should domestic production grow to levels sufficient to enable self-sufficiency, or should there be any issue such as payment default – for example through insufficient revenues, as electricity prices often do not reflect the cost of generation. Redeployment is, of course, only possible if there is a market for the FSRU elsewhere. Past experience in Puerto Rico and the Dominican Republic shows that bundled power and LNG projects which have a complementary LNG sale and purchase agreement (SPA) and power purchase agreement (PPA) have a key advantage (Haug and Cumberland 2013).

A lot remains to be done in Africa's power sector to ensure LNG-to-power projects are viable and to create an environment that is conducive to investments. In particular, governments need to provide regulatory and political clarity to prospective sellers. This includes setting up a transparent legal and regulatory regime for the power and gas sectors with transparent rules governing electricity transactions and network access; tariffs reflecting the true costs of electricity; the development of a project structure adapted to the market environment, ensuring that a credible buyer exists, seeking support from external institutions to guarantee the risks; and, finally, supporting the projects themselves. Financial institutions need to facilitate the access to capital and LNG suppliers to accept the risk of delivering to these new markets and building the gas and power infrastructure. Investors must also carefully analyze the gas and power markets that their project will serve in order to understand the risks associated. Lenders must also scrutinize the domestic gas and electricity buyer's offtake liabilities and ability to pay for the energy.

Introduction

Understanding the energy demand picture in potential African LNG importers

This report focuses on those African countries which have a coastline and are able to build their own LNG import terminal, but which do not have sufficient domestic gas production to meet their needs over the short to medium term. Accordingly, it excludes countries such as Nigeria, Mozambique and Tanzania, even though Mozambique also has a proposed LNG import project. Nor do we consider landlocked resource-poor countries in this report because they would need to build additional gas and power transmission infrastructure. This is not to imply that landlocked markets could not benefit from the development of LNG import infrastructure through the development of regional infrastructure projects, but this would be in a second phase. In practice, though, most import projects considered so far are aimed at domestic markets, with the exception of the project in Benin.

The countries considered here include, in alphabetical order: Benin, Congo, Côte d'Ivoire, Djibouti, the Democratic Republic (DR) of the Congo, Egypt, Eritrea, Gabon, Gambia, Ghana, Guinea, Guinea-Bissau, Kenya, Liberia, Mauritania, Morocco, Namibia, Senegal, Sierra Leone, Somalia, Sudan, South Africa, Togo and Tunisia. The population of these countries totals 495 million as of 2015, with Egypt (92 million), the DR of the Congo (77 million), South Africa (54 million) and Kenya (46 million) being the most populous (see Figure A1 in the Appendices). For comparison, this total is 1.5 times the population of the U.S.

The total energy consumption of the largest countries was around 15.2 million Terajoules (TJ) in 2014. (The IEA does not provide individual statistics for Djibouti, Eritrea, Gambia, Guinea, Guinea-Bissau, Liberia, Mauritania, Somalia and Sierra Leone.

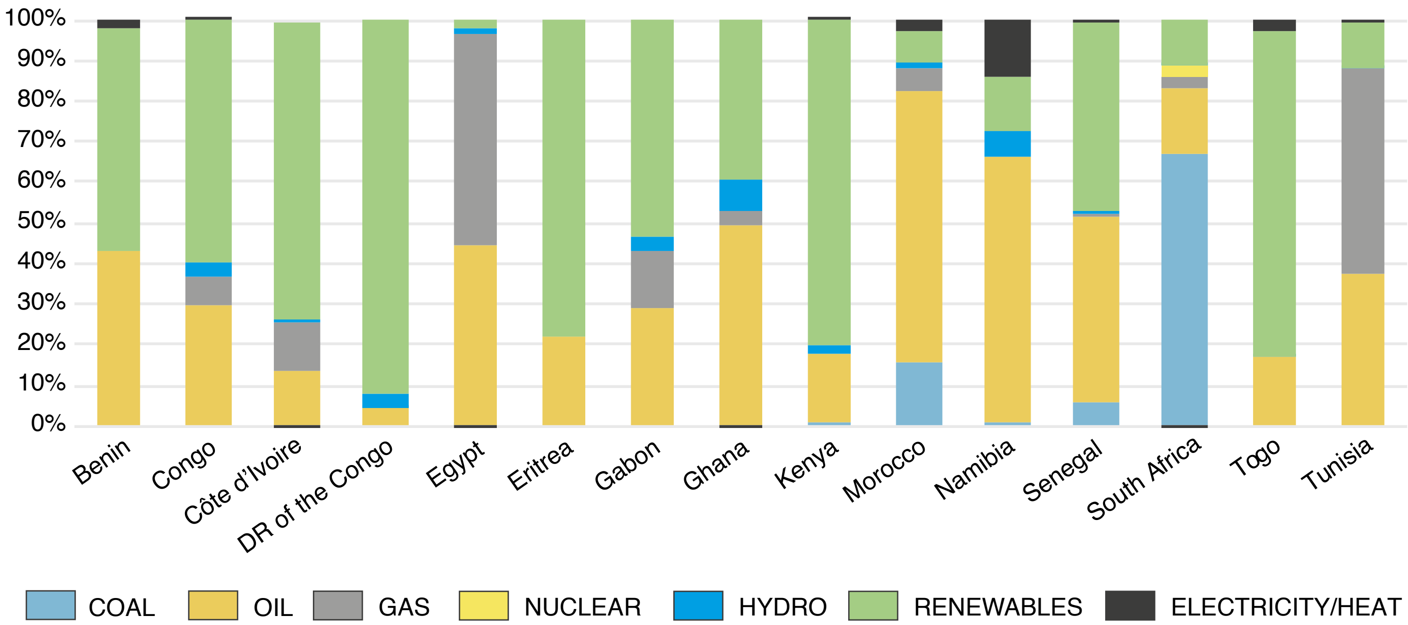

Figure 1. Primary energy demand mix by country (2013).

Source: IEA.

These countries are included with others in the 'Other Africa' group which together consumed around 2.9 million TJ in 2014). Egypt and South Africa represent together 9.3 million TJ. All other countries individually consume less than 1 million TJ, except for the DR of the Congo. If consumption of biomass – defined by the IEA as 'primary solid biofuels' – is excluded, their primary energy consumption reaches only 11.1 million TJ. To put this in context, Germany consumed 13.1 million TJ in 2015 for a population of 80.7 million, while the U.S. consumed 91.4 million TJ.

The energy mix of most African countries for which data are available is largely dominated by renewables, mostly biomass, and oil used in transportation and power generation. Excluding Egypt, Ghana, Morocco, Namibia, South Africa and Tunisia, biomass represents more than half of primary energy demand (See Figure 1). Among the countries considered here, coal is mainly consumed in South Africa and Morocco. Meanwhile, Africa's gas consumption amounted to an estimated 135 billion cubic meters (bcm) in 2015 (BP 2016).

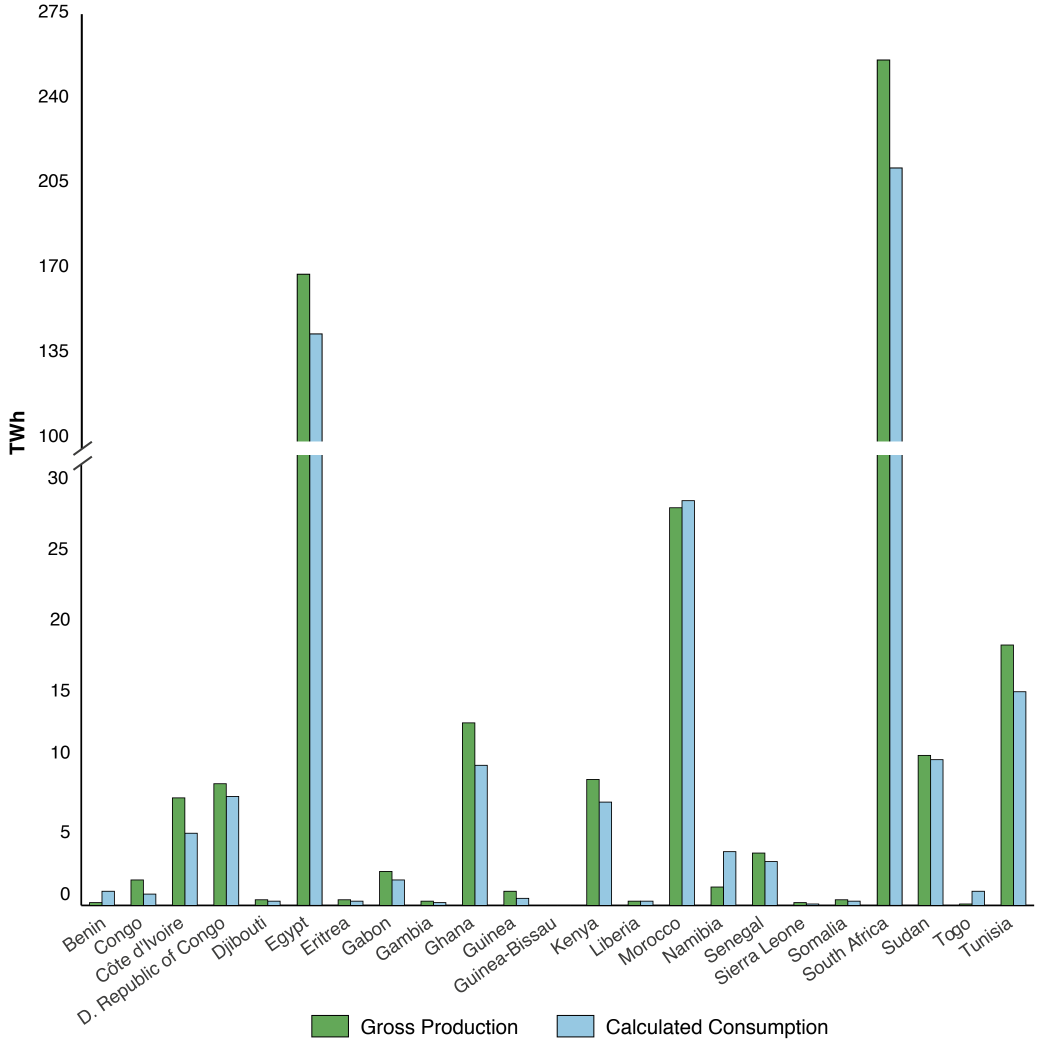

Figure 2. Electricity generation and consumption in selected African countries (TWh) (2013).

Source: UN data.

Egypt is the largest gas consumer in Africa (48 bcm), followed by Algeria (39 bcm) and Nigeria (18 bcm). The two latter are not included here as they are natural gas producers and exporters. Gas has a relatively important share in energy demand in Egypt and Tunisia, with the latter consuming 7 bcm in 2015. Besides those two countries, none of the markets considered here consumes more than 5 bcm.

There are around 600 million people without access to electricity in Sub-Saharan Africa (World Bank 2016). It has been estimated that around 210 million inhabitants in the countries studied here are without electricity (IEA 2015). The average national electrification rate in those areas is 32 percent, much lower than in North Africa. Electricity generated by these countries amounts to 531 terawatthours (TWh) and electricity consumed 452 TWh, similar to the electricity consumption of France. These numbers imply a significant loss factor. Two countries dominate the electricity generation and consumption picture: Egypt and South Africa (See Figure 2). Without them the electricity generated and consumed by the other countries amounts to only 107 TWh and 97 TWh, respectively. Table A1 in the Appendices shows the per capita electricity demand by country: most have a per capita power consumption lower than 400 kilowatthours (kWh), while the per capita average for Western European countries is 5,000-7,000 kWh.

Electricity consumption and economic development are closely linked. A review of over 40 studies by the Overseas Development Institute shows that energy use can be seen as either the cause or the facilitator of economic growth. Around three-quarters of the studies show a positive correlation between energy use and economic growth, while half reveal a positive and significant causal link from energy use to economic growth. In addition, the quality of power supply is important: insufficient and unreliable power supply constrains the development of businesses (CDC Group 2016). Countries with low electrification rates suffer from reduced per capita GDP. This is usually exacerbated by the high costs of electricity and, due to the unreliability of electricity supply, businesses have to use expensive diesel generators. The costs of emergency generation are in the range of $0.2 to $0.3/kWh, much higher than the cost of conventional generation (AfDB 2013). A step change in the power sector appears necessary in order for Africa to develop and industrialize in a viable manner.

The demand for electricity in Sub-Saharan Africa is undeniable and pressing. Consultants McKinsey forecast that by 2040 that region will consume as much electricity (1,570 TWh) as India and Latin America together in 2010 (McKinsey 2015). Gross national income in Sub-Saharan Africa has already tripled over the period 2003-15, according to World Bank data, albeit from a relatively low base, boosting household consumption (World Bank 2016). However the International Monetary Fund (IMF) projects GDP growth will slow down in 2016 and 2017 to 1.6 and 3.3 percent respectively, as against 5.1 percent in 2014 (IMF 2016). Insufficient generation capacity and transmission infrastructure and poor maintenance of existing power plants, together with poor metering and billing systems, are hampering investment in Sub-Saharan Africa, which is acting as a barrier to further economic growth (Deloitte 2015).

Initiatives addressing this issue already exist. In 2013, U.S. President Barack Obama launched the Power Africa Initiative seeking to “bring together technical and legal experts, the private sector, and governments to work in partnership to increase the number of people with access to power” (USAID 2016). Around $7 billion of U.S. government funds and another $43 billion from the public and private sectors have been raised (Chaar 2016), even though the initiative has delivered only 374 megawatts (MW) from six sizeable power projects so far (Clark 2016). Once President Obama steps down in January 2017, it will remain to be seen whether his successor will take the same interest in powering Africa. Meanwhile, institutions such as the World Bank are active through the Africa Energy project, which encompasses 48 projects representing investment of $3 billion. China is very active in Africa's power sector through investments in new electricity capacity additions, mostly coming from renewable energy. Beyond the issue of electricity is a more basic one: in 2012, around 730 million people in Sub-Saharan Africa heated their homes and cooked using traditional fuels like wood and dung (ONE 2016), which is neither healthy nor environmentally friendly.

The challenge of empowering Africa, coupled with innovative technologies for renewables and natural gas, could represent an opportunity to move away from traditional approaches and business practices to develop solutions more adapted to the unique characteristics of Africa's power challenges.

The Rise of LNG-to-Power Solutions

Why does gas make sense?

While Africa's demand for electricity is demonstrable, how to power it remains under debate. The electricity mix in the countries considered – excluding Egypt, where gas dominates – is heavily biased toward coal, due to the weighting of South Africa's power demand, followed by oil, which is the default solution for many resource-poor countries. Most of these countries want to diversify by adding renewable solutions – including off-grid and mini-grid solutions, as well as natural gas – to their power generation mix.

Many power generation development programs in Africa focus on renewables. These resources are domestic and their falling cost makes them increasingly commercially viable. They can also be used for remote applications. There are significant hydro resources which could generate 1,584 TWh per year, although it is uncertain how much of this capacity could move ahead (IRENA 2015). A large proportion is located in Central and Eastern Africa, for example in the DR of the Congo, where the Inga project has a total capacity of over 40 GW. Hydropower is less expensive than most technologies: costs in Africa are on average $0.1/kWh.

Africa's solar photovoltaic (PV) capacity has increased significantly, reaching 1,334 MW as of end-2014. In South Africa alone 780 MW was added between 2013 and 2014. Meanwhile 14 gigawatts (GW) of PV and 6 GW of concentrated solar power (CSP) are either announced or in the pipeline. As of March 2015, Algeria, Egypt, Morocco and South Africa had deployed around 180 MW of CSP projects while another 6.4 GW were underway. Wind power has also been growing, with around 2.5 GW of wind capacity installed at the end of 2014. Morocco has taken the lead in this. Additionally, 140 African wind farms totaling 21 GW are expected to become operational between 2014 and 2020. Investments are necessary, however, to bring power from the best wind locations to centers of demand, which can add from $0.05 to $0.2/kWh in terms of transmission costs. Finally, there is geothermal energy potential along the Rift Valley in Eastern and Southern Africa which could represent 15 GW. Capital costs for this have been increasing and range from $2,700/kW to $7,600/kW (IRENA 2015).

There are also large coal resources in Southern African regions, notably in South Africa, Botswana and Mozambique (IEA 2014). While the cost of power from LNG is less than from liquid fuels – assuming these prices are not subsidized – coal-fired plants are still more competitive than gas-fired plants (IEA 2015). However, unlike in Southeast Asia, very few African countries have coal-fired power plants or are considering coal for future power generation. In addition, financial support for coal from key lending institutions is declining. Though Sub-Saharan Africa includes large uranium resource-holders, nuclear power seems a far-fetched option, considering not least the high capital costs and long approval and construction times.

Many large funding institutions are giving priority to renewables as sources of sustainable energy. There is also a strong rationale for countries and power companies to consider natural gas. Not only for gas-rich countries such as Nigeria, Mozambique and Tanzania, but also for countries opting for imports, for example from LNG. Gas as a power generation fuel could be particularly relevant for developing African markets because of factors like cost-effectiveness, speed of construction, low capital risk and operational flexibility:

Capital costs for combined cycle gas turbine (CCGT) plants – and even more for open cycle gas turbine (OCGT) plants – are usually lower than alternatives (IEA 2015). Overnight costs for CCGTs in OECD countries range from $845 per kilowatt-electric (kWe) in Korea to $1,289/kWe in New Zealand.

In 2015, General Electric Co. calculated that gas-to-power solutions could deliver electric power at between $0.1/kWh (integrated LNG-to-power) and $0.15/kWh (small-scale LNG and distributed power). The integrated version, assuming a price for LNG of $9 per million British thermal units (MMBtu), represents a drop compared with reported costs of generating electricity in Africa ($0.18/kWh) (AfDB 2013).

Typical construction times of around two years are considerably less than for coal-fired and nuclear plants, of four and seven years, respectively (IEA 2015). This enables a faster response to power shortages.

Coal-fired and nuclear plants can face local opposition and take longer to build where institutional structures and electric grids are weak (Farina and Wilson 2015).

Gas-fired plants are flexible and can complement renewable energy sources; gas can act as an enabler for solar and wind energy by solving the intermittency problem.

Gas-fired solutions are modular and available from small scale (several MW) to large scale (hundreds of MW), recognizing that developing large scale power projects may not always be the best approach in some parts of Africa.

Some turbines are multifuel; LNG can thus replace oil when the technology of the turbine permits and oil products can be used should gas be unavailable.

LNG technology components (including FSRUs) are well established and available, diminishing the risks for the countries opting for such.

Gas-fired plants are very efficient (60 percent for a CCGT) compared with coal-fired plants (up to 47.5 percent) and existing oil-fired fleet (GE 2016).

Gas still fits with the COP21 objectives to move to lower carbon fuels. It emits less CO_2, NOx, SOx and particulate emissions (PM) than oil products.

Gas can be used in other applications such as industrial use – generation of heat and power or as raw material – transportation and cooking. The use of gas for heating is not relevant in Africa, but air conditioning units using gas could be used in commercial or administrative buildings.

However, gas may not be the best solution for remote inland areas, even if some small units exist.

An important consideration for these countries is the cost of generating electricity. LNG provides an opportunity to reduce dependency on oil products. But gas has to remain affordable beyond 2020 for those countries looking at LNG imports as a long-term solution.

There is still the need to develop a pipeline network, unless LNG is transported by truck as is done in China, but as previously noted, this is more expensive.

It is important to remember that residential electricity in African countries can be quite expensive, considering the low per capita incomes. According to a World Bank study, residential tariffs were more than $0.12/kWh as of 2010 in Senegal, DR of the Congo, Kenya, Benin, Côte d'Ivoire and Namibia. (This is also true in countries not considered here such as Burkina Faso, Cape Verde, Uganda, Madagascar, Mali and Chad). This meant that Africa's residential power prices were between 50 and 150 percent higher than the average residential tariffs in Latin America, Eastern Europe and East Asia (Cecilia Briceño-Garmendia 2011). Consequently, many companies have the problem of unpaid bills, threatening their finances and future investments (Reuters 2014) (Africa 2014).

Understanding the Challenges

LNG-to-power is seen as a new solution, particularly for the African LNG projects (see Table 1). However, as with any major energy development, to properly assess the risks it is necessary to fully understand the gas and power markets the proposed project will serve. Even though it is not as capital intensive as liquefaction – and many countries have opted for FSRUs – a combined LNG-to-power solution is likely to cost more than $1 billion and possibly more depending on the scale of the gas-fired capacity.

As demonstrated by Haug and Cumberland (2013), the option of developing LNG import terminals and power plants together can be successful. This was the case in Puerto Rico, which in the late 1990s developed its EcoElectrica power plant and associated LNG receiving terminal. That plant was the first to simultaneously finance and build LNG and power as a single facility, achieved through having matching LNG supply and power offtake contracts. Many developing countries in Central America, Africa and Southeast Asia have since tried to replicate this, but without much success, even though, as noted previously, the high oil prices of the past decade have often resulted in power prices high enough to support such a facility. Egypt and Jordan are other successful FSRU development stories, but both benefited from existing markets and infrastructure (Navigant 2016).

Resource-poor countries considering developing an LNG terminal face many challenges. The first is the **existing and future size of the prospective gas market**. All the African countries considered here, except Egypt, currently consume less than 5 bcm/y, or even less than 2 bcm/y. While the power generation sector is expected to serve as an anchor customer – 1 GW running 5,000 hours would require around 1 bcm – governments may want to develop demand from industry, cooking and transportation, which creates further upward uncertainties on demand. Some additional independent power producers (IPPs) may later want to use the LNG plant, raising issues of third party access to the LNG terminal.

The second issue is the **duration of the import needs.** Some imports may be considered only as a bridging solution during the period when domestic production recovers or increases. This is the case for Egypt and potentially also for Ghana, Senegal, Namibia and South Africa. FSRUs can prove the best option to support the import of small volumes of LNG, or to work with small-scale LNG vessels to meet smaller sized markets. Some countries find that once the gas infrastructure is in place, this drives new gas demand.

There is often **no established existing LNG (or gas) consumer** and sometimes no gas company. Some markets currently consume almost no gas, which implies that the gas infrastructure – not only the LNG import facility but also some pipelines – has to be developed and the authorities need to familiarize themselves with gas issues and develop a regulatory framework. A reliable offtaker able to pay a price high enough to support gas imports must be found. Benin, Togo and Ghana have some experience due to the existence of the 8 bcm/y West African Gas Pipeline (WAGP) from Nigeria, which was also aiming at power plants. Countries such as Senegal, Namibia, South Africa, and Kenya face the chicken-and-egg problem: which comes first, the LNG supply or the consumer? (Haug and Cumberland 2013). Puerto Rico and the Dominican Republic solved that by developing both together. In Jordan, the presence of existing power and transport infrastructure was a decisive factor (Navigant 2016).

Typically, most sellers would prefer a customer with reliable credit, able to sign a long-term contract based on oil indexation and to pass on costs to final end users. Such customers can be few. However, having financially credible gas offtakers is crucial for a project (Navigant 2016). Most countries considered here have relatively weak credit ratings, the highest rated being South Africa and Morocco (see Table 1). Government guarantees may not be considered sufficient for this. A long-term contract represents an important financial commitment, along with take-or-pay (TOP) commitments. Gas-fired IPPs in emerging markets will almost always put dispatch risk with the offtaker, insofar as capacity charges will be payable for availability and regardless of power demand (Down and Wilby 2015). However, if/when the LNG is not needed, the new conditions on the global LNG market may help mitigate this risk by allowing the cargo to be resold as a spot cargo. In that eventuality, long-term, oil-indexed and inflexible take-or-pay contracts are likely to be too ridged to permit the kind of capital and operational flexibility required for projects with variable demand to evolve as markets develop.

Another challenge is the **funding of the downstream infrastructure.** There is an appetite to invest in power generation and import facilities, but less to fund gas transmission and distribution pipelines (Smedley 2016). Downstream and LNG import infrastructure development can be delayed by the lack of an appropriate regulatory regime. For example, the FSRU Golar Tundra has been reported as waiting outside the port of Tema, in Ghana, for permission to dock and connect to the country's gas transport system, allegedly due to the fact that the port's infrastructure was not ready (Elston 2016).

This leads to the **relationship between the different elements of the project**: the FSRU, the pipeline(s), the IPP and the marine infrastructure. The link between the power plant and LNG supply/import development is particularly important, not only for the development of the project, making sure that the elements arrive simultaneously, but also for the contractual terms during the life of the project and for issues such as force majeure. The linking of different parts of the chain, and their development timetable, is key to developing a strong gas supply chain. South Africa's tenders distinguish between bundled and unbundled projects: in the bundled project the developer consortium would be in charge of everything from sourcing the LNG to building the FSRU and the power plant (Down and Wilby 2015).

In general, there are four different, main models for LNG-to-power projects, regardless of the regasification plant type, onshore or FSRU (Dameno and Lopez 2013). These reflect the different types of LNG import terminal investment structures across the world and whether the company investing is a power company or a gas company.

> A first option would be for the investor to develop and own the LNG import and power infrastructure. This requires an LNG sale and purchase aggreement (SPA) with a supplier, which is also supported by a power purchase agreement (PPA) guaranteeing the revenue flow. It allows the investor to receive credit from lenders, with the SPA and PPA serving as credit guarantees. This does, however, require power offtake guarantees from a credible power offtaker. In the case of Puerto Rico, this option succeeded because the power plant had long-term LNG supply contracts as well as power offtake contracts with matching escalations, and long-term non-recourse financing matching the LNG and power contract terms (Haug and Cumberland 2013).

> Another option is for the investor to draw up the LNG SPA supported by the PPA, as above. The difference here is that another company will build, own and operate (BOO) the FSRU and the power plant. In that case, the investing company does not need to finance the facilities,

though the PPA will serve as a guarantee for the other investor operating them. There may also be two different companies managing the FSRU and the power plant, as these require different competencies. The greater number of counterparties and companies involved can complicate the development of a project structured like this.

In a third option, the investor concludes the LNG SPA and the PPA. It is a shareholder of the power plant, but the regasification plant is operated by another company. A terminal use agreement is concluded between the investor and the terminal operating company.

Fourthly, the investor could opt to operate only the LNG terminal and the power plant. The independent power producer (IPP) would then import LNG itself, under a long-term purchase agreement with an LNG seller. The LNG terminal would then be operated under a tolling model, with capacity reserved by the IPP on a long-term basis, similar to the models used for the terminals at Gate and the Isle of Grain. In this case, other IPPs could also use the terminal in the same way.

The cases where the LNG terminal is operated by a company that is not the investor are often typical for FSRUs, as very few companies are specialized in operating them (Dameno and Lopez 2013). This option could also be easier for a company with no experience in LNG, such as Gasol in Benin. There is also the possibility that the BOO could include the acquisition of the facilities after a certain duration. This is known as build, own and transfer (BOT), or build, own, operate and transfer (BOOT). The investment solution will also depend on the development of the importing market: is there a gas or a power company and is it sufficiently creditworthy? In most cases, the investment is led by foreign private investors. The role of the state as a potential source of guarantee is also important, even though most countries considered are not highly rated, as previously noted.

To succeed, project stakeholders must sometimes align conflicting interests. The LNG supplier will want the highest price for its gas; the IPP will want a viable and profitable power project; and the government will want to minimize the costs for the end-consumer and the environmental costs, while supporting economic development (Farina and Wilson 2015). Electricity prices often do not reflect the cost of generation: in 2010, the average effective tariff in Africa was $0.14/kWh, against an average of $0.18/kWh in production costs (AfDB 2013). This implies losses for the power company, meaning an inability to invest further. But these tariffs are not very low by international standards: in the U.S., the average price of electricity for end-users was around $0.10/kWh in early 2016. The average price of electricity for household consumers in the EU was €0.21/kWh in the second half of 2015, with prices varying between €0.30/kWh and €0.096/kWh (Eurostats 2016). When there is no properly functioning market, strong power projects require a strong PPA that will enable cost recovery and protect the private investor against political intervention. Commercial and legal terms, as well as contracts, must align to encourage proper performance of all contractual obligations. Finally, the formulae in LNG SPAs could lead the gas price to vary substantially, as has been observed on gas markets over the past 10 years. Due consideration must be given as to how this may impact the PPA, for example whether the gas costs will be fully transferred to the end-user, which also has political implications.

A successful LNG-to-power project is more likely when project risks are allocated to those best able to mitigate them. The power and the regasification elements of an integrated project are significantly interdependent and a default by one party of the overall project will prevent the other(s) from generating cash flow. Accordingly, many LNG-to-power projects place more importance on flexibility. The choice of an FSRU can help mitigate construction delays on the power side because the FSRU can be redeployed elsewhere in the interim as an LNG carrier to generate extra revenue, if there is a market for that. Several technical, operational and legal challenges need to be considered and, where applicable, addressed in order to ensure the success and long-term viability of the project (White 2015). Access to a liquid and well functioning market is the critical precondition for doing so cost-effectively. In an ideal case, as previously noted, the LNG contract and the power contract back one other. That is, the fuel supplier's delivery obligations are guaranteed to the power generator and the power producer's obligation to take deliveries of gas are similarly supported. However, this rarely happens (Haug and Cumberland 2013) and, in practice, investors structure the projects on a limited recourse basis, which requires the lenders to analyze the entire contractual matrix (Norton Rose Fulbright 2016).

The Right Time for LNG Buyers ... and Sellers

Most of the countries currently importing LNG are relatively mature Organization for Economic Cooperation and Development (OECD) markets, or large developing gas markets like China, India and Brazil. LNG has so far rarely penetrated small developing countries with no or very limited gas consumption, or poor economies with low credit ratings where oil-fired technology is often the default solution (Haug and Cumberland 2013). Exceptions are Puerto Rico and the Dominican Republic, while Uruguay is trying to replicate their experience. Among recently emerging LNG importers, Egypt and Pakistan already had developed gas markets with consumption of more than 40 bcm/y; Jordan had pipeline infrastructure and gas-fired plants in place and at one time its demand exceeded 3 bcm/y. By contrast, among all the countries considered, only South Africa, Tunisia, Ghana and Côte d'Ivoire consume more than 2 bcm/y.

Sellers

Sellers' interest has started to shift in favor of new markets. Major LNG producers are considering investing in ship-fueling operations, FSRUs and power plants to open up new markets and absorb the current global LNG surplus. They are also now beginning to consider supplying local African markets, either with piped gas or with LNG (Smedley 2016). Total's CEO Patrick Pouyanné was reported as saying, “We are not a fan of investing in an IPP, but if we need to create demand, why not?" (Sonali 2016).

In addition, such markets might be a good short-term option for aggregators with a lot of uncontracted LNG. However, how committed would such sellers be after the initial lease if and when less risky and higher priced markets returned to solid growth? The answer would very much depend on the respective netbacks achieved by the sellers and whether African LNG can provide a cost-effective regional source of gas over time.

LNG supply is more diversified than it used to be, while the U.S. is emerging as a new LNG supply source which is also at a reasonable distance from most African markets. African LNG importers could also source LNG from their neighbors: African LNG exports reached 35 mtpa in 2015 and half of this was exported as spot and short-term LNG. Angola LNG restarted in the second half of 2016 and the Cameroon floating liquefaction project is expected to be operational in 2018. The proximity of Nigeria, Equatorial Guinea and Angola to West African countries, Namibia and South Africa makes them attractive as LNG suppliers. Moreover, the spot and short-term LNG market is expected to increase significantly over the coming years. There is also more diversity in terms of sellers, with trading firms such as Trafigura, Gunvor, Glencore and Vitol engaged in LNG supply, often as intermediaries, backed by primary LNG suppliers.

Market conditions have changed, bridging the gap between sellers and buyers. LNG sellers are looking for new markets able to absorb the current oversupply. Gas has become more affordable for developing markets seeking a way to produce electricity at an affordable cost and spur economic development.

These companies have been quite active in the tenders organized by new LNG importers Egypt, Pakistan and Jordan.

Infrastructure

The emergence of FSRUs facilitates the rise of new types of importers. FSRUs are planned by eight of the ten countries looking at LNG imports. Morocco is the exception, while Sudan has not disclosed what type of terminal it is considering. The attractiveness of a floating regasification unit comes from its low cost and faster implementation. A newbuild 170,000 cubic meter (cm) FSRU would typically cost in excess of $250 million, while the vessel plus the land-side infrastructure could add up to around $400 million. By contrast, the cost of an onshore terminal of comparable size is around $1 billion (White 2015).

In practice, importing countries will have to decide whether they want to lease the FSRU or to buy it. So far, most FSRUs have been leased. This is because FSRU developers such as Excelerate, Golar, Hoëgh and BW can secure lower costs at shipyards by developing multiple FSRUs (King & Spalding 2015). They can also achieve lower capital costs by converting old vessels – around $100 million for a secondhand converted LNG carrier. Also, the lack of operational experience is a deterrent for developers wishing to purchase FSRUs directly. When FSRUs are chartered, they are generally financed separately from the other infrastructure. Capex costs would also lie with the FSRU owner and not the charterer, which is an advantage for countries with limited payment possibilities for upfront costs. Nevertheless, the charterer has still to pay a day rate: leasing a FSRU can be quite expensive as daily rates vary between $113,000 and $155,000, according to the type of vessel and the duration of the lease (Toungara 2016). FSRUs may not be the ideal solution if additional breakwaters and jetties are needed (Smedley 2016). The choice of the technology and the size of the ship may also depend on the site – protected and calm, or a hostile weather site for which a larger vessel would be preferable (GasLog 2016).

FSRUs are said to be faster to bring onstream. Some have been deployed rapidly, as in Egypt. The newbuild FSRU deployed by BW in the port of Ain Sokhna took five months from project inception to first gas. The conversion of a conventional LNG vessel would take around six months, assuming a vessel and a shipyard slot are available (GasLog quotes 20-22 months) while a newbuild FSRU can be delivered within around 28-32 months (GasLog 2016) (White 2015). However, licenses and permits including environmental impact, marine operation, gas processing and trading are needed before deploying a FSRU on-site.

FSRUs offer additional advantages. Regasification capacity is usually between 2 and 8 bcm/y, based on data on existing facilities, with most being around 5 bcm/y (or 3.5 mtpa) (GIIGNL 2016). Such a facility may be large for a developing market, but 2 bcm/y used at 60 percent and fueling an open-cycle plant with a 40 percent efficiency would feed a capacity of 1.1 GW for 5,000 hours. FSRUs thus prove a good match for small to medium scale developments. Additionally, the vessel can be upgraded to increase sendout capacity as demand builds up. This kind of operational flexibility and potential to increase capacity incrementally in line with demand growth is a fundamental prerequisite for an investment like this. For example, in Dubai, DUSUP entered into a long-term time charter party agreement (TCPA) with Excelerate in 2014 for a larger and more efficient FSRU to replace its existing unit. Excelerate upgraded the Explorer and customized the FSRU to meet DUSUP's supply requirements (Excelerate

Energy 2016). The size of FSRUs on order has also increased, with the largest under construction, for Uruguay, having a storage capacity of 263,000 cm, compared to the typical 170,000 cm. The advantage of these units is that they offer flexibility, not only in terms of seasonal LNG supply in countries such as Kuwait and Dubai, but also in the chartering arrangements, as contracts as short as five years can be negotiated. FSRUs can provide mid-term solutions while a longer term solution involving a pipeline or domestic production is developed. They also represent a lower risk/cost means of testing and developing markets until they reach the critical mass required to support larger scale, longer term supply solutions.

A possible next stage in the longer term could be to replicate the small scale LNG project envisaged in Indonesia, should it be successful. Due to the size of the Indonesian archipelago, with numerous small island markets, any normal FSRU would be too large. Instead investors are considering small scale LNG transportation and receiving terminals, with plans for a range of smaller scale FSRUs down to 3,000 cm. However, the economic viability of the whole project may be imperiled by its limited size. Further analysis of the economies of scale in the small scale FSRU market is necessary to understand whether such developments can be economically viable in the future. The cost for a 20,000 to 50,000 cm FSRU would be in the region of $50 to $70 million (King & Spalding 2015).

Demand

For African LNG import projects, the crucial issue would be building demand, but here technology can help to mitigate the risk. In some countries, there are power plants that can run on natural gas. By contrast, most CCGT plants are capable of being configured to operate on liquid fuel as a backup when gas is unavailable, even though this decreases efficiency and increases both operational and maintenance costs. However fuel flexibility offers the IPP the ability to mitigate its exposure to delays in completion of the regasification infrastructure and to short-term LNG unavailability, which is likely to be a function of the price. Another issue would be the potential use of gas by third parties.

LNG prices and contracts

While LNG prices were quite high over 2011-14, notably in Asia, they have now reduced significantly due to the combined fall in oil prices and the global LNG glut. This has prompted interest in LNG imports among developing countries. But even though LNG prices fell to around $4-6/MMBtu, it has still not become a cheap fuel source. Prices may drop even further due to an increasing oversupply situation as more LNG comes to the markets by 2017-18, but they could reasonably be expected to rise again to a level enabling new LNG projects to proceed with their financial investment decision (FID).

However, not all the LNG that is sold is indexed to oil prices, though the greater part of it is at present. The rise of U.S. LNG will allow buyers to buy LNG on a Henry Hub plus basis. Given the proximity to Europe, it is also quite possible that buyers could get a price indexed to the UK National Balancing Point (NBP) price. That type of spot indexation better reflects supply/demand balances, though not those of the African market. This creates some uncertainty over the future evolution of the price of LNG. The pricing mechanism that is agreed by African buyers will be critical to determining the long-term viability of their LNG project. Affordability and predictability will be key. African buyers may have difficulties managing pricing risks they are not familiar with, especially where gas is largely used to produce electricity, which is sold to relatively low income residential consumers.

Additionally, some countries or project sponsors – in Ghana and Namibia – plan to use the current market oversupply to source their gas on the spot market, by organizing tenders. This is what Egypt has been doing since its two LNG imports terminals started up. It works relatively well in a situation of global LNG oversupply, but the product may become more expensive if the market tightens, highlighting the need to carefully assess pricing mechanisms and their possible long-term implications. For example, it would be a mistake to agree on a pricing formulae based on today's forward curves, as such price curves are often poor indicators of future price levels.

A Review of the Most Advanced LNG Import Projects

As of late-2016, ten countries are either importing LNG (Egypt) or considering LNG imports over the medium term: Benin, Côte d'Ivoire, Ghana, Kenya, Morocco, Namibia, Senegal, Sudan and South Africa. The reasons for turning to LNG vary, depending on the countries:

> In most cases, countries want to expand their power generation capacity and include natural gas in the mix.

> Egypt's power mix is already highly dependent on gas but, due to gas shortages, the country had to turn to LNG imports.

> Morocco has been importing gas through neighbor Algeria, but as the contract expires in 2021 it has been looking for alternatives. It is uncertain whether Tunisia could face the same issues.

> Some West African projects will also feed into the West African Gas Pipeline (WAGP), which transports gas from Nigeria to customers in Ghana, Togo and Benin.

> Many LNG projects are driven by the absence of gas resources or a development only planned in the medium to long term. These include Egypt, Ghana, Senegal, Namibia, Sudan and South Africa.

Eight countries have opted for FSRUs and most of these projects are led by small independent companies. Exceptions include Morocco, where its tender attracted some of the large gas players, Ghana, where GE is behind one project, and Côte d'Ivoire where Total has recently joined the LNG project. The recent interest shown by the international oil majors has not yet significantly led to concrete projects, but they could take part in some of the existing projects or develop alternative ones in other countries. As of late 2016, the projects the most advanced besides those in Egypt are in Ghana, Morocco and South Africa.

Egypt – importing LNG since 2015

Egypt started importing LNG in 2015 and, as of November 2016, already has two FSRUs in place (see Table 1). The country imported 2.6 mtpa in 2015 to meet gas shortfalls which had led to rationing for energy-intensive industries such as steel mills and fertilizer plants. Egypt's natural gas demand has increased rapidly from 20 bcm in 2000 to peak at 52 bcm in 2012, driven by power generation needs as well as gas use in industry, cooking and transport, supported by relatively low domestic gas prices. However, domestic production flattened from 2009 onward, resulting in demand dropping to 48 bcm in 2015. The Arab Spring halted reform attempts to increase prices. But prices were increased again in 2014 when President Al Sissi came to power. Egypt organized a third tender in mid-2016 for an FSRU (7.5 bcm/y) that is expected to begin operations in the second quarter of 2017.

While the evolution of LNG imports is very uncertain, with calls for the use of FSRUs with five-year charter times, expectations of the future growth of domestic production seem well founded. Oil Minister Tarek El Molla announced in May 2016 that gas production would increase to around 55-60 bcm by 2019 (Reuters 2016). In particular, the Zohr field discovered by Eni in 2015 is expected to ramp up to full capacity (28 bcm/y) by 2020. Even if delays occur, the development of that field is a priority for both Eni and the government. Meanwhile, other upstream players are investing in new fields, some of which are intended to replace declining production from existing fields. Depending on the pace of these production increases, imports could stop after 2020.

Egypt's gas demand, which has been constrained due to the lack of available supply, is also uncertain. Should spot prices remain low for an extended period of time, some industrials – notably the steel industry and fertilizer producers, which have been particularly affected by gas shortages – may decide that gas is still affordable and more competitive than oil products. Many expect LNG imports to stop by 2020, as the lease signed with Hoëgh for the FSRU runs for five years, though the tender for a third FSRU starting by 2017 questions that assumption (Energy Egypt 2016).

Morocco – an onshore LNG project

Morocco has limited domestic gas production and currently imports its gas from Algeria by pipeline. Most of this gas is consumed in the power generation sector. Its two gas-fired plants (Tahaddart and Ain Beni Mathar) were supplied through the payment of gas transit to Europe in kind until 2011. Then a new contract was signed for 10 years.

Unlike other countries where LNG supplements

Figure 3. LNG projects existing and planned in Africa.

Source: KAPSARC.

domestic production, LNG imports are likely to replace Algerian pipeline supplies after 2021, when the contract expires. Even if the contract is extended, Morocco would like to diversify gas supplies and increase consumption, notably in the power sector.

Morocco wants to boost its power capacity by increasing renewables: it plans to add 6.76 GW of renewable power capacity between 2015 and 2025, including 3.12 GW of solar, 2.74 GW of wind power and 0.9 GW of hydropower. It would also like to add 2.4 GW of gas-fired generation capacity. Another 6.3 GW of gas-fired capacity could be installed in the longer term (MEES 2015). Gas-fired power plants are seen as a way to manage the problem of intermittency created by the rapid expansion of renewables and a diversification away from coal and oil, which together represent more than half of the power mix. Morocco's proposed LNG terminal will be at the port of Jorf Lasfar, 100 km south of Casablanca, and will be connected to the existing pipeline system. Morocco plans to import 2 mtpa starting in 2020, increasing to 3.5 to 4 mtpa by 2025. Several companies including Engie, Shell, Gazprom and Taqa have expressed interest in the $4.6 billion project. This would be an integrated LNG-to-power project and the tender covers both the LNG terminal, the pipelines and 2.4 GW of gas-fired capacity (ONE 2015).

Benin (Togo and Ghana) – a three-country project

Gasol has been planning to build an FSRU in Benin since at least 2013. Its project is aimed at displacing the use of liquid fuels in the power and industrial sectors in Benin, Togo and Ghana, and thus reducing costs. Gasol has negotiated two offtake agreements, with the state utilities of Benin, Togo and Ghana and with the Benin Electricity Community and the Volta River Authority (signed in 2014). The company plans a 1.2 mtpa FSU/FSRU which would not only supply power users directly but also feed the WAGP via a subsea pipeline. The plant could be later expanded to 2 mpta. Gasol has applied to the West African Gas Pipeline Company (WAPCo) under its new open access policy to become a shipper on the WAGP. Gasol and WAPCo have been discussing commercial and technical issues such as the project's connection to the pipeline and the capacity in the WAGP that will be reserved for the Gasol project's use.

Côte d'Ivoire

Côte d'Ivoire's domestic production has been declining, and even though the WAGP could be expanded to reach its markets, it is unclear when this could be achieved and whether gas could be supplied in a regular manner. Accordingly, the country has considered LNG imports for quite some time. The government decided in June 2016 to set up an LNG supply project, Projet d'Approvisionnement de la Côte d'Ivoire en Gaz Naturel Liquefié (PACI-GNL).

Meanwhile, Côte d'Ivoire has ambitious plans to develop its economy and needs an additional 150 MW installed per year (Toungara 2016). While long-term plans foresee a strong increase in the share of renewable energies, the government expects the energy mix to evolve from 80 percent of fossil fuels in 2015, to 66 percent by 2020 and 58 percent by 2030. This implies an increase in renewable energies – hydro, but also solar and biomass – from 20 percent to 42 percent over 2015-30.

Starenergie 2073 and Endeavor Energy had been working on the 372 MW Songon gas-to-power project, located near Abidjan, before Starenergie 2073 broke the contract in early 2016 and turned instead to China Energy Engineering Corp (CEEC) to take over the project. It had been planned as an integrated project, including the power plant as well as purpose-built LNG import infrastructure and an FSRU. The LNG importation infrastructure was designed to enable development of additional phases of the project. The Songon power plant was planned as just the first phase of a much larger 1,200 MW gas-fired plant project. A further 370 MW gas-fired plant is planned in Grand Bassam, also near Abidjan. The construction of both power plants is expected to start by 2017.

In October 2016 the LNG import terminal which would be located near Abidjan, received some support from Total. It remains to be seen how much of the original LNG-to-power project will survive and how the LNG will be sourced, but now Total is likely to play a role in that. The business model is based on the lease of an FSRU from Golar for a 15-year term. The company managing the project would be 15 percent owned by Petroci and Energie de Cote d'Ivoire. Total, Shell, Socar, Golar and Endeavor Energy would hold the remaining 85 percent. The investment is estimated to around $200 million for the terminal and around $130 million for a pipeline network between Grand Bassam and Vridi, which would be built by Petroci under a BOT model. Endeavor signed a contract with Shell to buy 7 to 8 LNG cargoes per year during the first phase of the project, but the entry of Total could produce a different outcome.

Ghana

Ghana currently has two main sources of gas supply: domestic gas production and imports through the WAGP. Together they represent around 2 bcm of annual gas supply. Domestic gas production is expected to be boosted by recent discoveries and development of the Sankofa Gye Nyame gas fields. At the same time, imports from Nigeria have been erratic because of supply problems tied to pipeline vandalism in the Niger Delta region and debts from non-payment for the delivered gas. Frequent power outages sparked street protests in 2014 and 2015. In addition, most gas supplied has flowed to Takoradi in the western region, while gas-fired projects in the east are undersupplied. The government is planning to double national power capacity to 5 GW by 2017, by adding two thermal barges from Turkey, a 360 MW gas-fired plant near the existing Sunon Agoli plant, a 230 MW thermal plant near Tema and another 110 MW plant to be built by TAQA. Total gas-fired capacity amounting to 2.3 GW would require around 3 bcm/y (Africa Oil and Gas 2016).

Ghana's LNG import plans are quite advanced, even though there is some confusion about which projects should take precedence. In early 2016, the Ghana National Petroleum Corporation (GNPC) announced that it would start importing LNG by the end of 2016. Even though this has been postponed to 2017, or possibly 2018, Ghana remains interested in importing LNG, for which four different projects are planned.

> West African Gas Limited (owned 60 percent by the Nigerian National Petroleum Corporation (NNPC) and 40 percent by Sahara Energy) signed a contract for a FSRU for the 170,000 cm Golar Tundra. The FSRU, which is already on site, will be moored at the port of Tema. NNPC is also involved in the WAGP, and the imported LNG could be used to improve the reliability of the pipeline's supply. The FSRU has been leased for five years, with the option of a further five years. The plan is to source LNG from the spot market and so take advantage of the current market oversupply. LNG imports are expected to start by 2017.

> Another project located in Tema is sponsored by Quantum Pacific, an industrial investment group. In 2015, GNPC and Quantum Power signed

heads of terms for a 3.5 mtpa newbuild FSRU, which is expected to cost around $550 million. This project will be implemented on a BOOT basis with the assets transferred to GNPC after 20 years.

A third project, Ghana 1000, is led by Endeavor and General Electric (GE). Similar to the initial project in Côte d'Ivoire, this is a multiphase gas-to-power project that will eventually produce 1.3 GW. It will be located near Takoradi in the west. The project will be built in three phases: 375 MW, 375 MW and 550 MW. Gas supply will be from a combination of domestic gas from the Sankofa gas field and LNG from a FSRU, with the LNG only necessary for the second and third phases. This project has concluded its power purchase agreement with the Electricity Company of Ghana (ECG) and received regulatory approval for its power tariff.

The fourth project, Rotan Gas, will use a FSRU permanently moored off the coast of Aboatze, near Takoradi, and aims to supply mostly power plants. The project partners, which include EOSon Infrastructure Limited and Mitsui, plan on acquiring a wholesale gas supply license, and to secure their LNG and a FSRU on a long-term basis (20 years).

Controversy followed a recent statement by the African Centre for Energy Policy (ACEP) that the Quantum project should be ratified ahead of West African Gas Limited (WAGL). This is understood to be based on the relative costs: WAGL quotes a re-gasification unit cost of $2.20/MMBtu, against $1.47/MMBtu for the Quantum project. The difference would translate to a saving of $65 million (Classfm 2016). Another issue is that the WAGL terminal will be moored inside the port of Tema, which would require the port to be expanded. ACEP also considers that bringing the two projects at the same time would create more supply than is justified by domestic demand. In addition, depending on the development of domestic gas resources, the LNG import solution could represent only a bridging solution – though the third project includes both imports and production feeding power plants.

Ghana's debt has almost doubled over 2010-14 and the drop in international oil prices has not improved the situation since then. The question of project financing and the role of the state will therefore be particularly important. Finally, presidential elections taking place in December 2016 could potentially affect the country's energy policy.

Kenya

Kenya had planned to build an LNG terminal in Mombasa to meet rising power demand and to provide a solution to the chronic power blackouts and high electricity bills which had been fueling discontent among the population. A tender for the project was initially expected by early 2012, but was postponed. In 2014, it was reported that only two companies had returned bids, and did not meet the timelines: they proposed to build the plant over two years, instead of 18 months. In 2015, Kenya postponed signing an agreement with Qatar following the discovery of 1.8 tcf of domestic gas by Africa Oil and Marathon Oil Corporation.

LNG imports were to have supplied the 700 MW Dongo Kundu plant, but it was cancelled in mid-2016 after the domestic discoveries. That facility would have also supported KenGen's Kipevu I and Kipevu III thermal power plants in Mombasa, which currently use heavy fuel oil, though this would require construction of a pipeline. LNG could also have supplied the 90 MW Rabai power plant near Mombasa, which also uses heavy fuel oil.

A feasibility study financed partly by the World Bank showed the economic viability of an LNG import facility. The project's main competitor is domestic gas, while a pipeline from Tanzania to Mombasa, through Tanga, for power generation and other industrial applications had also been considered in the past.

Namibia

Namibia does not currently consume any gas and imports roughly two-thirds of its power demand. Following a public request for proposals by the Namibian Power Utility (NamPower) in 2014, Xaris Energy was selected in March 2015 to build a 250-300 MW power plant. It proposed an LNG-to-power project in Walvis Bay. However, this was put on hold by the new government. Xaris Energy now plans to enter into a public private partnership (PPP) agreement with NamPower to sell the electricity. Financial closure was expected by October 2016, with first power expected six months later, which seems ambitious. Xaris Energy Namibia Chairman Boni Paulino said that the open cycle electricity tariff would be N$1.94/kWh and that it could drop to N$1.49/kWh if the plant were to be expanded in 2017. There is also potential to export electricity (Windhoek Observer 2015).

Excelerate has been selected for the FSRU to be located in Walvis Bay, where the port would be expanded for the Southern Africa Development Communities (SADC). The hope is that the power plant would stimulate economic expansion (Xaris 2016). Meanwhile, natural gas could be used for other applications in industry and transportation and as domestic fuel. The company plans to source gas on the spot market, benefiting from the oversupply situation, without resorting to long-term contacts. There have been talks about developing the Kudu discovery for years, without much success. But should the field be developed, LNG could serve as a bridge to that.

Senegal

Senegal consumes limited amounts of natural gas – it is estimated 0.1 bcm in 2014 – which is produced by U.S. company Fortesa and consumed almost 50 percent by SENELEC and 50 percent by cement producer SOCOCIM. LNG imports have been considered for quite some time with a view to substituting expensive oil products with natural gas. In 2014, a World Bank Study concluded that Senegal could replace fuel oil and diesel with LNG, resulting in an LNG import requirement of 0.6 mtpa. This volume would be too small to make the project economical and it would need to be boosted by other demand, from industry, or by power exports to Gambia or Mali. In 2015, an agreement was nevertheless signed between the power company Senelec and Qatar's Nebras Power and Mitsui to build an FSRU and a 400 MW power plant.

Some recent gas discoveries have been made, which could change the outlook quite significantly. In early 2016, an ultra-deep gas discovery was made with the Geumbeul-1 well, on the greater Tortue field, which is a transborder offshore discovery between Mauritania and Senegal. Estimates for the greater Tortue complex are therefore estimated at 17 tcf (Oil & Gas Journal 2016). Paradoxically, such a discovery could be sufficient to export gas by pipeline or as LNG, though the fact that the field extends into two countries could complicate decisions such as the location of the LNG export facility. Consequently, LNG imports into Senegal could be a bridging solution until domestic gas resources are developed.

South Africa

South Africa's power mix depends heavily on coal and the country is suffering from chronic power shortages. As much as 85 percent of the country's electricity comes from 30-35 year-old coal-fired power plants (Baker & Mckenzie 2015). The Department of Energy (DOE) has been planning to expand total generating capacity by 40 GW by 2025, including hydro, renewable energies, coal and gas sources. It has set up a gas-to-power program with the aim of building and supplying 3.126 GW of gas-fired plants, to be run baseload and/or mid-merit (DOE, 2016). The gas required for these power plants will come from both imported and domestic gas resources; however, in the medium term, imports seem the only solution. Eskom is expected to be the sole buyer of electrical capacity and energy generated under the program. In May 2016 the DOE invited expressions of interest for the construction of a new 600 MW gas power plant at either the port at Saldanha, or at Richards Bay. Letters of interest had to be submitted by June 20 (DOE 2016). In October 2016 the DOE announced that there will be two LNG-to-power projects, located in Coega (1,000 MW), near Port Elizabeth, and at Richards Bay (2,000 MW). Both have deep water ports. Another site under consideration as a longer-term perspective is Saldanha Bay. All three ports have industrial development zones.

This is in line with the DOE's gas utilization master plan (GUMP) to develop domestic gas resources, notably shale gas. Recognizing the need for anchor customers, the plans include development of a gas economy based on the gas-to-power program, which would make it possible to supply industrial users located nearby. The DOE launched a request for information in 2015. Given its location, South Africa could easily source LNG from Angola and later from Eastern Africa. Using small-scale LNG could also be envisaged.

Sudan

Sudan's plans to import LNG are quite recent. President Omar al-Bashir announced in late 2014 that LNG imports were being investigated to supply natural gas for the power and industrial sectors. Sudan's electricity comes mostly from hydropower. LNG imports would not be the only source of gas as the country has some domestic gas discoveries that it plans to develop, even though progress has been slow so far. China has expressed its interest in the development of the country's oil and gas resources, which might provide a boost. The planned LNG terminal would be located in Port Sudan on the Red Sea, with a pipeline to the capital. There have been discussions with Qatar as a supplier of LNG as a result of increasingly friendly relations between the two countries.

Conclusions

Recently LNG projects in Africa have attracted renewed interest because of the current LNG market oversupply and sellers looking for new markets. Taking these two factors together, they could result in an African market that is more than ‘niche’ – which could represent a new demand center in global LNG markets. But there are many obstacles to African LNG imports, including significant capital investments requirements, the need for anchor customers, nonexistent demand in most cases, along with the lack of established gas consumers and existing infrastructure. Many projects are LNG-to-power projects, supported by FSRUs. Some seek to spur the development of national gas markets before domestic production or regional pipeline imports can take over, while others are proposed for the longer term. Compared with some of the large, mature gas markets, African imports do not grab the headlines, but many markets in this long-term business started small. Consequently LNG producers know that it takes decades to build large supply relationships.

While the need to electrify Africa is real, developing power generation faces substantial challenges, notably ensuring that electricity is affordable and that costs can be recovered. Though electricity tariffs in Africa are not the lowest in the world, many countries nevertheless face non-payment issues. Improving the creditworthiness of electricity utilities and enforcing payment discipline are therefore crucial. However, it can be argued that the development of reliable and affordable electricity supply could boost economic growth and increase populations’ standard of living and consequently their ability to pay. Finally, while renewable energies are currently a favored option, LNG could also offer a solution. However, affordability and predictability will be key. The pricing mechanism agreed by African buyers – should they opt for multiyear contracts – will be critical to ensuring the long-term viability of the LNG project in question, especially where gas is earmarked to produce electricity sold to relatively low income consumers.

Table 1. Comparison of the LNG import projects.

Country	Project	Capacity (bcm/y)	Status	Sponsor	FSRU provider	Gas demand (2015)	Duration
Egypt	Ain Sokhna (BW)	7.8	Op 2015	Egas	BW	47.8	Medium-term (depends on Zohr)
	Ain Sokhna (Hoëgh)	5.2	Op 2015	Egas	Hoëgh		
	Third FSRU	7.5	Pl 2017	Egas	*tender*		
Morocco	Jorf Lasfar	5.0	Pl 2021	ONEE	Onshore	1.2	Long-term
Benin	Cotonou	1.6 (2.7 later)		Gasol		0.0	Long-term
Côte d’Ivoire	Grand Bassam	5.0		Total (and others)	Golar	2.1	Long-term
Ghana	Tema (Golar Tundra)	1.8	UC 2017	WAGL	Golar	2.0**	Medium-term (domestic gas development)
	Tema	2.6 (4.6 later)		Quantum Pacific	Golar?		
	Ghana 1000	3.7		Endeavor, GE	Excelerate		
	Rotan Gas	Tbd		EOSon, Mitsui	Tbd		Long-term

Country	Project	Capacity (bcm/y)	Status	Sponsor	FSRU provider	Gas demand (2015)	Duration
Kenya	Mombasa	Tbd		Tbd	Tbd	0.0	Depends on development of domestic gas
Namibia	Walvis Bay	0.6*	Pl 2017	Xaris Energy	Excelerate	0.0	Long-term if Kudu not developed
Senegal	Dakar	Tbd		Nebras Power/ Mitsui	Tbd	0.1	Depends on development of domestic gas
South Africa	Saldanha Bay/ Richards Bay	Tbd		Tbd	Tbd	4.7	Depends on development of domestic gas
Sudan	Tbd	Tbd	Tbd	Tbd	undetermined	0.0	Depends on development of domestic gas

Table 1. continued.

Country	LNG-to-power	Credit Rating (S&P)	Credit Rating (Moody's)	Debt ($million) (2014)	GNI ($million) (2015)
Egypt		B-	B3	39,634	305,861
Morocco	Yes (+industry)	BBB-	Ba1	42,772	106,073
Benin		N/A	N/A	1,984	9,364
Côte d'Ivoire	Yes	N/A	Ba3	10,857	32,053
Ghana	Yes Yes Yes	B-	B3	17,612	40,615
Kenya	Yes	B+	B1	16,179	61,824
Namibia	Yes	N/A	Baa3	N/A	12,814
Senegal	Yes	B+	B1	5,655	15,104
South Africa	Yes	BBB-	Baa2	144,006	332,593
Sudan	Yes (+industry)	N/A	N/A	21,759	73,985

Source: Credit ratings: http://www.tradingeconomics.com/country-list/rating; debt: World Bank (defined as "External debt stocks"), GNI: World Bank (Atlas method). KAPSARC, IEA statistics.

** based on 1.4 million cm of LNG per annum. ** author's estimate.*

Appendix

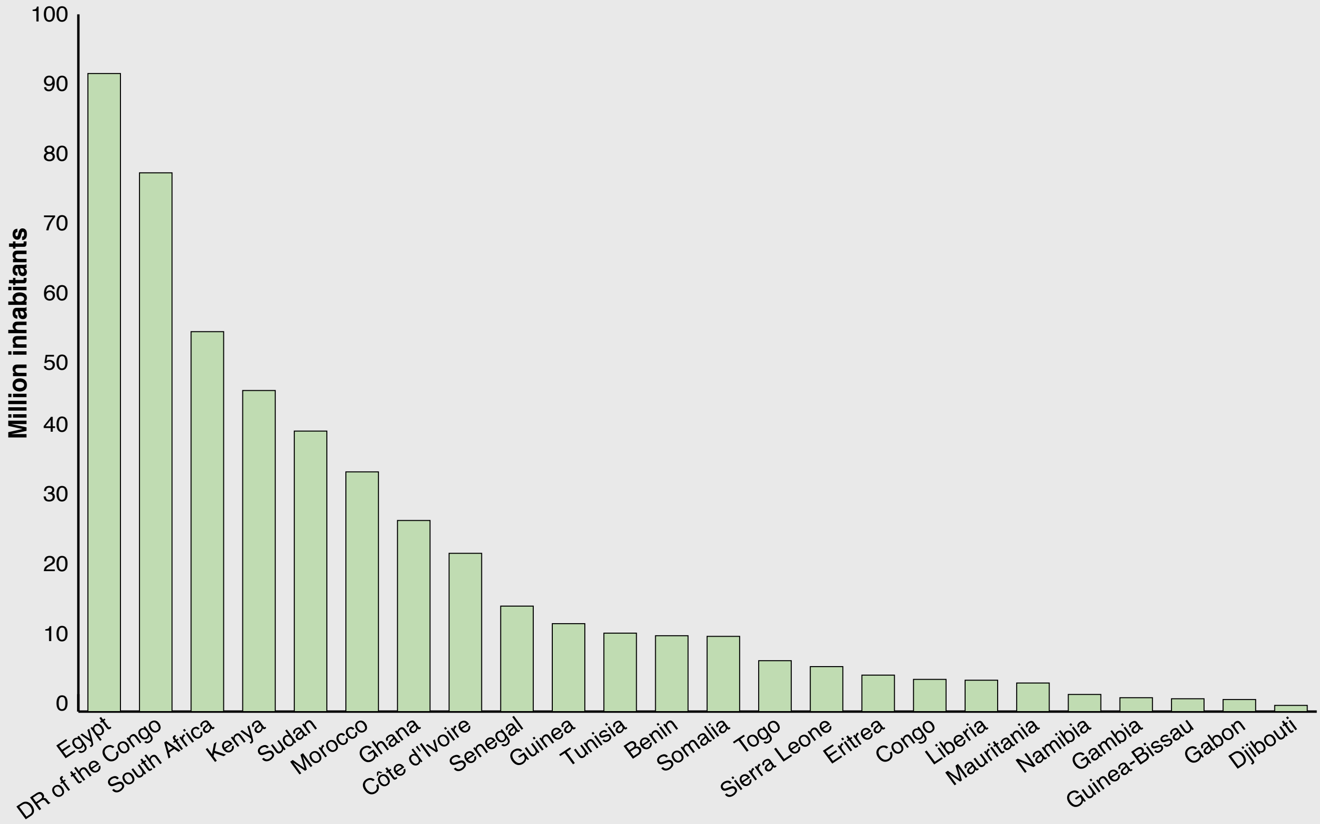

Figure A1. Population in selected African countries.

Source: KAPSARC.

Table A1. Electricity consumption per capita in selected countries.

	Electricity per capita (kWh/capita)
Benin	94
Congo	189
Côte d'Ivoire	235
Democratic Republic of the Congo	106
Djibouti	354
Egypt	1565
Eritrea	59
Gabon	1118
Gambia	133
Ghana	380
Guinea	42
Guinea-Bissau	20

	Electricity per capita (kWh/capita)
Kenya	167
Liberia	60
Mauritania	225
Morocco	855
Namibia	1611
Senegal	217
Sierra Leone	11
Somalia	31
South Africa	3962
Sudan	266
Togo	146
Tunisia	1368

Source: UNdata, UNPD.

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Notes

About the Author

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Anne-Sophie is a research fellow specializing in global gas markets. Before joining KAPSARC, she worked for the International Energy Agency and IHS CERA.

About the Project

KAPSARC is analyzing the shifting dynamics of the global gas markets, which have turned upside down during the past five years. North America has emerged as a large potential future LNG exporter while gas demand growth has been slowing down as natural gas gets squeezed between coal and renewables. While the coming years will witness the fastest LNG export capacity expansion ever seen, many questions are raised on the next generation of LNG supply, the impact of low oil and gas prices on supply and demand patterns and how pricing and contractual structure may be affected by both the arrival of U.S. LNG on global gas markets and the desire of Asian buyers for cheaper gas.

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