Harnessing African Natural Gas

A New Opportunity for Africa's Energy Agenda?

Energy and Extractives Global Practice

The World Bank

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Acknowledgments

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Abbreviations and Acronyms

AC	Alternating current
AG	Associated gas
AKK	Ajaokuta–Kaduna–Kano pipeline
BCF	Billion cubic feet
CAP	Calabar–Ajaokuta pipeline
CAPEX	Capital expense
CAPP	Central African Power Pool
CCGT	Combined-cycle gas turbine
CEB	Communauté Electrique du Bénin
CO_2	Carbon dioxide
DC	Direct current
DES	Delivered ex-ship (LNG)
DSO	Domestic supply obligation
EAPP	East African Power Pool
EDM	Electricidade de Moçambique
ELPS	Escravos–Lagos Pipeline System
GW	Gigawatt
HFO	Heavy fuel oil
IEA	International Energy Agency
IPP	Independent Power Producer
KPLC	Kenya Power and Lighting Company
LNG	Liquefied natural gas
MCF	Thousand cubic feet
MIGA	Multilateral Investment Guarantee Agency
MMBTU	Million British thermal units
MMCFD	Million cubic feet per day
MTPA	Million tons per annum of LNG
MW	Megawatt
MWh	Megawatt-hour
MYTO	Multiyear Tariff Order
NAG	Non-associated gas
NERC	Nigerian Electricity Regulatory Commission
N-Gas	N-Gas Limited
NLNG	Nigeria LNG Limited
NNPC	Nigerian National Petroleum Corporation
OCGT	Open-cycle gas turbine
OPEX	Operating expense
PIB	Petroleum Industry Bill
SAPP	South Africa Power Pool
SOMELEC	Société Mauritanienne d'Electricité

SPE	Society of Petroleum Engineers
TANESCO	Tanzania Electric Supply Company Limited
TCF	Trillion cubic feet
USGS	United States Geological Survey
VRA	Volta River Authority
WACC	Weighted-average cost of capital
WAGP	West Africa Gas Pipeline
WAPP	West African Power Pool

Conversion Factors

1 cubic foot	=	.0283 cubic meters
1 km	=	.62 miles
1 mmtpa (LNG)	=	48 BCF (gas)
1 MMBTU	=	1.055 Gigajoules

Executive Summary

Sub-Saharan Africa's persistent power shortages act as a severe constraint on its economic and human development. Over the last several years, a series of major offshore gas discoveries in Mozambique and Tanzania have rekindled interest in expanding the use of natural gas to address the continent's power shortages. Once thought of as a Nigeria-only story, gas-to-power in Sub-Saharan Africa is now being considered in a continent-wide context, both as a supplement to Africa's abundant hydropower resources and as a replacement for more carbon-intensive coal and liquid fuels. But the concentration of gas resources in just a few countries and the virtual absence of gas transportation infrastructure create economic challenges to the wider adoption of gas as a power generation fuel, particularly in smaller countries that cannot achieve economies of scale in gas production and transportation. As a result, the timeline between the discovery of gas and its commercialization is often measured in decades.

This study examines the economic conditions facing policy makers, planners, and commercial actors with a stake in gas-to-power development in Sub-Saharan Africa. It looks at the upstream, midstream, and downstream segments of the gas value chain to identify where the economics align in favor of gas-to-power development and where they do not.

The Natural Gas Resource Base

Based on a country-by-country analysis of public and proprietary data sources, this study estimates the total discovered natural gas resources in Sub-Saharan Africa at 359 TCF. If produced over 30 years and consumed in high-efficiency CCGT power plants, such a quantity of gas could fuel over 160 GW of power generation capacity, double the total existing installed capacity in Sub-Saharan Africa. The discovered gas resource estimates for each country are divided, according to standards employed in the oil and gas industry, into two categories. ***Reserves*** are only the quantities of gas that are currently being commercialized. Applying this criterion, the reserve estimates in this study are substantially lower than reported figures in almost all countries. ***Contingent resources*** are quantities of gas that can potentially be recovered from discovered fields but where development projects are not yet considered mature enough to be commercial.

Proved reserves in Sub-Saharan Africa are estimated at 136 TCF, a figure that grows to 169 TCF if probable reserves are also considered. Although reserves were identified in 14 countries, Nigeria accounts for 81 percent of proved reserves, and the three LNG exporting countries—Nigeria, Angola, and Equatorial Guinea—account for 92 percent. Thus, in terms of gas currently under commercialization, the story is still very much a West African LNG story.

Contingent resources are estimated at 190 TCF, which, when compared against the total resource base of 359 TCF, implies that over half the total discovered gas in Sub-Saharan Africa

is not currently being commercialized. The huge undeveloped fields in Mozambique and Tanzania account for 62 percent of total contingent resources, and it is these countries that give the new gas resource map of Africa its decidedly bicoastal flavor.

Although the total gas resource base in Sub-Saharan Africa is enormous in relation to current energy consumption in the continent, the commercialization options available to resource-holding countries are not all the same.

Nigeria's reported proved reserves are 180 TCF, yet this study puts that figure at just 110 TCF and possibly as low as 47 TCF if the strictest commerciality criteria are applied. However, even after these adjustments to the reported figures, Nigeria still holds at least 125 TCF of discovered but undeveloped gas in addition to the gas already committed to exports and the domestic market. This would be enough to generate 50 GW of power for 50 years. Future exploration would undoubtedly expand the resource base even further.

However, the domestic demands on Nigeria's gas resources are also huge, and it would be a mistake to view the country's resource base as infinite. Nigeria's Roadmap for Power Sector Reform sets a goal of 20 GW of generation capacity by 2020, and most of this capacity will be gas-fired. Meeting this ambitious target will require more than doubling domestic gas supply from 1.5 BCF per day to 3.4 BCF per day. Developing the roughly 30 TCF of reserves needed to support such a production increase will require huge amounts of capital, perhaps $20 billion or more, and most of this investment will need to come from the private sector. To attract such an amount of capital to the gas sector, Nigeria will need to develop a bankable commercial framework for gas that includes price reforms, improvements in regulatory arrangements, a redefinition of the role of public companies in the gas sector, and an alternative to the current NNPC JV financing model. Otherwise, gas supply risks becoming the Achilles' heel of the power sector reform.

Mozambique has emerged as the second largest gas resource holder in Sub-Saharan Africa as a result of a series of major offshore gas discoveries recorded since 2009. This study estimates the contingent gas resources from these discoveries at 100 TCF, although some sources put this figure even higher. License-holders are moving ahead aggressively on plans to build four LNG trains, and long-term plans call for up to 10 trains. However, developing LNG on such a scale could take 20 years or more to accomplish, particularly since Mozambique will face competition in global LNG markets from Australia, the United States, Canada, and other resource centers. Nevertheless, even if all the gas needed for 10 trains were set aside today, Mozambique would still hold at least 30 TCF of uncommitted gas, equivalent to 20 GW of generation capacity and more than the existing and projected thermal energy demand in the domestic market. Thus, the gas resource base is not a constraint on almost any commercialization options Mozambique wishes to consider. LNG exports, domestic power sales, pipeline exports, and petrochemical applications can all move forward, constrained only by market access, financing capacity, and inter-fuel competition.

Tanzania has also made recent major offshore gas discoveries, but so far not on the same scale as Mozambique. Contingent resources are estimated at 29 TCF, although estimates of more than 50 TCF have been reported. In the near term, the priority for Tanzania is to develop two initial LNG trains, entailing a commitment of 14 TCF of gas. In the long term, at least two further LNG trains are planned. However, in parallel, Tanzania is aggressively pursuing a domestic gas-to-power agenda that could result in over 8 TCF of gas being committed to the domestic market. With potential resource commitments of this magnitude, adequacy of the resource base is not assured. Unless the higher estimates of the resource base prove true or additional discoveries are made, Tanzania's domestic gas agenda and LNG export plans may collide, forcing the country to make difficult choices between export and domestic markets.

Angola and Equatorial Guinea are the other large-resource centers in Sub-Saharan Africa with discovered gas resources of 18 TCF and 13 TCF, respectively. Both countries are LNG producers with very small domestic thermal energy demand, and the prospects for expanding domestic gas-to-power are highly constrained. In the case of Angola, 400 MW of gas-fired power plants are under development, but further growth in domestic demand will be slow because hydropower projects under implementation will be able to accommodate electricity demand growth. In the case of Equatorial Guinea, the domestic electricity market is simply too small to sustain a gas-to-power program.

Eight other countries have discovered gas resources of 1 TCF or more, namely Cameroon, Ghana, the Republic of Congo, South Africa, Namibia, Côte d'Ivoire, Mauritania, and Gabon. None of these countries is considered to have a realistic prospect of developing an LNG export project. However, the gas resources in these countries are, with the exception of South Africa, enormous in relation to energy demand in those countries, representing at least 50 years of total electricity demand. But these countries face formidable barriers to gas-to-power development in the absence of minimum-scale economies in upstream and midstream gas development. In many cases, this will mean that gas development will be feasible only when undertaken on a regional scale via projects that serve power or gas needs in neighboring countries.

Potential shale gas resources of 390 TCF have been identified in South Africa and, if these resources are eventually proven to be economic on a wide scale, the gas and energy balances in southern Africa would be profoundly altered. However, testing of these resources is just starting and any potential development would face numerous technical, economic, and environmental barriers. As a result, supply from shale gas must be considered only a very long-term possibility.

Tradeoffs between LNG Export and Domestic Supply

For countries with large gas resources, allocating gas supply between LNG exports and domestic power markets involves economic trade-offs, particularly with respect to gas pricing.

From the point of view of a gas producer, these trade-offs almost always strongly favor LNG because of the superior contract terms usually available from foreign buyers. However, from a government perspective, the trade-offs are more complex, involving a balance between maintaining investment incentives for producers, maximizing royalty and tax income, and realizing much needed supply increases and cost reductions in the power sector.

To illustrate the range of prices that various commercialization options can present, this study has estimated two upstream price benchmarks. The ***minimum wholesale price*** is the sum of upstream capital and operating costs, royalties, and taxes, and a minimum after-tax rate of return (taken here to be 15 percent). The ***LNG netback price*** is the delivered LNG price in the destination market less the costs of liquefaction and shipping. The two benchmark prices carry implications for the allocation and pricing choices facing the large-resource holders in Sub-Saharan Africa.

Upstream Gas Price Benchmarks
($ per MMBTU)

	Minimum Wholesale Price	**LNG Netback Price**
Nigeria	$2.0	$4–6
Mozambique	$2.5	$6–8
Tanzania	$3.4	$6–8
Small-resource countries	$6–10	N/A

Nigeria needs gas to fuel its power generation growth plans. Yet domestic gas prices in Nigeria were, until recently, held at roughly $0.50 per MMBTU,[1] a level far below the minimum price needed to incentivize gas investment. A complex set of domestic supply obligations was imposed on producers but, at the domestic prices in force, this was effectively just an additional tax on LNG production. However, if Nigeria's announced plans to increase gas prices to $2.50 per MMBTU are fulfilled, prices could begin to stimulate investor interest in gas development, particularly among Nigeria's growing number of domestic independent producers. Nevertheless, increasing domestic gas prices to LNG netback parity levels of $4–6 per MMBTU seems improbable, so the incentives for gas producers with access to a viable LNG outlet will still favor export over domestic supply. Nonprice factors such as the creditworthiness of public utilities and other buyers reinforce this preference. As a result, Nigeria is likely to continue to need some form of domestic supply obligation. Further price increases and other supply incentives will also be necessary.

For ***Mozambique***, LNG exports are clearly the overwhelming gas allocation priority. Indeed, royalties, profit shares, and taxes from future gas exports offer a transformational

[1] All prices discussed in this report are in U.S. dollars.

opportunity to increase national wealth and income. However, because of the sheer size of its resource base, Mozambique can afford to allocate gas to domestic supply without compromising its capacity to export. Thus, the LNG netback price is not a measure of the opportunity cost of gas. In fact, over the long term, any gas application with a netback price above the minimum wholesale price could potentially be good business. This opens the door not just for the domestic power sector, but also for petrochemical and industrial applications and potential gas exports to South Africa (discussed below).

Tanzania is a slightly different case, and its gas allocation choices could be less clear-cut. Like Mozambique, LNG is the top near-term priority for the gas sector. But with a smaller resource base and a more aggressive domestic gas agenda, Tanzania must take the view that domestic gas sales to some extent substitute for LNG, whereas Mozambique can view such sales as incremental. Thus, gas sales at prices less than the LNG netback price represent a subsidy to the power sector.

The three country examples point to a general framework for assessing the costs and benefits of below-market domestic supply obligations. Directing gas from export to domestic markets can bring cost savings to the power sector. But if domestic gas is priced lower than LNG netbacks, there will be a cost in terms of reduced royalties and taxes from production. In the extreme case, low gas prices can result in upstream gas development projects not going forward at all. The cost-benefit balance among all of these factors varies according to specific country circumstances such as the extent to which diesel-fired power is the relevant alternative generation source, the extent to which domestic sales displace exports, the cost of upstream development, and the scope for negotiating higher royalties and taxes in lieu of below-market domestic service obligations.

Competitiveness of Gas in Power Generation in Large-Resource Countries

These pricing benchmarks also have implications for the competitiveness of gas-fired power in Nigeria, Mozambique, and Tanzania. This study uses the minimum wholesale price and the LNG netback price for each country to define a range of possible gas prices for supply to power generators. Using standard assumptions about CCGT and OCGT plant efficiencies and capital and operating costs, gas prices are then converted to levelized electricity costs that are compared to relevant generation alternatives in each country.

For ***Nigeria,*** this analysis paints a very clear picture. The estimated cost of gas-fired power is $41 and $68 per MWh at the minimum wholesale price and LNG netback price, respectively. At these costs, gas-fired power is the lowest-cost thermal generation option by a large margin. To the extent that gas displaces diesel, generation cost savings of 70 percent or more are achievable. With no viable domestic coal option and very limited hydropower potential, Nigeria's generation future rests overwhelmingly with gas.

Mozambique, on the other hand, has several viable generation choices. In addition to gas, Mozambique is endowed with abundant hydropower and coal resources. Hydropower is the least cost option at a levelized cost of $21– 23 per MWh. Coal-fired plants in Tete province are also potentially very competitive options since they would use low-cost discard coal from mining operations. For example, if discard coal were priced at $12.50 per ton, a 2000 MW or larger coal-fired plant could generate power at $68 per MWh. However, the viability of the large hydropower and coal options would depend on exporting power to South Africa because the output of each plant would exceed total domestic electricity demand.

Mozambican gas can be competitive with coal in a number of circumstances. As a baseload option, gas-fired power can match the cost of power from discard coal at a gas price of $5.70 per MMBTU. As argued earlier, Mozambique has leeway to sell its gas at less than the LNG netback given the enormity of its resource base. However, even if gas were priced at the full LNG netback price, gas would be competitive against coal at load factors of 60 percent or less, suggesting a potential role for gas as a mid-cycle generation option. Furthermore, the viability of gas-fired power projects would not have to rely on power exports because the economic scale of such project is just 300 MW, an amount that could realistically be absorbed by the domestic market alone.

Nevertheless, there are some notable barriers to gas-fired power implementation in Mozambique. The large gas resources are in the far north of the country, whereas Maputo and the large electricity loads are in the south. Power transmission costs would affect the comparison between gas and coal. In addition, consumer power tariffs in Mozambique are not currently sufficient to support the full cost of gas-fired generation, including transmission and distribution. On balance, while the economics of gas-fired power in Mozambique are broadly encouraging, it is likely that the role of gas is likely to be constrained by the presence of large-scale export-oriented hydropower projects that can satisfy the needs of Mozambique's currently small electricity market.

In ***Tanzania,*** long-term power generation planning again rests heavily on hydropower. But Tanzania is highly exposed to delays and cost overruns in construction of its hydropower projects and to rain shortfalls once the projects are in operation. To mitigate these risks, Tanzanian energy policy is emphasizing gas-fired generation projects in the short term, and over 1,000 MW of gas-fired capacity is planned. In addition, there are plans to harness Tanzania's indigenous coal reserves in the medium to long term.

The competitiveness of gas-fired power in Tanzania is even more apparent than in Mozambique. In baseload operation, gas-fired power can be produced for $89 per MWh based on a gas price equal to the LNG netback price. This compares with $96 per MWh for coal at international prices of $85 per ton. Even if domestic coal were discounted to $50 per ton, gas would still be competitive at load factors of 70 percent or less. Adding to the competitiveness of gas-fired power is its much shorter development timeline: gas-fired power plants can be built in

12– 18 months versus four to five years for hydropower and coal. Thus, the competitiveness of natural gas as a baseload power generation solution, its ability to complement hydropower in a mid-cycle application, and its shorter development timeline all point to a strong role for gas-fired power in mitigating the risks of Tanzania's hydropower program.

In all countries analyzed in this study, gas-fired power, even in an OCGT configuration, maintained a large cost advantage over diesel and HFO in baseload, mid-cycle, or peaking applications. However, the ability to capture this cost reduction depends on the location of the power generation requirement and its distance from a gas supply source.

Outlook for Regional Gas Transportation

Gas pipeline infrastructure in Sub-Saharan Africa is almost nonexistent apart from coastal Nigeria and a handful of small, subregional projects. This study examined the transportation economics for five potential new pipeline projects thought to be representative of the opportunities and challenges facing pipeline development in Sub-Saharan Africa.

Nigeria inland route: A 950-kilometer, 36-inch pipeline from Calabar to Kano would have very low per-unit transportation costs, resulting in delivered gas prices of $3– 5 per MMBTU, far cheaper than liquid fuels delivered to inland locations in Nigeria. Gas supply in these inland cities would also open possibilities for industrial demand. However, volume aggregation is a major challenge. The proposed pipeline would carry enough gas to generate 5,000 MW of power. Although Kano, Abuja, and other inland cities have significant populations that could eventually support such a level of demand, the weak industrial base in these cities makes rapid demand development a challenge.

WAGP expansion/extension: Not surprisingly, the incremental cost of expanding deliveries to Ghana through the existing West African Gas Pipeline is very low, as is the cost of extending the pipeline to Côte d'Ivoire. Delivered gas prices could be $7– 10 per MMBTU for Ghana and $9– 11 per MMBTU for Côte d'Ivoire, values that would be somewhat more expensive than domestic production but substantially cheaper than liquid fuels or LNG. However, policy makers and planners in Ghana and Côte d'Ivoire are unlikely to look at WAGP expansion as a realistic supply option, given the project's history of unreliability.

Mozambique to South Africa: For a 36-inch pipeline, the estimated transportation cost from northern Mozambique to Johannesburg is $3 per MMBTU, which would result in a delivered cost of gas in Johannesburg of $6– 11 per MMBTU. At the low end of this range, gas could be competitive against coal for baseload generation. Furthermore, given the size of South Africa's future generation requirements, aggregating enough demand to justify the pipeline is likely. A commercial and technical feasibility study seems warranted.

Tanzania to Kenya: Transportation costs from Tanzania to Kenya would be quite low, perhaps $2– 3 per MMBTU. But since exports to Kenya will be a low priority for the Tanzanian

government and producers, the commodity gas price would likely be set near Tanzania's LNG netback price. In that case, delivered gas costs to Kenya would be $9– 10 per MMBTU, prices that may not be competitive with other generation options. In addition, ongoing exploration in Kenya could result in gas discoveries that would undermine the rationale for imports from Tanzania.

Tanzania inland route: Transportation costs from Dar es Salaam to inland markets such as Shinyanga and Kigoma would be very high due to the seemingly very low off-take volumes in these markets. Power transmission is a more efficient option for delivering energy to these inland cities.

From the five case studies evaluated, it is clear that economies of scale are the main challenge to development of gas pipeline infrastructure in Sub-Saharan Africa. In most cases, the markets are too small and the distances too great to make pipelines economically viable. Indeed, the study suggests that over a distance of 1,000 kilometers, power transmission will be the lower-cost alternative unless enough demand can be aggregated to fill a 28-inch pipeline. In power terms, this equates to 3,000 MW, a thermal generation demand that very few markets in Sub-Saharan Africa can sustain. Where sufficient demand does exist, selected regional gas pipeline projects may go forward. But the prospect of a continent-wide, interconnected gas pipeline system like that of the southern cone of South America is very remote.

Importing Country Perspectives

The case for gas trade in Sub-Saharan Africa depends not only on transportation economics, but ultimately on the competitiveness of the delivered gas versus other generation options for the importing country.

South Africa has decided to impose a hard cap on CO_2 emissions from the electricity sector and this creates an opportunity for an expanded role for gas in power generation. Even without considering the cost of CO_2 emissions, gas is competitive against coal in baseload power generation at a delivered gas cost of $7 per MMBTU. Netting out pipeline transportation costs, this translates into a wellhead price in Mozambique of $4 per MMBTU, lower than Mozambique's LNG netback but still above its minimum wholesale price. At lower load factors, the generation economics move increasingly in favor of gas, although higher per-unit transportation costs could offset that advantage. Nevertheless, this study strongly suggests that exporting gas from the large offshore gas fields in northern Mozambique to South Africa could be good for Mozambique and good for South Africa, particularly if industrial gas demand can be combined with power sector demand to drive volumes up and per-unit costs down. At the same time, South Africa has other potential gas supply options including LNG imports, shale gas, and conventional exploration. A gas master plan, now underway, will be valuable in shaping South Africa's gas supply strategy.

For ***Kenya,*** the competitiveness of imported Tanzanian gas depends entirely on upstream gas pricing. If Tanzania priced its gas at its minimum wholesale price, gas would be extremely competitive with geothermal power and even with hydropower. But this scenario is unlikely, and Tanzanian producers would probably ask a price closer to LNG netback levels, resulting in a delivered cost in Kenya of close to $10 per MMBTU. At this price level, gas-fired power would lose its competitiveness against geothermal and would be broadly equal in cost to imported coal. Thus, while the market volume potential in Kenya could potentially be enough to sustain a pipeline project, production economics in Tanzania and generation economics in Kenya constrain the gas-to-power value chain to such a degree that prospects for Tanzania–Kenya gas trade are highly uncertain.

Ghana and Côte d'Ivoire, with their hydropower potential nearly fully exploited and with no viable coal options, both are turning increasingly to natural gas to satisfy power generation needs. In both countries, gas supply will need to come from a combination of domestic production and imports. Despite the clear-cut cost advantage that Nigerian pipeline gas could enjoy, planners in both Ghana and Côte d'Ivoire are focusing on LNG import options because of the perceived unreliability of WAGP supply. While offering a high level of supply security, LNG import projects in Ghana and Côte d'Ivoire will be challenging to finance and may not result in large savings over liquid fuels currently in use.

Opportunities and Challenges for Smaller-Resource Countries

While the resources held by smaller countries are not material on a regional scale, they are enormous in relation to current energy demand in those countries. For Ghana, Namibia, and Côte d'Ivoire, discovered gas is equivalent to more than 50 years of current levels of electricity demand, and for Cameroon, Congo, Mauritania, and Gabon, more than 100 years. Most of these countries rely heavily on liquid fuels for power generation at a cost of well over $20 per MMBTU. Replacing these liquid fuels is the big prize for the power sector.

However, economies of scale—or the lack thereof—form a powerful obstacle to gas-to-power development in smaller countries. Smaller power markets need smaller increments of new generation. Given the high efficiency of gas-fired power plants, the resulting production gas requirements are very small and often fall below the minimum economic scale for upstream and midstream development.

Potential for overcoming the economic barriers comes from several avenues. First, to increase volume above minimum scale, projects can export power or gas to neighboring countries. The Banda project in Mauritania is taking this approach. Another approach is to anchor gas development on large mining loads where these exist. Second, gas prices can be increased to levels needed to provide reasonable rates of return even at low volumes. While the minimum wholesale price for small-field development can be $10 per MMBTU or more, such seemingly high prices still offer important savings over liquid fuels. Last, where production

royalties and taxes are an important component of the minimum wholesale price—as this study suggests is often the case—governments can reduce these burdens to the degree needed to improve upstream economics to the point where projects go forward and the potential cost savings in the power sector are captured.

Conclusions

The analysis in this study provides both encouraging and cautionary notes. Clearly, the gas resource base itself is large enough to support whatever power sector demand could plausibly materialize. And the cost of gas-fired power competes very favorably against liquid fuels and, in a surprising number of cases, against coal. But at the same time, this study shows that Africa's abundant hydropower and coal resources and the high cost of moving gas from resource centers to demand centers are factors that can limit the economic reach of gas.

The study suggests three primary roles for gas in addressing Sub-Saharan Africa's power needs. Replacing liquid fuels such as HFO and diesel is the strongest argument for gas, although even this apparent low-hanging fruit depends on how liquid-fired generation is being used and where the gas supply would originate. Second, displacing coal with gas, although not always viable, shows up here as a surprisingly competitive option, especially when fuels are priced at international levels or where the opportunity cost of gas is low. In fact, when coal is priced at international prices, gas-fired power will be competitive whenever the price of the delivered gas is $9 per MMBTU or less. Last, the flexibility of gas-fired power plants suggest a strong role for gas in addressing short-term power deficits, supporting the implementation of variable renewable energy generation, and mitigating risks in hydropower implementation. The case for each of these three broad gas-to-power applications depends on local conditions in each country.

What is clear, however, is that gas is not a panacea for the acute power deficits in Sub-Saharan Africa. Gas must compete against other generation options, and large-resource holders face trade-offs between domestic gas utilization and LNG exports. Nevertheless, the gas production, transportation, and power generation segments of the value chain align in enough instances that an expanded role for gas-fired power in Sub-Saharan Africa is assured.

Introduction

Sub-Saharan Africa's chronic power generation deficit forms a major obstacle to economic growth and human development across the continent. Installed power generation capacity in the 48 countries of Sub-Saharan Africa totals just 80 GW—about the same as the Republic of Korea—and South Africa by itself accounts for more than half of that capacity. Nigeria, with more than three times South Africa's population, has only a tenth of its installed generation capacity and, along with many other countries in the region, suffers frequent power outages. Two out of three households in Sub-Saharan Africa have no electricity connection at all. In countries such as Mozambique and Tanzania, that figure rises to 85 percent.

Even when power is available, it tends to be costly. Businesses throughout the continent rely on expensive backup diesel generators. A growing number of countries have contracted emergency power units to help ameliorate national shortages. And few countries are able to benefit from economies of scale: 33 countries have power systems smaller than 500 MW, and 15 countries have systems smaller than 100 MW.

These twin generation sector problems of low capacity and high cost have several root causes. Investment in new generation capacity has not kept up with demand growth. In the case of state-owned utilities, maintenance and operational performance has often been poor, and tariffs and collections have been insufficient to support refurbishment or new investment. Even though many countries permit private sector participation in generation, shortcomings in planning and procurement have been common and international competitive tenders for new capacity have been lacking. External factors have also contributed to the problem. Hydroelectric output has been reduced by drought in some regions. And high oil prices have sharply increased the cost of diesel and HFO-fired thermal generation, particularly where fuels must be transported large distances inland.

Yet parts of Sub-Saharan Africa are endowed with abundant natural gas resources. Nigeria alone has enough discovered gas to generate over 80 GW of power for 30 years. Recent exploration in Mozambique, Tanzania, and elsewhere has shown that gas resources in Africa are larger and more widely distributed than previously thought. It's therefore reasonable for policy makers and planners to ask whether natural gas can play a central role in addressing Sub-Saharan Africa's power generation challenges.

Gas has a number of well-known advantages as a power generation fuel. Modern combined-cycle gas turbine (CCGT) generators operate at very high thermal efficiencies (55 percent or more) and can be constructed more quickly and for lower unit cost than coal or hydropower plants. Burning gas emits roughly half the CO_2 as compared with coal and 30 percent less than oil. And the flexible dispatch capability of gas-fired generators complements

large-scale renewable integration by compensating for the intermittency of wind and solar resources and by backing up hydropower during periods of drought.

Yet even with these apparent advantages, the case for gas-fired power in Sub-Saharan Africa is not always clear cut. Resources are concentrated in a small number of countries, and the distances between resource centers and major markets are large. Gas must compete against other generation options such as hydropower and coal that are also abundant in Sub-Saharan Africa. And large-resource holders face trade-offs between subsidizing domestic gas utilization on the one hand and export-driven royalty and tax maximization on the other. As a result, commercializing natural gas in Sub-Saharan Africa has proven exceedingly difficult, and the timeline between discovery and commercialization is often measured in decades.

The goal of this study is to look for opportunities to unlock the potential for gas-fired power in Sub-Saharan Africa. The study examines the gas-to-power value chain for resource holding countries in East and West Africa and derives cost and price benchmarks for gas production, gas transmission, and power generation. The resulting estimates of the cost of gas-fired power are compared against the cost of other generation options. The benchmarking is presented from the point of view of the financial incentives facing investors and governments rather than from the point of view of optimum economic prices. The quantitative benchmarks are used as the analytical platform for addressing a number of key policy questions:

- **How big is the gas resource base, and what options do resource-holding countries have in deciding what to do with their gas?**
- **What are the economic tradeoffs between domestic gas utilization and LNG export for the large-resource countries?**
- **Is gas an economic power generation solution in the large-resource countries?**
- **Is there a case for exporting gas or gas-fired power from large-resource centers to neighboring countries?**
- **What are the prospects for a continent-wide gas pipeline grid?**
- **What are the gas-to-power opportunities and challenges for smaller-resource countries?**

This report is intended as a resource for energy planners and policy makers within governments of Sub-Saharan African countries that have access to gas resources, either indigenous resources or imported supplies. It provides benchmarks and a frame of reference for screening gas-to-power opportunities within the major subregions of the continent. But at the same time, there are limits to the gas value-chain approach adopted here. Least-cost, profit-maximizing decision making is not always a given. Policy, political economy, and institutional factors can undermine the success of even those projects with the strongest apparent economic

drivers. However, a full exploration of how these factors operate and how they can be overcome was considered beyond the scope of the current study.

The report examines the gas-to-power value chain in Sub-Saharan Africa from a number of different perspectives. Chapter 1 provides an inventory of gas reserves and resources in Sub-Saharan Africa. Chapter 2 estimates key wholesale price benchmarks for production of natural gas in the three biggest resource centers—Nigeria, Mozambique, and Tanzania—and examines the tradeoffs between domestic gas supply and LNG exports. Chapter 3 estimates the cost of gas-fired power generation in those three large-resource countries and assesses the competitiveness of gas versus competing generation options. Chapter 4 estimates the costs of transporting gas from the big resource centers to domestic and regional markets. Chapter 5 looks at the gas-to-power choices from the importing country perspective. Chapter 6 looks at the opportunities and challenges facing smaller resource countries. Finally, Chapter 7 presents conclusions based on the entire gas-to-power value chain in the focus countries.

Chapter 1

Natural Gas Reserves and Resources in Sub-Saharan Africa

Quantification of Sub-Saharan Africa's natural gas resource endowment has typically focused almost entirely on Nigeria. In fact, in the gas reserves table of the *BP Statistical Review of World Energy*, only Nigeria is broken out on a separate line—all other Sub-Saharan African countries are aggregated in a line labeled "Other Africa." But natural gas has been discovered in at least 15 other Sub-Saharan African countries. Many of these discoveries—including the very large offshore discoveries in Mozambique and Tanzania—have occurred within the last decade.

This study has compiled a country-by-country inventory of the natural gas resources in Sub-Saharan Africa, taking into account current commercial reserves, undeveloped contingent resources, and risked undiscovered resources. The estimates are derived from multiple public and proprietary data sources, in many cases down to the individual field level of detail. Efforts have been made to reconcile a wide range of reporting standards appearing in public sources. The methodology adopted in this study results in resource estimates that are substantially different from official reserve figures in almost all countries.

The results show that Sub-Saharan Africa's natural gas resources, while still concentrated in a few countries, are more abundant, more diverse, and more widely distributed than proved reserve figures by themselves would suggest. But the results also highlight that commercialization options available to resource-holding countries are not all the same. The choices available to each country are influenced by the magnitude and composition of the resource base, the size of the domestic energy market, and the degree to which gas resources have been earmarked for export.

Box 1.1
What Is a TCF?

Under the English system of units commonly used in the oil and gas industry, gas volumes are measured in thousands of cubic feet, abbreviated MCF. One trillion cubic feet (TCF), equivalent to 1 billion MCF, is used throughout this study as a measure of large gas resources. If produced evenly over 30 years, 1 TCF of gas (28 billion cubic meters in metric units) would contain enough energy to generate over 500 MW of power.

Discovered Gas Resources

According to the resource classification standards employed in the petroleum industry, the term "reserves" refers to those volumes of gas that are commercially recoverable from known accumulations (SPE 2007). While not all announced reserve figures adhere to this strict definition (Box 1.2), the commerciality tests for gas reserves normally require existence of an established market, available infrastructure, and an approved field development plan. The term "proved reserves" refers to those reserves that are reasonably certain to be recovered, and "probable reserves" denotes gas volumes

that are more likely than not to be recovered. The sum of proved and probable reserves, denoted 2P reserves, is often considered a "best guess" estimate of ultimate recovery from commercial fields.[2]

Using these definitions, total proved gas reserves for Sub-Saharan Africa are estimated at 136 TCF distributed among 12 countries (Table 1.1). Nigeria accounts for 81 percent of total proved reserves, and the three LNG exporting countries—Nigeria, Angola, and Equatorial Guinea—account for 92 percent. Probable reserves are estimated at 33 TCF, resulting in a 2P reserve figure of 169 TCF. However, since proved and probable reserves measure only the extent to which gas has been commercialized, they are not by any means a complete measure of resource endowment.

Table 1.1
Discovered Natural Gas Reserves and Resources in Sub-Saharan Africa[3]

Country	Proved Reserves (TCF)	Probable Reserves (TCF)	Contingent Resources (TCF)	Total Gas Discovered (TCF)	Generation Potential (GW, 30 yrs)
Nigeria	110.3	22.1	36.0	168.4	85.6
Mozambique	2.7	1.8	100.0	104.5	53.1
Tanzania	1.4	0.3	29.3	31.0	15.8
Angola	12.0	6.0	0.0	18.0	9.1
Equatorial Guinea	2.6	1.4	8.5	12.5	6.3
Cameroon	0.0	0.2	5.5	5.7	2.9
Congo, Republic of	3.2	0.0	2.0	5.2	2.6
South Africa	1.0	0.0	2.4	3.4	1.7
Ghana	1.0	0.4	1.8	3.2	1.7
Namibia	0.6	0.0	1.3	1.9	1.0
Côte d'Ivoire	0.8	0.3	0.3	1.5	0.7
Mauritania	0.3	0.1	0.8	1.1	0.6
Gabon	0.1	0.0	1.2	1.3	0.7
Uganda	0.0	0.0	0.5	0.5	0.3
Botswana	0.0	0.0	0.2	0.2	0.1
TOTAL	**136.1**	**32.5**	**189.7**	**358.3**	**182.1**

[2] If stochastic estimation methods are used, there should be a 90 percent probability that ultimate recovery will meet or exceed the estimate of proved reserves and a 50 percent probability that recovery will meet or exceed 2P reserves.
[3] Excludes Lake Kivu gas in Rwanda and nonviable contingent resources in Benin, Chad, Ethiopia, Niger, Senegal, and South Sudan

Box 1.2
When Are Reserves Not Reserves?

The determination of oil and gas reserves and resources is usually carried out according to the Society of Petroleum Engineers Petroleum Resource Management System (SPE PRMS). However, quantities of oil and gas reported by governments, companies, and the press as "proved reserves" often differ greatly in their adherence to SPE PRMS standards. In interpreting public statements about gas reserves, a number of critical questions should be asked:

1. **Is the gas commercial?** Volumes described as proved reserves often more accurately reflect the total quantity of discovered gas. Gas not meeting the SPE commerciality criteria should not be classified as reserves but rather as contingent resources. Given the enormous challenges involved in commercializing gas, this distinction is important in assessing the true economic potential of a reported natural gas resource.
2. **Is the gas recoverable?** Some declarations about the quantity of proved gas reserves use gas in place as opposed to recoverable gas. Recovery factors can vary enormously but for non-associated gas fields can be 80 percent or so.
3. **Is the estimate conservative?** Quantities of gas reported as proved are often really "best guess" estimates of recovery, which should more properly be labeled as 2P reserves.

Contingent resources are quantities of gas that can potentially be recovered from discovered accumulations but where development projects are not yet considered mature enough to be commercial. Contingent resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on new technology, or where evaluation of the accumulation is insufficient to clearly assess commerciality.

Based on announced discoveries, total contingent resources are estimated at 190 TCF, 40 percent of which come from pending developments. Discovered gas resources—the sum of 2P commercial reserves plus contingent resources—are estimated at 358 TCF, more than twice the proved reserve figure. In mid-merit CCGT power plants, this quantity of gas could generate more than 180 GW of power for 30 years. Moreover, discovered gas resources are somewhat more widely distributed than proved reserves, with Mozambique and Tanzania accounting for roughly one-third of total discovered gas.

Large-Resource Centers

The five large-resource countries in Sub-Saharan Africa are Nigeria, Mozambique, Tanzania, Angola, and Equatorial Guinea. Given the size of their resources, all of these countries are focusing on LNG exports. Nigeria, Angola, and Equatorial Guinea have 31 million tons per annum (MTPA) of existing LNG capacity, and the likely first phase of LNG projects in Mozambique and Tanzania will take total capacity in Sub-Saharan Africa to 61 MTPA over the

next decade (Table 1.2). Total actual and planned export commitments amount to 85 TCF or some 25 percent of discovered resources.

Table 1.2
Export Commitments[4]

	LNG Capacity		Committed Resources (TCF)			% of
Country	Trains	MTPA	LNG	Pipeline	Total	Discovered Gas
Nigeria	6	22	26	1	27	16%
Mozambique	4	20	28	5	33	32%
Tanzania	2	10	14	0	14	45%
Angola	1	5	7	0	7	39%
Equatorial Guinea	1	4	4	0	4	32%
TOTAL	**14**	**61**	**79**	**6**	**85**	**25%**

With most of the gas in the large-resource countries uncommitted, there would appear to be ample scope for expanding domestic and regional use of natural gas in power generation. However, the tradeoff between gas exports and domestic gas use differs greatly from country to country.

Nigeria: Nigeria's proved gas reserves are estimated here at 110 TCF, roughly 40 percent lower than the 180 TCF figure commonly reported (Box 1.3). In fact, if the commerciality criteria were applied in the narrowest sense, Nigeria's proved reserves might total only 47 TCF. But even after the downgrades applied to official figures, Nigeria's existing gas resources are huge, and future exploration would no doubt result in significant new discoveries.

However, the demands on Nigeria's gas resources are also huge, and it would be a mistake to view the resource base as infinite. Current export commitments total 27 TCF and a further 16 TCF is committed to existing domestic power plants and industrial markets (NLNG 2012). Subtracting these amounts from discovered resources leaves 125 TCF in uncommitted gas, enough to power 50 GW of power generation for 50 years. This is roughly 10 times Nigeria's current thermal generation capacity. On the other hand, Nigeria's Roadmap for Power Sector Reform sets a goal of 20 GW of gas-fired generation capacity by 2020, and most of this capacity will be gas-fired (FRN 2013). Using this ambitious yardstick, an additional 30 TCF or more of gas would need to be dedicated to the domestic power sector. Although the resource base per se is adequate to support such an expansion, the pace of resource development will be a severe constraint. Developing 30 TCF of new gas supply will require huge capital spending—perhaps $20 billion or more. Spending of this magnitude would severely strain the capital budgets of both government and private investors, and Nigeria would find it very difficult to undertake new LNG export commitments at the same time.

[4] Mozambique and Tanzania export commitments are based on likely first-phase LNG developments, and resources shown as committed should be interpreted as probable commitments

Mozambique: Beginning in 2009, a series of major gas discoveries have been made in Mozambique's offshore Rovuma Basin. This study estimates recoverable gas from these discoveries at 100 TCF, although some sources put this figure even higher. While frequently reported as proved reserves, these volumes rightfully belong in the contingent resource category until commercial and field development plans are in place. Mozambique's proved reserves today are limited to the Sasol-operated Pande and Temane fields, currently producing roughly 350 MMCFD, mostly for export via the Mozambique–South Africa pipeline.

The exploration license-holders in Mozambique are moving ahead aggressively on plans to develop the big new offshore discoveries. Four LNG trains are expected to reach final investment decision in the near term, and up to 10 trains could ultimately be built. But even a project of this enormous scale can be easily accommodated by the existing resource base. The gas needed for the initial 4 trains is 28 TCF, just 32 percent of the discovered resources. Developing all 10 planned LNG trains could take 20 years to accomplish and other gas utilization options may jump ahead in the queue. But even if the entire 70 TCF needed to support 10 LNG trains were set aside today, it would still leave 30 TCF of uncommitted gas, equivalent to 20 GW of generation capacity and many times the thermal generation needs of the domestic market. Moreover, exploration is ongoing and additional gas discoveries are likely. In essence, Mozambique's gas resource base is not a constraint on any commercialization plans. LNG exports, domestic power sales, pipeline exports, and petrochemical applications can all move forward, constrained only by market access, economics, and financing capacity.

Tanzania: Major gas discoveries have also been made in the Tanzanian portion of the Rovuma Basin. This study estimates recoverable gas from these discoveries at 29 TCF, although estimates of more than 50 TCF have been reported. As in Mozambique, the offshore gas fields are properly categorized as contingent resources until commercial and development plans are finalized. The onshore and near-shore Songo Songo and Mnazi Bay fields are already under development and comprise 2 TCF of reserves directed to the domestic power market.

In the near term, Tanzania is likely to move forward with two LNG trains. This first phase of development will require 14 TCF of gas, almost half of the current discovered gas resource. Two more LNG trains are planned for the future, suggesting that, absent new discoveries, the resource base would be fully committed to export.

However, Tanzanian policy and planning are oriented strongly toward directing gas production into the domestic market. In fact, the May 2013 Draft Natural Gas Policy calls for the government to "ensure that [the] domestic market is given first priority over the export market in gas supply." Under the terms of the contracts with the offshore license-holders, a portion of the production from the LNG projects is reserved for the domestic market. Over 1,000 MW of new gas-fired generation capacity is under development. A 36-inch pipeline from Mtwara to Dar es Salaam is under construction, and this pipeline will have a capacity of 800 MMCFD, enough for

over 5 GW of generation capacity. Finally, the policy calls for creation of industrial parks utilizing natural gas in industrial activities.

But Tanzania could face tough challenges in balancing domestic and export markets for gas and tradeoffs may become necessary. Taken together, the domestic market obligation from the first two LNG trains plus the reserves at Mnazi Bay, Songo Songo, and other near-shore accumulations amount to 4 TCF of gas committed to the domestic market, which is 13 percent of current discovered resources. A further 4 TCF of domestic gas commitments would be necessary if the Mtwara–Dar es Salaam pipeline were operated at planned full capacity. Absent further exploration success, Tanzania may find it difficult to accommodate domestic commitments of this magnitude side by side with a further 14 TCF needed for the third and fourth LNG trains within the existing resource envelope.

Angola: Production from the 5.2 MTPA Angola LNG project began in July 2013. In conjunction with LNG development, 125 MMCFD of gas production capacity has been developed for the domestic market. This domestic gas supply will be enough to fuel the 400 MW of gas-fired capacity under development and the additional 400 MW of gas-fired capacity additions planned for the next decade. Taken together, the LNG and domestic market commitments account for 8 TCF, nearly half of Angola's estimated 18 TCF of estimated 2P reserves. Undeveloped gas fields presumably exist, but data limitations have made it impossible to quantify contingent resources in Angola.

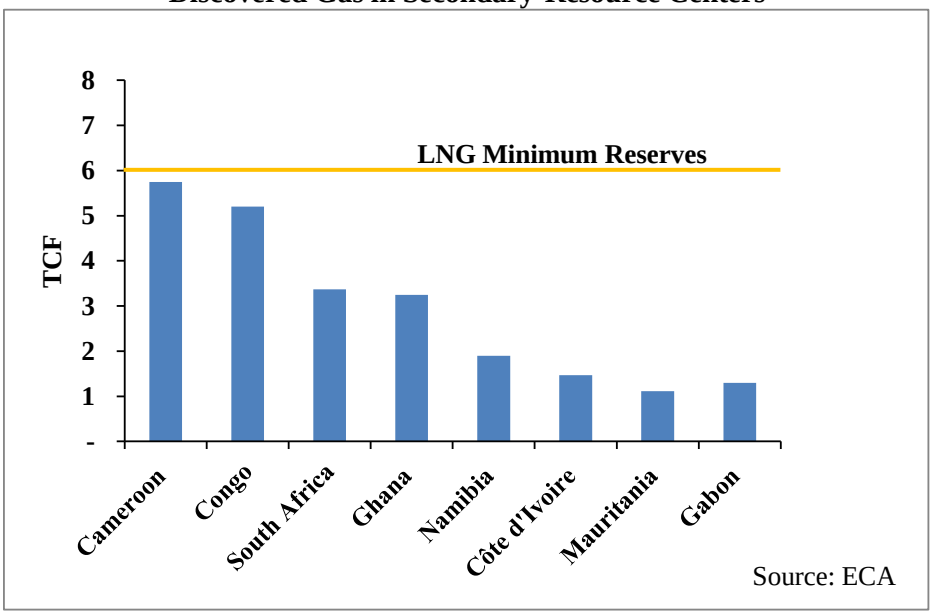
Beyond the current active project portfolio, Angola's prospects for expanding gas commercialization are highly constrained. Growth in domestic gas demand will be slow because the high-quality hydropower projects currently under implementation will be able to accommodate demand growth. The feasibility of pipeline exports looks questionable since distances to major markets to the south are large and the countries to the north have abundant gas of their own. Unless Angola strengthens regional power transmission lines, export of gas-fired power will not be a realistic possibility. An additional LNG train could be accommodated by the reserve base but, given the difficulties and delays that were encountered with the first train, investor appetite for expansion is probably limited.

Equatorial Guinea: Virtually all gas production in Equatorial Guinea is exported via the 3.7 MTPA Equatorial Guinea LNG project. Although total discovered gas resources are estimated at 12 TCF, only the volumes required for the existing LNG project have been designated as reserves. Equatorial Guinea presumably has enough gas to supply its own domestic power needs from gas, but the market is so small that expansion opportunities are very limited. Export opportunities are also highly constrained because all neighboring countries have significant gas resources of their own.

Secondary-Resource Centers

Outside the large-reserve centers, eight Sub-Saharan African countries have gas resources of 1 TCF or more: Cameroon, the Republic of Congo, South Africa, Ghana, Namibia, Côte d'Ivoire, Mauritania, and Gabon (Figure 1.1). With the exception of Cameroon and Congo, the discovered resources fall well below the roughly 6 TCF minimum economic size for an LNG export project. While the resources held by these countries are not material on a regional scale, they are, with the exception of South Africa, enormous in relation to energy demand in those countries. For Ghana, Namibia, and Côte d'Ivoire, discovered gas is equivalent to more than 50 years of total electricity demand, and for Cameroon, Congo, Mauritania, and Gabon, more than 100 years. Most of these countries rely heavily on liquid fuels for power generation.

Figure 1.1
Discovered Gas in Secondary-Resource Centers



Shale Gas and Coal Bed Methane Resources

A 2013 study issued by EIA estimates that the Karoo Basin in South Africa contains 390 TCF of risked, technically recoverable shale gas resources. Shell, Chevron, and other large international companies have taken acreage positions and begun evaluation of the resource. In addition, coal bed methane potential has been identified in both South Africa and Botswana. However, testing of these resources is just starting and any potential large-scale development would face numerous technical, economic, and environmental barriers. As a result, projection of a shale gas boom, like that underway in North America, would be highly speculative. Nevertheless, if South Africa's shale gas resources are eventually proven to be economic on a wide scale, the gas and energy balances in southern Africa would be profoundly altered.

Undiscovered Gas Resources

Finally, this study identifies 774 TCF of risked undiscovered prospective resources, an amount more than twice the current discovered resources (Annex 2). The main source used in compiling this estimate is the U.S. Geological Survey (USGS) World Petroleum Resources Project, a basin-by-basin geological assessment of exploration potential. While this data must be used with a high degree of caution, it does suggest that future natural gas exploration is likely to yield important new discoveries, both in established countries and in new areas.

Commercialization Is the Challenge

The inventory of gas resources laid out in this chapter clearly shows that, on a continent-wide level, resource endowment is not a constraint on further utilization of natural gas in Sub-Saharan Africa. Beyond the current commercial reserves of 169 TCF, the region holds 190 TCF of undeveloped discovered resources, at least 390 TCF of risked shale gas resources, and 775 TCF of risked, undiscovered prospective resources. Together these resources are enough to supply the entire thermal generation needs of the continent many times over.

However, commercializing gas in Sub-Saharan Africa is exceedingly challenging, whether in large- or small-resource centers and whether the market is export or domestic. The timeline between discovery and commercialization is often measured in decades (Table 1.3). As a result, oil companies have done very little exploration specifically targeted at gas until quite recently.

Table 1.3
Gas Project Commercialization Timelines in Sub-Saharan Africa

Field/License	Country	Resource (TCF)	Discovery Year	Production Start	Years to Production	Target Market
Songo Songo	Tanzania	1.0	1974	2004	30	Domestic
Mnazi Bay	Tanzania	0.7	1981	2006	25	Domestic
Blocks 1, 2, 3, 4	Tanzania	24	2010–12	TBA	10+	LNG
Pande/Temane	Mozambique	3.0	1961,67	2004	40	South Africa
Block 1, 4	Mozambique	75	2010	2018	8	LNG
Logbaba	Cameroon	0.1	1955	2012	57	Domestic
Etinde	Cameroon	0.5	1960s	TBA	50+	Fertilizer
Kudu	Namibia	1.0	1974	TBA	40+	Domestic
Alba	EG	5.0	2007	2011	4	LNG
Banda	Mauritania	0.7	2002	2016	14	Domestic
Sankofa	Ghana	1.8	2009	2018est.	9	Domestic
Calub/Hilala	Ethiopia	3.2	1973–74	TBA	40+	Stranded

The gas commercialization challenges in Sub-Saharan Africa are profound. Although large gas resources are present in several countries, there are large distances between production areas and major market centers. Gas production and transportation are capital intensive and

exhibit strong economies of scale. The remainder of this report will assess where these economic obstacles can be overcome and where they cannot.

Box 1.3
A Closer Look at Nigerian Gas Reserves

According to the Department of Petroleum Resources, Nigeria's proved natural gas reserves at year-end 2011 were 182.8 TCF, made up of 92.6 TCF of associated gas and 90.2 TCF of non-associated gas. But evidence suggests that not all of these reported volumes would qualify as proved reserves under SPE PRMS criteria. A 2007 presentation by NNPC provided detail on the components of natural gas reserves (see table). The line items labeled "marginal non-associated gas," "stranded reserves," and "gas cap blow-down" would almost certainly not pass the commerciality criteria under SPE PRMS. This study has downgraded these components to the contingent resource category, resulting in an estimate of 110 TCF for 2011 year-end reserves.

2007 NNPC Breakdown of Reserves

Category	TCF
Non-associated gas	65
Solution gas	20
Offshore gas	8
Marginal non-associated gas	6
Stranded reserves	13
Gas cap blow-down	54
Remaining solution gas	15
TOTAL	**181**

A bottom-up approach to reserve evaluation could show even more of a downgrade to published figures. Upstream consultancy Wood Mackenzie estimates commercial reserves in Nigeria at just 46.5 TCF, based on an analysis of the 38 blocks containing gas fields that are either producing or planned for development. Wood Mackenzie also identifies 82.6 TCF of "technical" gas reserves, a description taken to be roughly equivalent to contingent resources. Taken together, commercial and technical reserves from Wood Mackenzie are 128.3 TCF, very close to the 132 TCF 2P reserves derived in this study.

A final question to be asked about reported Nigerian reserves is why the figures don't change from year to year. According to the *BP Statistical Review of World Energy*, year-end reserves were 182 TCF in 2012 and have been within 5 TCF of this same figure each year for the last decade. Reserves in 2012 are the same as in 2005 even though 9 TCF were produced in the intervening years. This implies that an offsetting 9 TCF of new discoveries were made during a time when exploration activity in Nigeria, particularly for gas, was at a virtual standstill due to low gas prices, security issues, and uncertainties over changes in the upstream legal and fiscal framework.

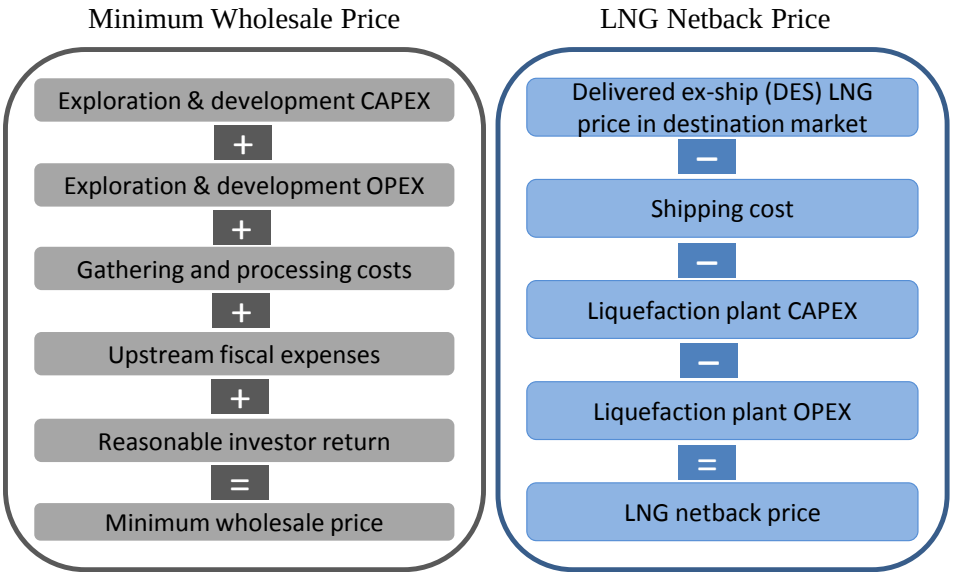
Chapter 2
Price Benchmarks for Natural Gas Production

For countries with large gas resources, what are the tradeoffs between LNG exports and domestic power sector gas utilization? The previous chapter looked at this question from the point of view of the adequacy of the resource base and the size of the domestic market. This chapter widens the question to address the economic choice, a choice that is driven to a large extent by gas prices.

To illustrate the range of prices that the alternative commercialization options can present, this study has developed estimates of two upstream price benchmarks. The ***minimum wholesale price*** is a bottom-up price consisting of capital and operating costs plus fiscal expenses and a 15 percent rate of return for the producer. Although not a direct measure of pricing in domestic power markets, the minimum wholesale price does illustrate the lowest price that can be offered to the power market that still preserves minimum economic incentives for the producer. The ***LNG netback price*** is a top-down approach wherein all costs associated with liquefying and transporting gas are subtracted from the delivered LNG price at the destination market. For countries with a viable LNG export option, the LNG netback price is the world market reference price and can represent the opportunity cost of gas.

The two price benchmarks define a range of potential wholesale gas prices that ensure sufficient returns to upstream producers and are competitive on international markets. Also, the difference between the two benchmarks is an estimate of the potential economic rent available from export.

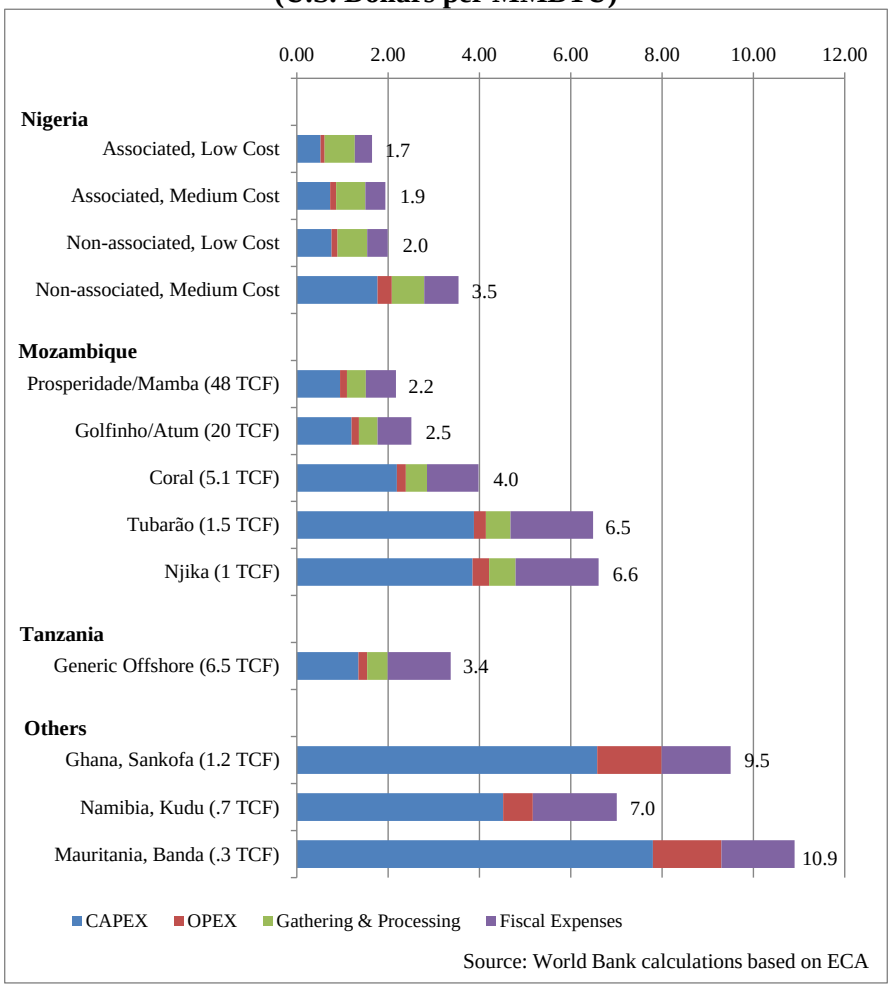
Figure 2.1
Cost Factors Determining Wholesale Price Benchmarks



Minimum Wholesale Price

The minimum wholesale price calculation is built upon assumptions regarding the capital and operating expenses (CAPEX and OPEX) for gas production. In the case of Nigeria, these estimates are derived from a 2004 report prepared by IHS, a highly respected oil and gas consultancy.[5] The 2004 IHS figures have been adjusted for oil sector cost increases. For Mozambique, the estimates come from the 2012 Gas Master Plan prepared by ICF International for the government of Mozambique.[6] Costs in Tanzania are assumed to be 25 percent higher than Mozambique due to smaller field sizes. Discounted cash flow models were created for example fields, adding in estimates of gathering and processing costs and applying the respective fiscal terms to calculate royalties, taxes, and other fiscal costs. An after-tax investor hurdle rate of 15 percent was applied to calculate the minimum wholesale price (Figure 2.2).

Figure 2.2
Minimum Wholesale Gas Price
(U.S. Dollars per MMBTU)



Source: World Bank calculations based on ECA

[5] "Strategic Gas Plan for Nigeria," February 2004, ESMAP.
[6] "The Future of Natural Gas in Mozambique: Towards a Natural Gas Master Plan," October 2012.

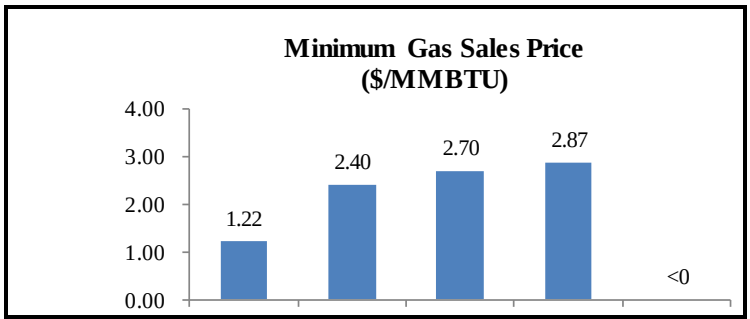
As expected, the results for Nigeria suggest that threshold wholesale gas prices are very low. The minimum wholesale price for associated gas is $2 per MMBTU or less, equivalent to 1.5 cents per kilowatt-hour as a fuel cost input to power generation. Gathering and processing costs comprise a large portion of total costs. Non-associated gas costs vary substantially. At the low end, costs are similar to those of associated gas, but other higher cost fields would need prices above $3 per MMBTU to be economic. Similar prices emerge from an economic analysis of a separate data set for specific gas fields slated for development (Box 2.1).

The results for Mozambique show that minimum wholesale prices for the giant Prosperidade/Mamba and Golfinho/Atum fields are similar to those in Nigeria, around $2 to $2.50 per MMBTU. But the cost of smaller fields escalates substantially, reflecting the fact that economies of scale in upstream gas development are strong (Box 2.2). For Tanzania, the minimum wholesale price for a 6.5 TCF field is estimated at $3.40 per MMBTU, a reflection of assumed higher capital and fiscal costs in Tanzania. Outside the big resource centers and for fields of roughly 1 TCF in size, the minimum wholesale price ranges from $7 to $11 per MMBTU.

Finally, the results suggest that fiscal expenses, particularly in the smaller resource centers, form an important component of the minimum wholesale gas price. For countries with no LNG options, this means there can be a direct tradeoff between upstream resource taxation and lower fuel costs for power generation.

Box 2.1
Economics of Selected Gas Field Developments in Nigeria

Respected oil and gas consultancy Wood Mackenzie maintains field-by-field estimates of production, capital and operating costs, and taxation for all Nigerian oil and gas developments. Wood Mackenzie's proprietary data were used to derive estimates of the minimum gas price for five specific gas fields that are either under development or planned for development over the next decade. The fields range in size from 508 to 1,990 BCF and are earmarked for a variety of different markets. The results of the analysis suggest that all of the fields in the sample can be produced for prices lower than $3 per MMBTU. The analysis of the Aje field is striking in that the calculated minimum gas price is less than zero, suggesting that the oil production by itself is enough to reach the investor's minimum rate-of-return threshold. This phenomenon is common for associated gas fields.



Field	Tuomo	Ima	Sonam	Uquo	Aje
Reserves (BCF)	1,990	1,551	792	1,013	508
Start Year	2013	2019	2017	2014	2018
Gas Market	NLNG	Brass	ELPS	IPP	WAGP
Operator	Eni	Amni	Chevron	Seven Frontier	Yinka Folawiyo

Box 2.2
Economies of Scale in Gas Production in Mozambique

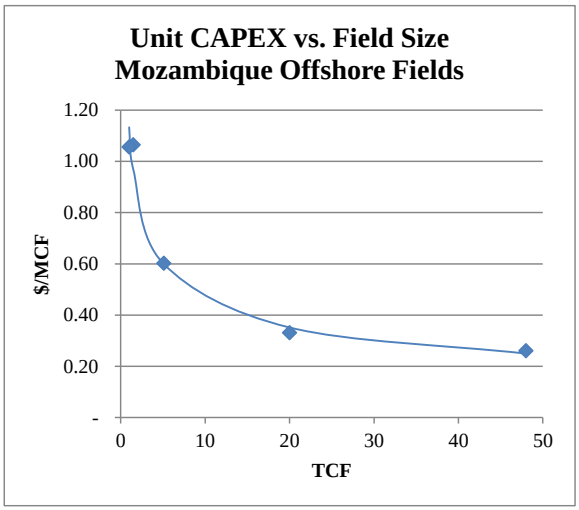
The Mozambique gas master plan prepared by ICF International presented CAPEX and OPEX estimates for five large offshore fields. The estimates were built up using petroleum industry drilling and facility cost benchmarks adjusted for the water depth, reservoir depth, reserve size, and peak production capacity of each field. The size of the fields analyzed in the ICF study ranged from 1 to 48 TCF.

Plotting unit CAPEX values in $/MCF versus reserve size (in TCF) reveals the following relationship:

$$c = 16.82 * Q^{-.39}$$

where c is the unit CAPEX and Q is the reserve size in BCF. This relationship can be rewritten using the ratios of costs and field sizes to get:

$$\frac{\text{Cost}_{\text{Field2}}}{\text{Cost}_{\text{Field1}}} = \left(\frac{\text{Size}_{\text{Field2}}}{\text{Size}_{\text{Field1}}}\right)^{.61}$$



When expressed in this manner, the capital cost estimates conform almost exactly to the "six-tenths" rule typically observed in the relationship between costs and capacity for industrial installations (Berthouex 1972). Main sources of economies of scale come from vessel and pipe geometry and from fixed and one-time costs that do not vary with volume.

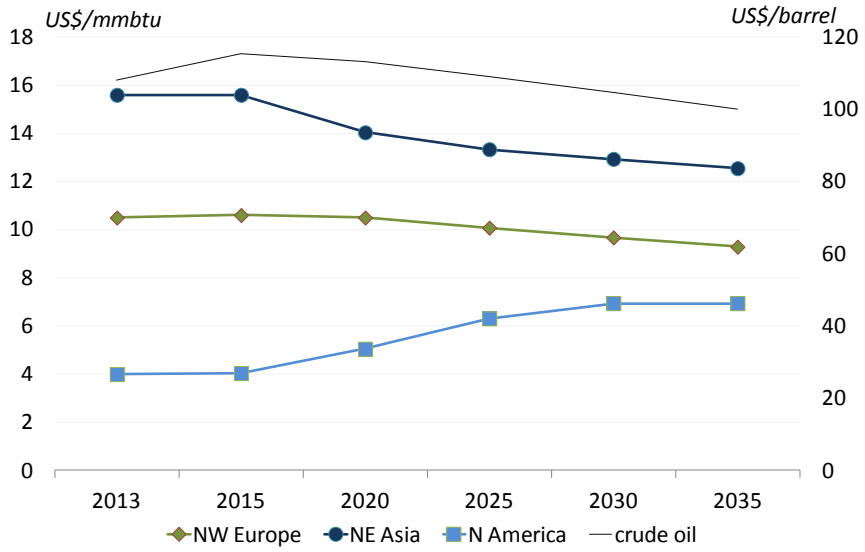
LNG Netback Prices

The starting point for the LNG netback calculation is the delivered ex-ship (DES) price of LNG in the destination market. Traditionally, gas prices in Asia (and to a lesser extent Europe) have been based on formulas linked to oil prices. By contrast, North American gas prices have been determined in the spot market on the basis of gas-on-gas competition. As a result of the increase in oil prices and the emergence of abundant, low-cost shale gas in North America, gas prices in Asia and North America have diverged sharply in recent years.

However, there is a strong argument that global gas prices will converge to some extent over the medium to long term. A number of large-scale LNG export projects are under development in the United States and Canada, and these projects will compete with new projects in Australia, East Africa, and elsewhere to serve the fast-growing Asian market. In response, many Asian buyers are beginning to move away from the historical oil-linked pricing formulas toward pricing linked to a portfolio of indexes, including the U.S. Henry Hub and the U.K.'s National Balancing Point (NBP). To reflect this newly emerging market paradigm, this study considers two global gas pricing scenarios. The Convergence Scenario assumes that Asian DES prices decline from their current levels of $15– 16 per MMBTU to $12– 13 per MMBTU over

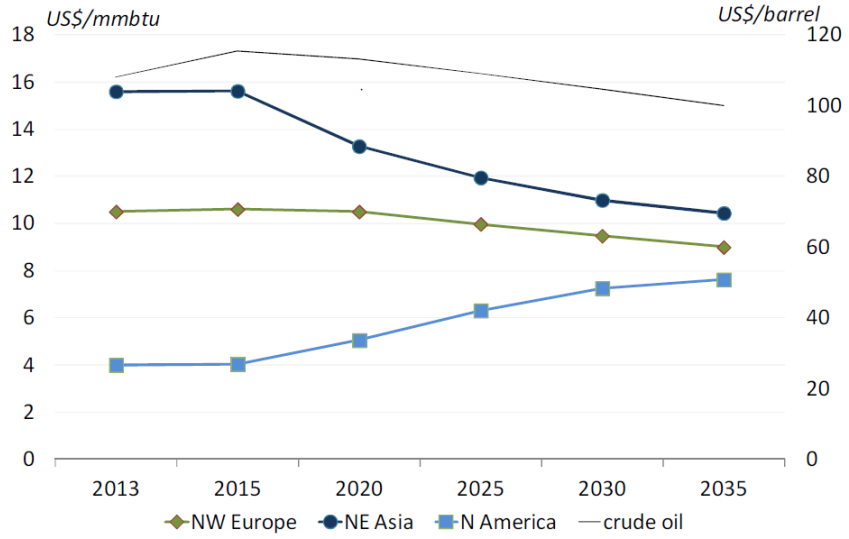
the long term, while U.S. Henry Hub prices increase to $6– 7 per MMBTU (Figure 2.3). This scenario follows the low oil and gas price projections made by IEA in the World Energy Outlook 2012. The Ultraconvergence Scenario assumes a fully globalized gas market in which prices across all regions converge to a global long-term equilibrium and regional price differentials are driven solely by transportation costs. In this scenario, Asian prices decline even further to $10–11 per MMBTU by 2030 (Figure 2.4).

Figure 2.3
Global Gas Prices: Convergence Scenario



Source: IEA and ECA

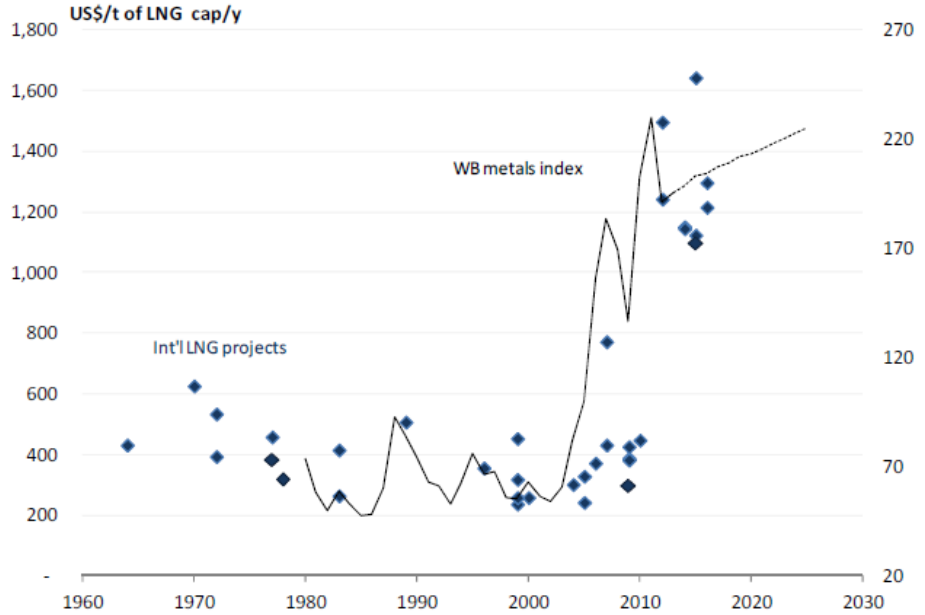
Figure 2.4
Global Gas Prices: Ultraconvergence Scenario



Source: IEA and ECA

Liquefaction costs are driven by the capital cost of the liquefaction facilities themselves. Over the past decade, liquefaction CAPEX per unit of production capacity has increased from $400–500 per ton to over $1,000 per ton as a result of construction contractor capacity constraints and price increases in steel and other primary materials (Figure 2.5).

Figure 2.5
Liquefaction CAPEX



Source: Cheniere Energy and World Bank

This study assumes that liquefaction CAPEX for the new projects in Mozambique and Tanzania will be $1,200 per ton, in line with the average cost of recent projects. Based on Nigeria's recent experience with cost overruns, the cost of future LNG projects in Nigeria is assumed to be $1,400 per ton,[7] although the existing LNG projects in Nigeria will continue to benefit from much lower locked-in costs. The unit CAPEX values are converted to equivalent "tolling" tariffs using a discounted cash flow model at a 10 percent discount rate.

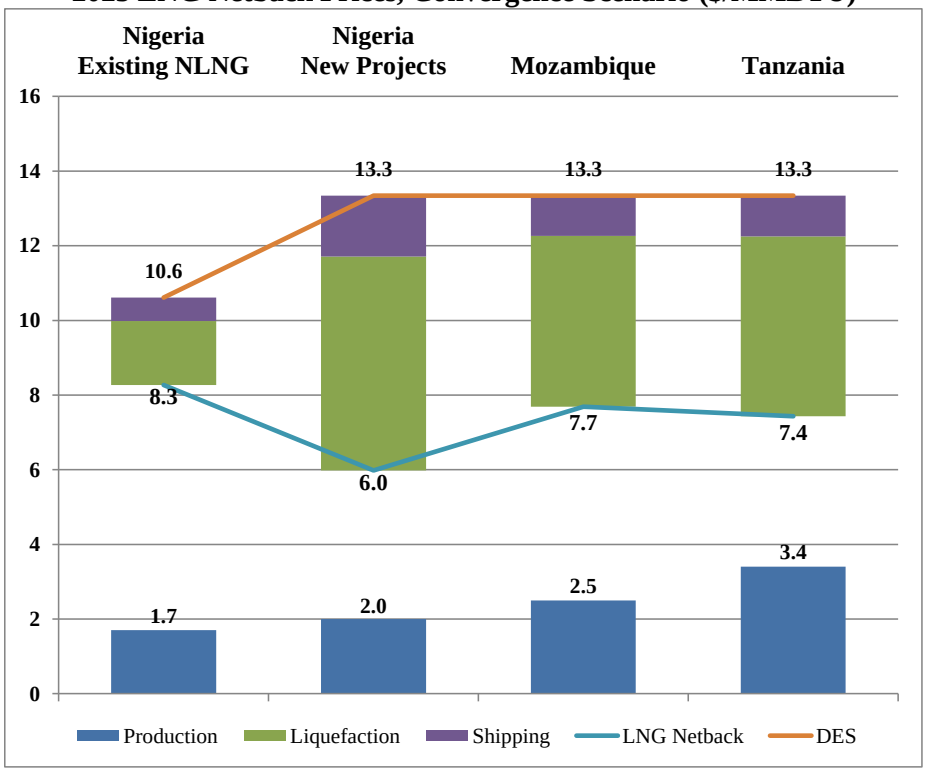
LNG shipping costs are calculated based on the current ship charter costs for a standard 145,000-cubic-meter LNG tanker, taking into account the distance to each market. While this is a highly simplified approach, the results show that shipping costs are a relatively minor element of LNG netback calculation.

The 2025 LNG netback prices under the Convergence Scenario are presented in Figure 2.6. Asian DES prices are assumed for all projects except for the existing NLNG project, where European deliveries are assumed. The minimum wholesale gas price is also plotted to illustrate

[7] This value is assumed to be representative of the proposed Train 7 at NLNG.

the magnitude of economic rent available from LNG exports. LNG netbacks under the Ultraconvergence Scenario would be $1– 2 per MMBTU lower than those in the Convergence Scenario.

Figure 2.6
2025 LNG Netback Prices, Convergence Scenario ($/MMBTU)



Implications for LNG Exporters

Nigeria: In Nigeria, the netback price analysis reveals two quite different worlds. Nigeria's existing LNG exports, though largely tied to lower-priced European markets, are nonetheless extraordinarily profitable due to very low locked-in liquefaction costs. Netback prices are more than $8 per MMBTU versus production costs of less than $2 per MMBTU. In addition, domestic gas prices in Nigeria have historically been held at roughly $0.50 per MMBTU, well below the minimum upstream price. With such a large disparity between export and domestic prices, the economic incentives for producers have been stacked overwhelmingly in favor of export.

For a new Nigerian LNG project such as a seventh train at NLNG, the picture is somewhat different. New projects would find it imperative to target Asian markets because of slow growth and lower prices in Nigeria's traditional Atlantic Basin markets. However, higher DES prices from Asian sales would be offset to a large degree by higher liquefaction and shipping costs. Under the Convergence Scenario, LNG netbacks of roughly $6 per MMBTU would be realized, and incentives for producers to export, while diminished somewhat, would

still be strong. However, under the Ultraconvergence Scenario or if some sales were made to Europe, netbacks could drop to $4 per MMBTU. With Nigeria having signaled its intent to increase domestic gas prices over time to $2.50 per MMBTU and above, the incentives could start to swing in favor of domestic gas supply, particularly for independent producers without a viable LNG outlet.

However, even where domestic production economics are favorable, gas developments in Nigeria will continue to be thwarted by the absence of a bankable commercial and policy framework for natural gas. Most of the gas produced today comes from the onshore and shallow-water joint ventures between NNPC and international oil companies. However, NNPC's persistent funding difficulties have generally limited investment in the joint ventures to only the most lucrative oil or LNG export projects. Worse still, many of the joint-venture blocks face uncertain license renewal, and oil companies operating under production-sharing contracts, where NNPC's financing is not a constraint, do not have contractual rights to sell gas. In addition, fiscal terms in the proposed Petroleum Industry Bill are much more stringent than existing joint venture terms, potentially rendering many gas projects uneconomic even in the absence of financing or licensing issues.

In the midstream gas sector, NGC and its subsidiaries act as monopoly buyer, seller, and transporter without a transparent network code covering pipeline nominations and market allocation. No independent midstream regulator exists, nor is there a system for third-party access. Gas exporters are subject to a system of domestic supply obligations (DSOs) that, at an aggregated price of $1 per MMBTU and with generally poor customer payment discipline, act as simply an additional tax on gas exports. Finally, no legally enforceable model gas sales agreements are in place, nor is there a framework for credit support for utility gas buyers. Thus, while economic incentives could begin to favor domestic gas production, uncertainties in the upstream and midstream commercial framework act as a powerful disincentive to domestic gas investment. From the producer perspective, the incentives to export LNG will remain strong.

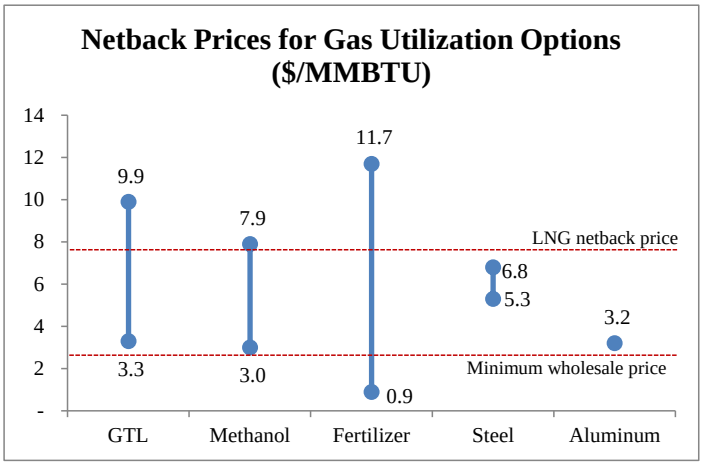
Mozambique: For Mozambique, the price benchmarks display the normal pattern where LNG netbacks are much higher than the minimum wholesale price. However, because of the sheer size of the Mozambique resource base, the LNG netback price is not a measure of the opportunity cost of serving other gas markets. Even if Mozambique realizes its ambition to build 10 LNG trains, there would still be at least 30 TCF of uncommitted gas. Therefore, gas sold to domestic markets would not displace LNG volumes. In fact, the Mozambique gas resource base can be thought of as virtually unlimited, and any markets that can afford to pay over the minimum wholesale price are economically beneficial to serve. It was precisely because of this multiplicity of potentially economic gas utilization options that Mozambique initiated its gas master planning process (Box 2.3).

Tanzania: For Tanzania, the gas allocation choices could be tougher. The price benchmarks, not surprisingly, are similar to those of Mozambique. However, the resource base is

smaller than in Mozambique, and each LNG train would consume more than a quarter of the current discovered gas. Therefore, gas committed to the domestic gas-to-power market could displace LNG sales with a netback value of more than $7 per MMBTU.

Box 2.3
Evaluating Mozambique's Gas Utilization Options

As part of Mozambique's gas master plan, netback gas prices were calculated for gas-to-liquids (GTL), methanol, fertilizer, and metallurgical applications (ICF 2012). The netbacks for each product vary greatly depending on commodity price assumptions. Generally, however, they exceed the minimum wholesale price from this present study and, under high commodity price assumptions, compete favorably against LNG netbacks.



Investor groups have proposed numerous projects for gas utilization. To sort through its options, Mozambique is considering conducting a gas "auction" wherein projects are selected based on the highest proposed netback. Other criteria, such as employment effects, regional development impact, and the quality of environmental and social management plans, could also be applied.

A Policy and Economic Framework for Domestic Gas Supply

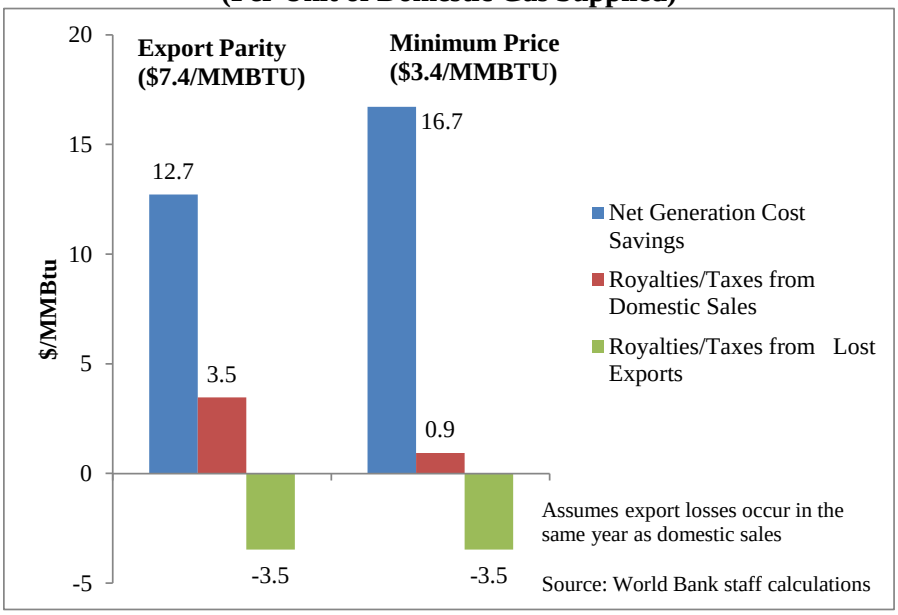
Gas supplied to the domestic power sector can bring benefits to the economy in the form of reduced cost and increased supply of electricity. For a country with an acute generation deficit, cost reduction can come from lower consumption of diesel in stand-by generators. For countries with adequate generation capacity, cost savings take the form of displaced output from the next highest cost generation source, which, in the African context, is again often diesel or HFO. At current prices, the value of displaced diesel is over $20 per MMBTU for the countries in this study. The benefit of expanding supply to serve otherwise unmet electricity demand is hard to quantify precisely, but evidence suggests that it can be many times the avoided diesel cost (Foster and Steinbuks 2009).

With such important benefits to be gained, governments have strong incentives to direct gas into the domestic market. A policy option that has been used in many countries is to introduce a domestic supply obligation (DSO) into petroleum contracts or regulations. A DSO obliges producers to make a defined portion of gas production available for domestic sale. In some cases, a DSO will specify that the gas be sold at export-equivalent prices, while in other cases a discounted price is defined.

There are costs and benefits associated with a policy of pricing domestic gas below export parity. Obviously, as the domestic gas price is reduced, the net cost savings from displacing diesel will increase. On the other hand, royalties and taxes on gas production will be lower, but only to the extent that domestic sales substitute for exports. If domestic sales are incremental, then incremental royalties and taxes are generated but at a lower rate if gas prices are set lower.

An example based on Tanzanian conditions is presented in Figure 2.7. As domestic gas prices are reduced from export parity to the minimum wholesale price, net generation cost savings increase, but two-thirds of the gains are lost through reductions in royalties and taxes. Nevertheless, the balance of costs and benefits improves as prices are reduced.

Figure 2.7
Tanzania: Cost and Benefit of Domestic Gas Supply
(Per Unit of Domestic Gas Supplied)



However, there are limits to the extent to which a policy of low domestic prices should be applied. First, the price of domestic gas should not be set below the minimum wholesale price, since this would not cover production costs or provide producers with an incentive to invest. Second, it should be kept in mind that a below-market DSO will be viewed by producers as another form of resource tax and will result in a reduced willingness to negotiate other forms of tax such as royalties and profit shares. Finally, the incidence of the costs and benefits should be considered. Power generation cost savings will be realized by utilities and commercial and industrial users, and these savings may or may not eventually benefit domestic consumers, themselves often not a large sector of the population given low rates of grid connection in Sub-Saharan Africa. On the other hand, reductions in royalties and taxes, either directly via lower

prices or indirectly through less favorable contract negotiation, will be incurred by the state, reducing the state's ability to provide public services that may benefit broader segments of the population.

Clearly, the costs and benefits will vary according to specific country circumstances such as the extent to which diesel is the relevant alternative generation source, the extent to which domestic sales displace exports, and the opportunities to replace below-market DSOs with higher royalties and taxes. For example, in Mozambique, the generation options, including coal, are more plentiful and export displacement is low. These factors would tend to guide Mozambique away from deeply discounted prices in DSOs.

An alternative to a DSO is for government to make all of the below-market domestic sales out of its royalty and profit production shares. While this removes the fiscal cost from upstream investors, it results in much lower value received for government's equity share.

Finally, it is worth keeping in mind that development of domestic markets independently without an anchor LNG project can be extremely challenging. In Tanzania and Mozambique, for example, the planned LNG projects will provide the necessary economies of scale and bankability to support infrastructure development that the domestic market alone could not sustain. However, this means that the timing of domestic gas supply will also be tightly linked to LNG project development cycles that can extend for 10 years or more.

Box 2.4
Evaluating the Tradeoffs of Domestic Gas Supply

The cost savings from gas-fired power generation per unit of gas supplied can be expressed as follows:

$$\Delta C = (A - G) * \frac{1000}{HR}$$

where: ΔC = generation cost savings, in $/MMBTU of gas utilized
A = generation cost from higher cost alternative, in $/MWh
G = gas-fired generation cost, in $/MWh
HR = heat rate, in BTU/kWh

If diesel is assumed to be the relevant alternative and if the capital cost of diesel generation is assumed to be a sunk cost, then the above equation can be rewritten as:

$$\Delta C = DF - P - GNF * \frac{1000}{HR}$$

where: DF = diesel fuel costs in $/MMBTU
P = gas price in $/MMBTU
GNF = gas nonfuel costs in $/MWh

Supplying gas to the power sector can also have an impact on the royalties and taxes received on upstream gas production, particularly if the gas price for domestic sales is different from the price in the alternative export market. The impact on royalties and taxes can be expressed as follows:

$$\Delta T = T(P) - TE$$

where: ΔT = difference in value of royalties and taxes per unit of gas supplied, in $/MMBTU
$T(P)$ = taxes and royalties from domestic gas supply as a function of sales price, in $/MMBTU
TE = value of taxes and royalties from forgone export sales, in $/MMBTU

For a royalty/tax fiscal regime, the tax function, T(P), can be approximated as follows:

$$T(P) = (r * P) + s * [(1 - r) * P - c]$$

where: r = royalty rate, in percent
s = government share of profits, in percent
c = cost per unit of gas produced, in $/MMBTU

The value of taxes and royalties from foregone exports, TE, depends on the extent to which domestic gas sales preclude exports. For countries with effectively unlimited resources, TE is zero, since no exports are lost by selling some gas domestically. For countries where domestic gas sales come at the expense of current or future export sales, TE is equal to the tax function, T(P), evaluated at the future export netback gas price and discounted by the number of years between the domestic sale and the export sale it displaces.

Chapter 3

Gas-to-Power Cost Benchmarks in Nigeria, Mozambique, and Tanzania

In Nigeria, Mozambique, and Tanzania, abundant gas resources and low production costs suggest that gas could be an economic source of future electricity supply. All three countries have very low per capita electricity consumption, large populations without any electricity service, and persistent generation deficits that constrain development and economic growth. However, the role gas can play in addressing generation challenges in these countries varies considerably depending on the cost and availability of alternative generation options.

To assess the competitiveness of gas as a power generation fuel in these large-resource countries, this chapter uses the benchmark gas prices developed in Chapter 2 to calculate levelized generation cost benchmarks for gas-fired power. The generation cost benchmark for gas is then compared to the cost of other generation options.

Methodology

For thermal generation options, the generation cost calculations use a uniform set of assumptions about capital costs, fixed O&M costs, and thermal efficiency (Table 3.1).[8] For gas, both CCGT and OCGT cases are considered. For hydropower projects, capital cost estimates are taken from regional power pool master plans for specific projects. The capital costs for these projects range from $1,234 to $2,864 per kW of capacity.[9] For each generation option, capital and O&M costs are levelized over the project life using a 13 percent rate of return for thermal plants and a 10 percent rate of return for hydropower plants.[10]

Table 3.1
Thermal Generation Cost and Efficiency Assumptions

	Gas CCGT	Gas OCGT	Coal	Diesel/ HFO
Capital costs ($/kW)	910	800	2500	1325
Fixed O&M ($/kW per year)	20	20	40	20
Variable O&M ($/MWh)	3.0	3.0	4.5	3.0
Heat rate (kJ/KWh)	7900	13500	9700	8000
Plant lifetime, years	25	25	30	20

Source: ECA(2013)

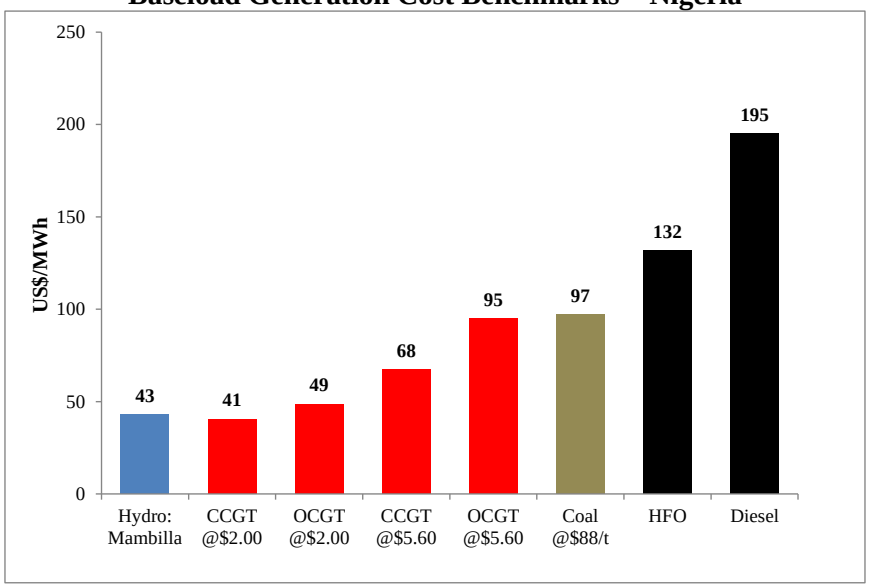
[8] A comparison of cost data from regional and country power master plans with generic data from AICD, EIA, and other sources did not reveal any important differences between countries.
[9] Some of the cost estimates could be low since they are taken from out-of-date master plans that in turn rely on old project feasibility studies. Analysis of more recent data suggests that current costs could be 15–20 percent higher. However, these cost adjustments, in general, do not change the merit order.
[10] The lower rate for hydropower projects is based on the assumption that these projects will be at least partly in the public sector and will carry lower minimum return requirements than private investment in thermal projects.

Fuel costs are assumed to vary from country to country. For natural gas, the minimum wholesale gas prices and LNG netback prices from Chapter 2 are used to create low and high gas generation cost benchmarks for each country. For coal, international prices are used as the base case, but a lower domestic coal price is also considered for Mozambique and Tanzania. For diesel and HFO, international prices are used. Carbon emissions costs are not explicitly considered, since the quantitative approach throughout this study is based on financial analysis from the point of view of commercial actors in markets in which carbon pricing mechanisms do not currently exist.

Nigeria

For Nigeria, the generation cost benchmarks paint a very clear picture. Gas is the lowest-cost thermal generation option by a large margin, even if domestic gas prices are raised to match LNG netback prices (Figure 3.1). To the extent that gas displaces diesel, generation cost savings of 70 percent or more are achievable.[11]

Figure 3.1
Baseload Generation Cost Benchmarks – Nigeria



The preeminence of gas in the future generation mix is strongly reflected in government policy. Nigeria's 2012 Road Map for Power Sector Reform envisages that over 20,000 MW of new gas-fired capacity will be added by 2020. The roadmap aims to address the root causes of the power sector's poor performance by implementing cost-reflective power tariffs to improve the financial health of the power sector and by improving management of the sector's generation, transmission, and distribution infrastructure. The roadmap also aims to improve the bankability

[11] The gas-fired generation cost benchmarks presented here are generally consistent with the values set in NERC's multiyear tariff order (MYTO 2).

of the power sector by unbundling the national utility's distribution and generation assets and gradually opening these unbundled entities to the private sector.

Meeting the ambitious goals for gas-fired generation that are contained in the roadmap would require more than doubling gas supply in the domestic power sector from 1.5 BCF per day to 3.4 BCF per day (FRN 2013). However, given the profound weaknesses in the commercial framework for gas discussed in Chapter 2, it is difficult to see how the investments needed to produce such an expansion of supply will happen. Without improvements in the commercial conditions for domestic gas production, a failure of the gas sector could thus jeopardize the power sector improvements envisioned in the roadmap.

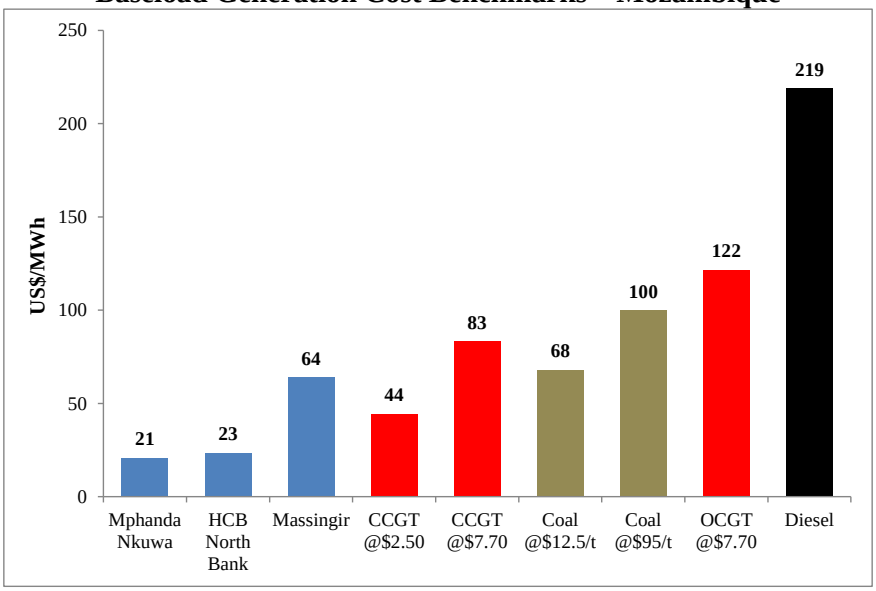
Mozambique

Mozambique is endowed with abundant hydropower, coal, and gas resources from which to generate electricity. Current generation is dominated by the 2,075 MW Cahora Bassa hydro-electric plant on the Zambezi River. This project delivers power to the domestic market and to South Africa. Mozambique also imports electricity back from South Africa, primarily to supply a large 950 MW Mozal aluminum plant. Excluding this load, total domestic power demand in Mozambique is less than 800 MW. Some small hydropower and gas plants and aging diesel generators provide the balance of electricity supply.

With respect to future generation additions, both the SAPP and Mozambican power master plans focus on a handful of large hydropower and coal projects. Hydropower is identified as the least-cost future capacity option, and the Mphanda Nkuwa (1,500 MW) and Cahora Bassa North Bank (1,275 MW) projects are seen as the most attractive projects at a levelized cost of $21–23 per MWh. The proposed Moatize (2,400 MW) and Benga (2,000 MW) coal-fired power stations in Tete province are also potentially economically attractive, since they would use low-cost discard coal from mining operations that produce coking coal for export. However, the output of each of these proposed large generation stations exceeds total domestic electricity demand (excluding Mozal), so the viability of these projects in the short to medium term depends on export contracts to the Southern African region.

The discovery of large gas resources in northern Mozambique opens up a third potential generation option that was not fully considered when the national and regional power plans were created. The generation cost benchmarks show that CCGTs are very competitive with coal-fired plants, but the results are highly dependent on fuel price assumptions (Figure 3.2). If both coal and gas are priced at international levels—coal at $95 per ton and gas at the LNG netback price of $7.70 per MMBTU—gas-fired generation is cheaper than coal by more than $20 per MWh. On the other hand, if discard coal, by virtue of being a by-product of export coal production, is priced at $12.50 per ton, coal gains a cost advantage over gas. However, this advantage would be negated at a gas price of $5.70 per MMBTU, a price less than the LNG netback price but very competitive with other non-LNG uses.

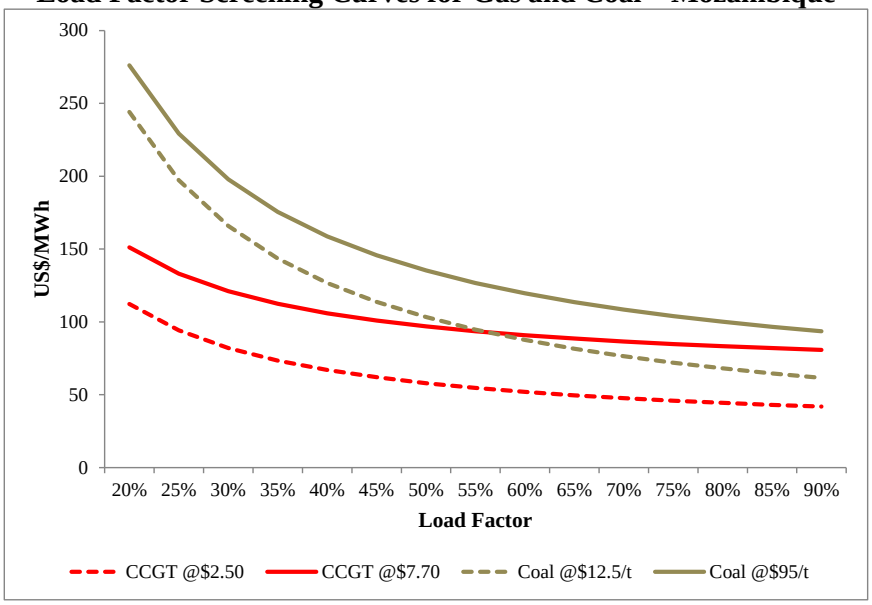
Figure 3.2
Baseload Generation Cost Benchmarks – Mozambique



The costs of gas-fired and coal-fired generation in Mozambique also depend on load factor (Figure 3.3). For load factors of 60 percent or lower, gas competes favorably against coal, even low-cost discard coal. The cost-effectiveness of gas in mid-merit applications has implications for project siting. Mid-merit gas plants should be located as close as possible to the gas production facilities since pipeline transportation costs increase sharply at lower load factors. Also, the production swing capacity needed to supply a mid-merit CCGT can normally be easily incorporated into a large LNG-oriented gas production operation. For example, a 300 MW CCGT operating at 50– 100 percent load factor would require production swing capacity of 25 MMCFD, but this would constitute only a 1 percent variation in the output of a four-train LNG project producing over 2.5 BCF per day.

The choice between gas and coal in Mozambique could also be influenced by scale economies and construction lead times. The minimum efficient scale for a CCGT plant is quite low—roughly 300 MW, whereas the proposed coal plants are more than 2,000 MW each. Thus, gas-fired capacity could be built specifically to address smaller increments of domestic electricity demand without the need to export power, as in the case of large coal or hydro projects. Moreover, gas-fired plants can be built in 12– 18 months, whereas coal or hydropower plants can take four to five years. On the other hand, the total "gestation period" for a gas-fired project can extend substantially if upstream field development is required to supply the project.

Figure 3.3
Load Factor Screening Curves for Gas and Coal – Mozambique



A further factor to consider in the choice between gas and coal power is the location of the resources in relation to electricity loads. Mozambique's large gas resources are in the far north, in the least developed part of the country. Maputo and the country's large electricity loads are in the south. For gas to make a major contribution to domestic power production, substantial investments will need to be made in transmission lines and/or pipelines, and this would increase the delivered cost of power in the major load centers.

Finally, it should be noted that although natural gas appears to be competitive with coal in terms of cost and flexibility, end-consumer tariffs in Mozambique are not currently sufficient to support the full cost of gas-fired generation including the cost of transmission and distribution.

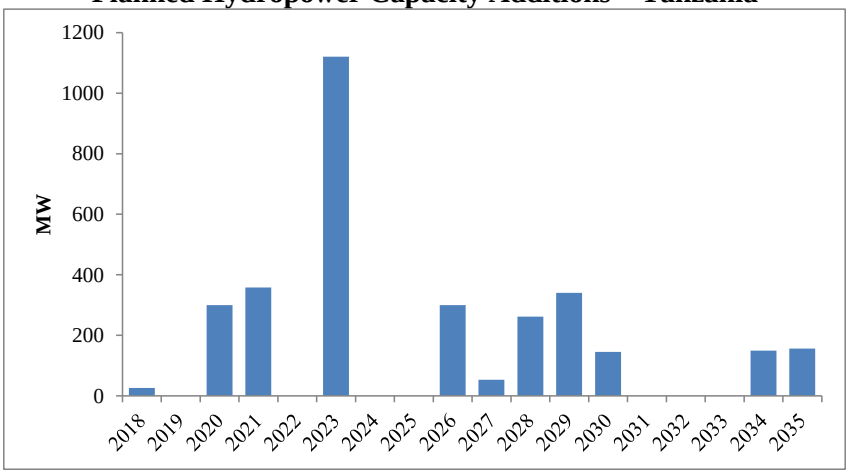
Tanzania

Tanzania's electricity demand is currently just over 1,000 MW and comes from a combination of hydropower, natural gas, and diesel/HFO sources. Gas-fired plants supplied from the Songo Songo Island gas development contribute just under half of total generation output. The Power System Master Plan 2012 update, drafted by the government of Tanzania's sector stakeholders under the leadership of the Ministry of Energy and Minerals, envisages peak electricity demand rising to 7,500 MW by 2035. A number of hydropower, coal, and natural gas–fired generation options are identified to meet this demand.

Generation planning rests heavily on hydropower. Between 2020 and 2030, hydropower projects totaling more than 2,800 MW are planned, and these are scheduled to be completed at the rate of roughly one project per year (Figure 3.4). As a result, Tanzania is highly exposed to delays and cost overruns in construction and to rain shortfalls once the projects are in operation.

To mitigate these risks and in response to the discovery of large offshore gas fields, Tanzanian policy is emphasizing gas-fired projects in the short term, and over 1,000 MW of gas-fired capacity is planned. Although there are currently no coal-fired power stations, indigenous coal reserves exist and there are plans to harness this resource as well.

Figure 3.4
Planned Hydropower Capacity Additions – Tanzania



The generation cost benchmarks for Tanzania tell a similar story to those for Mozambique (Figure 3.5). Hydropower maintains a cost advantage over other generation sources. Hydropower costs are higher than in Mozambique, in part because the Tanzanian hydropower projects, with the exception of Stiegler's Gorge, are smaller than those in Mozambique.

The cost comparison between gas and coal in Tanzania is also similar to Mozambique. If coal is priced at the international price and gas is priced at the LNG netback price,[12] the cost of gas-fired power is lower than coal by $7 per MWh. In fact, a general finding of this study is that, when coal is priced at international prices, gas-fired power is competitive against coal whenever the delivered price of gas is $9 per MMBTU or less. However, like Mozambique, Tanzania could choose to price domestic coal below international prices. If domestic coal were priced at $18 per ton, coal-fired power would be $6 per MWh cheaper than gas, but this would be negated with just a $0.80 per MMBTU decrease in gas prices. If gas prices are set at the minimum wholesale price, gas reclaims a substantial advantage over even subsidized coal and, in fact, becomes competitive against higher-cost hydropower projects.

The potential role for gas in the future Tanzanian generation mix is several-fold. Gas is competitive as a baseload fuel in the short and medium term, addressing the present-day generation deficit and protecting against delays in hydropower implementation. The short

[12] In the case of Tanzania, the LNG netback price has been increased from $7.40 per MMBTU to $8.40 per MMBTU to account for transportation from southern Tanzania to the presumed generation site in Dar es Salaam. Likewise, the minimum wholesale price has been increased from $3.40 per MMBTU to $4.40 per MMBTU.

development timeline for gas-fired power plants makes gas particularly flexible in planning for baseload power needs. However, gas can also serve as a long-term complement to hydropower. In a mid-merit role (e.g., 40–60 percent load factor), gas can be used to compensate for seasonal and drought-induced variations in hydropower output. A comparison of gas versus coal at medium-range load factors strongly favors gas (Figure 3.6). Finally, as a peaking fuel gas is cheaper than diesel and other liquid fuels.

Figure 3.5
Baseload Generation Cost Benchmarks – Tanzania

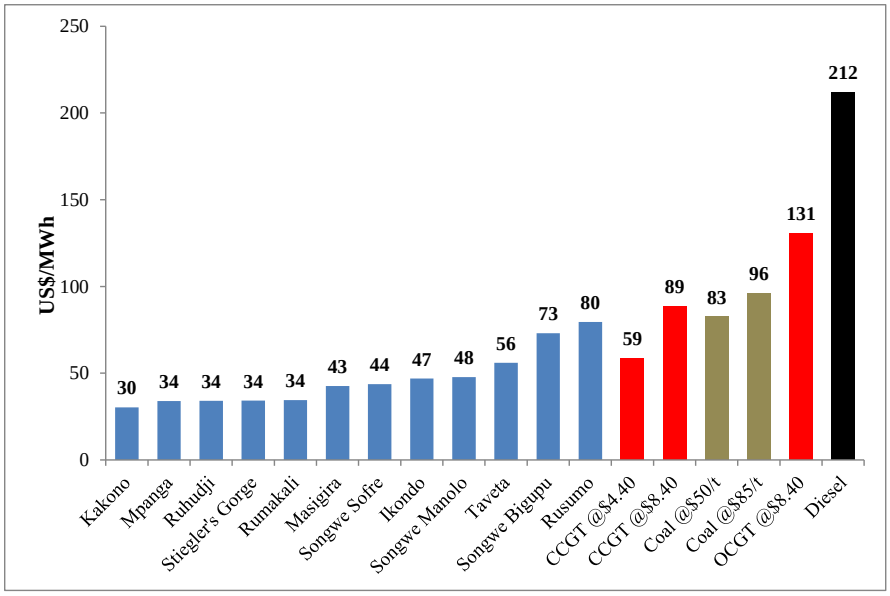
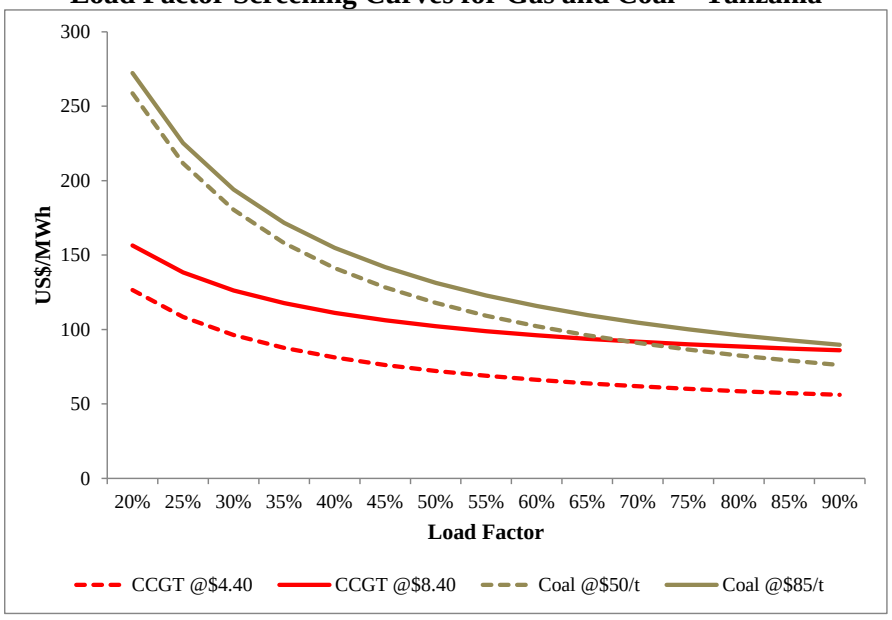


Figure 3.6
Load Factor Screening Curves for Gas and Coal – Tanzania



Current average retail tariffs are well below the actual cost of providing service today, and tariffs will need to increase if TANESCO, the national power utility, is to remain financially viable. The existing average tariff of $119.5 per MWh is well below the corresponding estimated marginal retail price of $162 per MWh, taking into account today's generation mix in Tanzania. Even with potential wholesale prices for natural gas–fired capacity, current retail tariffs seem insufficient to cover future natural gas–based power consumption including transmission and distribution costs.

Conclusions for Large-Resource Countries

Of the three Sub-Saharan Africa countries with major gas reserves and resources, Nigeria has the clearest case for rapid expansion of domestic gas-to-power implementation. It has a large and growing economy with significant suppressed and unmet electricity demand. Gas is the cheapest energy source for power in Nigeria even if domestic gas prices and LNG netbacks converge somewhat over the coming years.

Mozambique has the second largest gas resources in Sub-Sahara Africa. Even if LNG exports are aggressively developed, there will be ample remaining gas for domestic and regional use. While gas is likely to increase its share of power production, total growth in domestic gas demand will be relatively modest because Mozambique's economy is small and it has a wealth of untapped and competitive energy sources, including hydropower and coal. The main potential for increased use of gas for power is exports to the region, mainly, but not only, to Africa's largest economy, South Africa. This potential is discussed in Chapter 5.

Tanzania faces a policy and planning conundrum. Gas can be competitive in addressing a number of power sector challenges, but current discovered gas resources may not be large enough to support both aggressive LNG exports and ambitious domestic market development. Government understandably would like to use a significant share of its gas resources locally, but it also seeks to maximize its fiscal take from higher-priced LNG sales. At some stage a tradeoff may need to be made between maximizing revenues through LNG exports and growing domestic consumption. As will become apparent in subsequent chapters, the potential for regional power exports is also constrained. Tanzania would benefit from a coherent natural gas master plan that balances these different needs and opportunities and that provides a rational basis for prioritizing and sequencing investments.

Finally, although hydropower projects maintain a strong cost advantage over gas, gas-fired power plants can offer advantages over hydropower on noncost grounds. Hydroelectric dams are often difficult to finance and have long construction times and uncertain commissioning dates. They are also vulnerable to droughts, lower water flows, and curtailment of electricity output. Gas power plants, on the other hand, have lower capital costs, are more easily financed, can be built in smaller increments of capacity that better match future demand growth. They are also load following and can respond effectively to the load profiles of different

countries. Finally, gas is cheaper than diesel and heavy fuel oil, the liquid fuels in widespread generation use to complement hydropower.

Overall, the generation cost benchmarks developed here suggest a promising role for gas in the three largest resource-holding countries in Sub-Saharan Africa, although to varying degrees. The next two chapters explore whether gas exports from these countries can address generation challenges in neighboring countries.

Chapter 4
Gas Transportation within Sub-Saharan Africa

The previous chapters have demonstrated that natural gas can be produced and converted into electricity at competitive costs within the large-resource countries. But extending the economic reach of gas-fired power broadly to other parts of Sub-Saharan Africa depends on pipeline and transmission infrastructure. With respect to gas pipelines, infrastructure is almost nonexistent apart from coastal Nigeria and a handful of small, subregional projects. The regional power transmission grid is much further advanced, with a large number of projects operating or under development.

This chapter examines the cost of transporting gas from reserve centers in Nigeria, Mozambique, and Tanzania to potential domestic and regional demand centers. Gas transportation tariffs are estimated for five potential pipeline concepts. While by no means an exhaustive list of potential connections, these five concepts were considered to have strong market potential and to be representative of the opportunities and challenges facing pipeline development in Sub-Saharan Africa.

1. ***CAP/AKK:*** The pipeline concept studied here is based on two pipelines that the Nigerian authorities already have on the drawing board, namely CAP (Calabar–Ajaokuta) and AKK (Ajaokuta–Kaduna–Kano). The objective of the analysis is to estimate the cost of large-scale gas deliveries via a 36-inch pipeline from the Niger Delta gas-producing region to major inland demand centers in Nigeria.

2. ***WAGP Expansion/Extension:*** The current WAGP line connecting Nigeria with Benin, Togo, and Ghana has a capacity of 170 MMCFD, and this could be increased to 470 MMCFD through compression additions. The analysis here estimates the incremental cost of increasing delivery capacity to Ghana and extending the existing line to Côte d'Ivoire.

3. ***Palma–Johannesburg:*** South Africa is the largest demand center in Sub-Saharan Africa. It is currently experiencing power shortages, and increasing the use of gas could be an option. The pipeline concept studied here consists of a new 36-inch pipeline from Palma to Johannesburg. The objective of the analysis is to test whether the giant Mozambican gas fields near Palma can deliver gas to South Africa at a competitive price.

4. ***Tanzania–Kenya:*** Urban centers in Kenya are expected to have significant levels of unmet electricity demand in the medium to long term even after development of the Ethiopian interconnector. The pipeline concept analyzed here is a 20-inch line from

Dar es Salaam to Mombasa and Nairobi. The concept is based on a recently completed feasibility study for a pipeline between Dar es Salaam and Mombasa.

5. ***Tanzania Inland Pipeline:*** The pipeline studied here is a 16-inch line from Dar es Salaam to the inland cities of Shinyanga and Kigoma. Electricity demand in this region is expected to be high, driven by population growth and increased industrial and mining activity.

Cost Estimation Methodology and Results

Pipeline capital costs are the primary driver of transportation costs. Yet for Sub-Saharan Africa, robust pipeline capital cost benchmarks are difficult to derive because so few long-distance pipelines have been built. As a result, this study uses a rule-of-thumb capital cost index of $64,300 per inch-kilometer, a figure that is broadly consistent with inflation-adjusted cost data for U.S. pipelines (INGAA 2009) and with the unit cost of existing and planned pipelines in Sub-Saharan Africa (Table 4.1). For the five pipeline concepts studied here, the capital cost index is adjusted for African labor costs and terrain and then multiplied by the length and diameter of the pipeline to arrive at an estimate of total capital cost. Pipeline capital costs are converted to transportation tariffs using a 30-year discounted cash flow model at a 10 percent discount rate (Figure 4.1). Given this highly simplified estimation technique, the resulting cost estimates should be considered only as indicative, order-of-magnitude estimates.

Table 4.1
Gas Pipeline Costs in Sub-Saharan Africa

Pipeline	Status	Capacity (MMCFD)	Diameter (Inches)	Length (km)	Cost ($ Million)	Unit Cost ($/in-km)
WAGP	Operating	170	20	678	950	70,005
Sasoil	Operating	290	26	865	650	28,900
Mtwara–Dar	Under construction	780	36	532	1,200	62,660
Jubilee Ghana	Under construction	150	20	231	550	119,050
Dar–Mombasa	Feasibility	170	24	442	435	42,337
Trans-Saharan	Feasibility	2,500	48	4,300	10,000	48,450
AKK Nigeria	Feasibility	1,800	36	560	1,860	92,262
Average						**66,238**

For each pipeline concept, the delivered cost of gas in the destination market is computed as the estimated transportation tariff plus the commodity cost of gas at its source. Two commodity cost scenarios are considered based on the minimum wholesale prices and LNG netback prices from Chapter 2 (Figure 4.2). For the WAGP expansion/extension, the delivered gas cost assumes that tariff negotiation and regulation would result in new customers in Ghana paying the existing postage stamp tariff of $5.60 per MMBTU rather than the incremental cost of service. For the Tanzanian pipelines, an additional $1 per MMBTU is added to the transportation cost to account for transportation from Mtwara to Dar Es Salaam.

Figure 4.1
Estimated Gas Transportation Tariffs for Selected Pipeline Concepts

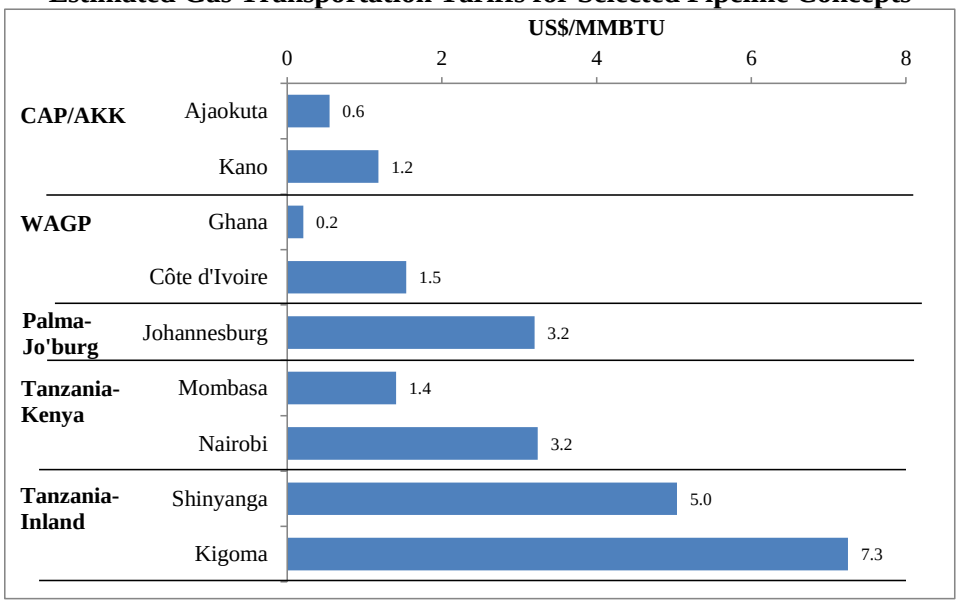
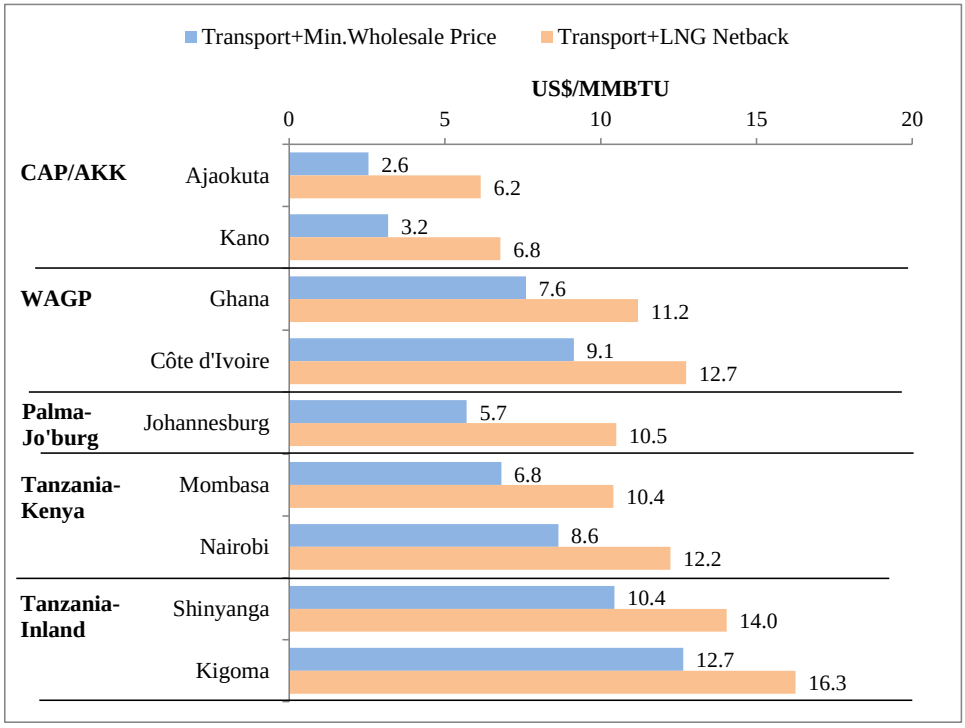


Figure 4.2
Delivered Gas Costs



Implications for Pipeline Concepts in this Study

The transportation cost and delivered gas cost estimates provide insights into the potential viability of the five pipeline concepts studied here.

1. ***CAP/AKK:*** The pipeline tariffs inland to Ajaokuta and Kano are estimated at $0.60 per MMBTU and $1.20 per MMBTU, respectively. Such low costs are attainable because of the economies of scale coming from a 36-inch pipeline. If the commodity gas were priced at or near the minimum wholesale price—quite likely given Nigeria's history of very low gas prices—the delivered gas cost at all points between Calabar and Kono would be $3.20 per MMBTU or less. At this level, natural gas would compete extremely favorably with diesel, the alternative power generation fuel for these inland locations. Moreover, low-cost gas supply would open up possibilities for industrial gas demand as a complement to power sector demand. Nevertheless, volume would appear to be the major challenge facing the CAP/AKK pipeline. A 36-inch pipeline would transport over 800 MMCFD of gas—enough to generate over 4,700 MW of power. Although Kano, Abuja and other inland cities have significant populations that could eventually support such a level of demand, the weak industrial base in these cities makes rapid demand development a challenge.

2. ***WAGP Expansion/Extension:*** Future generation additions in both Ghana and Côte d'Ivoire will be gas-fired, yet gas production from domestic sources will likely fall short of needs. For Ghana, Nigerian gas delivered via WAGP is extremely attractive vis-à-vis liquid fuels or LNG. This would hold true even if the commodity gas price in Nigeria were raised to match the LNG netback. An extension of WAGP to Côte d'Ivoire would also result in very competitive fuel supply. Reliability of supply is the main issue standing in the way of expansion and extension of WAGP. Deliveries to date have been far lower than expected because of supply shortages in Nigeria and accidents on the pipeline itself. As a result, neither Ghana nor Côte d'Ivoire views WAGP as a reliable supply source and both countries are seriously pursuing an LNG import option.

3. ***Palma–Johannesburg:*** The estimated pipeline tariff for a 36-inch pipeline from Palma to Johannesburg is $3.20 per MMBTU. This would result in a delivered gas cost of $5.70– 10.90 per MMBTU, depending on how the commodity gas is priced. The implications of these price ranges on the competitiveness of gas-fired power in South Africa will be explored in more depth in Chapter 5. However, given the size of the South African market, aggregating substantial power and nonpower demand volume seems feasible, and this could make a pipeline from Palma to South Africa an attractive proposition.

4. ***Tanzania–Kenya:*** Analysis of this pipeline concept creates a planning challenge for Tanzania. The estimated pipeline transportation costs are low: $1.10 per MMBTU to Mombasa and $2.50 per MMBTU to Nairobi. If commodity gas were priced at the minimum price, the delivered gas cost would be $6.80 per MMBTU in Mombasa and $8.6 per MMBTU in Nairobi, values that could be very competitive. However, this situation is not seen as particularly realistic. Tanzania's gas resources are not unlimited, and exports to Kenya would probably be lower priority for Tanzania than LNG exports and domestic power generation demand. To be competitive, exports to Kenya would need to be priced at LNG export parity. But this would result in delivered gas prices above $10 per MMBTU, which may render gas uncompetitive when compared against Kenya's other power generation options.

5. ***Tanzania Inland Pipeline:*** Demand in Shinyanga and Kigoma will not support a large-diameter pipeline, and the tariff for a 1,200km 16-inch pipeline would be very high. Providing energy to remote inland markets in Tanzania is likely to be far more efficient via power transmission lines.

Comparison of Pipeline and Power Transmission Costs

For each of the five pipeline concepts, pipeline transportation costs were compared against power transmission costs between the same points (Figure 4.4). The technical characteristics of the power transmission lines were chosen to be similar to existing studies or to coordinate with existing lines on these routes. Capital and operating costs assumptions were based on existing or planned power transmission line projects in WAPP, EAPP, and SAPP adjusted for inflation and terrain. In making the comparison, gas pipeline costs were converted to $ per MWh equivalent values using the heat rate of a CCGT plant.

Of the pipeline concepts studied here, only the two Nigerian options show gas pipelines as the lower-cost transportation alternative. In the case of the inland CAP/AKK pipeline, this is because of the economies of scale coming from a 36-inch pipeline. In the case of the WAGP expansion/extension, it is because the incremental cost of pipeline expansion is very low. If the full WAGP tariff were considered, pipeline costs would again be higher than power transmission costs.

Comparing the inland Nigeria route (CAP/AKK) with the inland Tanzania route is instructive. While the routes are similar in length, the volume of gas that is assumed to flow on the Nigeria pipeline is more than seven times that of the Tanzania pipeline. The modeling done for this study suggests that for a 1,000 km distance, the breakeven energy load between AC power transmission and gas pipelines is roughly 3,000 MW (Figure 4.5). In pipeline terms, this implies that transporting gas will be the lower-cost option only if enough demand can be aggregated to support a 28-inch or larger pipeline.

The Palma–Johannesburg route provides another interesting comparison between pipelines and transmission lines in the case where a large amount of energy is to be transported over a large distance. The comparison between a 36-inch pipeline and a point-to-point DC transmission line shows a slight cost advantage in favor of power transmission. However, such an analysis ignores the potential benefit of gas or power off-take at intermediate points along the route. The pipeline would emerge as the lower-cost alternative if compared either to an AC line or a DC line with multiple DC/AC inverters at points along the route.

Figure 4.4
Comparison of Pipeline and Power Transmission Costs

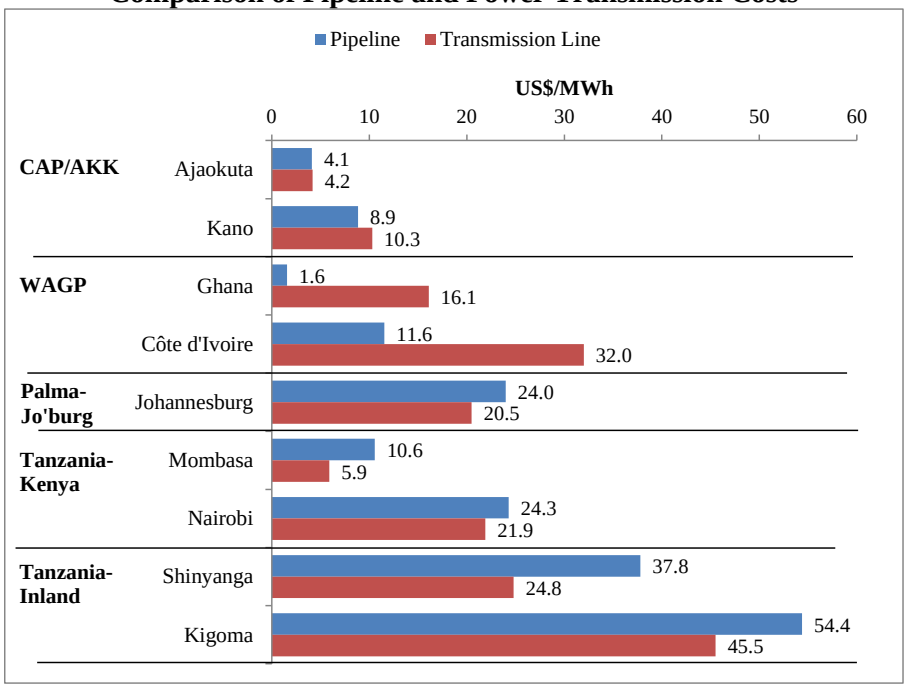
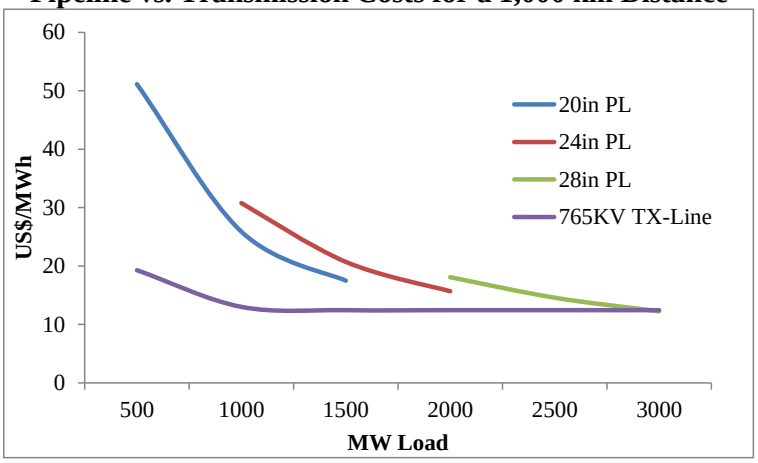


Figure 4.5
Pipeline vs. Transmission Costs for a 1,000 km Distance



The Outlook for Expanding Gas Transportation in Sub-Saharan Africa

The five case studies in this chapter illustrate the challenges for gas pipeline development in Sub-Saharan Africa. In most cases, the markets are too small and the distances too great to make pipelines economically viable. And the WAGP experience shows that even an economically attractive export project can founder unless every element in the gas value chain works as planned.

In most instances, the lowest-cost option for transporting energy from gas resource centers to markets will be via power transmission lines rather than pipelines. As a result, expanding the economic reach of gas-fired power more broadly in Sub-Saharan Africa will generally mean locating gas-fired power plants closer to gas production areas than to markets. As mentioned in Chapter 3, this solution is also likely to be the most efficient way of incorporating mid-merit, lower-load-factor gas generators into the energy grid. The flexibility of power transmission lines to move electricity from all types of generators (hydropower, gas, coal, renewables, etc.) further strengthens the case that they should be the primary avenue for regional energy integration in Sub-Saharan Africa.

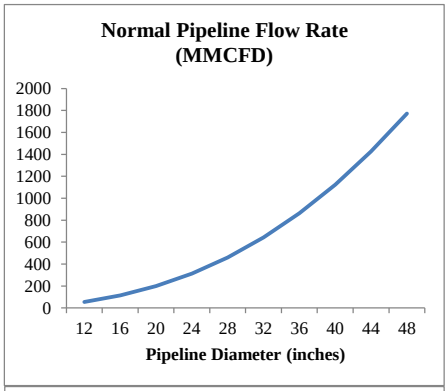
But this study does suggest that selected regional gas pipeline projects could go forward. New export pipelines from Mozambique to South Africa and from Tanzania to Kenya would seem to have a credible chance of aggregating enough demand to drive gas transportation cost down to competitive levels. And expanding and extending WAGP could be done for very low cost if improved supply conditions could be put in place. Of course the viability of these projects would depend ultimately on how the delivered cost of gas in the importing countries stacks up against other generation options. This will be the subject of the next chapter in this report. Nevertheless, the prospect of a continent-wide, interconnected gas pipeline system like that of the southern cone of South America seems very remote.

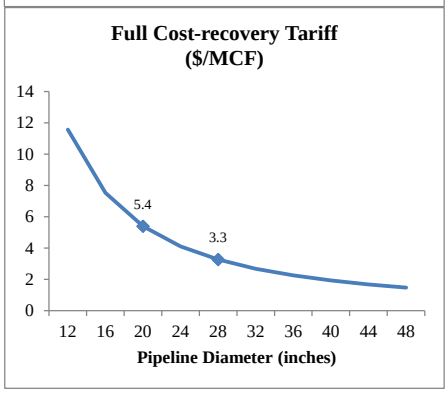
Box 4.1
Economies of Scale in Pipeline Transportation

The volume of gas that can be transported through a pipeline increases exponentially with the diameter of the pipe. In the engineering equations for pipeline flow, pipe diameter is raised to the power of 2.5, reflecting not just the increase in cross-sectional area as diameter increases, but also dynamic and frictional effects.

Pipeline construction costs, on the other hand, are usually considered to vary more or less linearly with pipeline diameter because the material costs of the steel line pipe itself are proportional to the circumference of the pipe. Construction costs are also normally assumed to vary linearly with pipeline length. The linearity with respect to both diameter and length serves as the basis for rules of thumb for rough estimation of pipeline construction costs in terms of $/inch-km or $/inch-mile. This study uses $64,300 per inch-km adjusted for terrain and African labor costs.

The combination of exponential volumes and linear costs leads to powerful economies of scale in the unit cost of pipeline transportation. For example, increasing the diameter of a 1,000 km pipeline from 20 to 28 inches reduces unit transport costs by 40 percent.





Chapter 5
Importing Country Perspectives

Development of regional gas markets depends not only on the availability of gas resources and the policies and plans of producing countries, but also on those of importing countries. Much also depends on the cost-competitiveness of gas versus other available power sources for base load, mid-merit, and peaking power. This chapter focuses on the needs and perspectives of the main potential gas-importing countries: South Africa from Mozambique; Kenya from Tanzania; and Ghana and other West African countries from Nigeria.

South Africa

South Africa looms large in Sub-Saharan Africa. South Africa's GDP is over $400 billion, around a third of the total for the continent. It generates more than half of Sub-Saharan Africa's electricity, and its electricity consumption is 4,800 kWh per capita per annum, compared to an average of 124 kWh per capita for the rest of the Sub-Saharan Africa countries.

South Africa has a generation capacity of around 43 GW. Until recently, Eskom, the publicly owned, vertically integrated national utility, generated 96 percent of the country's electricity, and the balance was produced by local municipalities and industrial cogeneration facilities. Power generation depends heavily on coal (92 percent) with nuclear, hydroelectricity, bagasse (from sugarcane), and emergency diesel-fired turbines accounting for the rest. However, this picture is starting to change. IPPs are entering the market, and there is a commitment to increase the proportion of renewable energy in the generation mix. Over the past two years, there have been three highly successful tenders for wind and solar IPPs totaling 3.9 GW.

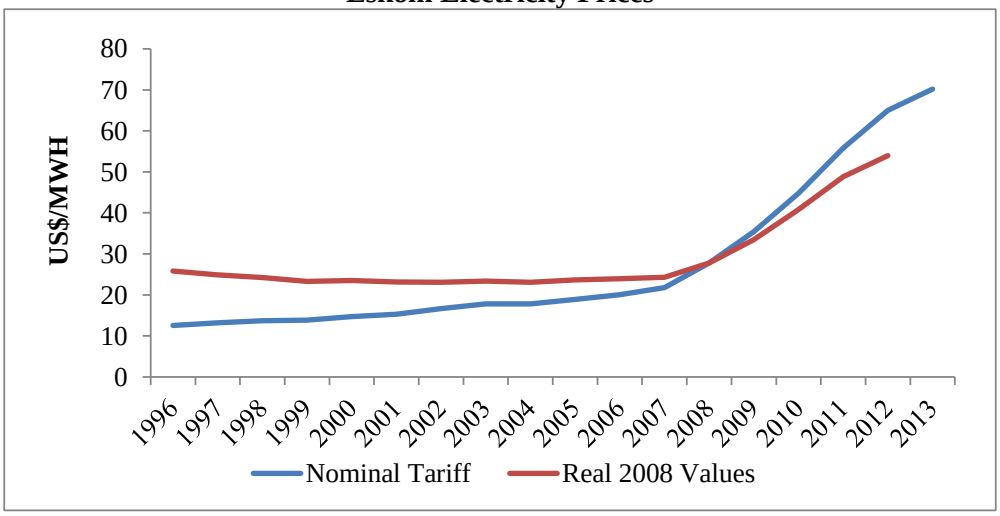
Eskom owns and controls the national integrated high-voltage transmission grid and distributes about 60 percent of electricity directly to customers. The remaining electricity distribution is undertaken by about 179 local authorities, which buy bulk electricity supplies from Eskom. Eskom imports power from Mozambique and, in the past, also from the Democratic Republic of Congo and Zambia. It also sells electricity to neighboring countries (Botswana, Lesotho, Mozambique, Namibia, Swaziland, Zambia, and Zimbabwe). Imports and exports constitute about 5 percent of total electricity on the Eskom system.

Eskom embarked on a massive investment program in the 1970s and 1980s. It overestimated demand growth, and in the 1990s there was significant overcapacity. However, after a decade or more of low investment, Eskom recently has had to play catch-up. It is building two massive new coal-fired plants, each 4.8 GW, as well as a new 1.3 GW pumped storage project.

South Africa's electricity used to rank among the cheapest in the world. Eskom's average electricity sales price in 2007–2008 was as low as $25 per MWh. In effect, Eskom had paid for

much of its existing capacity and prices were close to short-run marginal costs. However, after 2008 tariffs were increased sharply to allow Eskom to fund its $50 billion investment program, a large portion of which comprised the two new coal-fired power stations. Even though Eskom has access to international capital markets and substantial sovereign guarantees, these tariff increases were necessary to maintain the utility's financial viability. Further tariff increases above inflation have been approved by the regulator for the next five years. However, it is still not clear whether the average electricity price has reached a level that can support investments in new generation.

Figure 5.1
Eskom Electricity Prices



South Africa has a fairly rigid energy planning system. By law, Department of Energy has to produce and maintain an integrated resource plan.[13] Based on this plan, the minister of energy makes periodic "determinations" of what power needs to be built, by whom and when. The regulator can license new capacity only within these ministerial determinations. Recently, the minister announced approximately 10 GW of new determinations covering the period through 2023. These include the option of imports from Mozambique.

The most recent integrated resource plan is for the period 2010–30. About 45 GW of new capacity is planned over the next 20 years. South Africa has limited hydropower availability but abundant coal reserves. Although coal is the least-cost supply option (if environmental externalities are excluded), it does not figure heavily in the integrated resource plan. Instead significant amounts of renewable energy (17.8 GW) have been included in the plan, as well as 9.6 GW of nuclear and about 2.4 GW of gas. These changes reflect South Africa's voluntary offer to cut carbon emissions by 34 percent by 2020 and 42 percent by 2030. A peak, plateau, decline carbon scenario is envisaged with a carbon cap of 275 MT/annum total.

[13] In practice this activity is delegated to the planners within Eskom.

South Africa has a number of economically viable options for baseload generation (Figure 5.2). Importation from the Mphanda Nkuwa hydroelectric dam in Mozambique is the cheapest option, followed by coal. Although coal-fired generation is competitive even with a carbon cost of $15 per ton, South Africa has decided to impose a hard cap on carbon emissions from the electricity sector. Hence only a limited number of new coal plants will be built, mostly to replace old plants on their retirement.

Gas imports from Mozambique are competitive with coal at a delivered price of $7 per MMBTU or less. Netting out the estimated tariff for a 36-inch pipeline from Mozambique, the competitive wellhead gas price in Mozambique would be $4 per MMBTU, lower than the LNG netback by roughly $3 per MMBTU but substantially higher than the minimum wholesale price for Mozambican gas production. Even if Mozambican gas is priced at the full LNG netback price, the delivered price in South Africa still renders gas-fired power very competitive against the nuclear alternative. As in the other countries in this study, gas is clearly the preferred option for mid-merit and peaking operations (Figure 5.3). However, low load factors could easily negate the economies of scale achievable with a 36-inch pipeline.

Figure 5.2
Baseload Generation Cost Benchmarks – South Africa

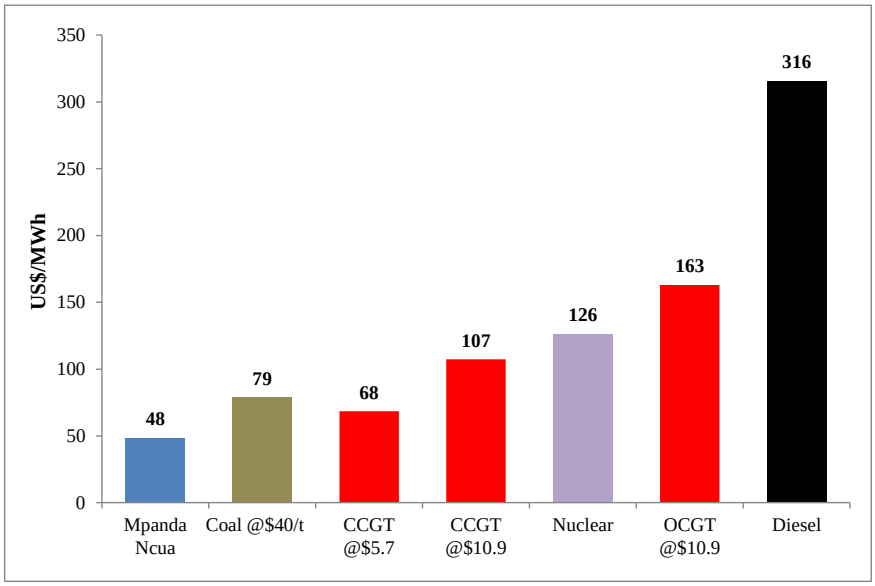
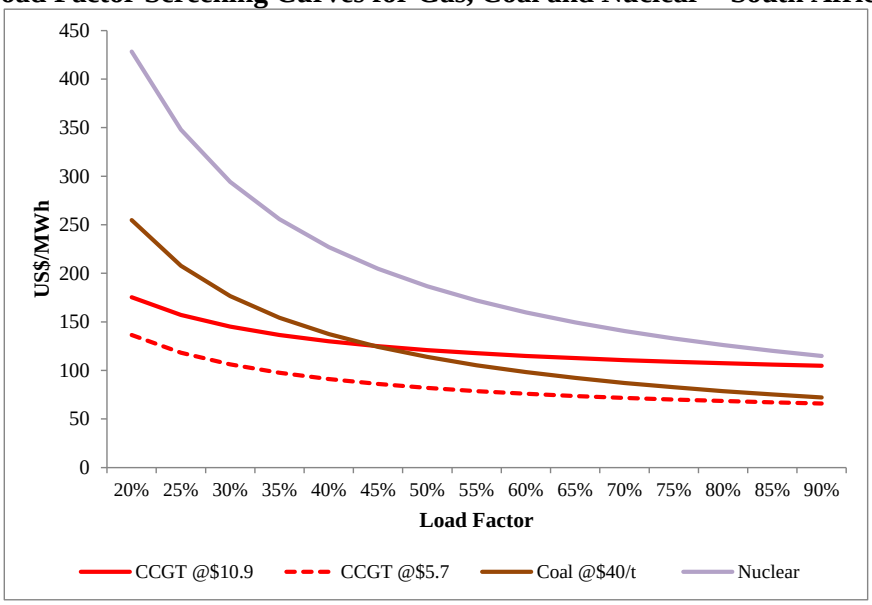


Figure 5.3
Load Factor Screening Curves for Gas, Coal and Nuclear – South Africa



In summary, there is significant power demand in South Africa and the country will need major expansions in baseload generation capacity over the coming years. Until recently, gas did not feature as a major source of power. However, this is changing. South Africa is committed to reducing the carbon intensity of its economy, and carbon emissions from gas power plants are half those from coal power stations. The value of gas as a mid-merit, peaking, and load-following option is also widely recognized.

The integrated resource plan is currently being updated and is likely to include a higher proportion of gas. A number of gas options are being considered, including South Africa's own modest offshore resources, LNG imports, a gas pipeline from Mozambique, shale gas, and coal-bed methane. However, no detailed assessment, prioritization, sequencing, or timing of these options has yet been decided. In addition to power sector demand, there is potential for Sasol to increase its use of gas, both for its own needs and for sale to industrial customers. It is clear that South Africa will use much more gas in the future.

However, much depends on the price at which Mozambique is prepared to sell gas to South Africa, as well as the volumes delivered and hence the cost of gas transportation. As already mentioned, delivered gas prices have to be $7 per MMBTU or less to compete with coal as a baseload option. While gas for mid-merit and peaking loads could be competitive, the lower volumes may make transport costs too high. A gas pipeline from Mozambique will also need to compete with possible LNG imports or, in the future, Karoo shale gas or even South African offshore gas if more discoveries are made. Further detailed feasibility studies are needed on the different gas supply options. In October 2013, South Africa commissioned the development of a gas master plan, which will assist in sorting through its gas options.

Kenya

Kenya's economy is the largest in East Africa. Its GDP is around $34 billion, as compared to Tanzania's $24 billion. Kenya's installed power generation capacity is around 1.7 GW, of which over half is supplied by hydropower. The balance is made up of HFO and diesel generators, geothermal, and wind energy.

Like many countries in Sub-Saharan Africa, Kenya has experienced inadequate generation capacity and an unreliable power supply. In recent years, however, power sector reforms have led to greater coordination between planning and implementation. As a result, an increasing number of IPPs and public sector–funded capacity expansion projects are being developed.

In the past, severe droughts have led to decreases in hydropower output and widespread power cuts. In response, the Kenyan government in 1997 commissioned two thermal IPPs with combined capacity of 100 MW. When the 1999 drought exacerbated existing problems, an additional 105 MW of emergency thermal generation was deployed in 2000. These two interventions proved costly, and the price paid by consumers for electricity rose considerably. Electricity prices in Kenya remain higher than those in much of East and Southern Africa. However, higher prices were considered necessary to reflect the cost of producing and delivering electricity to end consumers.

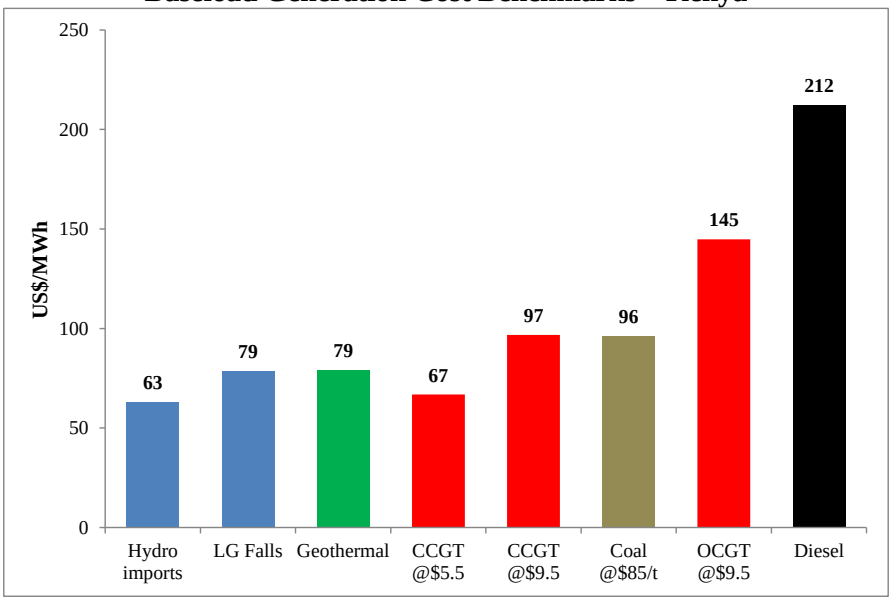
While the persistent drought forced the government to introduce stopgap measures, a more fundamental reform of the electricity sector was also initiated in the late 1990s. This saw the establishment of an independent regulator and the unbundling and liberalization of the electricity sector. As a result, by 2011 Kenya had been able to attract a significant 347 MW of generation capacity from IPPs, which at the time was more than any other Sub-Saharan African country. Since then, a further six IPPs have been developed: three medium-speed diesel plants were procured through an international competitive-bidding process, two wind-power plants were contracted on an unsolicited basis, and an existing geothermal IPP project was expanded. The combined contribution of these proposed plants will add a total of approximately 700 MW to Kenya's installed generation capacity. These IPPs, coupled with capacity expansion, reinforcement, and electrification being undertaken by the two dominant utilities, the Kenya Electricity Generating Company (KenGen) and the Kenya Power and Lighting Company (KPLC), mean that Kenya is making progress toward overcoming the challenge of inadequate and unreliable electricity supply.

Power sector planning is coordinated by the Energy Regulatory Commission and the Least Cost Power Development Plan is regularly updated. Kenya is now managing to translate plans into timely initiation of international competitive bids for thermal power. Typically, bids are invited by KPLC, which has developed admirable capacity to run competitive procurement

processes. The government, through the Ministry of Energy, may also consider unsolicited bids provided they adhere to public procurement legislation.

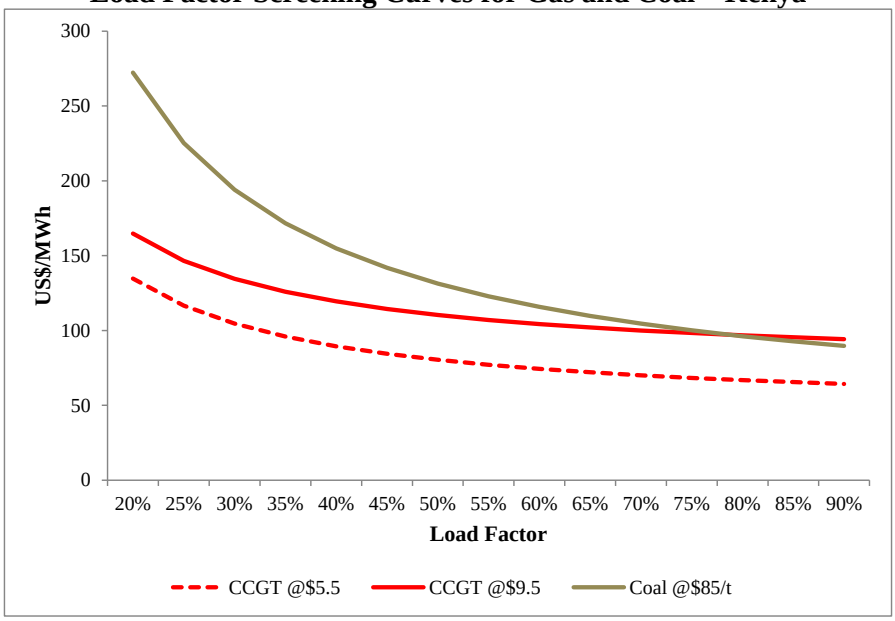
Electricity demand is expected to reach 15 GW by 2030. Kenya plans to meet this demand through further thermal, geothermal, hydroelectric, and wind-power investments as well as hydropower imports from Ethiopia. A comparison of Kenya's benchmark generation costs confirms that hydropower is the lowest-cost option for new baseload supply (Figure 5.4). Imported hydropower from Ethiopia is the cheapest option at $63 per MWh. Then there are a range of domestic hydropower projects at $79– 111 per MWh. Geothermal power, at $79 per MWh, is also a very attractive option.

Figure 5.4
Baseload Generation Cost Benchmarks – Kenya



The competitiveness of gas in the generation mix depends again on gas pricing assumptions. Imported Tanzanian gas delivered to Mombasa at $5.50 per MMBTU would be competitive with hydro and geothermal power and significantly cheaper than coal. But this would require the wellhead gas to be priced at the minimum wholesale price, a situation that is not seen as particularly realistic. Exports to Kenya would probably be a lower priority for Tanzania than LNG exports and domestic power generation demand. For exports to Kenya to be attractive to Tanzania, gas would need to be priced at around LNG export parity. But this would result in delivered gas prices of around $9.50 per MMBTU and would render gas uncompetitive against hydro and geothermal power. However, even at this price level, gas remains competitive against coal, particularly in mid-merit and peaking applications (Figure 5.5).

Figure 5.5
Load Factor Screening Curves for Gas and Coal – Kenya



Ghana and Côte d'Ivoire

With its hydropower potential nearly fully exploited and with no viable coal option, Ghana is turning increasingly to gas to satisfy its power generation needs. Gas demand for the power sector alone could reach 400 MMCFD by 2023, an amount which, until recently, was assumed to be readily available from a combination of domestic production and WAGP deliveries from Nigeria. However, growing doubts about the sufficiency and reliability of these gas sources are now prompting Ghana to reconsider its fuel supply strategy. An LNG import option is under active consideration, and the prospect of continued long-term utilization of LCO, diesel, and HFO remains a possibility.

Ghana's domestic gas production picture shows how supply can be subject to tremendous volume and timing uncertainties when the resource base is primarily associated gas and when the number of commercial fields is small. The foundation of Ghana's domestic gas supply is expected to come from 100 MMCFD of associated gas from the giant Jubilee oil field. However, Jubilee gas infrastructure has experienced extensive delays and is unlikely to be complete until late 2014, at which point Jubilee production will have less than a decade to go before production decline begins. The TEN and Sankofa fields will be the next fields to produce and will eventually contribute around 200 MMCFD of gas supply.[14] However, development of these fields has yet to begin, and by the time production starts decline of Jubilee production could already be within sight. Gas production beyond Jubilee, TEN, and Sankofa depends on success

[14] Integrated development of the Tweneboa, Enyenra, and Ntomme fields

in future exploration and appraisal drilling. Future fields cannot be counted on to be as large as Jubilee and as a result may have much shorter production lives.

Nigerian imports via WAGP form the other major piece of Ghana's gas picture, but supply to date has been unreliable. WAGP began operations in 2010, but deliveries have been extremely erratic, averaging 40–80 MMCFD, far short of the 123 MMCFD take-or-pay commitments under the WAGP foundation agreements between N-Gas and VRA. In addition, WAGP shipments have been prone to prolonged interruptions, the most recent of which was an accident in Togolese waters that ruptured the pipeline and caused a one-year interruption in supply. As a result, Ghana does not currently view WAGP as a reliable long-term supplier.

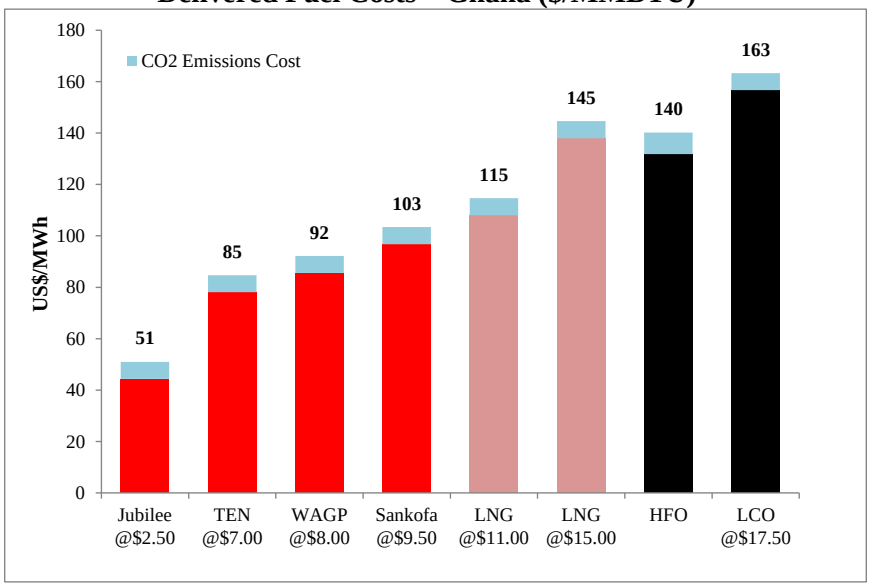
LNG is another possible supply source. With both domestic and Nigerian gas volumes being subject to uncertainty, security of supply is a growing concern. Based on its recent experience burning expensive crude oil to compensate for interruptions on WAGP, Ghana is considering importing LNG via a floating regasification terminal. However, LNG is a globally traded commodity subject to significant and unpredictable variations in pricing. In Asian markets, LNG currently trades for around $16 per MMBTU, although the influence of future U.S. shale gas exports is widely expected to bring about some softening in this price. Even so, given the capital intensive nature of the LNG business, LNG is unlikely to be a cheap option for Ghana.

Taken together, the three gas sources available to Ghana—domestic gas, WAGP gas, and LNG—constitute a supply portfolio with a wide range of delivered costs (Figure 5.5).[15] Ghana's gas pricing policy aims to set wholesale prices at WAGP equivalent levels of around $8 per MMBTU, a level that would be adequate for Jubilee and TEN but which would not cover the cost of Sankofa non-associated gas or LNG.

As demand grows in Ghana, additional Nigerian imports are likely to be the lowest-cost new supply source—estimated in Chapter 4 at $8– 10 per MMBTU. However, committing to firm take-or-pay contracts will be difficult for both Ghana and Nigeria. Nigeria will be reluctant to enter into new firm export commitments until domestic supply shortages have been alleviated. Likewise, Ghana will find it difficult to extend firm commitments for imported gas until the results of ongoing oil and gas exploration are clearer and until the reliability of WAGP is improved. These considerations suggest that flexible, interruptible supply arrangements could be beneficial to both sides.

[15] The delivered cost of domestic fields was estimated using the minimum wholesale price methodology used to derive the estimates in Chapter 2.

Figure 5.5
Delivered Fuel Costs – Ghana ($/MMBTU)[16]



Côte d'Ivoire is already heavily dependent on gas for power generation, 75 percent of which is gas-fired. Existing discovered gas fields have a maximum production potential of 250 MMCFD, enough to satisfy power sector demand until roughly 2018– 20. But strong potential demand from mining and other nonpower consumers will still result in an overall gas shortage. Absent additional domestic gas production, Côte d'Ivoire would also be unable to satisfy demand for expanded power exports to Mali and Burkina Faso, even though these countries are already interconnected with the Ivoirian grid. Nevertheless, ongoing exploration in Côte d'Ivoire has led to some new discoveries, which are being evaluated for commerciality. In addition, some additional hydropower potential will be developed in the coming years but will not have an effect until 2017–20.

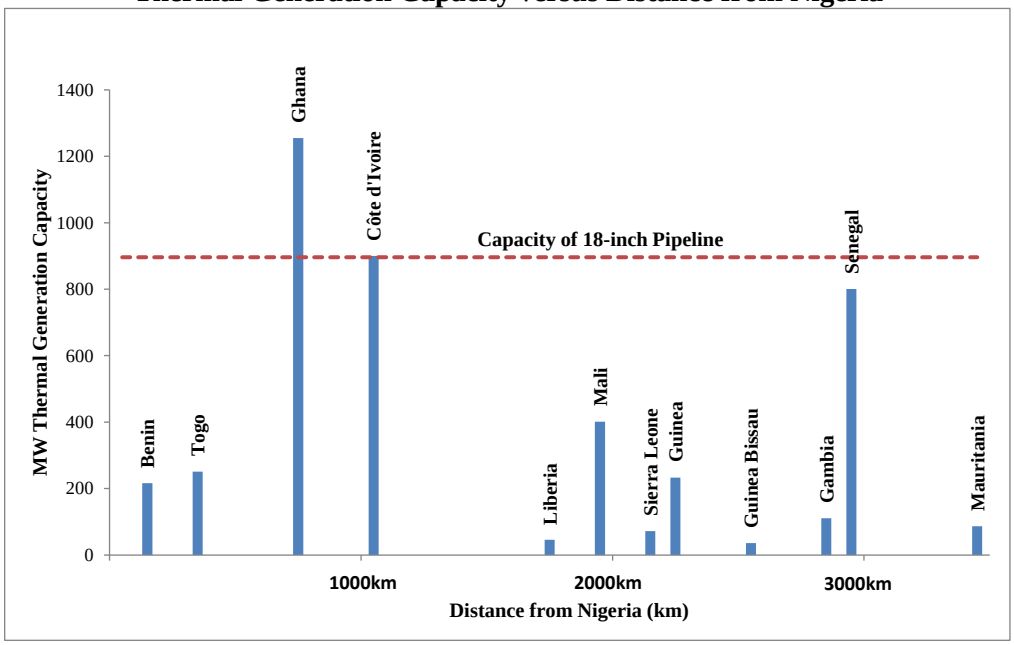
Côte d'Ivoire has no existing gas import capacity, so it too is considering a floating LNG facility. The analysis in this report suggests that extending WAGP from its current terminus in Takoradi would be a lower-cost solution. However, WAGP is not currently viewed as a sufficiently reliable supply option, so serious evaluation of a WAGP extension is not being undertaken. Even so, a 50 km gas pipeline stretching eastward from Abidjan toward the Ghana border is essential for the planned exploitation of small, marginal gas reserves in the Kudu, Eland, Ibex, and Gazelle fields. This project is being finalized by Petroci, the national oil company, and would be a first step towards an eventual extension to interconnect with the Ghanaian pipeline network currently under construction west of Takoradi.

The evidence from Chapter 4 strongly suggests that extending WAGP further up the coast of West Africa is not a viable option. The power markets in Liberia, Sierra Leone, and Guinea are very small and the distances to those markets are large (Figure 5.6). Transmission

[16] For delivery at Takoradi

lines are likely to be the preferred way to extend the benefits of gas-fired power to these smaller, more remote markets via existing and planned WAPP interconnections.

Figure 5.6
Thermal Generation Capacity versus Distance from Nigeria



Summary of Gas Export Potential in Sub-Saharan Africa

The potential for scaling up gas exports from Mozambique to South Africa appears promising. Baseload gas-fired power appears to be somewhat more costly than coal, but South Africa's commitment to reducing greenhouse gas emissions makes gas an attractive option to pursue. Furthermore, South Africa has a number of potential sources for gas, including Mozambican pipeline gas, LNG imports, and domestic production from shale gas or coal-bed methane. What is needed is a coherent natural gas plan that evaluates these options in greater detail and incorporates them into an updated power sector master plan. These planning activities would then be followed by feasibility studies of the more promising options.

From Mozambique's perspective, there is also a need for further planning and feasibility work. The market potential in South Africa needs to be seriously evaluated versus the other potential outlets for Mozambican gas. The concepts and economics developed in Mozambique's gas master plan must be evaluated further.

In East Africa, the potential for gas trade is more constrained. Tanzania's resources are insufficient to support LNG sales, domestic power sector sales, and an aggressive regional export program. Kenya, the largest demand center in the region, has competitive power options in the form of domestic geothermal and wind and imported hydropower. For smaller countries like Uganda, Rwanda, and Burundi, the economics of transporting small quantities of gas inland over large distances do not stand up.

In West Africa, the resources in Nigeria are sufficient by themselves to power all of Africa. But the export potential of Nigerian gas is again constrained. Expanding pipeline deliveries to Ghana through the existing WAGP pipeline is clearly economically attractive, and extending WAGP further to Côte d'Ivoire could also be interesting. However, the reliability of WAGP deliveries must improve before planners can be expected to move seriously on these ideas. Extending WAGP further up the coast of West Africa to serve smaller, more distant countries is not a viable option, and transmission lines are likely to be the preferred approach. But even this option would depend on removing the bottlenecks on Nigerian gas and power supplies.

Chapter 6
Opportunities and Challenges for Smaller-Resource Countries

For countries with smaller resource endowments, the potential benefits from harnessing gas to address domestic energy needs are similar to those in the larger-resource centers. Gas-fired power plants, being relatively quick to construct, can be effective in addressing acute, short-term generation deficits. Gas can displace higher-cost and higher-emission liquid fuels in existing and planned thermal plants. And gas-fired power can complement renewables, providing backup against drought-induced hydropower shortages and compensating for the intermittent nature of wind and solar generation.

However, commercialization of gas in these countries faces a number of special challenges. Chief among these is the loss of economies of scale that comes from developing and producing smaller gas fields. For example, the data in Chapter 2 suggest that developing a 1 TCF gas field requires a price of $6– 10 per MMBTU to be economic, whereas larger fields in the big resource centers can be produced for $2– 3 per MMBTU. Chapter 4 shows that powerful economies of scale are present in pipeline transportation as well.

This chapter briefly examines the experiences of these countries in addressing the opportunities and challenges coming from a smaller gas resource base in order to identify some common themes.

Mauritania and Namibia: Exporting Power to Reach Minimum Scale

Mauritania's installed generation capacity is 186 MW made up mainly of HFO and diesel units. There are plans to expand capacity to roughly 400 MW, displacing HFO and diesel to a large extent with gas and renewables. Significant demand growth is anticipated, particularly in the mining sector.

Offshore exploration in Mauritania has yielded a number of gas discoveries, of which only the Banda field is large enough to support standalone development. Recoverable gas at Banda is estimated at 700 BCF, an amount that, if produced over 25 years, could generate roughly 600 MW of power, far exceeding Mauritania's current demand.

To support a more appropriately sized project of 300 MW, a drastically scaled down field development plan for Banda has been put forward that calls for production of 40–60 MMCFD of gas from just two wells. Production at this level would recover less than half of the potentially recoverable gas. However, at this level of production the required minimum gas price is estimated at more than $10 per MMBTU, and the project is subject to capital cost escalation that could push this figure substantially higher during final commercial negotiations.

Yet even 300 MW is far beyond the near-term capacity needs of SOMELEC, the national power utility. As a result, the feasibility of the project rests on exporting 135 MW of power to Senegal and 24 MW to Mali. The national utilities of Senegal and Mali are willing buyers and the necessary transmission connections are in place. However, the cross-border element greatly complicates project structuring. For example, the contract guarantees needed to support the gas development have to be applied to both the SOMELEC and export off-takes.

A similar set of circumstances exists in Namibia. The 2 TCF Kudu offshore gas field was discovered in 1974 but has yet to be commercialized. Minimum-scale field development has been proposed that would supply 100 MMCFD to an 800 MW CCGT plant. However, as in the Mauritania case, the output of this plant greatly exceeds domestic capacity needs and power exports to South Africa are needed to make the project feasible.

As with Mauritania, the minimum gas price needed to support field development is above $7 per MMBTU and subject to substantial escalation during final negotiation. Unlike Mauritania, however, Namibia has a viable coal option that could become the preferred option if Kudu gas prices escalate.

Finally, it is worth noting that the fiscal components of minimum gas price in both Mauritania and Namibia are substantial. Because the benefits coming from reduced generation costs are so high, both countries would appear to have room to reduce the fiscal burden on upstream gas production in the event that the final gas price becomes uncompetitive. In the case of Namibia, where a competing coal option is viable, excessive taxation could render the entire gas-to-power project uncompetitive and result in zero gas production revenue.

Cameroon, Republic of Congo, Gabon: Flare Reduction and Oil Replacement

The gas and power sectors in Cameroon, the Republic of Congo, and Gabon are driven to varying degrees by a common set of factors. All three countries are oil producers with substantial volumes of associated gas. Although the wellhead production cost of associated gas is low, the cost of gathering and transporting small and widely dispersed sources of low-pressure gas is high. As a result, gas commercialization has been very limited and most gas production is either flared or reinjected (Table 6.1).

Table 6.1
Disposition of Gas Production (MMCFD)

	Cameroon	Rep. Congo	Gabon
Marketed	45	140	30
Flared	80	150	165
Reinjected/own use	10	630	325
Total	135	920	520

All three countries have small power sectors that depend heavily on hydropower (Table 6.2). Hydropower provides one-third to two-thirds of current generation capacity, and hundreds

of megawatts of hydropower are planned in each country. The combined undeveloped hydropower potential exceeds 30,000 MW. Nevertheless, despite the abundance of hydropower and gas resources available, all three countries make heavy use of costly liquid fuels (diesel and HFO) in power generation.

Table 6.2
Installed Generation Capacity (MW)

	Cameroon	Rep. Congo	Gabon
Hydropower	721	209	170
Gas	216	350	175
Diesel/HFO	128	36	76
Total	1065	595	421

These fundamental gas and power sector conditions create an extremely challenging policy and planning environment. Although demand is growing rapidly on a percentage basis, annual demand growth in absolute terms is small: 30– 40 MW in Gabon, 40– 50 MW in the Republic of Congo, and 80– 100 MW in Cameroon. On the other hand, the lowest-cost generation option is almost always large-scale hydropower in the 300– 400 MW range. Such large hydropower projects can take several years to be absorbed into the market and consequently are likely to operate at low capacity in early years. Exporting power can offer the potential of higher utilization, but viable power off-takers are few and cross-border issues greatly complicate project structuring and financing. Moreover, large hydropower projects can effectively block one another. For example, if Gabon or the Republic of Congo wished to export power to Nigeria, they would need to cross Cameroon, which may have its own ambitions to build a sub-regional hydropower project. Facing such a complex set of challenges, development timelines for such projects can reach six to ten years.

Gas-fired power plants, on the other hand, can be built in much shorter time frames and in smaller increments that more closely match demand growth. However, due to their high efficiency, small gas-fired plants consume very low volumes of gas and this factor can push gathering and transportation projects below the minimum economic scale. For example, a moderately efficient 100 MW gas-fired power plant would consume only around 20 MMCFD. Building dedicated gathering and transportation infrastructure for such a small volume would be economically unviable in most cases.

Gas flaring further complicates the picture. Cameroon, the Republic of Congo, and Gabon are all participants in the Global Gas Flaring Reduction partnership and have policies and regulations aimed at reducing or eliminating flaring. Gas flaring is a wasteful and environmentally damaging practice. Yet all three countries rely on oil production as a major source of government income and are not likely to take any action that reduces oil production.

Despite this exceptionally challenging policy environment, the three countries have registered some success in implementing gas-to-power projects. In Cameroon, the 216 MW Kribi

power plant entered service in 2013 using non-associated gas from the Sanaga South field. Future expansions, now being considered, could include commercializing associated gas that is currently flared. In the Republic of Congo, the CEC integrated gas-to-power project uses previously flared gas from the M'boundi gas field to supply 350 MW of gas-fired power plants in vicinity of Pointe Noire. The project includes a 55 km gas-gathering pipeline, a new 300 MW open-cycle gas-fired power plant, expansion of an existing CED power plant to 50 MW, and a high-voltage transmission line connecting to Brazzaville. And in Gabon, 30 MMCFD of previously flared gas is being used in 175 MW of gas-fired power plants in Libreville and Port Gentil, replacing liquid fuels in those plants. All of these projects have benefitted from decrees and regulations calling for reduction or elimination of gas flaring.

Going forward, there would appear to be additional potential for further replacement of liquid fuels. Cameroon, for example, has at least 128 MW of grid-connected diesel and HFO capacity, and fuel inputs to these plants currently cost $13– 20 per MMBTU. The electricity market is growing by almost 100 MW per year. A 100– 200 MW gas-fired power plant could be absorbed relatively easily by the market even if Nachtigal and other large-scale hydropower projects go ahead as planned. Although a 100 MW plant would consume at most 20– 40 MMCFD of gas, there would seem to be scope for pricing this gas at a level that would make it commercial but would still generate a substantial savings over HFO and diesel.

Ghana: Reconciling Gas Economics with Legacy Hydropower

Ghana's position as a gas importer was discussed in some detail in Chapter 5. However, as a gas resource holder, Ghana faces opportunities and challenges in the gas and power sectors that echo those of the other countries covered in this chapter. In particular, economies of scale are still a major issue. Ghana plans to develop fields with production rates of 100 MMCFD or more, but the fields are in deep-water environments where costs are very high. As a result, the minimum wholesale gas price will be in the range of $8– 10 per MMBTU, a level more or less consistent with the price of imported Nigerian gas. But gas at these price levels would still be cheaper than LCO and LNG, the relevant alternative fuels.

The pricing challenge in Ghana is on the power side of the house. Gas supply at $8– 10 per MMBTU translates into wholesale electricity costs of $92– 107 per MWh assuming CCGT efficiencies and including carbon emissions costs. Generation costs from LNG would be even higher. However, Ghana's past experience with a hydropower-dominated power sector has left a legacy of very low wholesale power tariffs. Even after recent tariff increases, Ghana's bulk power tariff is only around $80 per MWh. Given Ghana's increasing reliance on gas for power generation, additional tariff increases will be necessary.

The pricing challenges in Côte d'Ivoire are equally large, since over two-thirds of gas currently purchased by the power sector is priced at only $5.50 per MMBTU. The supply cost of any LNG import project would be two to three times this level.

Common Themes and Lessons Learned

In all of the examples covered here, economy of scale—or the lack thereof—is the main obstacle to gas-to-power development. Smaller power markets need smaller increments of new generation. Given the high efficiency of gas-fired power plants, the resulting gas requirements are very small and can easily fall below the minimum economic scale for upstream and midstream development.

A further challenge comes from the fact that gas supply in many countries rests on a very small number of fields—in the case of Mauritania and Namibia, just one commercial field each and in the case of Ghana, only two to three fields. Individual fields can be prone to production and timing risks, and these may be exacerbated in the case of associated gas, where production volumes and timing are dependent on oil production and where field life may be short.

The big prize for smaller countries is replacing liquid fuels in power generation, and this strategy also offers the best hope for overcoming the economic barriers coming from low-volume production. In the current $100 per barrel oil price environment, the cost of diesel is over $20 per MMBTU and can go much higher for distant inland locations. If, as suggested here, gas prices of $6– 10 per MMBTU or more are often necessary to make smaller fields economic, then gas can still offer smaller countries major potential savings in electricity costs.

The other solution is to increase the scale of gas and power development beyond the needs of the domestic power market. There are at least two avenues available here. One option is to export power or gas to neighboring countries, as in the case of Mauritania. Another option is to anchor a larger gas-to-power project on power demand from the mining sector, which in some countries studied here can reach 1,000 MW. The opportunities and challenges associated with anchoring domestic power markets on the mining sector are covered in detail in a 2014 report by the World Bank.[17]

Finally, the experience of the smaller resource-holding countries suggests a number of other supporting and enabling policy orientations that can facilitate gas-to-power development:

- Implement regulations to reduce or eliminate gas flaring;
- Ensure that fiscal terms on gas production are not onerous and adopt a flexible approach to midstream taxation where needed to make projects economic;
- Promote infrastructure development anchored on long-lived gas assets such as non-associated gas fields to provide a platform for future developments;
- Where gas supply is variable or uncertain, require new thermal plants to be dual-fuel capable.

[17] Sudeshna Ghosh Banerjee, Zayra Romo, and Gary McMahon, *The Power of the Mine: A Transformative Opportunity for Sub-Saharan Africa* (Washington, DC: World Bank, 2014).

Chapter 7
Conclusions

So how important is the role of natural gas in addressing Sub-Saharan Africa's persistent power deficits? The economic benchmarks in this study provide both encouraging and cautionary notes. Clearly, the gas resource base itself is large enough to support whatever power sector demand could plausibly materialize. And the cost of gas-fired power competes very favorably against liquid fuels and, in a surprising number of cases, against coal and even high-cost hydropower. But at the same time, this study also clearly demonstrates that Africa's abundant hydropower and coal resources and the high cost of moving gas from resource centers to demand centers are factors that limit the economic reach of gas. As a result, both gas-producing and gas-consuming countries have choices along the gas-to-power value chain. Producing countries have choices about which markets they will serve, and consuming countries have choices between competing generation options. These choices may not always favor domestic gas-fired power.

For Nigeria, the choices line up strongly in favor of gas and point to a potential shift in emphasis away from LNG exports and toward the domestic power sector. Gas-fired power can be produced at far lower cost than Nigeria's other large-scale power generation options, and the discovered resource base is not a constraining factor, even when measured against Nigeria's enormous current and future electricity demand. Gas pricing is now moving toward a level that could attract capital into upstream investments, while at the same time the outlook for new LNG projects in Nigeria is weakening due to escalating liquefaction costs, increased competition for Asian LNG markets, and investor concern over political and fiscal stability.

These pricing and economic trends favoring domestic gas supply are reinforced by a growing determination at the policy level to find solutions to Nigeria's chronic power shortages. The Roadmap to Power Sector Reform embodies reforms that address the root operating and financial factors that have historically plagued the power sector, reforms that seem likely to improve the bankability of the power sector and make it a better customer for the gas sector.

However, the Achilles' heel of the power sector reforms could lie in the gas sector itself. Billions of dollars of investment capital will need to flow into the upstream and midstream gas sectors if gas supply is to meet the generation targets laid out in the roadmap, and the majority of this capital will have to come from the private sector. For this to occur, Nigeria will need to develop a bankable commercial framework for gas, including further gas price reforms, a transparent and nondiscriminatory regulatory and tariff system for gas transportation and sales, and a redefinition of the role of public companies in the gas sector, including, most critically, an alternative to the current NNPC JV financing model. Given the magnitude and scope of these changes, it seems probable that gas sector reform will, to some degree, need to follow a separate track from that of the oil sector.

For Mozambique, LNG exports are clearly the overwhelming gas allocation priority. Indeed, royalties, profit shares, and taxes from future gas exports constitute a transformational opportunity to increase national wealth and income. However, Mozambique's 10 planned LNG trains could take decades to be developed, and even this investment would consume only about 70 percent of the current discovered gas resource base. Thus, even with aggressive LNG development, Mozambique can afford to allocate gas to domestic and regional supply without compromising its capacity to serve export markets. And it can do so even if the alternative gas markets cannot afford to pay the full LNG netback price since the opportunity cost for the incremental gas sold to non-LNG markets is very low.

Nevertheless, it is unlikely that gas-fired power will play a major role in Mozambique's domestic power sector itself. The domestic electricity market is quite small and distances from the big resource centers in the north to Maputo and other population centers are large. Moreover, Mozambique has other competitive generation options, namely hydropower on the Zambezi River and discard coal in Tete province, which are likely to be prioritized for development even if, as this study suggests, the coal projects are not always cheaper than gas. Domestic gas-to-power projects, in the short to medium term, could be limited to peaking applications or to supplying local area demand in the north.

The intriguing question, though, is whether Mozambican gas can supply larger demand centers in South Africa and the rest of the Southern African Power Pool via either gas pipelines or further expansion of the regional transmission network. This study provides a basis for optimism. The estimates here suggest that gas could be delivered to South Africa at a price competitive with coal while still providing producers in Mozambique with a netback price competitive with other non-LNG markets. A pipeline to South Africa would offer Mozambique the opportunity to diversify its gas sales and stimulate gas-consuming industry along the pipeline route. For South Africa, increased gas utilization would help the country achieve its carbon emission reduction targets by reducing reliance on coal and provide load-following capacity to complement intermittent output from wind and solar projects.

On the other hand, gas presents some very tricky planning challenges for South Africa. The competitiveness of gas against coal is evident only at intermediate load factors, yet the economics of a pipeline from Mozambique would depend on high utilization. Moreover, South Africa must consider other potential sources of gas besides Mozambique. The potentially huge shale gas resources in the Karoo Basin are being evaluated and, if ultimately proven to be commercial on a large scale, would dramatically change the energy balance in South Africa. Conventional gas exploration is ongoing and LNG imports are also being considered. South Africa is beginning work on a gas master plan that will presumably assist policy makers sort through the options. Yet surprisingly, no detailed feasibility study has been done of a large gas pipeline from northern Mozambique to South Africa. Such a study seems warranted.

In Tanzania, as in Mozambique, the highest gas allocation priority is LNG. Government and private stakeholders are broadly aligned in viewing the first two LNG trains as essential to attaining economies of scale and maximizing the long-term value of Tanzania's gas resources. However, Tanzania is in parallel aggressively pursuing a domestic gas agenda that could eventually result in a quarter of the current resource base being committed to the domestic power market. Unless additional gas resources are discovered, these two parallel gas agendas could eventually collide. The current resource base may not support a further two LNG trains and an aggressive long-term expansion of domestic gas-to-power.

From a power sector point of view alone, Tanzania's gas push seems justified. Immediate cost savings are attainable by displacing emergency diesel generation. Gas is cost competitive against coal, and even high-cost hydropower, as a long-term generation option. Most important, gas provides an effective way to mitigate the drought susceptibility and cost, timing, and financeability risks inherent in Tanzania's hydropower portfolio.

However, in a world where difficult tradeoffs are likely, the gas and power sectors in Tanzania must operate efficiently and with a minimum of market distortions. Unfortunately, Tanzania's track record here is not encouraging. Generation procurements have been fraught with problems, TANESCO's financial performance has been consistently poor, and the Mtwara–Dar es Salaam pipeline has seemingly been oversized. Attaining the required levels of efficiency in the sector will require greater adherence to market discipline through, for example, power and gas prices linked to international prices of competing fuels, open access provisions and rate-of-return tariffs for pipeline projects, and competitive international bidding for generation projects. It is almost impossible to see how these market-based reforms could occur without a fundamental rethink about the role of the public sector in the gas and power sectors, including reform of TANESCO and TPDC.

From the analysis here of the three largest resource countries, it is clear that the economic and policy environment in Mozambique and Tanzania is markedly different from that in Nigeria. The resource base in Mozambique and Tanzania is overwhelmingly non-associated gas, whereas in Nigeria it is currently dominated by associated gas. Mozambique and Tanzania have viable coal options and abundant hydropower potential, whereas Nigeria does not. Mozambique and Tanzania are building new institutions specifically to manage gas, whereas in Nigeria gas is embedded within an existing oil-dominated institutional and regulatory structure. The transformative potential of gas in Mozambique and Tanzania is from future royalties and taxes, whereas in Nigeria the big payoff from gas is through increased supply and the lower cost of domestic electricity. These fundamental differences in circumstances will show up in differences in how these countries assess their gas and power sector choices.

However, beyond the three largest-resource countries, it is worth stepping back, as at the outset of this report, to take a continent-wide perspective on gas-to-power in Sub-Saharan Africa. Taking into consideration the circumstances facing large-resource holders, small-resource

holders, and potential importers, this report suggests three primary roles for gas in addressing Sub-Saharan Africa's power needs. Replacing liquid fuels such as HFO and diesel is the most clear-cut argument for gas in many countries, since the potential cost savings are large. But even this apparent low-hanging fruit depends on how liquid-fired generation is being used and what gas supply is available. Second, displacing coal with gas, although not as clear cut an economic proposition, shows up in this report as a surprisingly competitive option, especially when fuels are priced at international levels and when policy measures aimed at reducing carbon emissions are in place. Third, the flexibility of gas-fired power plants suggest a strong role for gas in addressing short-term power deficits and mitigating risks in hydropower implementation. The case for each of these three broad gas-to-power applications will depend on local conditions in each country (Table 7.1).

Table 7.1
Roles for Gas-to-Power in Sub-Saharan Africa

Application	Local Conditions Influencing Adoption of Gas-Fired Power
Replace liquid fuels	When liquid fuels are in use to generate baseload or mid-cycle electricity, gas from domestic production or pipeline imports is likely to offer significant cost savings.
	When liquid fuels are used for peaking or backup generation, the viability of gas may depend on locating the peaking plant near the source of gas production. Otherwise, the cost of underused pipeline capacity could negate fuel cost savings.
	Using imported LNG to replace HFO or diesel is likely to be unattractive unless high utilization rates can be achieved.
	For small, inland markets, pipeline gas is unlikely to be economic, and liquids replacement will depend on transmission grid capacity.
Displace coal	When gas at LNG export parity competes with coal at international prices, gas is often cheaper as a baseload solution, even without taking carbon into consideration.
	When domestic coal prices are below international levels, the competitiveness of gas is likely depend on its availability at less than international prices. This can make sense for a producing country when reserves are insufficient to support an LNG project or when reserves exceed LNG requirements to such a degree that the opportunity cost of gas is driven down to petrochemical levels.
	The competitiveness of gas versus coal improves dramatically when strong carbon-reduction policies are in place, either through self-imposed caps on emissions or incorporation of carbon pricing into least-cost generation decisions.
	Gas competes very effectively against coal as a mid-cycle (e.g., 50%–70% load factor) solution across a wide range of fuel prices.
Complement to hydropower	Even where abundant hydropower potential exists and where it is the least-cost long-term generation option, gas-fired plants can be attractive: • when hydropower will operate at mid-cycle load factors • when implementation and drought risks in the hydropower program are high, and • when the minimum efficient scale of hydropower greatly exceeds incremental market growth

Returning at last to address the paradox described at the very outset of this report, Sub-Saharan Africa is endowed with abundant natural gas resources that to date have not been exploited sufficiently to alleviate the continent's persistent power shortages. Although this report suggests a much more important future role for gas, it also highlights that gas is not a panacea for Sub-Saharan Africa's acute power deficits. Gas must compete against other generation options, and the large-resource holders face tradeoffs between domestic gas use and LNG exports. Even where the economics of the gas-to-power value chain are favorable, projects can be thwarted by the absence of a bankable commercial framework linking producers, transporters, and customers. The political will to establish workable commercial and policy frameworks and institute supporting reforms can come only when domestic gas is viewed not as a by-product of oil production, nor as a source of outsized resource rents, but rather as an engine of development by virtue of its potential to increase energy supply and reduce cost. This is the fundamental gas-to-power challenge for energy sector policy makers in Sub-Saharan Africa.

Annexes

Annex 1
Discovered Natural Gas Reserves and Resources in Sub-Saharan Africa
(TCF)

		Commercial Reserves			Contingent Resources (2C)			Discovered
Country	AG/NAG	Proved	Probable	2P	Pending	Unclarified	Total	2P+2C
Angola	AG	12.0	6.0	18.0	-	-	-	18.0
Botswana	NAG	-	-	-	0.2	-	0.2	0.2
Cameroon	AG	0.0	0.2	0.2	5.5	0.0	5.5	5.7
Congo, Republic of	AG	3.2	-	3.2	-	2.0	2.0	5.2
Côte d'Ivoire	NAG	0.8	0.3	1.1	0.2	0.1	0.3	1.5
Equatorial Guinea	NAG	2.6	1.4	4.0	3.2	5.3	8.5	12.5
Gabon	AG	0.1	-	0.1	-	1.2	1.2	1.3
Ghana	AG/NAG	1.0	0.4	1.4	1.8	-	1.8	3.2
Mauritania	NAG	0.3	0.1	0.4	-	0.8	0.8	1.1
Mozambique	NAG	2.7	1.8	4.5	24.1	52.1	76.2	80.7
Namibia	NAG	0.6	-	0.6	-	1.3	1.3	1.9
Nigeria	AG/NAG	110.3	22.1	132.4	18.0	18.0	36.0	168.4
South Africa	NAG	1.0	-	1.0	1.7	0.7	2.4	3.4
Tanzania	NAG	1.4	0.3	1.7	23.6	-	23.6	25.3
Uganda	AG/NAG	-	-	-	-	0.5	0.5	0.5
TOTAL		**136.1**	**32.5**	**168.6**	**78.8**	**83.4**	**162.2**	**330.8**

Notes

1. Excludes Lake Kivu gas in Rwanda, very small discoveries in Senegal and Benin, and non-viable gas in Ethiopia
2. AG denotes associated gas, NAG denotes non-associated gas

Annex 2
Prospective Gas Resources in Sub-Saharan Africa
(TCF)

Country	TCF	Data Source
Madagascar	167	USGS
Mozambique	164	Consultant Report
Nigeria	142	Government
Tanzania	71	USGS
Angola	46	USGS
Gabon	30	USGS
Seychelles	20	USGS
Cameroon	20	Oil Company
Cote d'Ivoire	17	USGS
Ghana	17	USGS
Liberia	13	USGS
Chad	12	USGS
Sierra Leone	9	USGS
Mauritania	9	USGS
South Africa	9	Government
Senegal	8	USGS
Equatorial Guinea	7	Consultant Report
Niger	4	USGS
Botswana	3	Consultant Report
Guinea	2	USGS
Guinea-Bissau	2	USGS
TOTAL	774	

Note: Figures reflect risked, recoverable gas

Annex 3
Upstream Capital and Operating Cost Assumptions

Nigeria

Category	No. of Fields	Total Resource	Unit Capex	Unit Opex
		(tcf)	($/mcf)	($/mcf)
Non-associated Gas				
Low Cost Fields	4	12.5	0.208	0.139
Medium Cost Fields	7	3.3	0.485	0.322
High Cost Fields	3	5.9	0.556	0.368
Associated Gas				
Low Cost Fields	3	11.2	0.143	0.095
Medium Cost Fields	4	20.0	0.201	0.134
High Cost Fields	5	2.0	0.466	0.311
Total	26	54.9		

Source: IHS, ECA

Mozambique

Field	Resource	Development Capex		Annual Opex	
		Total	Per Unit	Total	Per Unit
	(tcf)	($mil)	($/mcf)	($mil)	($/mcf)
Prosperidade/Mamba	48.0	12,468	0.260	218	0.204
Golfinho/Atum	20.0	6,600	0.330	99	0.223
Coral	5.1	3,064	0.601	31	0.277
Tubarao	1.5	1,595	1.063	12	0.359
Njika	1.0	1,055	1.055	11	0.496
Pande (Onshore)	3.7	350	0.096	12	0.148

Source: ICF

Annex 4
LNG Netback Calculations

		Asian Deliveries					European Deliveries				
		2015	2020	2025	2030	2035	2015	2020	2025	2030	2035
DES Price											
Convergence Case		15.60	14.04	13.34	12.94	12.55	10.61	10.50	10.08	9.68	9.29
Ultra-Convergence Case		15.62	13.28	11.95	10.99	10.44	10.61	10.50	9.97	9.48	9.00
Shipping Costs											
Nigeria		1.59	1.61	1.63	1.64	1.66	0.63	0.64	0.64	0.65	0.65
Mozambique		1.06	1.07	1.08	1.09	1.10	0.96	0.97	0.98	0.99	1.00
Tanzania		1.07	1.08	1.09	1.10	1.11	0.96	0.97	0.98	0.99	1.00
Liquefaction Costs	Liq. Capex (US$/ton)										
Nigeria (existing NLNG)	400						1.64	1.64	1.64	1.64	1.64
Nigeria (NLNG Proposed Train 7)	1,400	5.73	5.73	5.73	5.73	5.73					
Nigeria (Greenfield project)	1,800	7.37	7.37	7.37	7.37	7.37					
Mozambique	1,200	4.57	4.57	4.57	4.57	4.57					
Tanzania	1,200	4.82	4.82	4.82	4.82	4.82					
Convergence Case LNG Netback prices											
Nigeria (existing NLNG)							8.34	8.22	7.80	7.39	7.00
Nigeria (NLNG Proposed Train 7)		8.28	6.70	5.98	5.57	5.16					
Nigeria (Greenfield project)		6.64	5.06	4.34	3.93	3.52					
Mozambique		9.97	8.40	7.69	7.28	6.88					
Tanzania		9.71	8.14	7.43	7.02	6.62					
Ultra-Convergence Case LNG Netback prices											
Nigeria (existing NLNG)							8.34	8.22	7.69	7.19	6.71
Nigeria (NLNG Proposed Train 7)		8.30	5.94	4.59	3.62	3.05					
Nigeria (Greenfield project)		6.66	4.30	2.95	1.98	1.41					
Mozambique		9.99	7.64	6.30	5.33	4.77					
Tanzania		9.73	7.38	6.04	5.07	4.51					

Notes:

Existing NLNG Trains 1-6 assumed to be marketed in Europe

New LNG capacity in Nigeria, Mozambique, and Tanzania assumed to be marketed in Asia

Annex 5
Fuel Price Assumptions Used in Generation Cost Benchmarks

	Gas ($/MMBTU)		Coal ($/ton)		Diesel ($/GJ)
	Low	High	Low	High	
Nigeria	2.00	4.00	88.00	88.00	19.91
Mozambique	2.50	7.70	12.50	95.00	22.92
Tanzania (Dar es Salaam)	4.40	8.40	50.00	85.00	22.06
South Africa	5.70	10.90	40.00	80.00	35.00
Kenya (Mombasa)	5.50	9.50	50.00	85.00	22.06

Annex 6
Pipeline Modeling Assumptions

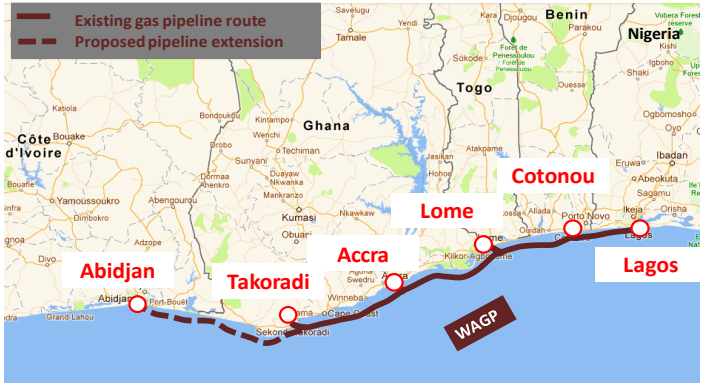
Origin & Delivery	Length (km)	Diameter (inches)	Capacity (MMCFD)	Standard Unit CAPEX ($/in-km)	Africa Cost Adjustment	Terrain Adjustment	Adjusted Unit CAPEX ($/in-km)	Total CAPEX ($million)	Annual OPEX (% of CAPEX)	Fuel Gas (%)	Tax Rate (%)
CAP/AKK	953	36	863	64,300	90%	1.043	60,358	2,071	3%	0.7%	34%
WAGP Expansion/Extension	292[18]	20	170/470[19]	70,000	100%	1.000	70,000	459[20]	3%	1.8%	34%
Palma–South Africa	2513	24	313	64,300	90%	1.068	61,805	3,728	3%	1.4%	35%
Dar Es Salaam–Mombasa–Nairobi	810	20	313	64,300	90%	1.263	73,090	1,184	3%	0.7%	45%
Dar es Salaam–Dodoma–Shinyanga–Kigoma	1252	16	114	64,300	90%	1.300	75,231	1,507	3%	0.9%	45%

[18] Takoradi–Abidjan only. Additional Ghana capacity achieved by compression only.
[19] Capacity with and without additional compression.
[20] Includes $50 million of additional compression.

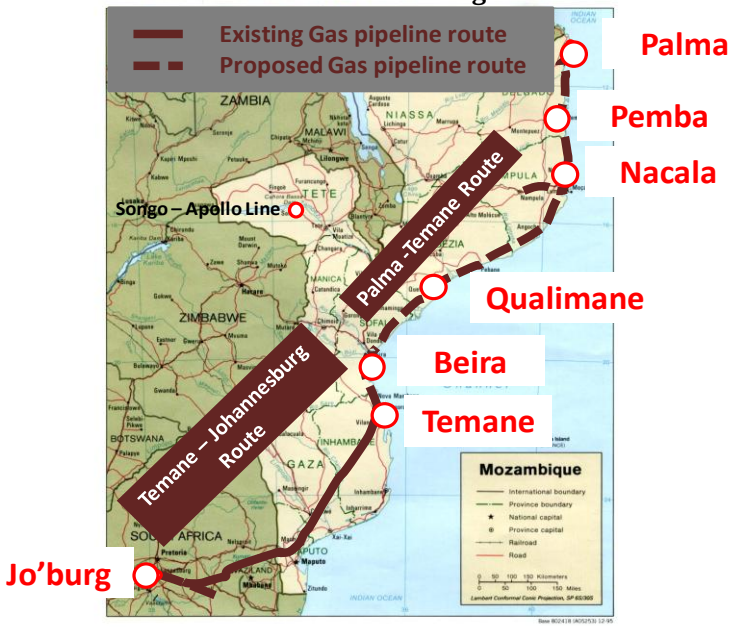
Annex 7
Pipeline Concepts Studied

CAP/AKK

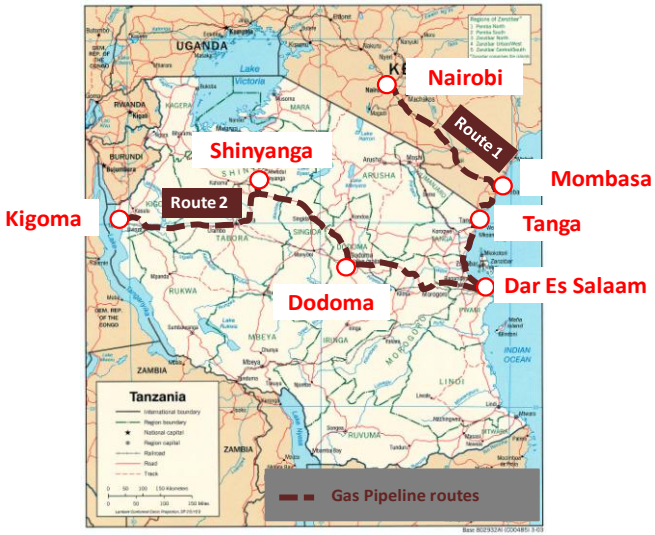
WAGP Expansion/Extension



Palma-Johannesburg



Tanzania Routes (Inland & Export)



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