

# Angola and Mozambique Gas Monetization for Economic Development

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Gas Based Industry Feasibility Study

For: The African Development Bank, Tunis

By: DNV KEMA Energy & Sustainability  
June 30<sup>th</sup> 2013

Contract N° / OPSM.2/2012

Final report

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## List of Acronyms

Acronym	Meaning
ACM	Dutch Authority for Consumers and Markets
AfDB	African Development Bank
ANA	Autoridad Nacional del Agua
ANG	Angola
APAC	Asia Pacific
API	American Petroleum Institute
APT	Additional Petroleum Tax
ASM	Artisonal and Small-scale Mining Enterprises
Bbl/day	Barrels Per Day
BC	Business Concession
Bcf	Billion Cubic Feet
BOE	Barrels of Oil Equivalent
¢/kWh	United States cents per kilowatt hour
Capex	Capital expenses
CCGT	Combined Cycle Gas Turbine
CFC	Customer Foreign Currency
CIT	Corporate Income Tax
CMH	Companhia Mocambicana de Hidrocarbonetos
CNG	Compressed Natural Gas
CTL	Coal-to-Liquid
DMO	Domestic Market Obligation
DPSA	Development Production Sharing Agreement
DRC	Democratic Republic of Congo
DSO	Distribution System Operator
E&P	Exploration and Production
EAF	Electric Arc Furnace
EBN	Energie Beheer Nederland
EdM	Electricidade de Mozambique
EIA	Energy Information Administration
ENH	Empresa Nacional de Hidrocarbonetos
EPCC	Exploration and Production Concession Contract
ESCOM	Electricity Supply Commission
EWURA	Energy and Water Utilities Regulatory Authority
EU	European Union
F-T	Fisher- Tropsch
FAO	Food and Agriculture Organization
FES	Fund Economic Structure
FID	Final Investment Decision
FLNG	Floating LNG liquefaction and storage facility
FOB	Free On Board
GDP	Gross Domestic Product
GIS	Geographic Information System
GJ	Gigajoule
GoM	Government of Mozambique
GT	Natural Gas Turbine
GTL	Gas-to-Liquid
GTS	Gasunie Transport Services
GW <sub>e</sub>	Gigawatt Electric

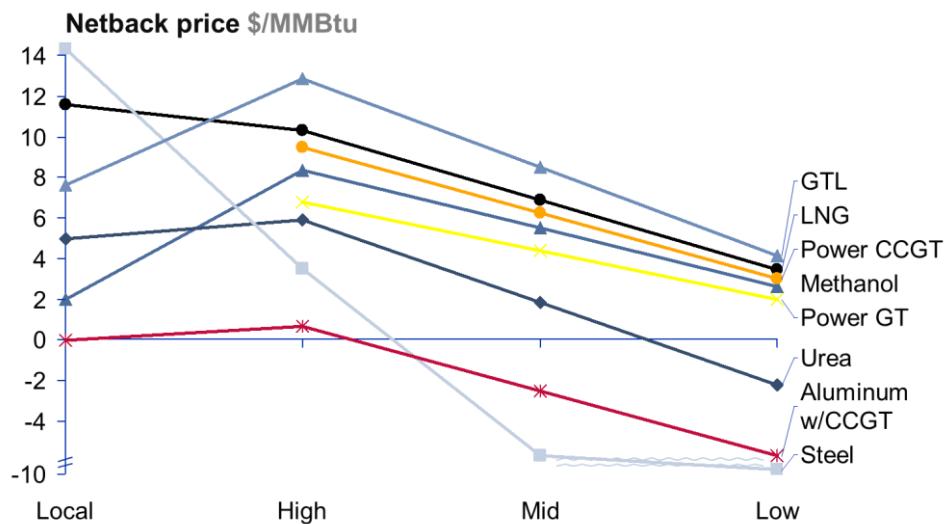
Acronym	Meaning
GWh	Gigawatt Hour
HSF	Heritage and Stabilization Fund
IBRD	International Bank for Reconstruction and Development (World Bank)
ICF	ICF International
IDA	International Development Association
IEA	International Energy Agency
IFC	International Finance Corporation
IMF	International Monetary Fund
INE	Instituto Nacional de Estadística
INP	Instituto Nacional de Petróleo
IOC	International oil companies
ISO	Independent System Operator
IRR	Internal Rate of Return
JCC	Japanese Crude Cocktail
K2O	Potash
kg/ha	Kilogram Per Hectare
Kg/pp	Kilogram Per Population
km	Kilometer
ktoe	Thousand Tonne Oil Equivalent
kTonne/yr	Thousand Tonne Per Year
kW <sub>e</sub>	Kilowatt Electric
kWh	Kilowatt Hour
LIS	Land Information System
LLC	Limited Liability Company
LNG	Liquefied Natural Gas
LSM	Large-scale Mining Enterprises
LSP	Large-scale Project
mb/d	Million Barrels Per Day
Mcf	Thousand Cubic Feet
ME	Ministry of Energy
MEA	Dutch Ministry of Economic Affairs
MGC	Matola Gas Company
MGPM	Mozambique Gas Planning Model
MIC	Ministério de Indústria e Comércio
MINEA	Ministry of Energy and Water
MINPET	Ministry of Petroleum
MIREM	Ministry of Mineral Resources
MMBtu	One million British thermal units
MMEWR	Ministry of Minerals, Energy and Water Resources
MOZ	Mozambique
MPRDA	The Mineral and Petroleum Resources Development Act
MSME	Micro, Small and Medium Enterprises
MTPA	Million Tonne Per Year
MTPY	Metric Tons Per Year
MW <sub>e</sub>	Megawatt Electric
MWh	Megawatt Hours
N	Nitrogen
NAM	Nederlandse Aardolie Maatschappij BV
NDF	National Directorate of Fuels



Acronym	Meaning
NESPS	Angolan National Energy Security Policy and Strategy
NIP	Norm Inkoop Prijs
NREL	National Renewable Energy Laboratory
O&M	Operating and Maintenance
OECD	Organisation for Economic Co-operation and Development
OPEC	Organization of Petroleum Exporting Countries
Opex	Operating expenses
P205	Phosphate
PASA	Petroleum Agency South Africa
PIT	Petroleum Income Tax
PPP	Public-Private Partnership
PPT	Petroleum Production Tax
PSA	Production Sharing Agreement
PTT	Petroleum Transaction Tax
PV	Photovoltaic
QP	Qatar Petroleum
RCS	Risk Service Contracts
ROMPCO	Republic of Mozambique Pipeline Company
SADC	Southern African Development Community
SAPP	South African Power Pool
SF	Surface Fee
SFP	Small Field Policy
SME	Small and Medium Enterprises
Sonagas	Sonangol Gas Natural
SPA	Sale and Purchase Agreements
SPI	Sasol Petroleum International Ltd.
SSA	Sub-Saharan Africa
TAA	Technical Assistance Agreements
Tcf	Trillion Cubic Feet
TCP	Technical Corporation Permits
toe	Tonne Oil Equivalent
TPDC	Tanzania Petroleum Development Corporation
TSO	Transmission System Operator
TTF	Title Transfer Facility
TWh	Terawatt Hour
USGS	United States Geological Survey
\$	United States Dollar
VAT	Value Added Tax
VGB	VGB PowerTech
WB	World Bank
WTI	West Texas Intermediate

## Executive Summary

Angola and especially Mozambique have significant natural gas resources which are in the process of being monetized to promote their domestic economies and provide government revenue. For Angola we investigate options for reserves varying between 13 and 25 Tcf, for Mozambique we consider reserve estimates between 97 and 192 Tcf. We have evaluated eight different large industries, and assessed their economic viability under three price forecasts. The results of our netback analysis are given in the chart below.



**Figure 1. Netback analysis for industry options**

Based on the netback and further analysis of the eight industries we conclude the first phase should involve a combination of the following three industries: LNG, Power plants, and Urea (fertilizer). Power plants and Urea have the greatest impact on domestic small and medium enterprise development, while LNG serves as anchor project to develop required infrastructure.

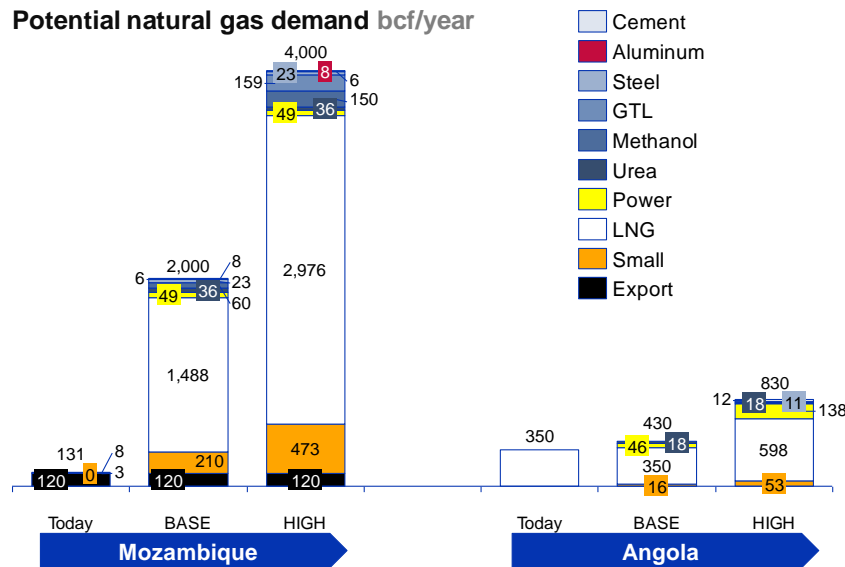
- LNG is an important anchor project, but it is not the best use of country resources to spur domestic development. Still it is a necessary component of the development because it provides significant revenue while building up a skills base to do more complicated projects. The high economic returns available from serving global LNG demand justify the significant investment in gas infrastructure required to develop the resources and bring them to market.
- Power plants should be developed as often as needed to stabilize the grid and grow demand as new hydroelectric facilities are built in parallel. The primary dependence on hydro power limits gas used for electric power and the resulting revenues, but makes gas available for other uses. If hydroelectric facilities are slow to develop, additional gas power plants can be built to ensure a reliable electric supply.
- Urea is an important project to develop both Mozambique and Angola domestic economies, and Mozambique is in a clear position to create great value by building a urea plant. There is significant urea demand in the SADC region which Mozambique is well positioned to serve. Based on this regional demand and the corresponding local prices, we see a netback value in the neighborhood of LNG and power. We do not recommend building urea plants in this region for global export as the corresponding netback value is very low or even negative.

For the second phase we propose additional units of the three industries mentioned above in combination with Methanol, Gas-to-Liquids, Steel, and Cement production facilities.

- Methanol does not compete with LNG in terms of the netback analysis, but we see opportunity for the country from a diversification perspective. As there is presently a lack of local expertise for this industry, we recommend it to start up at least three years after first LNG. As it is vulnerable on global markets in the near term with large oversupply we would recommend vertical integration, so the buyer of methanol takes a stake in the gas production, or agrees to long term supply contracts from the producer to ensure security of future revenue. It is also encouraged to develop local beneficial uses for methanol, which could include its use as an energy carrier.
- Gas-to-Liquids (GTL) is the most complicated facility that requires a deep base of local expertise to be built economically. We only recommend GTL in a high case scenario for Mozambique.
- Steel production should be considered in Mozambique if ore reserves prove economical as expected. The netback value was not as high as LNG and the global market is oversupplied, but steel is an important industry that allows a lot of expansion in the manufacturing and construction sectors. Natural Gas is competing with coal to be the most economical fuel, so on this basis natural gas may not be needed. A decision in Angola can be deferred until economical iron resources are validated.
- Cement, like steel production, can readily utilize coal resources that are available in Mozambique and to a lesser extent in Angola via regional trade. From a netback perspective cement is not that promising. However, from an environmental perspective gas use in cement production is preferred above coal. This environmental perspective was the background for the fuel switch in 2008 for the cement factory in Mozambique.

From a netback perspective we see no ground for gas use in aluminum production. As hydro sources are available in the region generally aluminum smelters will be delivered with hydro generated power. As shown in the industry section the gas use in aluminum production is only substantial if the electricity used is generated by gas. Implicitly this gas use is already been taken into account when describing the Power generation.

A potential outlook of a gas based industry in both countries is provided in the chart below:



**Figure 2. Future natural gas demand by sector and scenario**

To enable the gas based industry as shown above our most important recommendations are:

- Stable and transparent regulation is key to any economic development. It provides confidence to investors and reduces investment risks.
- The planning of gas transport infrastructure co-jointly with the planning of gas-fired power generation (and large gas-using projects in general) is of major importance to Angola and Mozambique.
- The declared exclusive state property rights for dry natural gas in Angola seem a major barrier for IOCs to invest in gas exploration and development in the country. We recommend abolishing these exclusive state property rights.
- A constructive industrial development plan for natural gas in Mozambique is key, given the huge gas reserve base. A clear coordinated approach, which has been shown by the Qataris, may help to develop integrated large-scale projects linked to LNG exports and downstream industries that use natural gas as a feedstock. The government of Qatar has clearly prioritized domestic projects enabling to serve industry e.g. in terms of providing input for large plants such as fertilizer, GTL and methanol.
- LNG is a global market and new projects are being considered all around the world. Angola and especially Mozambique should bear in mind that this industry may show a boom-and-bust investment cycle. We have clear indication that traditional oil indexation will not hold in future. Innovative pricing and other terms and conditions may help to serve as well the producer with a reasonable return, the governments with reasonable tax income and the buyer with affordable prices in their market.

# 1 Introduction

A brief review of the Southern African Development Community (SADC), Angola, and Mozambique are provided for basic context to the remaining report which evaluates the opportunities to use natural gas to encourage domestic economic growth and generate government revenue. We begin with some background, followed by an overview of key economic indicators, demographics, and energy use trends. Regional aspects within the countries are also touched upon.

## 1.1 Southern African Development Community (SADC)

The Southern African Development Community (SADC), founded in 1992, is an inter-governmental organization that aims to achieve socio-economic development through an increased regional integration among its 15 Member States.<sup>1</sup> The 15 countries of the SADC comprise an area of 9,882,959 km<sup>2</sup> with 277 million inhabitants. In 2009, the average life expectancy was 55.1 years.<sup>1</sup>



**Figure 3. Members of the SADC<sup>1</sup>**

### 1.1.1 Economics

In 2010, the aggregated GDP of the SADC 15 countries was \$575.5 billion where services contributed 51%, industry 32%, and agriculture 17%. Total imports and exports were \$91.6 and \$89.2 billion respectively. From 2000 to 2011, the average annual GDP growth rate was 4.25%.

Petroleum and agricultural products, electricity and some clothing and textiles are the main products traded within the SADC. The primary exports to the rest of the world are natural resources (coal, ferrochromium, manganese ores, platinum, precious metals, and diamonds), resource intensive goods (mainly for the automotive industry), clothing, textiles and tobacco. From 2000 to 2010, 45% of exports went to the Asia-Pacific, 27% to the EU, and 15% to the Americas, while 10% stayed within the SADC and 3% went to the rest of Africa.

<sup>1</sup>Member States are: Angola, Botswana, Democratic Republic of Congo, Lesotho, Madagascar, Malawi, Mauritius, Mozambique, Namibia, Seychelles, South Africa, Swaziland, Tanzania, Zambia and Zimbabwe

### 1.1.2 Current Energy and Gas Use

The SADC faces challenges related to energy provision and use with a Regional Infrastructure Development Master Plan highlighting the following primary issues:<sup>2</sup>

- Only 5% of rural areas have access to electricity
- SADC lags other Regional Economic Communities in Africa with only 24% of the region's residents having access to electricity
- Low tariffs, poor project preparation, issues with Power Purchase Agreements, and absent regulatory frameworks hinder investments in the energy sector
- Weak infrastructure inhibits regional utilization of abundant petroleum and natural gas resources, and also limits export opportunities
- Financial and infrastructural hurdles constrain the region's renewable energy potential

In 2009 the energy consumption of 10 countries in SADC amounted to 230,179 ktoe of which 63% were consumed by South Africa. The average per capita energy use was 0.784 toe whereas the per capita consumption in South Africa equaled 2.756 toe followed by Botswana with a per capita consumption of 1.102 toe.

Electricity demand in the SADC region is largely met by coal, followed by hydro, nuclear and diesel generation. Wind and solar energy projects are being developed but contribute only small fractions to meeting demand. Electricity access is low with an electrification rate of 24%.

The SADC region is a net importer of petroleum products. Angola and Mozambique have the largest oil and gas reserves of the community respectively. However, the region is a net exporter of coal with South Africa, Botswana, Swaziland and Mozambique having large coal reserves. Besides exporting coal, it is domestically used for power generation.

Traditional biomass provides ~37% of the SADC energy mix and is the most important renewable energy source. Hydropower provides 2% of renewable energy and modern biomass 0.4%. Although the potential of further renewable sources (e.g. wind, solar PV, geothermal energy) is large in the region, they are hardly deployed.

## 1.2 Angola

Angola is a presidential republic located in the Southwest of Africa with an area of 1,247,000 km<sup>2</sup>. It became independent from Portugal in 1975. Soon after independence, a civil war started that lasted until 2002. The country consists of 18 provinces, one of them being the capital Luanda. The official language is Portuguese but native languages include Umbundu, Kimbundu and Kikongo.

### 1.2.1 Economics

In 2011, Angola's nominal GDP was \$104.3 billion.<sup>3</sup> Accordingly, this corresponded to a nominal per capita GDP of \$5,320. Angola shows high annual GDP growth rates averaging 12.6% between 2001 and 2011 due to low starting level and large natural resource exports.

The industrial sector contributes most to the GDP with a share of 62.1% in 2011. The service sector's GDP share amounts to 28.6%, and agricultural provides for 9.3% of the total Angolan GDP. Out of the

62% industry's GDP share, the oil and gas industry contributed 46.6%, followed by the construction sector (7.9%) and manufacturing (6.5%).<sup>4</sup>

Between 2001 and 2011 exports and imports rose at average annual growth rates of 7.5% and 20.7% respectively with the total export and import volumes reaching \$67.7 and \$45.1 billion by 2011. The main export commodities are crude oil, diamonds, refined petrochemical products, coffee, sisal, fish, timber, and cotton. The main import commodities are machinery and electrical equipment, vehicles and spare parts, medicines, food, textiles, and military goods. The country's largest trading partners are China (36% of exports and imports), the US, Portugal, South Korea, and the Netherlands.<sup>5</sup>

### 1.2.2 Demographics

At the end of 2011 a population of ~20 million lived in Angola with an annual growth rate of 2.9% from 2005-2011. 43.5% of the population is aged 0-14 years, 20.3% 15-24 years, 29.2% 25-54, 4% aged 55-64, and 2.9% of the population is 65 or older. The current life expectancy is 51 years. The largest religion is Christianity (~53%), followed by traditional religions (47%).<sup>5</sup> In 2011, 59% lived in cities, 40.5% of the population lived below the national poverty line, 51% of the population had access to improved water, and 70% of the population above 15 years is literate.<sup>6</sup>

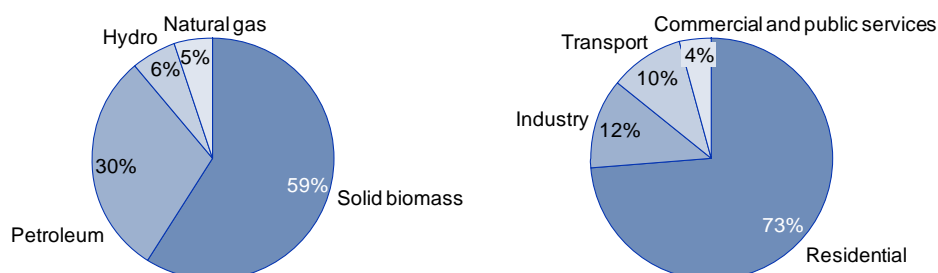
### 1.2.3 Current Energy and Gas Use

The average consumption of oil products in 2011 was 88,000 barrels per day, while production was 1,840,000 bbl/day. Thus, 1,752,000 barrels were exported daily, and national demand corresponded to a mere 5% of domestic production. Angola has large domestic reserves of crude oil, which are mainly exported to China and the US. Natural gas production is small relative to its potential, with 27 billion cubic feet of oil-associated natural gas being consumed by the industrial sector.

The main source of energy for the residential sector is traditional biomass with domestic heating and cooking needs generally being met through fuel wood and charcoal. Hydroelectric facilities generate more than two-thirds of Angola's electricity, but diesel generators are the main source of electricity in the north of the country. 1.16 GW of installed power capacity generated 5.1 TWh of electricity, of which 4.6 TWh were consumed domestically.<sup>7</sup>

In 2011, almost 60% of the primary energy use was solid biomass, followed by petroleum (30%). The remainder is natural gas and hydroelectricity. From a sectorial perspective, residential energy consumption dominates (73%), followed by industry (12%), the transport sector (10%), and the service sector (4%). The following illustrates energy consumption per energy carrier and sector.

**Angola primary energy consumption 2011 % by source and sector**



**Figure 4. Energy consumption per energy carrier in 2011 (left) and sector (right) in Angola<sup>8</sup>**

Angola is in critical need for additional infrastructures, most notably for electricity supply which regularly fails every other day for several hours. Accordingly, most industries and residential houses rely on their own diesel generators thanks in part to diesel and gasoline being highly subsidized. The subsidy for diesel and gasoline amounts to \$0.40 and \$0.60 per liter respectively.

In 2012, the total value of subsidizing fossil fuels was \$6 billion. Sonangol, the Angolan State oil company, subsidies were included in the national budget for the first time in 2012 which resulted in an Angolan state budget deficit. The President of Sonangol has made a reference to the “termination of subsidies in the future” as it is considered critical for the development of natural gas and gas-based industry. Subsidy termination is expected to raise prices by a factor of three.

With respect to electricity and water supply it is worth to note that most residences do not have meters and therefore do not pay for electricity or water. Accordingly, there is a culture of “not paying” for such services among the population and some companies. In turn, the electricity companies (EDEL for Luanda and EDA for the rest of the country) face revenue issues.

## 1.3 Mozambique

Mozambique is a presidential republic with an area of almost 802,000 km<sup>2</sup>. It became independent from Portugal in 1975, and soon after independence, a civil war broke out that lasted until 1992. The country consists of 11 provinces, one being the capital Maputo. The official language is Portuguese but native languages include Swahili, Makhuwa and Sena.

### 1.3.1 Economics

In 2011, Mozambique’s nominal GDP was \$12.8 billion, corresponding to a nominal per capita GDP of \$536.<sup>9</sup> It is one of the poorest countries in SADC and has low development indices. Mozambique shows high annual GDP growth rates in the last years with an average of 7.2% between 2001 and 2011 due to its low starting level and its large natural resource endowment.

The agricultural sector employs the majority of the population (~80%) and represents the second largest economic sector with a share of ~30% of the country’s GDP in 2011. The service sector is the largest GDP contributor (47% in 2011), and 23% of the country’s GDP arise in the industrial sector. Manufacturing represents the majority of the industrial sector with 58% of its GDP contribution. Due to its wealth of natural fossil and mineral resources (e.g. coal, gas, titanium, bauxite), the petroleum, chemicals, and metals industrial sectors are growing particularly fast.

Between 2001 and 2011 exports and imports rose at an average annual growth rate of 8.7% and 7.6% respectively. In 2011, the total exports amounted to \$2,656 million, whereas imports amounted to \$4,465 million. The main export commodities are aluminum, prawns, cashews, cotton, sugar, citrus, timber, and electricity. The main import commodities are machinery and equipment, vehicles, fuel, chemicals, metal products, foodstuffs, and textiles. The country’s largest trading partners are South Africa (28.9% of exports, 35.4% of imports), Portugal, Spain, Italy, China and Belgium.<sup>10</sup> Economic reforms led to the privatization of small formerly state-owned enterprises and the gradual liberalization of infrastructure services (i.e. telecom, energy, railways, ports) is anticipated.



### 1.3.2 Demographics

At the end of 2011 a population of ~24 million lived in Mozambique with average annual growth rates of 2.4% in the years 2005-2011. 46% of the population is aged 0-14 years, 21% 15-24 years, 27% 25-54%, and 3.5% aged 55-64, and 2.9% of the population is 65 or older.<sup>10</sup> Current life expectancy is 50 years. The largest religion is Christianity (~56%), followed by Muslims (~18%), and traditional religions (~7%). Two north-central provinces contain 45% of the total population. In 2011, 55% of the population lived below the national poverty line, 31% lived in cities, 47% of the population had access to improved water, and 56% of the population above 15 years was literate.<sup>11</sup>

### 1.3.3 Current Energy and Gas Use

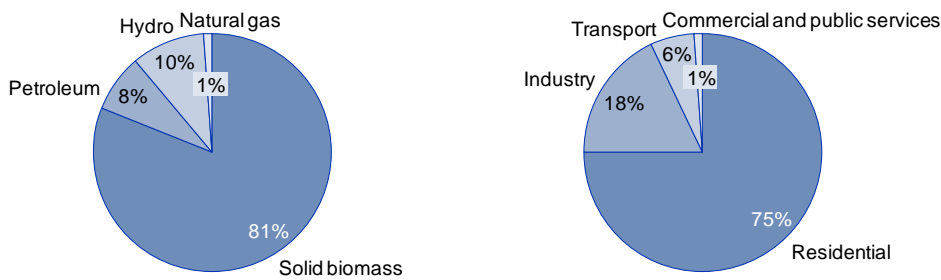
Besides biomass, the second largest source of primary energy production is natural gas. The country is rich in forest resources, with a total forest area of approximately 40.6 million hectares and 14.7 million hectares of other wooded areas. The annual deforestation rate is estimated at about 219,000 hectares per year, equivalent to a change of 0.58% annually.<sup>12</sup> According to the national forest inventory, the main cause of deforestation in the country is human pressure from burning forests to open cultivation areas, firewood collection, and charcoal production.

The average consumption of petroleum products in 2011 was 17,000 barrels per day with almost all of this being imported (16,980 bbl/day). Part of the imported petroleum derived products could be replaced by natural gas and biofuels produced locally. Around 110 Bcf of gas was produced, of which ~11 Bcf is consumed in Mozambique and ~100 Bcf is exported to South Africa. The facilities from the Pande and Temane natural gas reservoirs are most relevant.

Mozambique has vast deposits of mineral coal. With the start of large scale coal production and export of coking coal in 2011, the remaining steam coal has become an important contributor to the power sector and industrial sectors, by making electricity supply more affordable and reliable. 36 and 42 thousand ton of coal were consumed and produced yielding exports of 6 thousand tons. 2.43 GW of installed power capacity generated 16.5 TWh of electricity with 10.2 TWh consumed domestically and the remainder exported. Thus, power demand was 62% of domestic generation.<sup>13</sup>

In 2011, biomass (wood, charcoal, animal and other waste) accounted for 81% of the total energy consumption and 90% of the residential sector demand. Electricity provides for 10% of energy needs, but 80% of it went to the industrial sector. Oil products and gas account for 8% and 1% of total energy consumption with 75% of oil being consumed in the transport sector, and 73% of gas being consumed in the industrial sector. From a sectorial perspective, residential energy consumption dominates (75%), followed by industry (18%), the transport sector (6%), and the service sector (1%). The following illustrates the energy consumption per energy carrier and sector.<sup>14</sup>

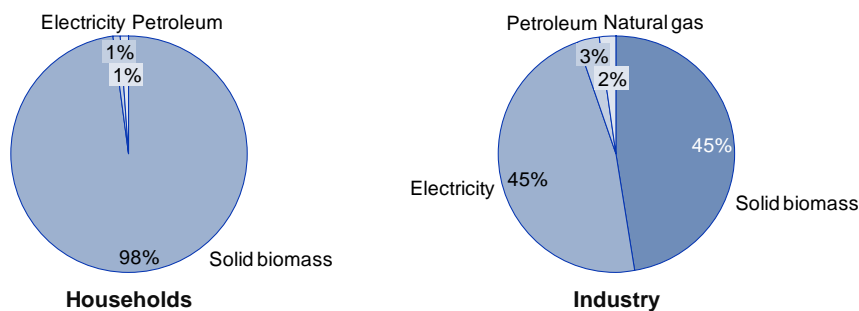
**Mozambique primary energy consumption 2011 % by source and sector**



**Figure 5. Main energy carriers and sectorial consumption in Mozambique 2011<sup>15</sup>**

Biomass provides ~98% of household energy needs. The industrial sector had a similar energy mix until commissioning of the Mozal aluminum smelter caused the power consumption of industry to rise sharply. Now electricity and biomass provide ~45% of industrial energy needs each. Mozal consumes ~84% (7,884 GWh) of Mozambique’s total electricity consumption and 39% (1.1 Bcf) of the Matola Gas Company’s total piped gas, meaning it has driven Mozambique’s demand for gas and electricity. The following figure shows the final energy mix of the household and industrial sectors.

**Mozambique energy consumption 2007 % by household and industry**



**Figure 6. Final energy carrier mix of households (left) and industry (right) in Mozambique**

Mozambique has a vast potential for renewable electricity and fuel production. The country has the second largest coastline in Africa with unexplored wind resources, large solar power potential across the entire country, and significant undeveloped biomass resources. The potential for mini-hydro exceeds 1,000 MW, with much of this potential in areas that are currently lacking electricity.

Since 2005, gas has substituted for heavy fuel oil (predominately in industry) to drive gas demand from 0.8 to 11.3 Bcf/yr over 2005-2011. Gas fired power started in 1998 with consumption growing to 8.4 Bcf/yr by 2011, while the other sectors add up to 2.9 Bcf/yr. The following table shows the domestic gas consumption in 2010.

Segment	Note	Bcf/yr	Share
<b>Power</b>	Consumption in 2011	8.4	74%
<b>Cement and clinker factory</b>	Cimentos de Mocambique	1.46	13%
<b>Aluminum production</b>	Mozal	1.14	10%
<b>Other industry</b>	Piped gas	0.21	2%
<b>Other industry</b>	CNG	0.08	1%
<b>Commercials / residentials</b>		0.02	~0%
<b>Total Demand</b>		11.3	100%

**Table 1. Gas consumption in Mozambique 2010<sup>16</sup>**

Recently, several industry requests for gas supply were filed by project developers in the domain of gas-to-liquids, methanol, fertilizer and power generation to predominately serve export markets.<sup>17</sup> These industries are discussed in the specific industry sections.

## 1.4 Outlook

In line with historic trends, Mozambique and Angola population, GDP and energy use are expected to grow significantly. The following table summarizes the main corresponding indicators.

Metric	2010-2023 annual growth in%		
	Mozambique	Angola	SADC
Population	2.44%	2.75%	~2.5%
GDP (real)	7.5%	8%	5%
Total energy demand	3%	~4%	~2%
Electricity demand: volume	10% <sup>ii</sup>	15%	3.9%
Electricity demand: capacity	6.5% <sup>iii</sup>	9%	4.6%

**Table 2. Expected yearly growth rates for population, GDP and energy use**<sup>18,19,20,21,22,23</sup>

The demographic and economic outlook for Mozambique and Angola is rather similar and also in line with regional trends as forecasted for the whole SADC region. Forecast differences exist for electricity demand and peak load in Angola and Mozambique, which partly is due to different historic electricity demand levels. Moreover, regional growth rates for both annual and peak electricity demand are significantly lower which results from the uneven initial position with South Africa being both a big economy and having relatively high per-capita consumption already today.

<sup>ii</sup> Excl. Mozal

<sup>iii</sup> Organic growth, excl. large energy projects

## 2 Gas Reserves and Production

### 2.1 South African Development Community (SADC)

The SADC countries' gas reserves, production and relevant remarks are inventoried below. In the SADC region only 6 countries have proven gas reserves with Namibia being the only one of these with no gas production. The following shows the proven and probable natural gas reserves, and current production for SADC countries. The remaining SADC countries Lesotho, Madagascar, Malawi, Mauritius, Seychelles, Swaziland, and Zambia have no known reserves.

Country	Proven reserve (Tcf)	Prob. reserve (Tcf)	Production (Bcf/yr)	Remarks
Angola	1.6	13	350	See section in this chapter.
Botswana	0	15	-	Coal bed methane is mentioned (up to 15 Tcf) but no plans for exploration.
D.R. Congo	35	35	0.3	Despite the considerable gas reserves, exploration & exploitation are not planned though oil production and exports flourish. Small amount of gas are used for electricity generation.
Mozambique	97	192	162	See section this chapter.
Namibia	2.2	2.2	-	Exploitation not yet proven to be economically feasible (Kudu field is 170 km offshore).
South Africa	~2	15 (+485 shale)	45 (Mossel Bay)	100 to 120 Bcf/yr imported from Mozambique for industrial use; ~25 Bcf/yr expansion from end 2012.
Tanzania	22	67	30	Gas production will probably develop similar to neighboring Mozambique.
Zimbabwe	0	0	-	Possibly coal bed methane deposits.

**Table 3. Overview of gas resources in SADC region<sup>24</sup>**

#### 2.1.1 South Africa

Gas is imported since 2004 from Mozambique's Pande and Temane fields through a 865 km 26" pipeline (operating at about 50% max capacity of 212 Bcf/yr) to supply industries in the north of South Africa at Secunda. Here, Sasol operates chemical and Coal-to-Liquid (CTL) plants which use coal as the main material input, but rely on gas for energy needs. Further gas is distributed to industries in the Johannesburg and Durban area. The Temane field processing facility capacity in Mozambique was expanded in 2012 to support ~25 Bcf/yr more imports to South Africa.<sup>25</sup>

Offshore gas is produced in the very south (Mossel Bay area). Remaining reserves in this area are small, in the order of 0.7 Tcf. The gas is converted in Gas-to-Liquid (GTL) facilities. A few other fields have been discovered that most likely will continue the supply to the Mossel Bay GTL plant in future (F-O field, project Ikhwezi, reserves ~1 Tcf proved and 7 Tcf probable).<sup>26</sup> Between Cape Town and Alexander Bay on the west coast there are potential resources offshore which might be developed to fuel a 750 MW<sub>e</sub> CCGT power plant (Ibhuesi; 201 Bcf proved, 869 Bcf probable, 8 Tcf potential).<sup>27</sup>

High volumes of recoverable shale gas (485 Tcf) are expected in the large Karoo basin; exploration is about to start but there are concerns over water usage and discharging.<sup>28</sup> Given the success of shale

gas exploration in the US, and transfer of this experience to companies in South Africa, the delivery of shale gas volumes in a few years from now is not unrealistic, however volumes are expected to be low in the next decade.

South Africa is energy constrained, and gas reserves will most likely be used in the country itself and not exported. There is also a drive to lower carbon dioxide emissions and gas is an opportunity to reduce the use of coal. Therefore South Africa is not envisaged to become a competitor for Angolan and Mozambique gas exports before 2025.

### **2.1.2 Tanzania**

A few small fields are producing on- and offshore Songo Island. Approximately 30 Bcf/yr is piped to Dar es Salaam (200 km) for electricity generation and a cement factory since 2004. Directly adjacent to the Mozambique offshore blocks are the Tanzanian discoveries, of which BG – Ophir has reported 13.3 Tcf and Tanzania Petroleum Development Corporation, Statoil and ExxonMobil discovered 8.9 Tcf.<sup>29</sup>

Wentworth Resources, active in the Mnazi Bay south of Mtwara and close to the Mozambique offshore blocks, reports 1.4 Tcf proved with upside to 2.6 Tcf probable finds (on and offshore).<sup>30</sup> Gas was discovered in 1982, but not feasible to develop at that time. Work restarted in 2006 with seismic and successful drilling in 2009. Gas is already supplied to the city of Mtwara, and there are plans for a 300 MW<sub>e</sub> gas fired power plant (presumably in execution) at Mnazi Bay and for a petrochemicals project (methanol, fertilizer – ammonia/urea). Gas finds are not too remote from the capital Dar es Salaam (appr. 500 km) to be transported by pipeline and construction of a 532 km 36” line started in November 2012 (with Chinese capital).

USGS expects 37.5 Tcf proved to 67.6 Tcf probable present which means that over time, when more drilling and discoveries are made, considerable reserves will be found to legitimize investment in LNG or other conversions to exportable products.<sup>31</sup> BG Tanzania disclosed in May 2013 plans for a two-train LNG facility following successful drilling; it also mentions that their gross recoverable reserves stand close to 10 Tcf.<sup>32</sup> We expect cooperation to occur with Mozambique LNG production as the Anadarko and ENI operated areas in north Mozambique deep waters are close by.

### **2.1.3 Kenya (adjacent to SADC)**

The explored offshore basin in East Africa stretches from Mozambique north to Tanzania and Kenya. Seismic suggests oil and gas prospects up to 3.96 billion barrels and 10.7 Tcf respectively in the L6 block currently being investigated off of Kenya.<sup>33</sup>

### **2.1.4 Republic of the Congo (adjacent to SADC)**

North of the Democratic Republic of the Congo, the Republic of the Congo also holds onshore and offshore oil and gas deposits. 334 Bcf/yr of oil-associated gas is now produced, but 68% is re-injected for oil production, 17% is flared and only 41 Bcf/yr finds a way to consumers.<sup>34</sup> Two power stations of 300 and 50 MW<sub>e</sub> have been constructed (with an interest of oil company Eni) to reduce flaring and provide electricity.<sup>35</sup> Gas reserves are assumed to be 3.2 Tcf.<sup>36</sup> Congo and Angola share revenues from the Lianzi oil field which is situated offshore on the maritime border between the two countries.

## 2.2 Angola

### 2.2.1 Discoveries and Natural Gas Reserves

Geology has favored blocks in the north of the country where the biggest reserves fan out from the mouth of the Congo River due to the deposit of large quantities of vegetable material which became oil. An example is Block Zero that lies off Cabinda. The concession map below shows this area, and the blocks of current interest beyond the range of existing discoveries.

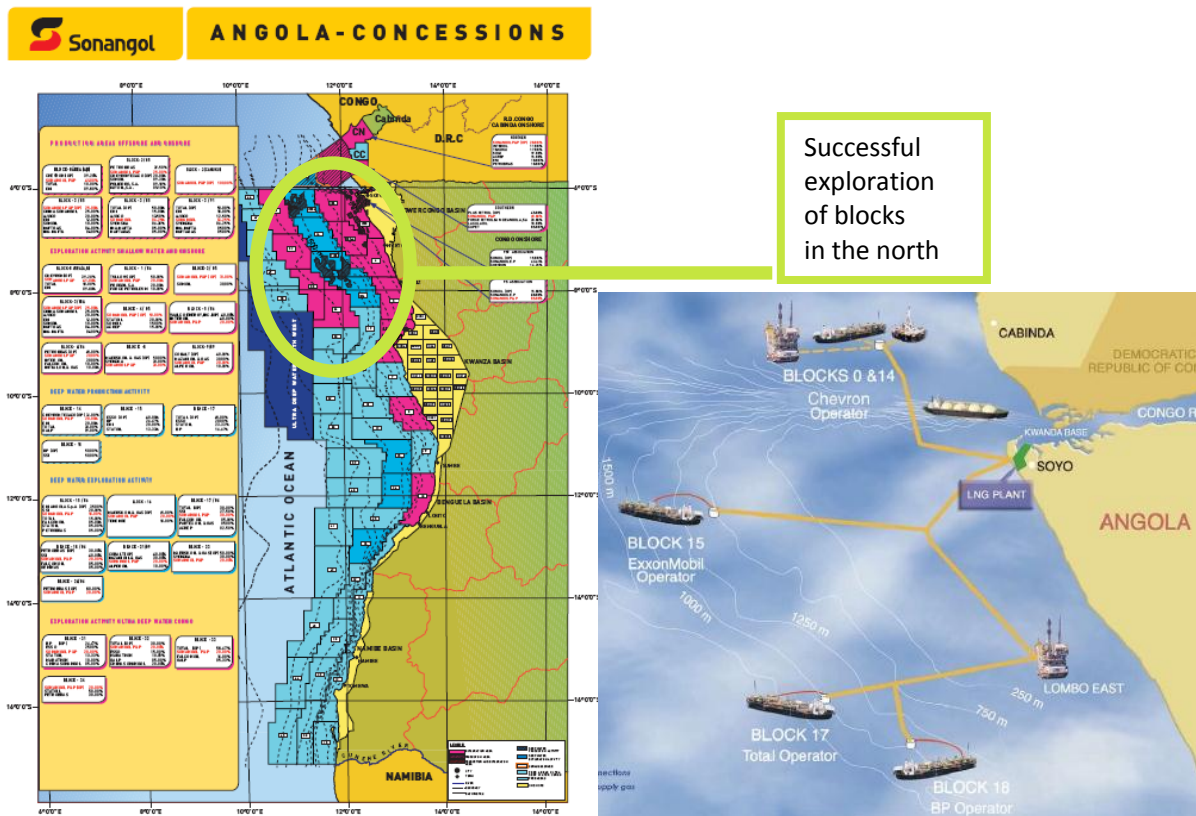


Figure 7. Current production area offshore Angola

The southern coastal region of Angola remains unexplored after the failure of blocks 09, 21, 22 and 25 located offshore of southern Luanda. Drilling has also been unsuccessful off the coast of Namibia, Angola's southern neighbor, which has further discouraged exploration.<sup>37</sup> Nevertheless, geologists in Sonangol advocate a comprehensive survey of blocks in the Namibe basin.

Most oil fields produce gas in association with oil. The IEA reported that the Ministry of Petroleum puts proved plus probable reserves at 10 Tcf, with another 26 Tcf possible; while the EIA assumes proved reserves at 1.6 Tcf with another 9.5-25 Tcf possible. Only two small gas-only fields have been discovered (offshore in blocks 1 and 2, close to Soyo).<sup>38</sup> Total proven plus probable gas reserves for offshore blocks south of the Congo River are estimated to be 8.8 Tcf.<sup>39</sup> The US Energy Information Administration (EIA) mentions in January 2013 that proved reserves are 12.9 Tcf,<sup>40</sup> which is consistent with the information from OPEC (2013).<sup>41 42 43</sup>

Sonangol states 11 Tcf of proved and probable reserves in 2013 with the remark that the lack of more accurate knowledge of natural gas reserves is due to the absence of dedicated investment and non-existence of a legal and contractual framework to promote the exploration and development of

natural gas. Discovered non-associated gas wells are abandoned by the blocks contractor groups due to lack of incentives for development. Sonagas, the gas branch of Sonangol, has the intention to review seismic and associated data to obtain a better picture of the gas resources.<sup>44</sup>

Summarizing: current knowledge of gas reserves is: 1.6 Tcf proved (1P); 13 Tcf proved + probable (2P); with an upside of ~25 Tcf possible (3P). There is a lack of information on dry gas fields.

### 2.2.2 Oil & Gas Production and Gas Flaring

Gross natural gas production was ~357 Bcf in 2010. Of this, 244 Bcf (68%) was vented or flared, 81 Bcf (23%) was re-injected to aid in oil recovery, and only 24 Bcf (7%) was marketed for domestic consumption. The World Bank estimates flared volumes from Satellite Data for Angola to be: 124 Bcf/yr (2007- 2008); 120 Bcf/yr (2009), and 145 Bcf/yr (2010-2011). This suggests ~100 Bcf was vented in 2011. Approximately 70-80% of oil-associated gas was flared in the past years.

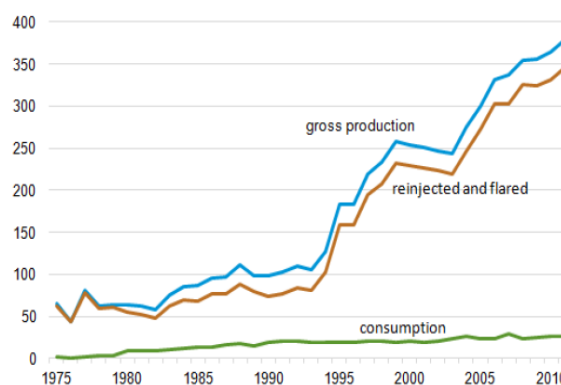


Figure 8. Natural gas flows (Bcf/year)<sup>45</sup>

Flaring occurs because gas production is offshore, transport to the beach is expensive, and there is no domestic gas industry. The driving force not to flare or vent comes from national regulation, and apart from re-injection, the only option is to monetize the gas to recover resulting costs.

By regulation, all new fields must be zero flaring and routine flaring should cease at existing fields by 2010, though this has not been achieved. Flaring reduction plans have focused on re-injection and the LNG export plant in Soyo. Oil companies do not own the gas they produce as their concessions mean all gas not used by the oil companies in their own operations belongs to Sonangol.

After a peak of 2 mln bbl/day in 2009, oil production slipped due to maintenance and decline of older fields. Currently 1.8 million bbl/day is produced, but new fields coming on line by 2013 and 2014 should restore the targeted 2 million bbl/day level.<sup>46</sup> Associated gas from oil production is expected to reach 424 Bcf/yr. Forecasts of dry gas production are not available.

### 2.2.3 Current Infrastructure and Use

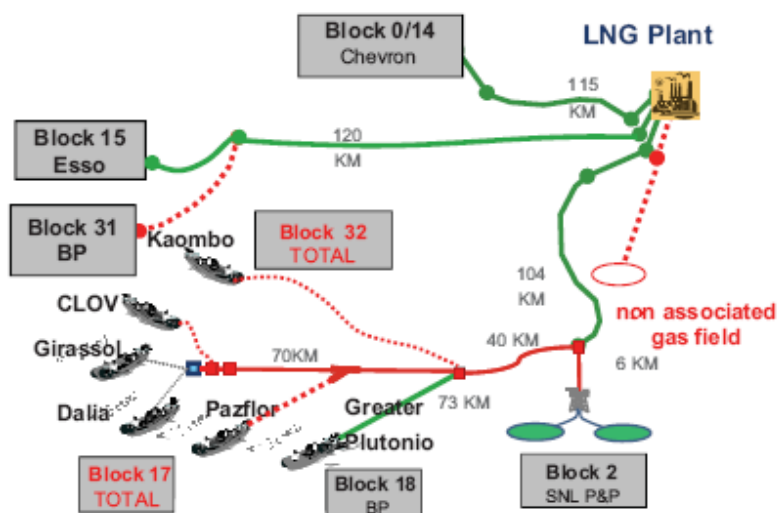
Volumes that are vented and flared have been subject of study and already since the late 1990's the Angola LNG project (ANLG) was proposed. Finally this is realized with the LNG liquefaction unit near Soyo, which is south of the Congo River. The Soyo plant has a capacity of 5.2 million ton per year (MTPA), 360,000 cubic meters of LNG storage, and a loading jetty sized to accommodate ships up to 210,000 cubic meter along with LPG and condensate storage.<sup>47</sup> First LNG was expected in earlier 2012 but due to delays, amongst others technical problems such as fire in the installation, the start-up has been in June 2013.

Soyo will require up to ~274 Bcf/yr of natural gas supply to deliver ~240 Bcf/yr of re-gasified natural gas. The project plans to receive up to 1.1 Bcf/day of associated gas from offshore oil fields and will process 125 Mcf/day for Angola’s domestic needs and produce 63,000 barrels per day of natural gas liquids. 21 Bcf/year will be used for processing. The accumulated supply required is ~350 Bcf/yr.

Gas resources from reserves, lying in water depths of up to 1,500 m have been designated for the project. These come from blocks 0 and 14 (Chevron), 15 (ExxonMobil), 17 (Total) and 18 (BP), along with future ultra-deep water blocks and previously discovered non-associated gas fields in blocks 1 and 2. It is anticipated that non-associated gas from previously discovered gas fields will ultimately feed the plant, as oilfields mature and associated gas production declines.

Angola LNG Limited awarded a contract for advance engineering and procurement and construction to Bechtel, and a contract for preparation of the plant site in Soyo to the joint venture of Boskalis International BV – Jan de Nul Dredging Ltd. A joint venture of JGC Corporation, KBR and Technip was awarded the front-end engineering design contract for the facility in 2005. In December 2007, the final investment decision was made after years of planning.

Sonagas and Chevron are the co-leaders of the Project with 22.8% and, 36.4% interest respectively while ENI, BP and Total each have 13.6% stakes. Investment is estimated at \$4 billion for the plant, though literature mentions \$9-10 billion for the entire project including the subsea pipelines and other processing facilities. Most associated gas is produced north of the Congo River in blocks 0/14. Constructing a pipeline across the Congo Trench was assumed technically difficult and costly, but preparation for the 115 km pipeline with a capacity 0.25 Bcf/day (~25% of the feed required for the LNG plant) started in 2011. The image below shows illustrates the LNG project gas feeds.



**Figure 9. Gas feeds to Soyo LNG terminal and projected dry gas feed<sup>48</sup>**

Initially conceived to supply the US market, Angola LNG shifted its strategy after the development of shale gas reserves in North America. Angola LNG Marketing was set up to commercialize the resource and enter worldwide markets, particularly in Europe and Asia, with aim to sell on a spot basis. The company also made arrangements to have access to a fleet of seven LNG tankers, each with a 160,000-cubic-metre storage capacity, to ship the LNG abroad. The first cargo from Angola LNG left in June 2013 towards Brazil.



## 2.2.4 Conclusions

All sources report recoverable gas reserves at ~13 Tcf. Only the northern geological basin has been thoroughly surveyed and oil and associated gas is produced in that area. Possibilities in the southern part of the coastal region are very uncertain and until today no discoveries have been made there.

With gas use of ~350 Bcf/yr, the Soyo LNG plant will consume most of the gas available from oil production, and with a project lifespan of 25-30 years, a considerable part (~10 Tcf) of the 13 Tcf proved and probable reserves are bound. Reinjection enhances the oil production and it may not be feasible, from an economic or reservoir technical viewpoint, to make this ~80 Bcf/yr volume available for sale. Thus there is uncertainty over the amount of natural gas available for other industries.

The bulk reserves are associated gas since despite dry gas fields being discovered, their reserves are not published due to a lack of developer incentives since found gas directly belongs to the state. When a regulatory framework is in place to encourage international oil companies (IOCs) to search for and report dry gas, we expect dry gas finds to be reported, and reserve estimates to rise.

From this background we assume 25 Tcf as potential reserve to assess the feasibility of a gas based industry in Angola. For additional gas use on top of ALNG this would mean a reserve base of around 15 Tcf, which – given a production period of 30 years – yields a volume potential of additional 500 Bcf/yr. However the majority of the fields have not been located yet and therefore the presence of this gas, its character (associated or non-associated) and production profile are no basis for additional investments in e.g. a second LNG train, industries or enhancing the domestic consumption.

As gas production comes from oil production, there is limited control over gas supply. Appropriate use of the gas usually requires some flexibility in production capacity. For gas to be applied to users with a continuous off take such as large industries and base load power plants, flexibility is required from a pure gas facility such as the LNG liquefaction plant equipped with sufficient storage volume.

With no major increase in oil production expected, gas production will remain at the current level unless non-associated gas is developed separately. Available gas volume and capacity for LNG and other industries may be limited by this reality. We currently envisage that non-associated gas will only be developed if necessary to keep the LNG facility supplied with sufficient volume.

Governmental regulation and incentives could encourage oil companies to develop gas resources for export sales. Alternatively the state oil company could take the lead in developing of non-associated gas fields with technical support from international oil companies, and the state oil company bearing the (financial) risk. Field development must go hand-in-hand with development of sales propositions, e.g. additional LNG, power plants, domestic gas use.

## 2.3 Mozambique

### 2.3.1 Natural Gas Reserves

Gas exploration and exploitation started in the south of Mozambique with the discovery of the Pande and Temane gas fields. Pande (proved 2.3 Tcf; probable 3.6 Tcf; already produced 0.46 Tcf) was discovered in 1961, Temane (proved 1 Tcf, proved + probable 1.5 Tcf; already produced 0.2 Tcf) in 1967. Another field, Buzi, was too small to be feasibly exploited (0.2 Tcf). In 1998 SASOL of South Africa proposed to transport the gas to their petrochemical plants in Secunda (near Johannesburg). A pipeline (865 km, 26 inch, capacity 212 Bcf/yr or half of that without compression) was laid and SASOL started operating these fields in 2004, and produced ~120 Bcf/yr. In 2012 the Temane processing plant was expanded from 106 to 162 Bcf/yr and this gas is around 50/50 allocated to South Africa and the domestic market (natural gas condensates are also produced).<sup>49</sup>

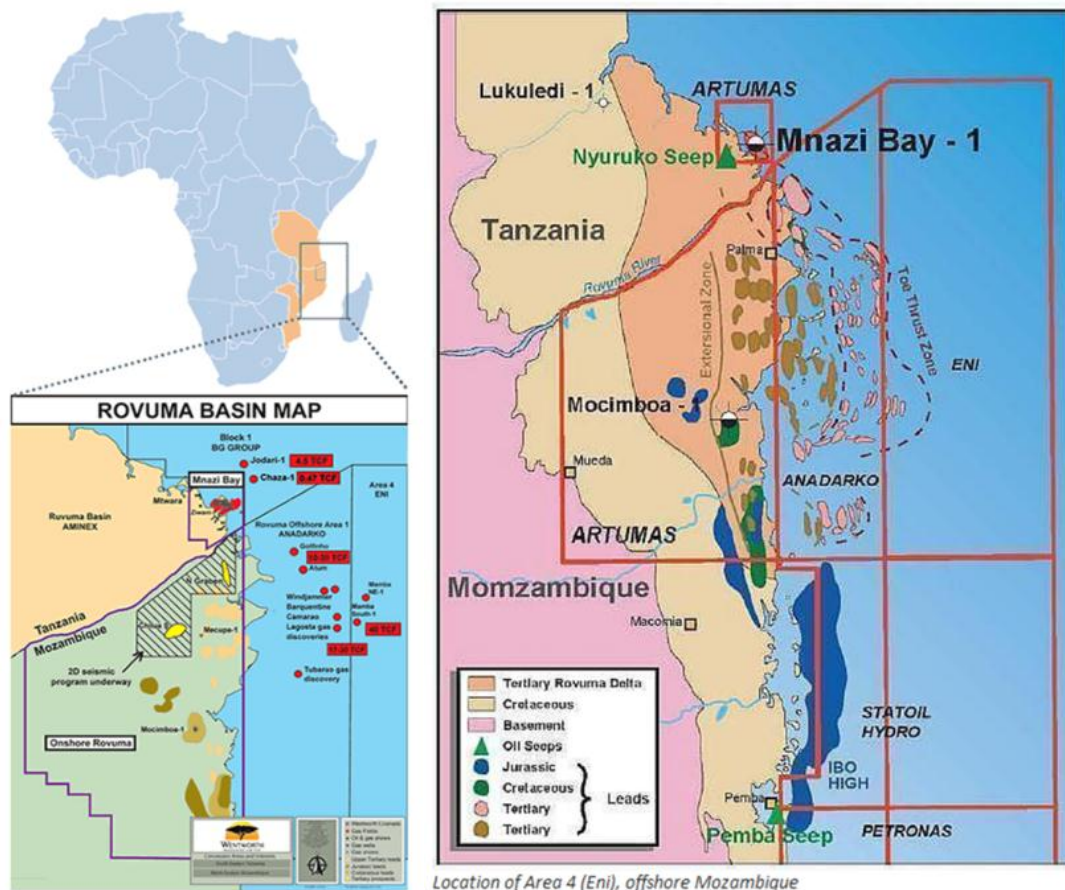
The fields are located approximately 600 km north of Maputo and a branch of the pipeline supplies industries in the Maputo area with primary customers being a 107 MW<sub>e</sub> power plant (2012) and a fertilizer plant in Inhambre (expected start operations between mid-2014 and early 2015). A pipeline network is being constructed in the Matola/Maputo area to supply large customers such as hotels, hospitals and bakeries; later commercial and domestic users will be connected.<sup>50</sup>



**Figure 10. Red dotted line is the pipeline from Pande and Temane to Secunda<sup>51</sup>**

Anadarko Petroleum Corporation (operator with 36.5% share) signed an oil and gas exploration and production concession contract with the government of Mozambique for the Rovuma basin in the north (partly onshore and mainly offshore). Gas was found in 2010, 2011 and 2012.

Eni (operator with 70% stake) followed the same path and explores an area more offshore than Anadarko. Their well results have exceeded expectations and Eni has updated the estimate of the Mamba Complex and Coral discoveries to 80 Trillion cubic feet (Tcf) of gas in place. The following image shows the Mozambique offshore concessions.



**Figure 11. Mozambique concessions**

Seismic surveying and exploration and appraisal drilling continues to date<sup>52</sup>. Anadarko announced the discovery of a new natural gas accumulation fully contained within the Offshore Area 1 of the Rovuma Basin of Mozambique: the Orca-1 discovery well encountered approximately 190 net feet of natural gas pay in a Paleocene fan system.<sup>53</sup> WesternGeco announced that it has begun acquisition of a major multi-client seismic survey using the ObliQ sliding-notch broadband acquisition and imaging technique which optimizes the recorded bandwidth of the seismic signal enabling more detailed imaging of the subsurface and more reliable extraction of rock properties.<sup>54</sup> Such recent developments clearly indicate reserves estimate may rise in the coming months and years.

Based on discoveries made as published by several sources<sup>55 56</sup>

- Anadarko, Golfinho/Atum complex: 15 to 35+ Tcf (discovered 2012)<sup>57 58</sup>
- Eni, Mamba complex and Coral discoveries: Eni reports gas in place 200 Tcf and Eni plans to drill deeper in the southern part of Area 4 which has not been tested.<sup>59 60</sup> We estimate with 60 to 70% recovery at least 60 Tcf recoverable (1P) and 120 Tcf recoverable (2P).
- Anadarko & Wentworth, onshore: proved 0.6 Tcf, including probable 1.3 Tcf<sup>61</sup>
- Sasol discovered Inhassoro east of the Temane field in 2003. It is a combined oil and gas reservoir with expected recoverable gas reserves of 0.4 Tcf.
- Sasol discovered the Njika field further east offshore in Blocks 16 & 19 in 2008 which is estimated to contain 1 Tcf, but is considered uneconomical

DNV KEMA comes to the following assessment of Mozambique natural gas reserves:

Region	Field	1P reserves (Tcf)	2P reserves (Tcf)
North	Anadarko area	32	65
	Eni area	60	120
	onshore	0.6	1.33
	Subtotal North	92.6	186
South	Temane	0.8	1.3
	Pande	1.8	3.1
	Inhassoro	0.4	0.4
	Njika	1.0	1.0
	Subtotal South	4	6
<b>Total</b>		<b>96.6</b>	<b>192</b>

**Table 4. Summary of Natural Gas Reserves in Mozambique**

We use a range of 97-192 Tcf to assess the feasibility of a gas based industry in Mozambique.

ICF and USGS have made assessments from the geological data of the *undiscovered* recoverable conventional oil and gas resources. USGS has published a 2P estimate of 174 Tcf, while ICF uses 3P values with 60% recovery to come to a figure of 277 Tcf.<sup>62</sup> USGS and ICF both expect large volumes of gas liquids and oil as well. In addition, the area around Moatize basin in the north-central Tete province may contain significant resources of coal bed methane.

### 2.3.2 Existing Gas Utilization Plans

Most often a project/production period of 25-45 years is indicated, but no explicit production profiles have been published for the Rovuma basin, and fields are not yet in operation. Pande and Temane fields are in operation with 2.6 Tcf remaining reserves and 5.8 Tcf probable with current production of 162 Bcf/yr to supply industries in the Matola region and continue exports to South Africa over the next 16-35 years.

A pipeline 2,500 km across the coast line to the south is mentioned to connect gas to industrial hubs (Pemba, Nacal and Beira) and the capital. Due to the proximity of Maputo, LNG is an alternative to a pipeline with the advantage of less environmental risk than a pipeline crossing vulnerable land during construction and leaking during operation, and more flexibility in demand/supply needs since the early years of market build up does not support the pipeline's maximum capacity.

Anadarko and Eni advocate development of an LNG liquefaction terminal near Palma. Initially both companies had plans for own terminals. In December 2012 an agreement was signed in which the companies laid down principles for coordinated development of the reservoirs to conduct separate but coordinated offshore activities, and joint planning and construction of an onshore LNG terminal.

Anadarko planned an LNG terminal near Palma with 2 trains (each 5 MTPA), and ENI investigated a terminal of 2-3 trains. A total of 5 trains (25 MTPA) would be equivalent to around 1.25 Tcf/yr, but recent increase in probably reserves suggest the total LNG capacity could move to ten trains or 50 MTPA. The investment decision is expected in 2013 with operation from 2018 at the earliest.

The State is keen to distribute the benefits of the gas richness to other parts of the country and build industrial hubs based on gas: one in Palma, close to Tanzania's border and near the discoveries made

by Anadarko and Eni, and three others in Pemba, Nacala, and/or Beira further south. *"We want more than just LNG. We have huge reserves and we want to see how we can use the gas in the local, regional and international market,"* Minerals Minister Esperanca Bias said.<sup>63</sup>

Mozambique hopes the gas will become a game-changer for a country where more than half live below the national poverty line of ~\$0.65 a day and 60% have no formal job. As net importer of fuel, Mozambique hopes to use gas to manufacture liquid fuels. It also aims to produce cheap electricity to help supply the four-fifths of its 24 million people who still have no access to power.

Companies from South Africa, Germany, Japan, India and South Korea among others have expressed interest in setting up gas-to-liquids, methanol or fertilizer plants or in processing gas for power generation or production of steel and aluminum.

### 2.3.3 Conclusions

Reserves in the South are quite modest and vary between 4 Tcf (1P) and 6 Tcf (2P), mostly in fields already in production. If export to South-Africa would continue at current levels (120 Bcf) for the next two decades, these reserve leave room (80 – 120 Bcf/yr) for gas use in Mozambique itself, part of which is already in operation in the south-east of the country near the capital Maputo.

Reserves in the North are substantial and vary between 93 Tcf (1P) and 186 (2P) Tcf. Both Anadarko and ENI have proposed LNG as first use for gas. If their indicated total of 5 trains is built, this would require 1.25 Tcf/yr. Assuming a long project period of 45 years, this would imply allocating 60% of the 1P reserves to LNG. As decisions have not been made yet, we assume in our feasibility study the whole range of 93-186 Tcf to be available as resource base.

As production facilities have to be fully built and take the deep water area into account, we assume first gas not to be available before 2018. Assuming project periods of ~50 years DNV KEMA assesses the yearly available volumes starting from 800 Bcf/yr in 2018 climbing to a value between 2,000 and 4,000 Bcf/yr after 2020, depending on the amount of reserves.

The opportunities to monetize gas are still open. The government prefers to set up industrials hubs, produce power for the non-electrified parts of the country and reduce the imports of fuels, and to in general to use the resources to the benefit of the people in Mozambique.

### 3 Eight Natural Gas Industries

Eight uses of natural gas are evaluated for their ability to afford a high natural gas price, encourage domestic growth, and lead to the expansion of small and medium domestic enterprises with corresponding local job creation. The industrial options reviewed include: LNG liquefaction, Electric power generation by Combined Cycle Gas Turbine (CCGT) or Gas Turbine (GT), Urea, Methanol, Gas-to-Liquids, Steel, Cement, and Aluminum production with hydroelectricity or gas-fired electricity.

#### 3.1 Summary of inputs and results

This chapter presents the netback natural gas price for each industry which is calculated from the assumed commodity market price, the required capital investment, and the non-gas operational expenses of each facility. Global and local markets for each commodity are presented to provide context to each industries supply-demand situation. The following figures show each facility's product commodity capacity and the required natural gas volumes for each assumed facility.

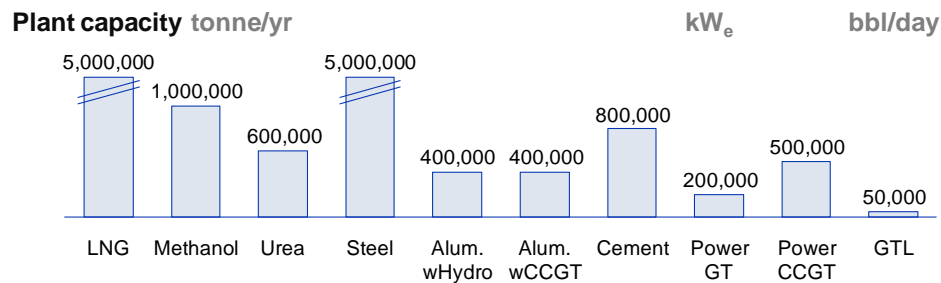


Figure 12. Facility production capacity

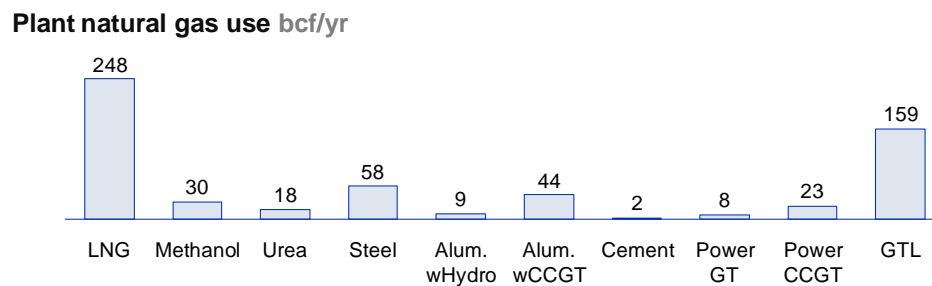


Figure 13. Facility annual natural gas demand

As will be shown in each industries respective section, these facilities represent moderate to large scale uses of natural gas compared to comparable facilities around the world. The following figure shows the gas required per unit of product commodity.

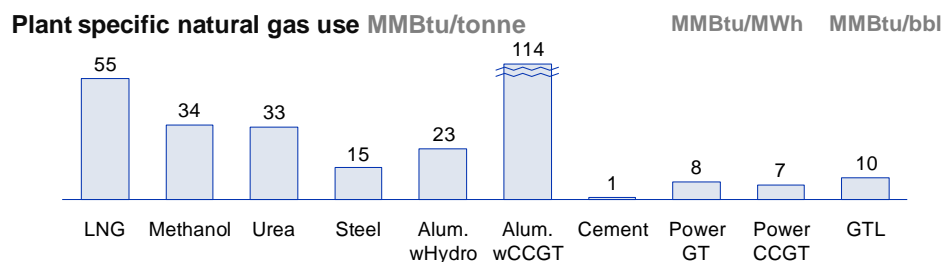
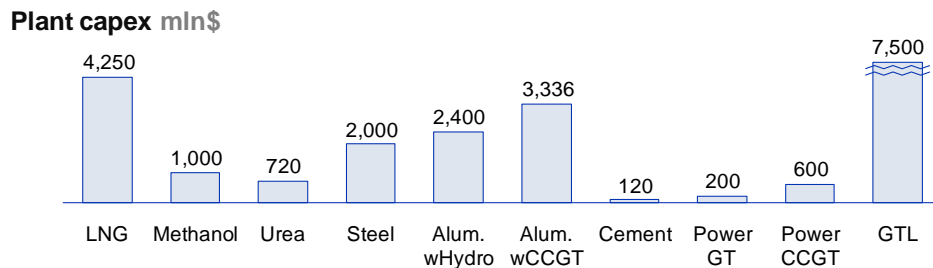
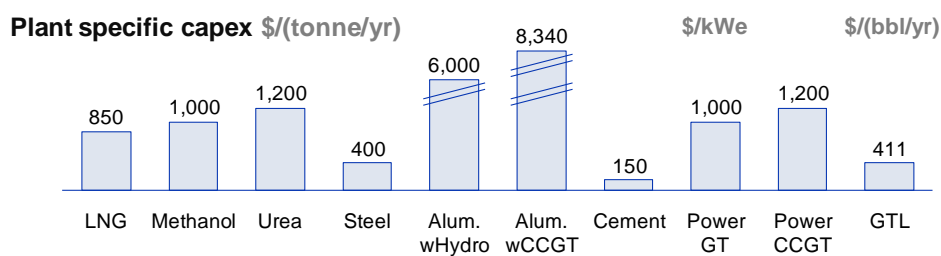


Figure 14. Facility gas use per unit commodity produced

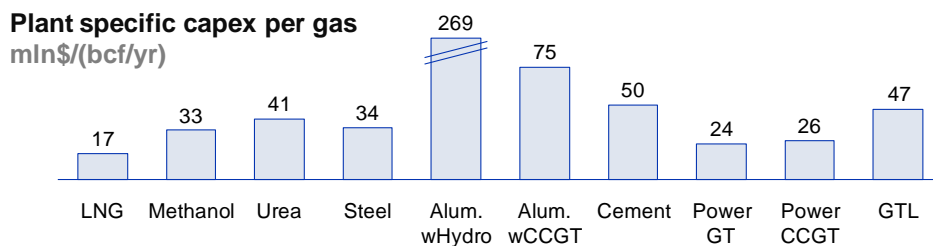
The following figures show the total and specific assumed capital investment for each example facility, the amount of capital investment required per annual natural gas used, the required construction time prior to commissioning, and the capacity factor of each facility.



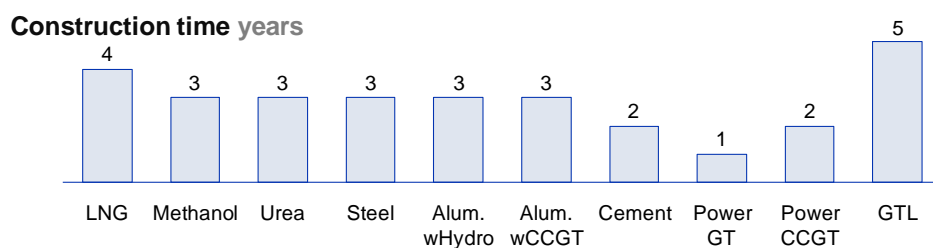
**Figure 15. Facility capital cost**



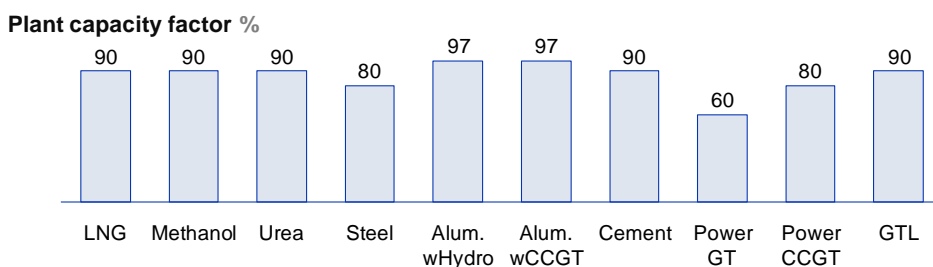
**Figure 16. Facility specific capital cost**



**Figure 17. Facility specific natural gas use**

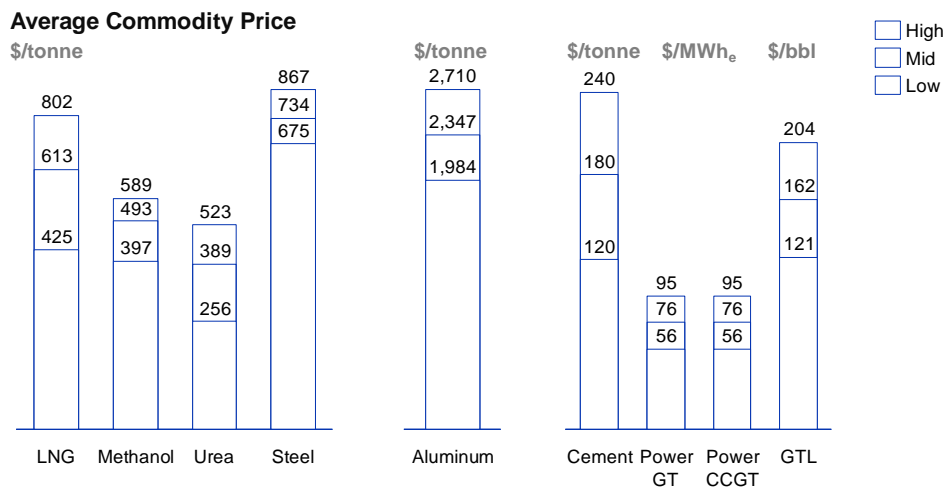


**Figure 18. Assumed construction time of each facility**



**Figure 19. Assumed capacity factor of each facility**

The following figure presents the average commodity price assumed over the 20 year economic lifetime of each facility’s operation. The three commodity sales prices reflect high, basecase, and low price assumptions. The sources for these forecasts are detailed in the respective industry sections.



**Figure 20. Average commodity price forecasts for 1<sup>st</sup> 20 years of operation**



## 3.2 Netback analysis methodology

The netback analysis is based on typical plant sizes and yearly gas use per industrial plant, and other assumptions presented in the prior section. These typical values are derived from actual projects, and act as building blocks for an overall gas based industry plan. Information on the plants is noted in the paragraph of each industry.

A discounted cash flow (DCF) analysis is performed to calculate the required netback natural gas price based on the assumed facility capital cost, operating cost, and performance paired to our price forecast for each product. We make the following assumptions:

- The return on equity or hurdle rate is set by corporate requirements with the two most deciding factors being project risk and default risk. The duration of debt financing is set by lead arranger and credit syndicate. For our project finance assessments we assume a special purpose vehicle company, and do not independently address debt/equity financing (Modigliani–Miller theorem).
- A depreciation period of 20 years is assumed, and the marginal tax rate is assumed to be 35%. These periods are often set by regulators, and incentives are commonly negotiated on a plant by plant basis, but for a consistent perspective, special tax treatment is not considered.
- The netback value of gas is found by setting the net present value in 2014 from 20 years of plant operation after commissioning to zero. Each facility takes from 1-5 years to build before it starts generating revenue over its 20 year lifetime at the assumed commodity prices.
- Three price forecasts are generally used to present high, base, and low estimates to plant economics, and additional sensitivities are performed on the assumed commodity sale price, WACC, capital cost, construction period, depreciation period, and economic project lifetime.

### 3.2.1 WACCumulator:

We estimate the debt and equity rates of return around the world for different industries using our WACCumulator model. A WACC of 10.7% (real, post tax) is used to discount future opex and revenue. This value for the gas based industry is based on actual business and risk profiles for the chemical industry in Angola and Mozambique.

The debt financing impact is included in the WACC which assumes (for this country/industry) that 43% of the required capital is from debt financing at 9.2% pre-tax cost of debt and the remaining 57% is from a 'relevered' cost of equity of 20.1% which is based on an 'unlevered' return on equity of 13.4%. The relevered value is used to adjust for Angola and Mozambique specific risks.

The WACC calculated accounts for non-diversifiable, non-project specific risks and does not contain any markups for project specific risks, such as commissioning delays and changes in market structure. Such project specific risks should be explicitly modeled using probability weighted cash flow scenarios, but are initially addressed through the high, base, and low commodity price scenarios.

The construction period for each plant varies, but all are depreciated over 20 years, corresponding to the economic lifetime over which the netback analysis is performed. The above values follow:

Assumption	Value
Debt-equity ratio	43/57
Relevered return on equity (%)	20%
Depreciation (years)	20
Debt interest rate (%)	9.2%
Project lifetime (years)	20

Table 5. Assumptions regarding financing of all plants

### 3.2.2 Netback comparison

Gas-to-Liquids, LNG, power, and methanol are the most economically favored choices, but urea offers specific opportunities in Mozambique. Gas-to-Liquids represents a financially riskier use of gas that should be investigated after the industry has matured further through implementation of LNG projects. Steel and Cement are important enablers for the domestic economy, but do not support a high natural gas price as it can easily switch to domestic coal. Aluminum is not recommended due to negative netback gas values from high capital and operating costs that are dependent on imported raw materials. A chart of the calculated netback gas price is shown below.

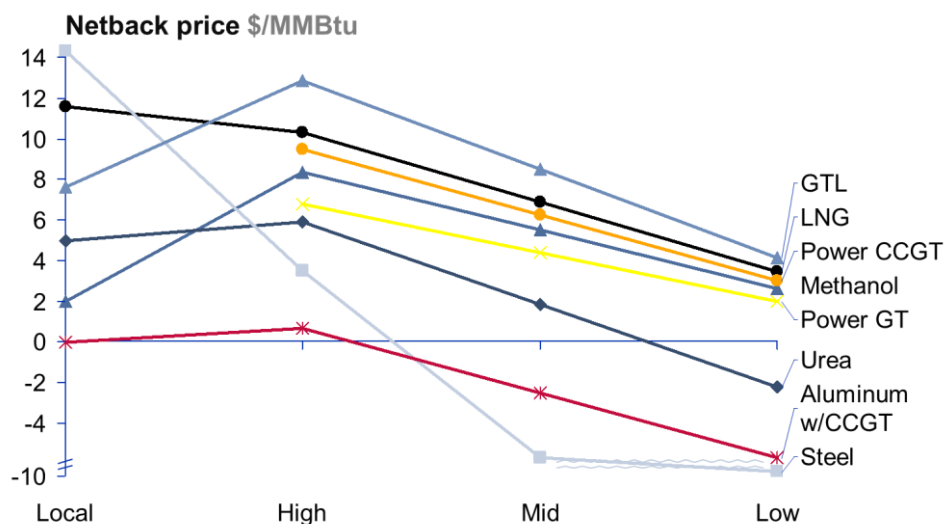


Figure 21. Netback analysis for industry options

### 3.3 LNG

Natural gas is condensed to liquefied natural gas (LNG) by cooling it to  $-162^{\circ}\text{C}$ . This reduces its volume ~600-fold, making it economical to ship over larger distances and smaller volumes than required for economical pipeline transport. LNG transport is more economical than a pipeline at distances over 2,500 to 3,000 km. After natural gas is extracted from the well, the LNG chain consists of liquefaction, transport, and regasification. The following figure displays the LNG supply chain.

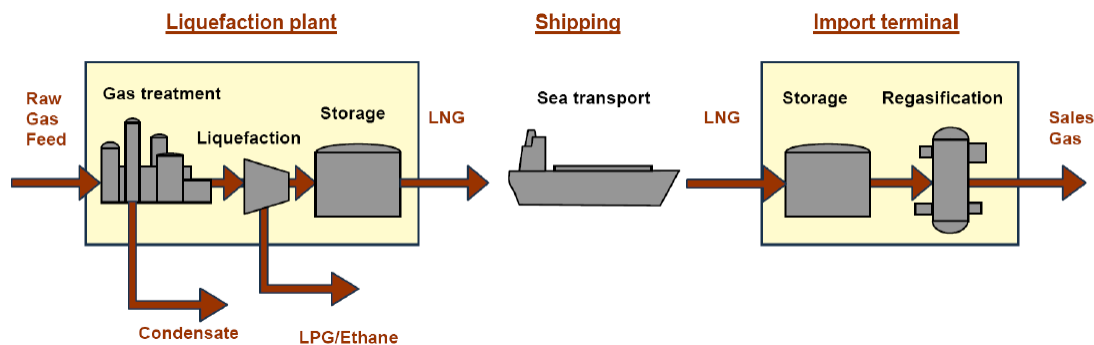


Figure 22. LNG Supply Chain<sup>64</sup>Error! Bookmark not defined.

Natural gas liquefaction entails three separate process steps<sup>64</sup>. The first is natural gas treatment or purification, which is necessary to provide for consistent composition and combustion characteristics. Raw feed gas is purified from contaminants such as  $\text{H}_2\text{S}$  and  $\text{CO}_2$ , and dehydrated to remove water which could freeze during cooling and damage the liquefaction plant. In parallel, heavy hydrocarbon is extracted and sold separately. The second step is the cooling of the natural gas by the application of refrigeration technology. Third, LNG obtained from the previous step is stored to await transport.

LNG transport involves special vessels with the standard capacity being  $160,000 \text{ m}^3$  of gas, but for the Qatar LNG projects, ships were developed with a volume of  $210\text{-}260,000 \text{ m}^3$  (Q-Flex and Q-Max vessels). At the destination, regasification requires a heat source to convert the fluid back into the gas phase. The heat is preferably residual heat from an industrial process or a power plant, and this resulting 'cold' can be sold to industries.

LNG can be utilized in a similar fashion as normal natural gas. However, similar to normal natural gas being tied to physical pipeline interconnections, LNG is bound by the availability of regasification terminals in order to reach its destination markets (which can be the same conventional markets as for normal natural gas such as power generation, industry, etc.).

#### 3.3.1 Global Market Outlook<sup>64</sup>

##### 3.3.1.1 Historical Natural Gas and LNG demand and supply

In 2012, global demand for LNG was 236.3 million tons. This was a decrease of -1.9% compared to 2011, and the first drop in demand for 30 years. This demand was dispersed over 26 countries importing LNG, which combined operated 93 LNG regasification terminals with a total regasification capacity of 668 million ton/yr. Below, three regions importing LNG are discussed.

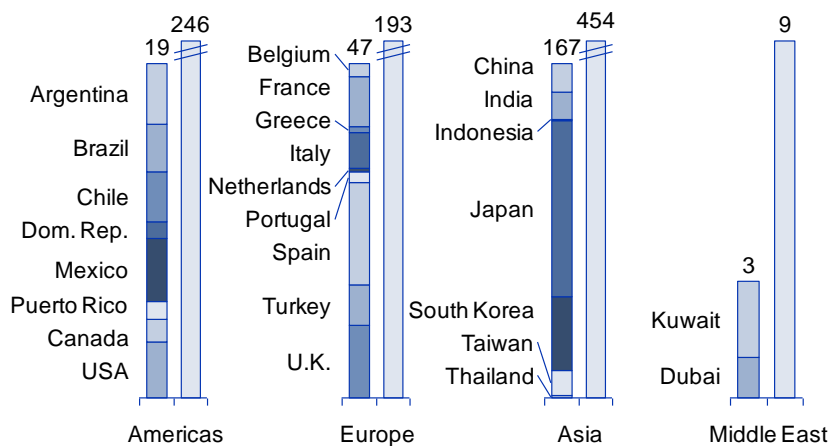
Asia is the largest importer of LNG with 71% of global demand. A major driver for the high demand in Asia was the tsunami hitting Japan in 2011 and the Fukushima disaster that caused Japan to switch most of its nuclear generation to gas-fired power generation and leading to 11.4% year-on-

year growth in LNG demand. Together, South Korea and Japan consume 64% of Asian LNG imports and 53% of global demand. All Asian countries recorded a growth in LNG imports compared to 2011. Given Asia's demand for LNG and its projected growth, as discussed further on, particular attention is paid to this region throughout this section.

In contrast to Asia, European LNG imports saw a steep decline of -25% compared to 2011 reaching imports levels below those of 2009 due to the economic downturn lowering gas demand. LNG provides more contractual flexibility than pipeline gas, causing shipments to be diverted to other regions. Therefore, LNG acts as the marginal supplier of natural gas to Europe as contracted pipeline gas volumes are usually tied to strict take-or-pay obligations. LNG serves two main goals in Europe: First, it provides security of supply in case of supply disruptions by pipeline. Second, it strengthens the negotiation position of European gas buyers against pipeline exporters (Russia).

In North America, LNG imports were significantly reduced recently due to shale gas developments which pushed the utilization rates of regasification terminals below 2% in 2012. Moreover, the US is expected to become an exporter of LNG as Cheniere Energy plans to bring the first liquefaction terminal online in 2015. In South America, LNG demand increased 40% compared to 2011, in part because large amounts of hydroelectricity in 2011 caused Brazil's imports to triple in 2012 due to relative drought. However, absolute demand in South America is still relatively low compared to Asia and Europe. The figure below shows imports and regasification capacity by region:

**LNG imports (left) and regas capacity (right) in 2012 mln tonne<sub>LNG</sub>/yr**



**Figure 23. LNG imports and regasification capacities in 2012 in million tonne per yr**

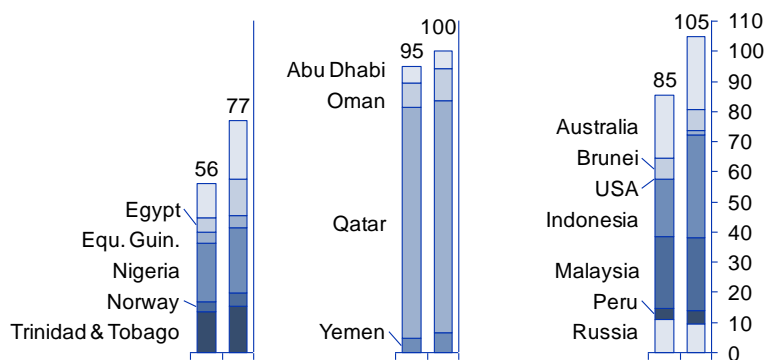
Globally in 2012, 89 liquefaction trains operated in 18 countries, of which 8 countries supplied 83% of the market. Only one new liquefaction train was added in 2012, Pluto in Australia. Total combined liquefaction capacity was 282 million ton/yr. Given the demand of 236 million tons, total average utilization rate was ~85%. Although demand dropped, the LNG market was tight in 2012, due to lower than expected capacity additions and loss of capacity due to maintenance shutdowns and unexpected interruptions in LNG production.

LNG supply is grouped into three geographic regions: Atlantic Basin, Pacific Basin, and Middle East:

- In the Atlantic Basin, Nigeria, Norway and Trinidad & Tobago increased outputs; however these were offset by lower supplies from Algeria, Egypt and Equatorial Guinea resulting in an overall drop of 2.2%.
- The Pacific Basin saw a decline in output of 3% caused by lower supplies from Indonesia and Malaysia. New capacity additions from Australia were unable to result in a net growth in LNG exports from the Pacific Basin.
- Middle Eastern LNG exports saw a decline as well when capacity added in Qatar did not manage to counteract production shutdowns in Yemen.

Qatar is the largest supplier of LNG in the world with 63% of Qatari supplies shipped to Asia. Qatari exports to Japan and South Korea were 15.7 and 10.8 MTPA respectively in 2012, which is an increase of more than 200% for Japan and 50% for South Korea compared to 2010. The figure below shows exports by region and liquefaction capacity:

**LNG supply (left) and liquefaction capacity (right) in 2012 mln tonne<sub>LNG</sub>/yr**



**Figure 24. LNG exports and liquefaction capacity in 2012**

### 3.3.1.2 Natural Gas and LNG demand and supply forecasts

Steep increases in natural gas demand are expected in India and China with annual growth of 5.5% and 4.6% to 2035 respectively. Other non-OECD Asia is expected to grow at 2.9% annually, and demand growth in the Middle East is expected at 2.7%/yr. Demand in the US, Europe, and Russia are expected to slowly grow towards 2035 at 0.5%, 0.7%, and 0.1% respectively on an annual basis. Noteworthy are the annual growth rates expected in Brazil (5.1%), Mexico and Chile (combined 3.4%) and Africa (3.5%). The figure below shows the Energy Information Administration (EIA) forecasted natural gas demand by region:

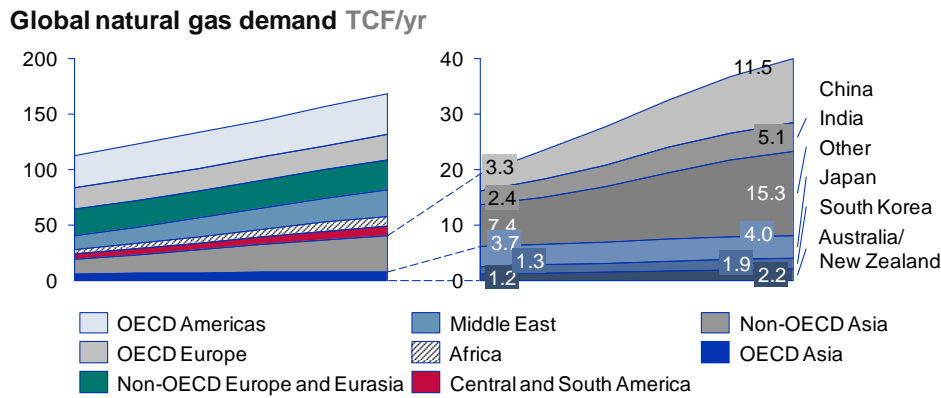


Figure 25. Global natural gas demand as provided by EIA<sup>65</sup>

As shown above, demand for natural gas in 2035 is expected to increase by about 49% compared to 2010 (approximately +1.6% annually). In connection to this, demand for LNG is expected to undergo even larger growth than overall natural gas. There is consensus around an annual LNG demand growth of 5-6% up to 2020, and that while after 2020 growth is expected to decline, it will still stand at 2-3% per year. The following figure shows forecasted global LNG demand up to 2030. As can be observed, most LNG demand growth is expected to occur in Asia, though not in more mature LNG markets such as Japan, South Korea and Taiwan (JKT).

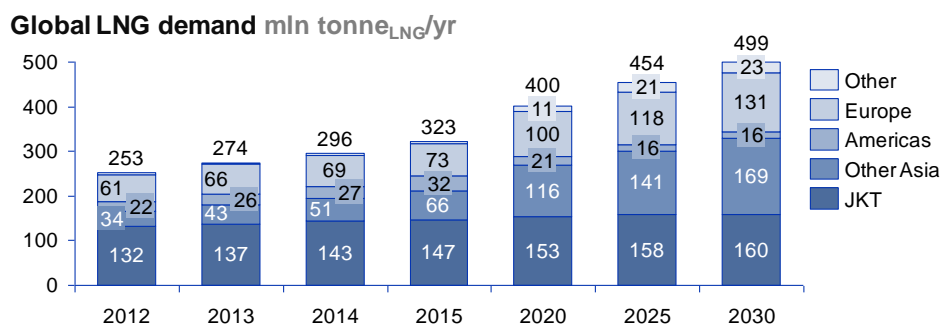
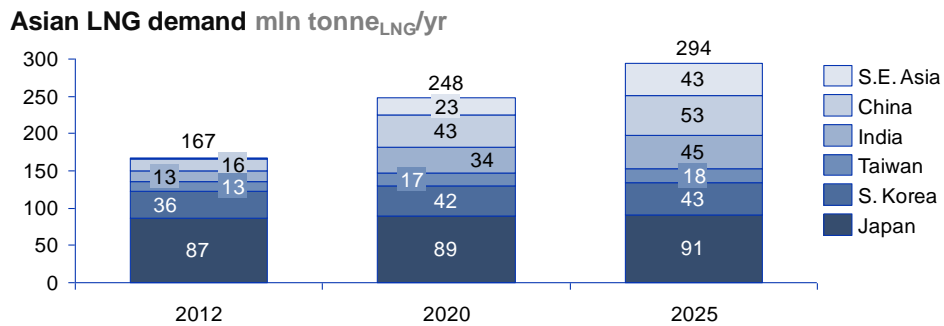


Figure 26. Global LNG demand in million tonnes per year<sup>66</sup>

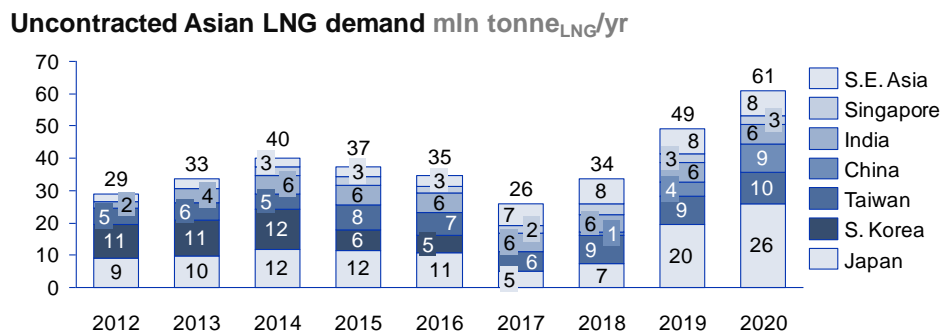
Although the JKT market is expected to be relatively stable in terms of volumes, these markets are generally regarded as premium LNG markets due to their large demand, heavy industrialized nature and remote location from other energy sources. Other Asian markets are expected to have more options to diversify energy supplies and thus be more price-sensitive.

In China, demand for natural gas is expected to more than double 2012 values by 2020. The Chinese Five-Year Plan calls for an increase in the share of gas in the energy mix from about 4% in 2010 to 8% by 2015. Although China may be able to ramp up domestic gas production, including shale gas, and pipeline imports; LNG is expected to increase threefold to balance demand. The following figure provides a more detailed overview of Asian LNG demand by specifying LNG demand in the largest Asian LNG markets.



**Figure 27. Asian LNG demand<sup>67</sup>**

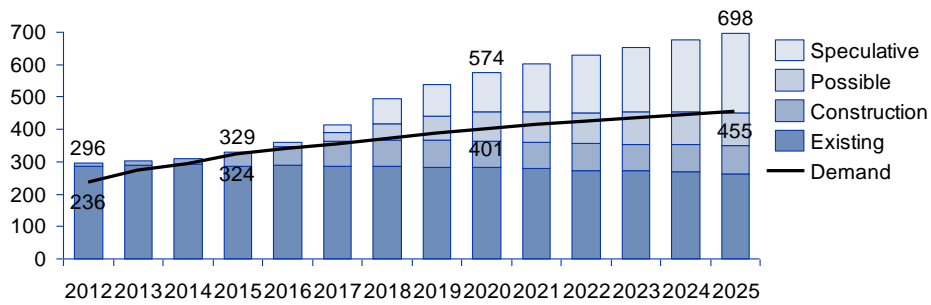
LNG supplies to Asia are based on long-term contracts usually planned ~5 years ahead. Comparison of contracted supplies (including existing non-binding sales agreements) with expected demand growth shows that there are 37 and 61 MTPA of un-contracted demand by 2015 and 2020. Excluding the non-binding options, the un-contracted demand would increase to respectively 49 and 82 MTPA. The following figure shows the un-contracted LNG demand in the major Asian markets.



**Figure 28. Uncontracted Asian LNG demand including existing options<sup>68</sup>**

Regarding world-wide LNG supplies, Algeria, Malaysia and Indonesia have historically been the main suppliers of LNG, providing up to 60% of total LNG capacity. However, their share is expected to decline to 20% in 2020. Today's LNG supply is dominated by Qatar and Australia, whose share in the total LNG market has risen from 20% about a decade ago to nearly 50% by 2020. Several other countries, with little or no LNG export capacity, could together provide up to 30% of the world's LNG capacity if projects are realized. The uncertainty surrounding these projects is significant due to the scale of the required investment, the current economic situation, and/or geopolitical reasons (e.g. Iran). The following provides an outlook on future LNG capacity and demand. By 2018, demand is expected to exceed currently existing and currently under construction LNG capacity.

**Global LNG production capacity and demand mln tonne<sub>LNG</sub>/yr**

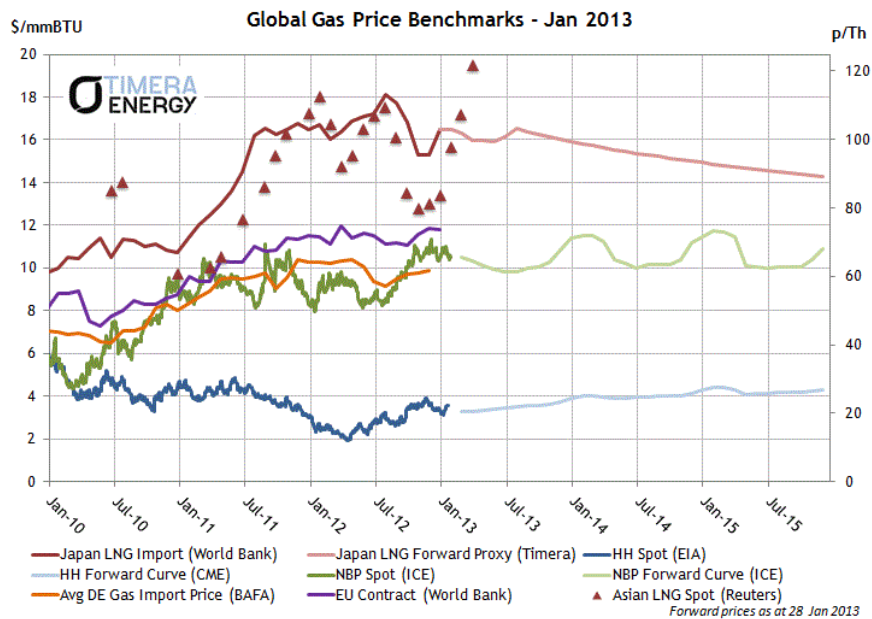


**Figure 29. Global LNG liquefaction capacity and demand<sup>66</sup>**

The current Asia-Pacific demand and supply tightness is expected to loosen as new supplies directed towards Asian consumers could top the expected increase in demand. At the moment though, much of this supply capacity is un-built and/or un-contracted and thus not certain to reach Asian markets.

### 3.3.1.3 Prices

Global gas prices have undergone diverging trends in recent years as shown in the figure below. Whereas US prices (Henry Hub) have seen a steady drop due to the discovery and production of natural gas from shale deposits, European prices have steadily increased since 2010 and are nearly back to 2008 pre-crisis levels. Japanese LNG import prices have seen a similar increasing trend as in Europe although Japanese prices are higher in absolute sense.



**Figure 30. Global gas prices and near term outlook (January 2013)<sup>69</sup>**

Shown is the apparent volatility in Asian spot prices compared to long-term contracts which are generally indexed to well-known crude oil benchmarks such as Brent, WTI or JCC.<sup>iv</sup> In the near future, prices are expected to show a converging trend due to expansion of liquefaction capacity in the US and Australia, although absolute differences will remain between the three regions. The following

<sup>iv</sup> WTI = West Texas Intermediate, JCC = Japan Crude Cocktail (average crude oil import price into Japan)



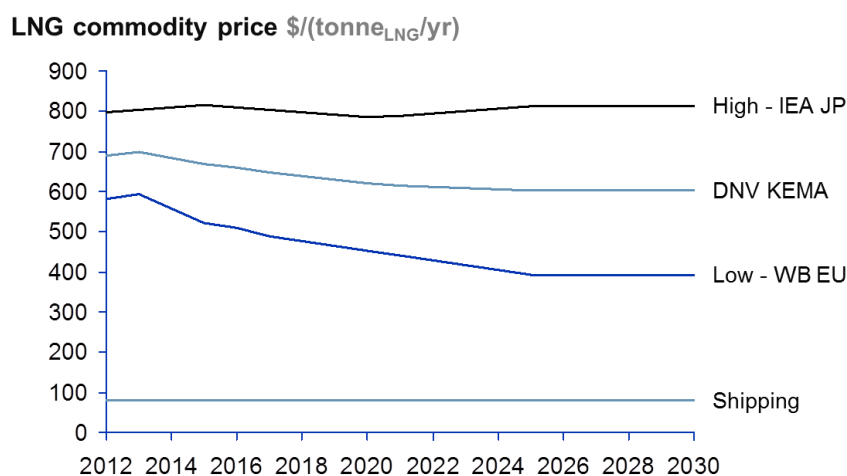
shows WorldBank and IEA forecasts for natural gas prices, which while diverging, still support Asian markets remaining the favorable destination for LNG despite higher shipping costs.

Natural gas price (\$2013/MMBtu)	2013	2014	2015	2016	2017	2018	2019	2020	2025
WorldBank - Japan	14.7	14.1	13.6	13.2	12.7	12.2	11.9	11.4	9.5
WorldBank - Europe	11.4	10.7	10.0	9.8	9.4	9.2	9.0	8.7	7.6
WorldBank - US	3.6	3.7	4.1	4.2	4.3	4.4	4.5	4.7	5.4
IEA - Japan	15.5	15.6	15.7	15.6	15.5	15.3	15.2	15.1	15.6
IEA - Europe	10.7	11.1	11.5	11.7	11.9	12.1	12.2	12.4	13.3
IEA - US	4.5	4.6	4.7	4.9	5.1	5.3	5.5	5.6	6.6

**Table 6. WorldBank and IEA Natural Gas price forecasts**

It is expected that once the US exports LNG, contract terms will move from oil pricing to hub pricing given the location and depth/liquidity of the US-based Henry Hub. Both Deutsche Bank<sup>73</sup> and Société Générale<sup>70</sup> state that the Asian price should move to Henry Hub plus 6-7 \$/MMBtu in order for the economics for new liquefaction capacity to work out.

DNV KEMA supports this view and DNV KEMA’s estimated price series is based on this presumption. However, in the short-run, we do not expect an immediate switch to hub-based pricing and foresee that prices are more likely to follow the average of the World Bank and IEA estimates. The following price forecast is used in the netback analysis for LNG liquefaction.



**Figure 31. Assumed LNG Commodity Price**

These prices represent the price paid in Asian markets, and the corresponding shipping charge to these destinations of \$80 per tonne is deducted from the received revenue. The high and low price scenarios are based on IEA’s Japan and WorldBank’s Europe forecasts respectively.

### 3.3.2 LNG Use and Pricing in Africa

Currently, there are no regasification terminals in African. However, there is significant liquefaction capacity located north of the Sahara in Algeria, Libya and Egypt, and several liquefaction plants in Nigeria and Equatorial Guinea. Their characteristics are shown in the following table:

Country	Plant	# trains	Capacity (MTPA)	# tanks	Storage (m <sup>3</sup> )	Start-up
Algeria	Arzew GL 1Z	6	7.9	3	300,000	1981
Algeria	Arzew GL 2Z	6	8.3	3	300,000	1972
Algeria	Skikda	3	3.2	5	308,000	1972/1981
Egypt	Damietta	1	5.0	2	300,000	2005
Egypt	Idku	2	7.2	2	280,000	2005
Eq Guinea	Bioko Island	1	3.7	2	272,000	2007
Libya	Marsa-el-Brega	4	3.2	2	96,000	1970
Nigeria	Bonny Island (T1-T3)	3	9.6	3	336,800	1999-2002
Nigeria	Bonny Island (T4-T5)	2	8.1	Shared with above		2006
Nigeria	Bonny Island (T6)	1	4.1	1	84,200	2008

**Table 7. Characteristics of African liquefaction plants<sup>64</sup>**

Full capacity has not been fully utilized in 2012 due to feed gas shortages from sabotage actions, e.g. in Nigeria, or increasing domestic demand. The latter is the case in Egypt which is expected to soon become an importer of LNG. More severe is the shutdown of the liquefaction plant in Libya due damage sustained during the civil war in 2011.

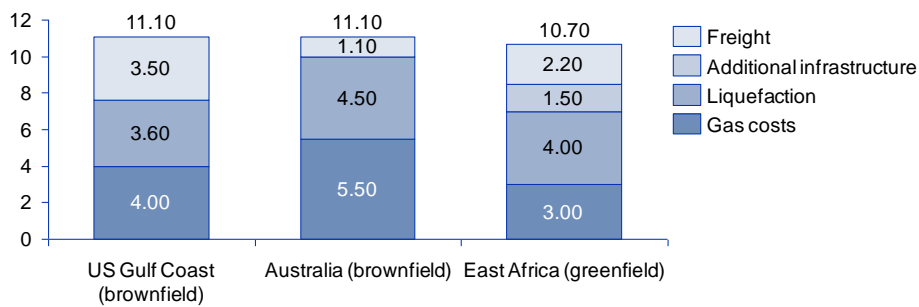
In Algeria, a new 4.7 MTPA liquefaction train is scheduled to become operational in 2013 to replace three existing trains with a capacity of 3.0 MTPA that were destroyed by fire in 2004. Plans for a 7<sup>th</sup> train in Nigeria have been put on hold due to expected competition with potential LNG supplies from East Africa. Finally, newly discovered gas in Equatorial Guinea could support the construction of an additional train, but this project is not expected to materialize before the end of this decade.

There is one LNG liquefaction plant being built in Angola by Sonangol, Chevron, BP, Total and ENI. Due to technical issues, the start-up of this plant is delayed to June 2013. The liquefaction train's capacity will be 5.2 MTPA using oil-associated gas to reduce flaring. Initially this LNG was to be sent to the US, but now it is likely that these volumes will be diverted to the east<sup>71</sup>, although first shipment has been made towards Brazil.

### *3.3.2.1 Competitiveness of African LNG supplies*

The competitiveness of an LNG project in Africa is dependent on the prices for other LNG projects around the world. Notwithstanding the results of the netback analysis for LNG discussed hereafter, we present the results of several studies assessing the competitiveness of various LNG projects around the world. Firstly, a study conducted by the Oxford Institute of Energy Studies<sup>72</sup> suggests that the costs of LNG from Africa to Japan will be similar to LNG exports from Australia and the US Gulf Coast to Japan. This is shown in below:

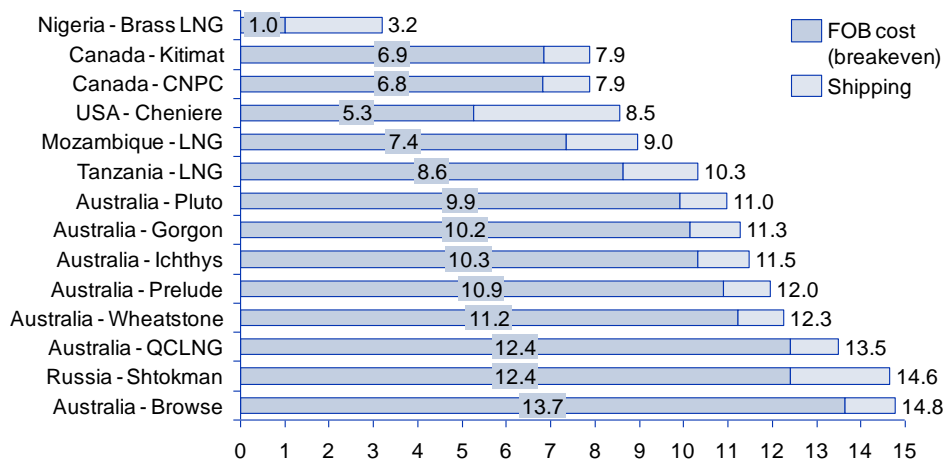
**Delivered costs of LNG to Japan \$/MMBtu**



**Figure 32. Comparison of delivered costs of LNG to Japan<sup>72</sup>**

Similarly, Deutsche Bank<sup>73</sup> reviewed the prices required to deliver a 12% internal rate of return based on the net back LNG price for different projects to derive the marginal cost curve of the LNG supply industry. The results are provided in the following figure, which suggest supplies from the US and Africa are more economical than Russian and Australian supplies to Japan.

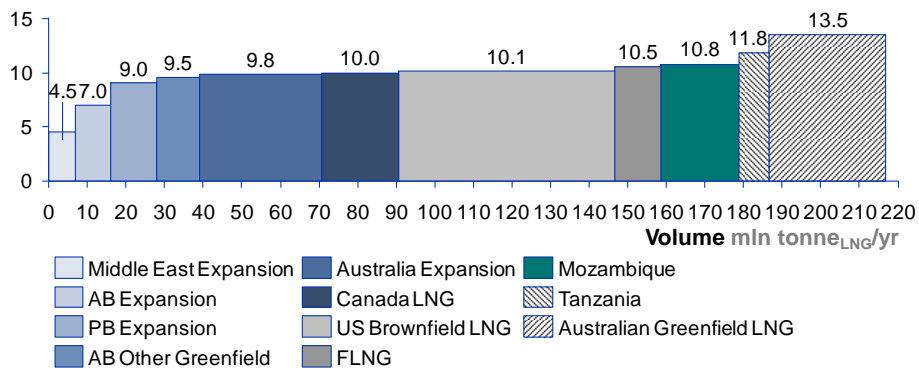
**Japanese LNG prices required for 12% IRR \$/MMBtu**



**Figure 33. Japanese LNG prices required to attain 12% IRR for various LNG projects<sup>73</sup>**

Besides the costs of each project, the volume that may be delivered by these projects in relation to the total demand is of importance as well. Therefore, a merit order or cost curve can be created for 2025 showing potential projects, their estimated costs and planned capacity. Deutsch Bank estimates that by 2025 another 190 MTPA of demand is required. In this case, supplies from Africa are just within the merit order at the expense of Australian Greenfield projects. It should be noted though, that this cost curve only contains those projects most likely to materialize. If other more speculative projects are being developed, such as Iran and Nigeria expansion, LNG supplies from Africa can be pushed out of the merit order to make US Brownfields the marginal projects.

**LNG supply break-even price \$/MMBtu**



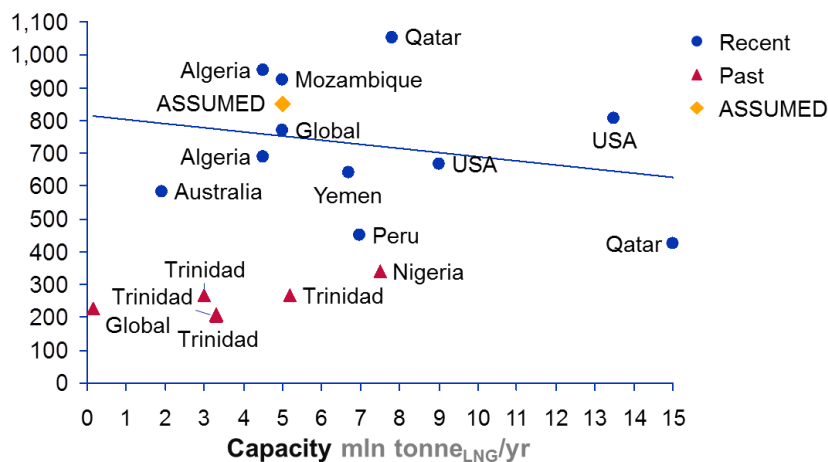
**Figure 34. Resource cost curve for 2025 of potential LNG projects<sup>74</sup>**

Although the netback analysis implicitly assumes sufficient demand to absorb all supplies, the figure above shows that the projects currently being planned or developed could result in oversupply.

### 3.3.3 Capex, Opex, Pricing, Gas netback value

The financial viability and competitiveness of LNG liquefaction projects is heavily influenced by their capital costs. Engineering Procurement and Construction (EPC) costs have escalated since 2006 when they were around \$400/MTPY to almost \$1,200/MTPY in 2009 before settling to lower values post-economic crisis. DNV KEMA’s current cost estimates range from \$700-1,000/MTPY. Given the recent cost tempering, the numerous liquefaction projects being developed or planned, and the specific African circumstances, we expect costs of \$850/MTPY for a 5 MTPA facility. The figure below shows where this cost lies with respect to past and recent projects:

**Plant specific capex \$/(tonne<sub>LNG</sub>/yr)**



**Figure 35. Liquefaction EPC costs<sup>75</sup>**

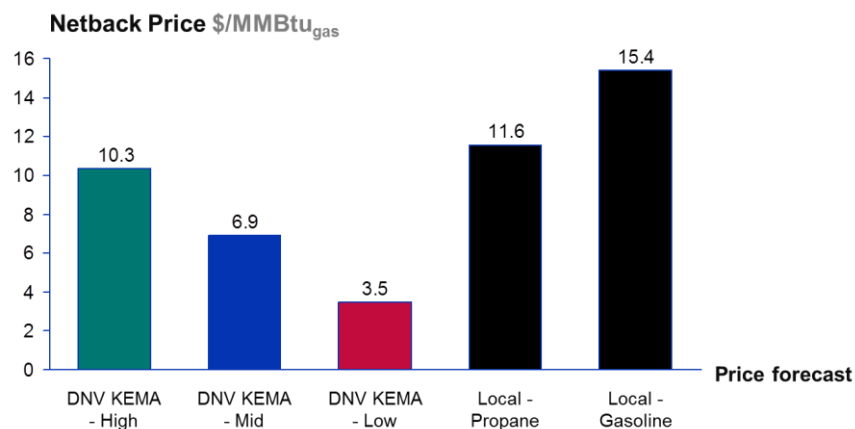
Using these figures, the following parameters are used in the net back calculations for LNG:

Plant parameter	Value	unit
Plant capacity	5,000,000	tonne/year
Capacity factor	90%	%
Annual gas consumption	247.5	Bcf/year
Gas intensity	55	MMBtu/tonne
Specific capex	850	\$/tonne/year
Specific O&M	16	\$/tonne/year
Total capital cost	4,250,000,000	\$
Annual O&M cost	80,000,000	\$/year
Construction time	4	year

**Table 8. Parameters for LNG plant project**

The finance assumptions are the same as detailed in the initial section of this chapter. Finally, forecast Japanese LNG prices as provided by IEA and the World Bank are used in the netback calculation. These values were corrected for shipping costs to Japan. DNV KEMA then applied its own relatively flat cost perspective as a middle base case forecast scenario.

Natural gas netback values are found to be from 3.5-10.3 \$/MMBtu under the three scenarios. When price is set by local propane and gasoline values, a netback of 11.6-15.4 \$/MMBtu is reasonable.



**Figure 36. Netback price for natural gas used to make LNG**

The local propane and gasoline displacement scenarios exclude the \$80 per ton shipping charge to get the methanol to Asian market. The proposed facilities are expected to be built primarily to support Asian demand, but will also result in a new regional market hub around it.

It should be noted that FLNG (Floating LNG liquefaction and storage facilities) have emerged as a potentially less expensive alternative to land based units in situations where the need for importing expertise/equipment and project risk have led to cost overruns in developing markets. FLNG is estimated to cost \$750 per tonne/year capacity and can be available on a small scale from 0.5 MTPA. While this optimistic specific capex cost is yet to be validated, FLNG could reduce the need for building pipelines to shore and can be moved to other gas fields as production shifts which means it should be evaluated further in any small field developing market gas development plan.<sup>76,77</sup>

### 3.3.4 Risks & Abatements

A risk around investing in LNG liquefaction capacity is a reduction in anticipated gas demand due to various reasons related to gas market fundamentals. A few drivers for declining gas demand have been observed in recent years around the globe, and include:

1. Reduction in demand due to economic slumps
2. Availability of competing sources of natural gas and LNG supply
3. Switching to alternative sources for energy in general

The first has occurred in Europe as a consequence of the financial crisis. In 2012 EU demand dropped 2% after falling 10% in 2011, and may take until the end of the decade before demand for natural gas returns to pre-crisis levels<sup>78</sup>. The crisis has led to an oversupply of gas in Europe, and allowed large consumers to renegotiate long-term contracts with major gas suppliers such as Gazprom.

Secondly, demand for LNG may be reduced due to the availability of other supply sources such as Russian gas supplies reaching India and China by pipeline, domestic production ramping up due China and other countries own shale gas revolutions, or LNG competition closer to premium markets such as Asia (e.g. Australia). Prices may be lower due to lower shipping costs from closer supplies, or due to accelerated development of these projects locking in demand through long-term contracts.

The expected oversupply in LNG deliveries and the looming US energy independence is fueling a race to supply Asian customers. After 2015, an additional 100 MTPA liquefaction capacity is expected to come on-stream on a global level which may lower gas prices and improve the negotiation positions of Asian buyers. A dedicated gas hub may be set up in Tokyo to set prices in the Asia-Pacific region.

Thirdly, with increased likelihood, demands for natural gas may decrease due to the alternative sources of energy satisfying demand. For example, natural gas may be pushed out of the merit order by other types of electricity generation, including sustainable renewable sources or, even more economical coal-fired generation as seen in Europe recently.

Besides a lower demand, other risks may lay in the high capital costs of liquefaction projects and the uncertainty in actual costs compared to projected costs. Deutsche Bank reports that from the last twelve projects, only two were delivered on time and within budget.<sup>73</sup> Reasons for overruns include the increasing size of LNG projects, their technological complexity, and more difficult access to upstream areas. These findings are also supported by analyses from JP Morgan.

As LNG needs to be shipped to its destination markets, sufficient LNG shipping capacity is needed. At least up to 2015, the market for LNG shipping capacity is expected to be tight with shipping capacity utilization between 96-98% and corresponding high shipping rates. Currently, most of the few shipyards that can build LNG vessels are fully booked through 2014. Estimates for the number of new vessels required by 2020 range from 175 to 220.<sup>79</sup> Taking into account ~60 new build orders, another 100 new vessels will need to be built in order to ship LNG to destination markets.<sup>80</sup>

The above mentioned risks apply to every gas market. However, the development of gas in Africa probably means facing deteriorated infrastructure, maritime piracy, regulatory and political uncertainty and skilled labor shortages.<sup>81</sup> The risk of skilled labor shortages applies to the whole LNG industry in general, but particularly in Africa and Australia where LNG projects have encountered high cost inflations due to a surge in demand for skilled labor.<sup>66</sup>

### 3.4 Power Generation

Herein we provide a brief overview of the global electric power market, followed by observations on electricity use and pricing in Africa, the SADC region, and specific countries. We then discuss capex, opex, pricing and gas netback values for Natural Gas Turbine (GT) and Combined Cycle Gas Turbine (CCGT) technologies, before detailing sector risks and abatements.

#### 3.4.1 Global Market Outlook

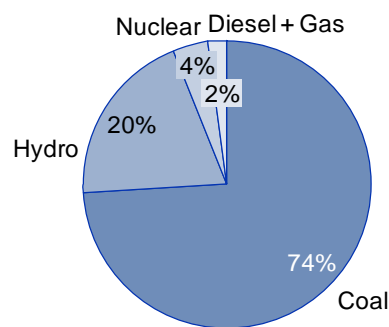
Since 1973, global electricity consumption has more than tripled to roughly 20,000 TWh in 2010. Half of the total global power generation takes place in OECD countries, followed by China (20%) and other Asian countries (~10%). Africa’s share is only 3%.<sup>82</sup> By 2050 electricity is expected to require up to half of total global energy demand. Moreover, many energy sector scenarios foresee at least a doubling of global power demand, reaching 40-48,000 TWh by 2050.<sup>83</sup>

The main challenges the power sector faces are meeting significant electric demand growth and addressing current low levels of electrification, environmental issues related to air emissions, a tightening supply of fossil fuels, and fast developing decentralized generation technologies. While new decentralized technologies will play a significant role in electrifying Africa, there is still enormous need for central generation plants to meet organic and inorganic growth in the sector.

#### 3.4.2 Electricity Use and Pricing in Africa

The total installed power capacity in Sub Saharan Africa is ~56 GW<sub>e</sub>, but only 49 GW<sub>e</sub> are currently available due to maintenance and unplanned shutdowns. The generation mix within the South African Power Pool (SAPP) is dominated by coal (74%), followed by hydro (20%), nuclear (4%), and diesel- and gas-fired power plants (2%). Coal dominates in South Africa, Botswana and Zimbabwe.<sup>17</sup>

**Sub-Saharan Africa power generation % by source**



**Figure 37. Current power generation mix in Sub-Saharan Africa<sup>15</sup>**

The electrification rates are very low in Africa. Angola and Mozambique are no exception, with only 26% and 12% of these populations having access to electricity respectively. The figures below show the electrification rates and the resulting number of people without electricity in each Sub-Saharan African country. North Africa is seen in sharp contrast with nearly 100% electrification.

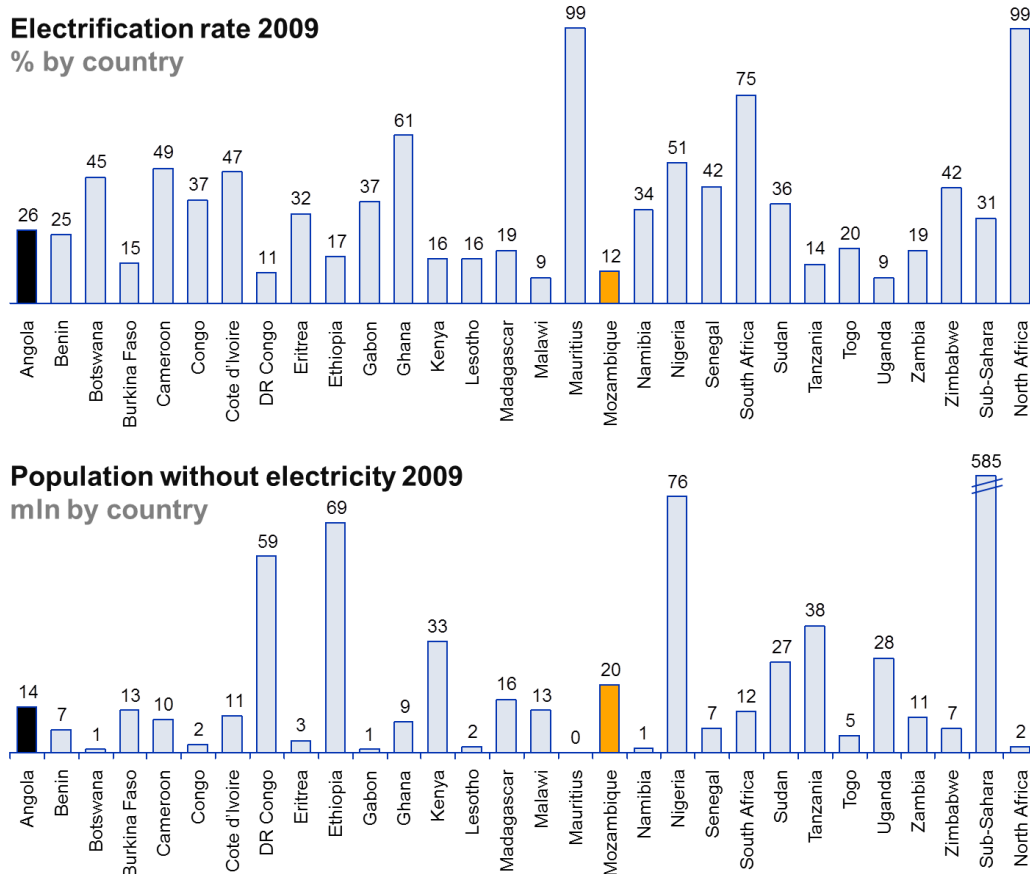


Figure 38. Electrification rate in Sub-Saharan Africa

Angola currently operates 160 MW<sub>e</sub> of gas-fired capacity, Tanzania 485 MW<sub>e</sub> (an additional 240 MW<sub>e</sub> planned by 2015), and Mozambique 207 MW<sub>e</sub> (another 450 MW<sub>e</sub> planned by 2015 and an additional 2,840 MW<sub>e</sub> by 2030), while South Africa plans 2,760 MW<sub>e</sub> of new gas generation according to SAPP plans.

The average regional per capita power consumption in 2009 was 1,404 kWh/yr, but this ranged broadly from South Africa with the highest average consumption at 4,500 kWh/yr and Malawi the lowest at 100 kWh/yr.<sup>17</sup> The following figure illustrates the per capita electricity use and generation:

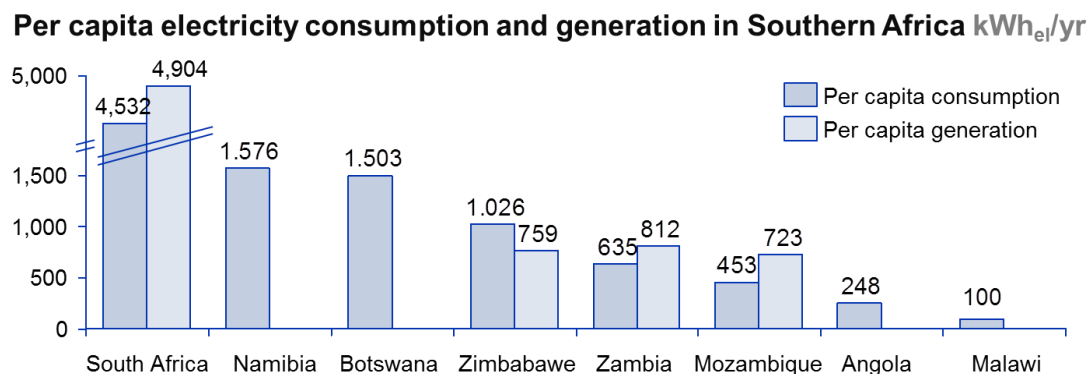


Figure 39. Per capita electricity generation and consumption in Southern Africa<sup>17</sup>



### 3.4.2.1 Southern Africa Power Pool (SAPP) electricity demand

The SAPP connects all SADC members on the continent. South Africa is its largest power market with a power capacity of 43.5 GW<sub>e</sub> (consisting of domestic and contracted import capacity). SAPP power demand has grown 2.8% per year since 1998. Alongside mining and manufacturing industries, increased electrification of households is driving demand. Total available capacity exceeds peak demand, but local capacity shortages occur due to limited transmission infrastructure.<sup>17</sup>

The regional SAPP expansion plan foresees an average demand growth rate of 3.9% per year, and expects almost 22 GW<sub>e</sub> of new generation capacity by 2015. This is ambitious given that in 2011 the installed capacity was only 56 GW<sub>e</sub> and implies that generation capacity needs to increase by 40% in four years, or 5.5 GW<sub>e</sub> per year. The following table lists the priority expansion plan generation projects, 52% of which are coal fired, 28% hydro based, and 20% gas fired.<sup>17</sup>

Country	Coal (GW <sub>e</sub> )	Gas (GW <sub>e</sub> )	Hydro (GW <sub>e</sub> )	Sum (GW <sub>e</sub> )
Botswana	1,800			1,800
South Africa	6,400	2,760	2,330	11,490
Namibia	400	800	85	1,285
Mozambique	1,200	450	34	1,684
Congo			1,128	1,128
Zambia			1,280	1,280
Other SAPP	1,500	288	1,114	2,902
<b>Total</b>	<b>11,300</b>	<b>4,298</b>	<b>5,971</b>	<b>21,569</b>

Table 9. Priority generation projects in the SAPP until 2015<sup>17</sup>

These ambitious expansion plans are not supported by the current power tariff structure, which in SAPP does not support the total costs of new generation projects. Thus, sector development will likely be hampered due to insufficient economics. Tariffs are lowest in South Africa (~3¢/kWh) and highest in Tanzania and Angola (~11¢/kWh), while new gas-fired levelized costs of electricity (LCOE) range from 8 to 12.5 ¢/kWh using a 10% discount rate. The following figure shows the average wholesale electricity tariffs in selected SADC countries:

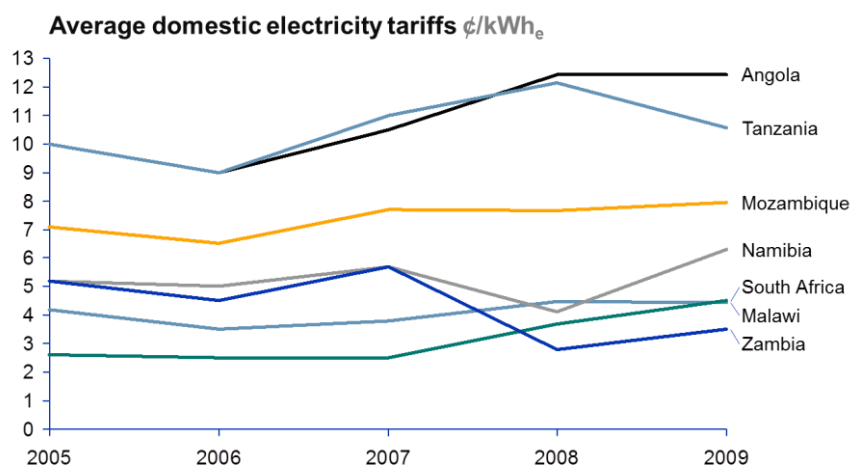


Figure 40. Average wholesale electricity tariffs in selected SADC countries<sup>2</sup>

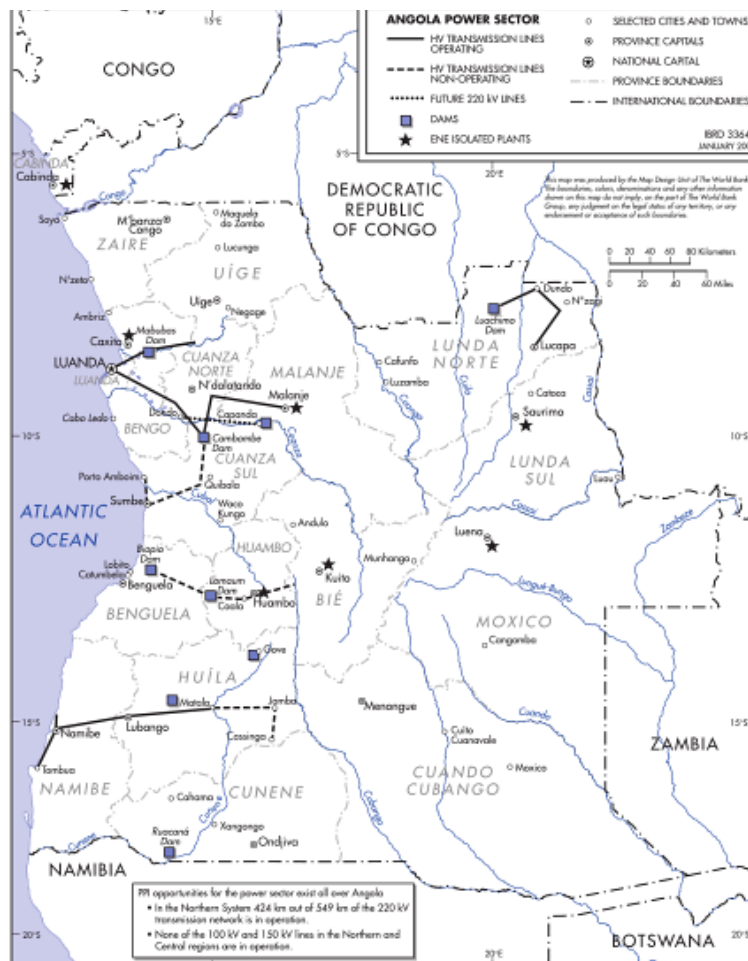
### 3.4.2.2 Angola electricity supply and demand

The peak demand in 2012 amounted to 1.32 GW<sub>e</sub>.<sup>84</sup> In 2010, the per-capita electricity consumption was 248 kWh/yr, which is 18% of the average regional consumption. The installed centralized power capacity in Angola was 1 GW<sub>e</sub> with hydro power comprising 76% of the total capacity. The major plants are shown in the table below:

Generation type	Plant	Installed capacity (MW <sub>e</sub> )
Hydro	Capanda	520
Hydro	Cambambe	180
Hydro	Gove	60
Thermal	Benguela	83
Gas		160
<b>Total</b>		<b>1,003</b>

**Table 10. Installed power generation capacity in Angola<sup>15</sup>**

Several small gas turbines are installed in Angola, although currently only two are operational in Luanda (2 x 56.8 MW<sub>e</sub>), which are fuelled by jet fuel. Luanda, Angola’s capital, consumes around two-thirds of the nation’s total electricity demand. The following shows the location of power plants and grid infrastructure in Angola:



**Figure 41. Power sector in Angola**

Empresa Nacional de Electricidade (ENE) is primarily responsible for the generation and supply of electricity in Angola, but there are also several privately owned generating companies. One of the sector's major hurdles is low electricity tariff levels that are not cost reflective. Electricity theft is a big issue as well, with about half of the electricity produced being consumed through illegal grid connections.

Angola's power consumption is expected to increase from 5.3 TWh in 2012 to 10.4 TWh in 2017. Business Monitor International forecasts that Angola's overall power generation will increase by an average of 15.4% per year from 2012-2017, to reach 11.9 TWh. This growth is driven by hydro power generation rising 16.2% per year, and hydro power will continue to dominate the electricity mix.<sup>85</sup>

Since 2010 infrastructure plans for electricity and the new national budget reference new hydro power plants and the associated transmission grid they require. Currently, 3 GW<sub>e</sub> of hydro are planned in the North and 1.4 GW<sub>e</sub> of hydro are planned in the Centre and South of Angola. The government has set a target of increasing generation capacity to 7 GW<sub>e</sub> by 2016 to enable a per capita consumption of 4,000 kWh/yr, which corresponds to only 1,700 full load hours per year.<sup>86</sup>

Given Angola's natural gas reserves, thermal generation is likely to gain increasing importance in the coming years. Accordingly, building gas-fired power plants near the oil operations, in part to supply these industries is being discussed.<sup>87</sup> The National Energy Security Strategy and Policy of 2011 seeks a 400 to 500 MW<sub>e</sub> CCGT plant based on gas available in Soyo by SONANGOL and ENE.<sup>88,v</sup>

The plant was envisioned to be operational in two to three years to supply Luanda via a new 400 kV transmission line. A second phase foresees a second CCGT. Assuming a total generation capacity of 1,000 MW<sub>e</sub> for these two CCGT plants, an 80% capacity factor and an electrical efficiency of 50%, this implies annual gas consumption roughly equivalent to 46 Bcf for these two CCGT plants.

To meet demand growth to 2025, installed generation capacity is required to increase from 1 to 9 GW<sub>e</sub>. As mentioned, this expansion will be based mainly on additional hydro capacities, followed by gas-fired capacities. Given that currently 760 MW<sub>e</sub> of hydro power are installed and 4.4 GW<sub>e</sub> are planned in the short- to medium-term, the total maximum potential for gas fired capacity is in the range of 2-4 GW<sub>e</sub> by 2025. Realizing this potential would require a total gas demand of 90 to 180 Bcf/yr to the Angolan power sector.<sup>vi</sup> Gas fired power plants face competition from hydro-power due to their lower levelized cost of electricity, but gas-fired plants offer a bridge to meet new demand and balance a dispersed grid before hydro power can come online. Hydro power plant capital costs in non-OECD countries range from \$830 per kW<sub>e</sub> (China) to \$2,500 per kW<sub>e</sub> (Brazil). Applying the netback analysis economic assumptions yields levelized generation costs for hydro plants in the range of \$31 to \$68 per MWh,<sup>vii</sup> which is below the cost of gas-fired plants.

On the other hand, natural gas power plants are modular, and can be distributed where best suited to match load growth and take into account constraints of the power grid's efficiency. Diversifying the generation mix can enhance security of supply in case of low hydro availability due to drought.

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<sup>v</sup> The most recent 5-year public investment plan (PIP 2013-2017), which was just issued in the beginning of March, gives key references to infrastructure in general but does not explicitly refer to gas.

<sup>vi</sup> Assuming an electrical efficiency of 50%.

<sup>vii</sup> Values are in real \$2013 terms with O&M costs of \$10/MWh and a capacity factor of 55%.

As such, gas fired power plants can provide short-term flexibility (to balance short-term supply or demand fluctuations) and long-term back up (to compensate periods of low hydro output).<sup>89</sup>

As a conclusion with respect to market potential for gas-fired power generation in Angola we consider 1 GW in a first phase and an additional 1-3 GW in a second phase.

### 3.4.2.3 Mozambique electricity supply and demand

In 2011, the electricity peak load was 620 MW<sub>e</sub> and is expected to grow steadily by roughly 50 MW<sub>e</sub> per year until 2030 to 1,600 MW<sub>e</sub> in 2030. The peak is being driven by increased household access.<sup>15</sup>

The peak demand in the EdM system reached 620 MW<sub>e</sub> in 2012 and is increasing rapidly (at 14% per year on average from 2005 to 2011). This excludes demand by the Mozal aluminum smelter, located near Maputo, which alone represents about 900 MW<sub>e</sub>.<sup>90</sup> As such, the total peak demand in 2011 was around 1,500 MW. In 2010, the per-capita electricity consumption in Mozambique amounted to 444 kWh, which is just 32% of the regional average. Electricity demand of the Mozal aluminum smelter is entirely imported from South Africa. This demand amounted to 8,350 GWh on average per year. Further domestic consumption amounted to 4,100 GWh in 2011. On average, the Mozal demand accounted for 72% of Mozambique’s total electricity demand in the past few years.

Electricidade de Mozambique (EdM) is the vertically integrated electric utility in Mozambique. EdM also manages participation in the Southern African Power Pool. Excluding Mozal’s supply, electricity generation in the EdM network in 2011 was 16,525 GWh. On average 81% of this total production was exported (measured over the period 2005-2011). National demand is mainly met by large-scale hydro power (88%) followed by local small-scale generation (10%), of which thermal power contributes 6% and hydroelectric power 94%, and, finally, imports (2%). Additional small-scale renewables (such as solar power) are insignificant in the power mix.

The installed electrical capacity in the country is estimated at 2,400 MW<sub>e</sub>, of which hydro power comprise about 2,200 MW<sub>e</sub> (92%). The EdM electricity generating facilities have an installed total capacity of 205 MW<sub>e</sub> (consisting of a mix of hydro, open cycle diesel and open cycle gas generators). The largest hydro power plant is located at the Cahora Bassa dam (2,075 MW) in the Zambezi River, followed by EdM’s own installed hydro plants in Mavuzi, Chicamba and Corumana. All of the capacity at Cahora Bassa, except for Mozambique’s entitlement of around 500 MW, is committed to the supply of electricity to South Africa and other countries in the Southern African region. Natural gas and liquid fuel based plants either belong to EdM or an independent power producer (EIGas).

The following table summarizes the main indicators of the Mozambican power system. It is worth noting the high combined commercial and technical losses in the system.

Indicator	2011 Value
Total peak demand	1,500 MW
Average demand growth (2005-2011)	14%
Domestic consumption (excl. MOZAL)	4,100 GWh
Total transmission and distribution losses	25%

**Table 11. Main indicators of the power system in Mozambique<sup>18</sup>**

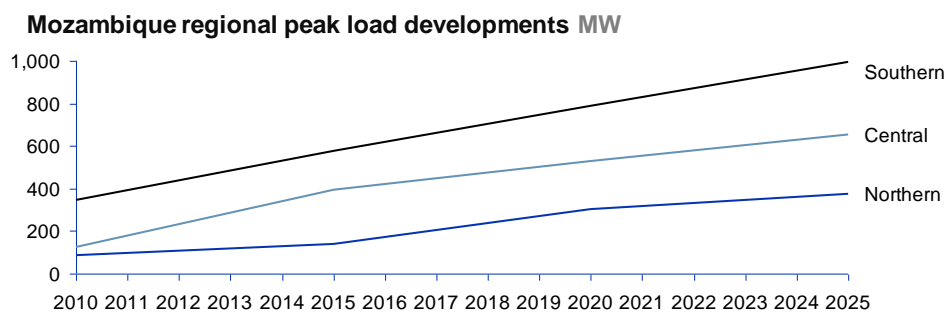
Mozambique’s gas-fired power stations consume a mere 8.4 Bcf of natural gas per year. This includes two power stations with a total installed capacity of 91 MW<sub>e</sub> which were provisional to start

in 2010 and 2011 respectively. The following table shows how the power sector’s gas consumption is split up among all gas fired power stations.

Power station	Annual gas use (Bcf/yr)	Commission
Temane (6x315 kW)	0.14	2006
Expansion of Temane (3x946 kW)	0.19	2009
New Temane	1.42	2011
Nova Mambone	0.01	2003
Maputo Thermal (3x24.7 MW)	4.74	2010
Beira (17 MW)	1.90	2011
<b>Total</b>	<b>8.40</b>	

**Table 12. Gas consumption of gas fired power stations in Mozambique<sup>91</sup>**

By 2025, the country’s total peak demand, excluding Mozal, is forecasted to rise to 2,026 MW. The South of Mozambique (around Maputo) will remain to be the key consumption area although higher growth rates are expected in the Central and Northern regions (see the figure below).



**Figure 42. Mozambique Peak Demand Forecast by Region<sup>17</sup>**

Regarding supply, most importantly, the country is in the process of further developing the hydro power potential including the Mphanda Nkuwa plant installation with a total capacity of 1,500 MW. Other projects in the planning phase include the Cabora Bassa North Bank, Lupata, Boroma and Lurio sites. Besides hydro power, coal and natural gas based power stations and wind and solar projects are being developed as well.

Adding to the small existing gas-fired power generation capacity (see table above) an independent power producer, Central Térmica de Ressano Garcia S.A, jointly owned by Aggreko and Sanduka Group, recently added in 2012 107 MW<sub>e</sub> of natural gas driven turbines to the country’s installed power capacity at Ressano Garcia. Additional gas turbines are planned to be installed in the near future increasing the gas fired capacity to 610 MW<sub>e</sub> (shown below).

Project	Location	Installed Capacity (MW)	Average annual generation (GWh)	Construction start date
Kuwaninga	Chokwe (Gaza)	40	280	2013-2015+
CTM	Maputo	70	491	2013-2015+
Sasol gas-fired plant	Ressano Garcia	150	1051	2013-2015+
Gigawatt gas-fired plant	Ressano Garcia	100	701	2013-2015+
Electrotec gas-fired plant	Ressano Garcia	250	1752	2013-2015+
<b>Total</b>		<b>610</b>	<b>4275</b>	

**Table 13. Planned and potential new gas fired power plant facilities in Mozambique<sup>Err</sup>**

Furthermore, Oilmoz plans to construct an oil refinery in Matatuine, south of Maputo, to be operational in 2014. The capacity of this refinery will be 350,000 bbls per day at an investment cost of \$8 billion. A 500 MW<sub>e</sub> gas-fired power plant is also planned at the project site. It is expected that some 15,000 jobs will be created in the construction phase of the refinery and power plant, along with the potential for roughly 2,000 permanent jobs to be created when the facility becomes operational, though most of the staff will be allocated to the oil refinery.<sup>92</sup>

Assuming 500 to 1,000 MW<sub>e</sub> of gas-fired capacity will be operational by 2025 to partly serve national and export demand<sup>viii</sup>, the annual gas consumption of the power plant fleet will be in the range of 23 to 46 Bcf.<sup>ix</sup>

As the hydroelectric potential of Mozambique is estimated to be more than 12,000 MW<sub>e</sub>, hydro-power will remain the key-pillar of Mozambique's power system. Given the low electrification rates and high, yet untapped, generation potentials, the development of the power sector is critical for further socio-economic development. Besides hydro capacity expansion, natural gas power plants, albeit their less favorable economics, offer the mobility to locate where best suited to match load growth and power grid constraint considerations. Furthermore, diversifying the generation mix can enhance security of supply in case of low hydro availability due to drought.

Sasol started operating a 280 MW<sub>e</sub> Combined Cycle Gas Turbine (CCGT) plant in Secunda, South Africa in July 2012 with gas supplied from Mozambique. They are now progressing with a 140 MW<sub>e</sub> gas-to-power opportunity in Mozambique with an investment cost of ~138 million EUR (\$180 million or \$1,280/kW<sub>e</sub>) scheduled for completion by May 2014. Gigawatt Mozambique, a Mozambican company with a minority stake from South Africa, is expected to invest ~\$230 million in 100 MW<sub>e</sub> of gas-fired power plants starting in 2013.

As a conclusion with respect to market potential for gas fired power generation in Mozambique we consider 0.5 GW in a first phase and an additional 0.5 GW in a second phase, though an additional 2 GW could be supported if exports are pursued to neighbors.

#### **3.4.2.4 Power prices in Angola and Mozambique**

According to the Regional Electricity Regulators Association, average electricity tariffs for consumers in Angola were 11 ¢/kWh in 2007.<sup>93</sup> Export prices of EdM in Mozambique have risen over the last years from 1.3 ¢/kWh in 2006 to 4.1 ¢/kWh in 2009.<sup>17</sup> According to the Regional Electricity

<sup>viii</sup> National peak demand for 2025 is forecasted at ~2 GW.

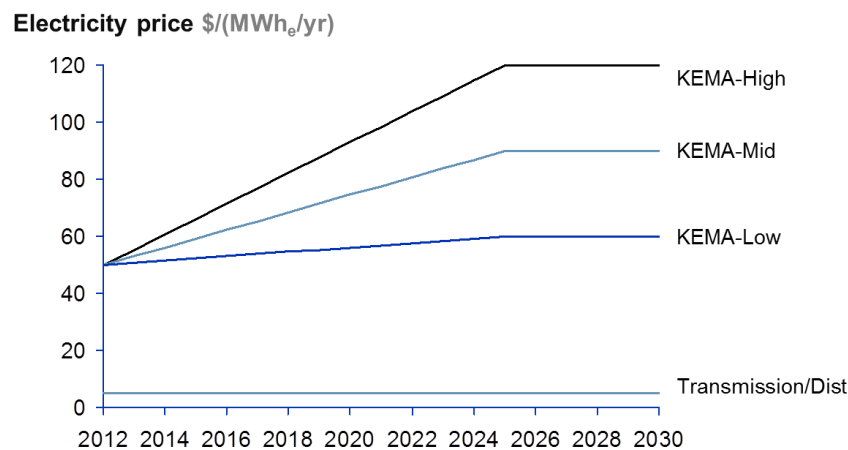
<sup>ix</sup> Assuming an electrical efficiency of 50% and an 80% capacity factor for CCGT.

Regulators Association, average electricity tariffs for consumers amounted to roughly 7.5 ¢/kWh in 2007. The following table lists retail and generator electricity prices assumed by ICF:<sup>17</sup>

	2012	2015	2020	2025
<b>Retail Price (2011¢/kWh)</b>	7.8	10.3	15.3	21.3
<b>Real annual increase (%)</b>	10.1	8.6	7.9	6.6
<b>Price for generators (2011¢/kWh)</b>	5.6	7.4	11	15.3
<b>Assumed price (2011¢/kWh)</b>	4.5	5.9	8.8	12.2

**Table 14. Assumptions for retail and wholesale power prices in Mozambique<sup>17</sup>**

DNV KEMA agrees that prices will rise in the short term to justify required investments, but that by 2025 they should level off and cease their increase as a balance between investment in and expansion of electric infrastructure is achieved. A \$5/MWh transmission charge deducted from the received revenues. The following three price scenarios are assumed for the netback analysis:



**Figure 43. Power price forecast for Angola and Mozambique**

### 3.4.3 Capex, Opex, Pricing, Gas netback value

To assess the netback value, assumptions on retail and generator prices and typical investment projects are taken from ICF International<sup>17</sup>, National Renewable Energy Laboratory (NREL)<sup>94</sup>, VGB<sup>95</sup>, the International Energy Agency<sup>96</sup>, and the U.S. Energy Information Administration.<sup>97</sup> The sources show a broad range of investment, operational, and maintenance costs for gas-fired power plants.

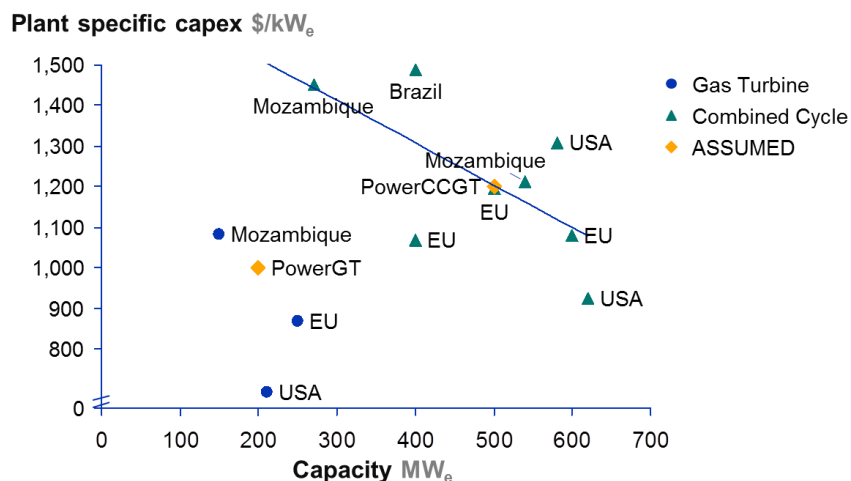
For open-cycle gas turbines, investment costs mentioned by NREL and VGB are at the lower end (ranging from \$670-845/kW<sub>e</sub>) whereas ICF reports investment costs of \$1,050/kW. Similarly, estimates for fixed and variable operational and maintenance costs also differ significantly.

Investment costs for CCGT plants range from \$917-1,415/kW<sub>e</sub>. Similarly to gas turbines, estimates for variable and operational maintenance costs show a broad cost range. The following table shows the costs for investment, operation and maintenance and technical efficiencies of various gas-fired power plant types:

Plant type	GT	CCGT	CCGT	GT	CCGT	GT	CCGT	CCGT
Source	ICF	ICF	ICF	NREL	NREL	VGB	VGB	EIA
Unit Size (MW)	150	270	540	211	580	250	400	620
Capacity factor (%)	80	80	80					
Investment costs (Million \$)	158	382	637					
Invest. Cost (\$/kW)	1,053	1,415	1,180	651	1,230	780	960	917
Fixed O&M (\$/kW yr)	25	20	20	5.26	6.31	23.4	24	13.17
Var. O&M (\$/MWh)	3.5	1	1	29.9	3.67			3.6
Heat rate (BTU/kWh)	9,315	7,100	7,100	10,390	6,705			7,050
Efficiency	37%	48%	48%	33%	51%	45%	60%	48%

**Table 15. CAPEX and OPEX for open cycle and combined cycle gas turbines**

The IEA lists CCGT investment cost ranges for European countries from \$1,000-1,500/kW<sub>e</sub>, providing support for VGB and NREL figures. For Brazil, IEA reports CCGT investment costs of \$1,440/kW<sub>e</sub>, which hints to higher costs for plants constructed in developing countries. This number fits with the high-cost assumption of ICF for a 270 MW<sub>e</sub> plant. The following figure illustrates the capital cost ranges for GT and CCGT power plants:<sup>x</sup>



**Figure 44. Capital cost ranges for GT and CCGT plants (\$2013)**

It can be concluded that the various publications implicitly take into account geographical issues that may alter investment costs. Specifically, the above table shows that power plants in different regions show significantly varying costs. Cost increases are thus expected for plants in remote locations. Cost differences can also occur due to seismic design differences, wage, logistical and productivity differences. Costs per kW differ with size of the plant, due to economies of scale. For Angola and Mozambique we assume \$1,200/kW<sub>e</sub> for a gas-fired CCGT plant of 500 MW<sub>e</sub> and \$1,200/kW<sub>e</sub> for a gas turbine unit of 200 MW<sub>e</sub>.

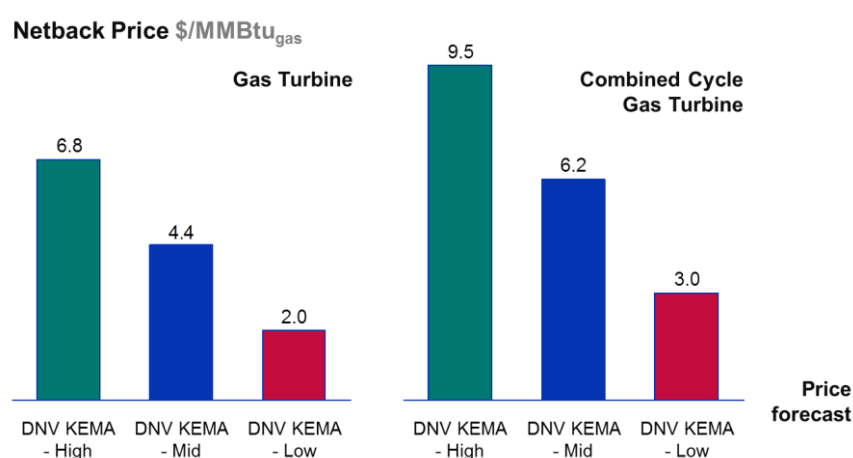
<sup>x</sup> Note that hydropower plants show capital cost of \$830-2,500/kW in non-OECD countries according to the IEA. We calculate according total generation costs of 3.1 to 6.8 ¢/kWh assuming a 10.7% WACC and O&M costs of 0.5 to 1 ¢/kWh. Also compare this with LCOE of new gas fired power plants ranging from 8 to 12.5 ¢/kWh. **Error! Bookmark not defined.**



Plant parameter	Power GT	Power CCGT	unit
Plant capacity	200	500	MW
Capacity factor	60%	80%	%
Annual gas consumption	8.4	22.8	Bcf/year
Gas intensity	8	6.5	MMBtu/MWh
Specific capex	1,000	1,200	\$/kW <sub>e</sub>
Specific O&M	25	20	\$/kW <sub>e</sub>
Total capital cost	200,000,000	600,000,000	\$
Annual O&M cost	5,000,000	10,000,000	\$/year
Construction time	1	2	Years

**Table 16. Parameters for Power plant project**

Natural gas netback values are found to be from 2.0-6.8 \$/MMBtu for simple Gas Turbine and 3.0-9.5 \$/MMBtu for CCGT under the three scenarios.



**Figure 45. Netback price for natural gas used to make power**

These facilities are assumed to meet local demand. Additional investments in electric grid would be required to meet regional demand that could negatively impact the netback value in an export oriented scenario.

### 3.4.4 Risks & Abatements

#### 3.4.4.1 Angola

Angola's average per capita power consumption is just a fifth of the regional SADC average. Thus, increasing electrification corresponds to a major, not only infrastructural, challenge.

Hydro-power potential is mainly untapped and represents – from a total cost perspective – a cheaper expansion option. As such, deployment of gas-fired plants will be limited, especially serving industrial demand, demand regions which are away from major hydro power plant sites and back-up and balancing purposes. Assuming a total deployment of gas plants amounting to 2-3 GW by 2025 yields an annual gas consumption of 96 to 140 Bcf/yr.

#### 3.4.4.2 Mozambique

Currently an approximate 1 million households are connected to the national grid. Efforts are made to develop off grid and micro-grid projects to decrease the number of households without electricity.

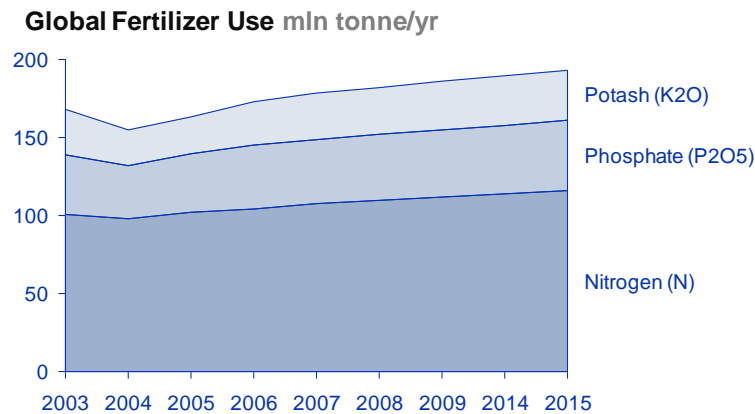
Besides a lacking grid and power plant infrastructure, funding is a critical issue and barrier to electrification. The North of the country appears particularly challenging, showing the highest demand growth rates, albeit from a low consumption level. Funding barriers for new infrastructure projects are further hampered by regulated end-user prices, which due to the associated price caps, limit possibilities for cost recovery of new investments.<sup>17</sup>

Mozambique has a large untapped hydro power potential which has to be taken into account when assessing the prospects for gas-fired power plants. Moreover lifetime costs of hydro plants are lower than those of gas plants. As such, alternative uses of gas might offer a higher value for the general economy. However, due to the high flexibility of gas-fired power plants, they have a certain role to play for providing peak power and supplying industrial facilities, serving as backup capacity in case of a low hydro availability and settling short-term supply/demand imbalances.

The increased use of gas in the power generation industry could facilitate the export of electricity to South Africa which is facing power supply shortages. Furthermore, there are requests filed by international power project developers amounting to 54.9 Bcf/yr at a gas price of \$4/MMBtu for a duration of 30 years.<sup>17</sup> However, this would concern power projects outside Mozambique and are thus uncertain. In any case, total gas use for the Mozambican power sector (to supply domestic and export demand) and for international power generation projects located abroad will stay rather limited until 2025. Our analysis indicates total annual gas consumption amounting to 130 to 150 Bcf/yr by 2025. Domestic power supply has the potential to reach annual gas consumption of roughly 50 Bcf/yr by 2025.

### 3.5 Urea

The three most significant crop nutrients (nitrogen, phosphorus, and potassium) are mixed together to produce a solid marketable fertilizer for crop application. Nitrogen is provided as ammonia which is often converted to urea or ammonium compounds. Phosphorus is provided from phosphate minerals from the US and Morocco, but also occurring in Africa. Potassium is provided in potash which is primarily produced in Canada, Russia, and Belarus, and hence must be imported to Africa. Total global demand for all nutrients is expected to grow steadily at 2% per year by the UN Food and Agriculture Organization (FAO) as shown in the figure below.



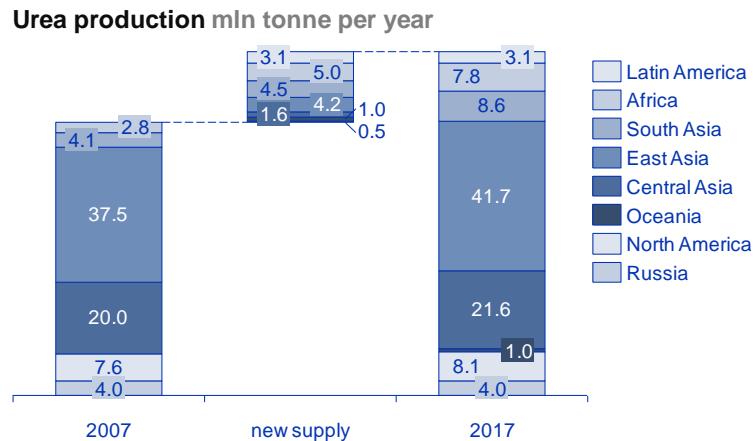
**Figure 46. Global Nutrient (N+P<sub>2</sub>O<sub>5</sub>+K<sub>2</sub>O) Consumption**

Nitrogen represents the most energy intensive component of fertilizer, and the basic building block of fertilizer initiatives. It comes in two principal forms, liquid ammonia and solid urea. Ammonia is derived from natural gas and air in the Haber-Bosch process, and urea comes from ammonia and carbon dioxide using the Bosch-Meiser process. Urea is measured by its nitrogen content with 1 ton of nitrogen being in every 2.14 ton of urea. Urea is the common nitrogen currency in fertilizer, and is considered as a final product from natural gas produced in Angola and Mozambique.

#### 3.5.1 Global Market Outlook

In 2011, 105 million ton of nitrogen fertilizer was produced globally, and this is expected to grow to 113 million ton/yr in 2015 driven by increased demand in Asia which accounts for 68% of this growth. India (25%) and China (24%) account for most nitrogen demand growth with remaining growth occurring in America (18%), Europe (10%), Africa (3%) and Oceania (1%).

Urea is one of the most widely produced chemicals and is a globally traded commodity. Urea from ammonia offers a gas monetization opportunity for low-cost stranded gas resources, and as a result the Middle East and Africa are increasing their urea production for export purposes. Currently the Middle East accounts for 32% of urea exports, and this is expected to grow through 2020. The figures below show where urea is currently produced and where new ammonia capacity is expected.



**Figure 47. Global urea production and new ammonia production capacity to 2017**

The International Fertilizer Industry Association expects 58 new urea plants to be built between 2010 and 2015. Increasing gas costs in the Middle East and North Africa has spurred interest in other African gas sources in Mozambique, Tanzania, Algeria, Nigeria, and the Republic of Gabon.

Approximately 50% of urea production capacity around the world is not utilized, and in South Africa over 70% of capacity is not operated. The primary reason this capacity is not used is because of high gas prices, but South African has specific problems resulting from an underinvestment in its facilities due to government forced price controls. Natural gas accounts for over half the production cost of urea, and because urea is a globally traded commodity with relative low transport costs, production has been driven to countries with low cost 'stranded' natural gas.

Prices for urea closely track natural gas prices which derives from Asian and European marginal producers setting the global price based on their higher natural gas prices.

Expectations for future urea prices can be bounded by IEA and Worldbank forecasts. The IEA assumes steadily rising prices in line with increases in energy costs, while the Worldbank takes a view in which prices reduce to 2035. DNV KEMA expects future urea prices to vary between \$380 and \$400 per ton in the period 2012-2030. We expect producers will respond to historically high prices by building newer and more cost effective facilities, but that they will seek to maximize profits by not overproducing and by retiring older more expensive capacity. The prices shown in the figure below are FOB from Europe, and would require about \$40 per tonne shipping charge for delivery to South Africa. This price, minus the shipping charge, is what urea is expected to fetch on the global market.

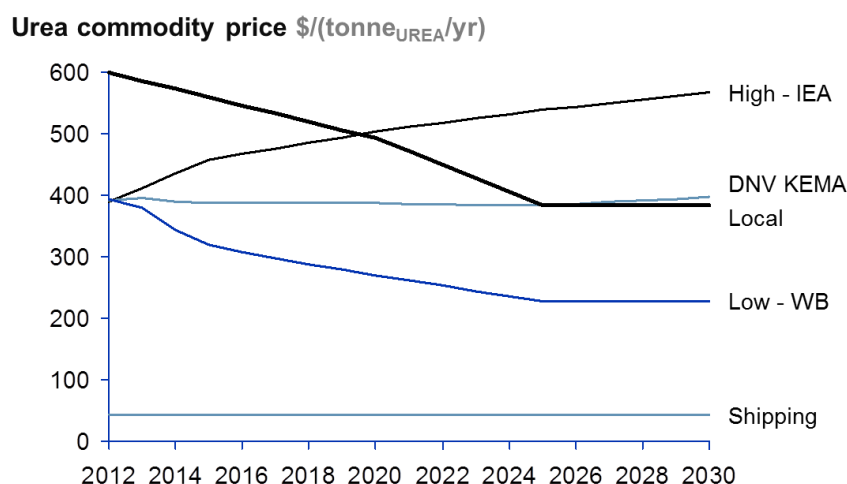


Figure 48. Urea price forecasts (\$2013)

### 3.5.2 Urea Use and Pricing in Africa

Africa has consistently lagged behind the rest of the world in its overall and per capita nitrogen use due to economic and societal constraints to the intensive agriculture it requires. Below are fertilizer per capita use in Africa compared to the Netherlands. Significant increases in fertilizer use are expected when the region is compared to South Africa and the Netherlands fertilizer use.

	Population (x 1000)	% GDP in agriculture	Workers in agriculture	Cultivated area (‘000 ha) <sup>98</sup>	Nitrogen use 2009 (ton/yr) <sup>99</sup>	Capita use (kg/pp)	Area use (kg/ha)
<b>Angola</b>	19,618	9.6%	85%	4,390	5,593,100	0.3	1.3
<b>Mozambique</b>	23,930	28.4%	81%	5,400	33,000	1.4	6.1
<b>Malawi</b>	15,880	30.2%	90%	3,730	61,165	3.9	16.4
<b>Zambia</b>	12,620	21%	85%	3,435	64,145	5.1	18.7
<b>Zimbabwe</b>	12,460	19%	66%	4,220	65,707	5.3	15.6
<b>South Africa</b>	50,460	3%	9%	12,446	414,304	8.2	33.3
<b>Tanzania</b>	46,218	27.8%	80%	13,300	66,942	1.4	5.0
<b>Netherlands</b>	16,665	2%	4%	1,078	256,887	15.4	238.3

Table 17. Key indicators across countries

Looking closer at a comparison of Mozambique, Tanzania, and Malawi shows the potential for expanded fertilizer use in Mozambique which has much fewer farmers using fertilizer that have to travel much farther to get it.

	Mozambique	Malawi	Tanzania
<b>Market size 2010 (tonne):</b>	33000	333,463	302,000
<b>Imports by private sector:</b>	100%	100%	100%
<b>No. of major Importers:</b>	5	20	5
<b>No. of Agro Dealers:</b>	>200	170	3885
<b>% Farmers using chemical fertilizers:</b>	4%	86%	45%
<b>Avg. distance to purchase fertilizers:</b>	+/-50km	7km	5km
<b>Workforce in agriculture:</b>	81%	90%	80%
<b>Fertilizer law</b>	No	No	Yes
<b>Fertilizer inspections:</b>	No	Yes	No
<b>Tariffs/import taxes:</b>	No	Yes	No
<b>Subsidy programs:</b>	Yes	Yes	Yes
<b>Fertilizer production plants:</b>	No	Yes	No
<b>Fertilizer blending plants:</b>	Yes	Yes	No

Table 18. Key indicators<sup>101</sup>

Demand and supply issues have prevented fertilizer use from growing. Demand is spatially dispersed between many small local markets with high seasonal variability which prevents economies of scale developing on the supply side for the production, import, and transport of fertilizer. In general high transport costs in Africa have further retarded its expanded use in new markets.

Less than 0.8% of global nutrients are consumed in Africa according to the International Food Policy Research Institute. Nitrogen accounts for 53% of nutrients used, while phosphate and potash account for 29% and 18% respectively. Currently Africa imports the majority of its nutrient needs. The majority of which are used in South Africa, with significantly smaller amounts being used in Zimbabwe, Malawi, Zambia, Mozambique, and Tanzania as shown in the figure below. Use is not expected to grow significantly due to continued high prices and a lack of familiarity with fertilizer use.

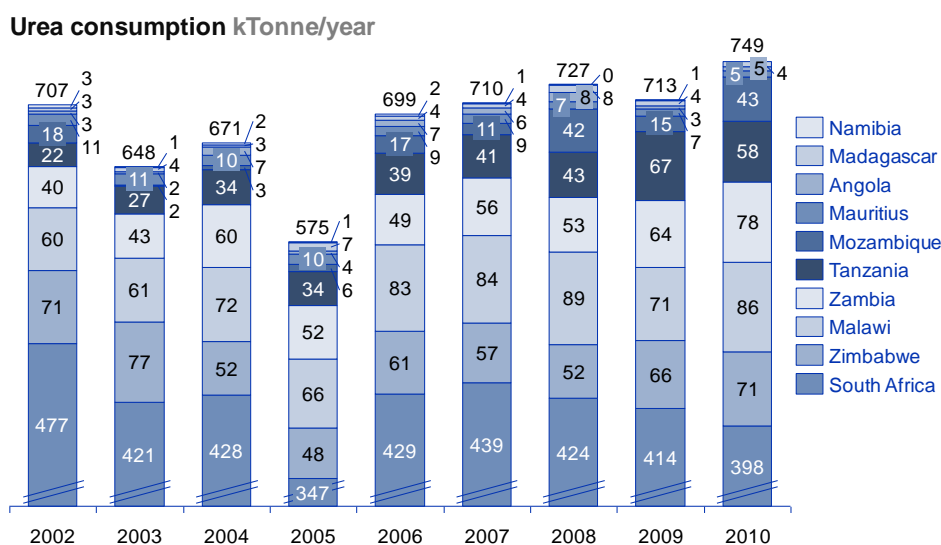
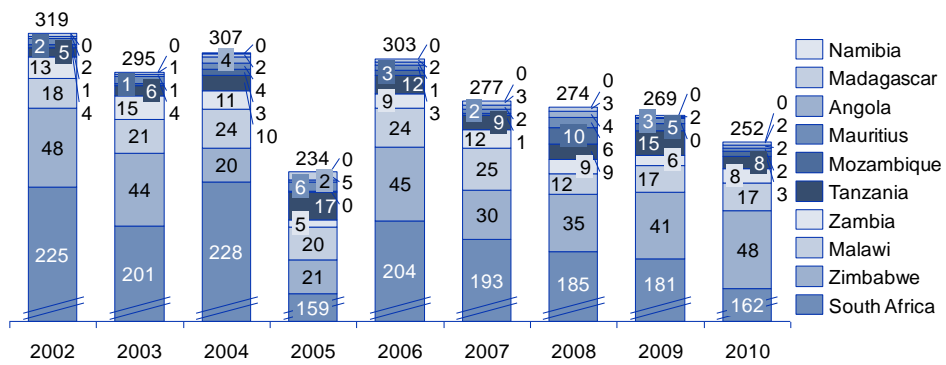


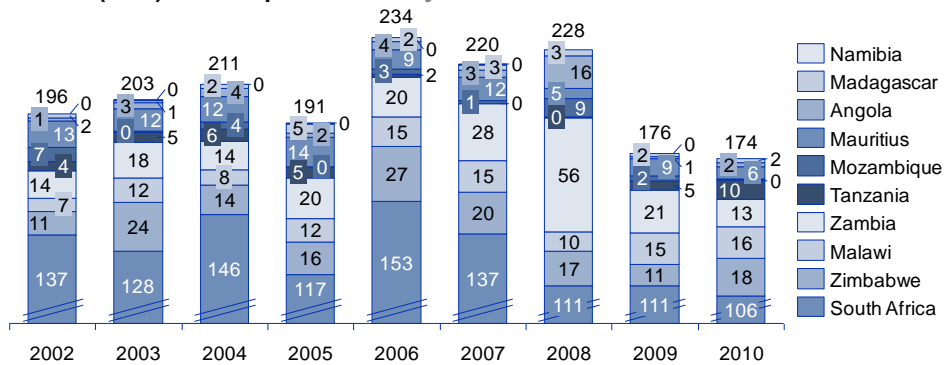
Figure 49. Nitrogen (N) consumption in Africa

**Phosphate (P2O5) consumption kTonne/year**



**Figure 50. Phosphate (P2O5) consumption in Africa**

**Potash (K2O) consumption kTonne/year**



**Figure 51. Potash (K2O) consumption in Africa**

Fertilizer producers are mostly in South Africa (Sasol Nitro, Foskor Ltd, Yara SA, Omnia Fertilizers Ltd, AECl, Triomf) and Zimbabwe (Chemplex, ZIMPHOS), but also Zambia (Greenbelt Fertilizers Ltd) and Nigeria (Port Harcourt). Ammonium nitrate is mostly produced in Zimbabwe, Senegal leads in the production of phosphoric acid and DAP/MAP, and the Ivory Coast is the main producer of complex NPK fertilizers. South African has the most ammonia production followed by Zimbabwe. South Africa leads in producing fertilizers, but is dependent on exports for the majority of its consumption today.

In 2009, the average global price for urea was ~\$250 per tonne. In Dec 2009 the typical FOB price was sub \$325 per tonne, but in South Africa the FOB price was \$520 per tonne. The figure below shows a comparison of FOB costs in Dec 2009. FOB includes freight charges to the respective hubs.



**Figure 52. Urea prices around the world for 2010**

South Africa, which is the largest fertilizer market, has greatly increased its fertilizer imports from 20% to 65% of total demand over the past twenty years. This shift was due to high domestic production costs that favored sourcing from global nutrient markets which opened up after Apartheid ended in 1994. Overall this has led to higher prices compared to other global regions.

In general the capacity of fertilizer production in SADC countries is underutilized because of competition from lower cost international producers, but there are a variety of other factors that serve as lessons to new developments in Mozambique or Angola:

- High natural gas prices or lack of its availability
- Reduced demand in major markets
- Lack of working capital, high costs, and limited access to financing
- Low performance of production capacity due to lack of investment in maintenance
- Lack of reliable water and electricity supplies
- Inefficient and deteriorating transport infrastructure
- Loss of skilled labor
- Protective barriers to trade that reduce cross border marketing
- Export bans to prevent subsidized fertilizer leakage

The import situation in South Africa creates an opportunity for Mozambique, but the items above are a reminder that many pieces must be coordinated to ensure a successful fertilizer industry can develop. Access to low cost energy is essentially a pre-requisite to compete with imports, but the other items are vital to create a profitable industry that can thrive.

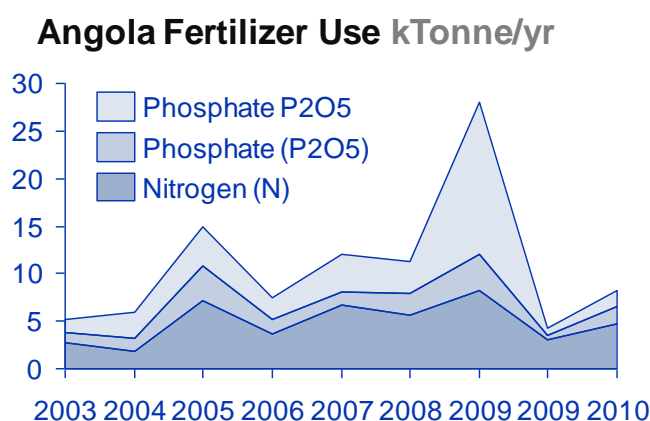
There are five fertilizer projects currently under consideration in Africa including two in Mozambique. These projects are seeking large and cheap quantities of natural gas, and involve foreign partners providing equipment and knowledge to build and operate such facilities:

1. Sumitomo Corp. and Toyo Engineering Corp have announced plans to invest \$1.2 billion over the next four years to build a 0.63 million tonne/yr fertilizer plant in Mozambique.
2. Pakistan's Fatima Group and its Danish partners are looking at building a fertilizer plant estimated to cost \$1 billion in African countries with phosphate and natural gas resources including: Mozambique, Algeria, Nigeria, and Tanzania.
3. Dangote announced construction of Africa's largest fertilizer plant in Nigeria with a capacity of 2.8 million tonne of urea per year. The plant is being built by Saipem Group and is expected to start operations in 2014.
4. Tata chemicals is setting up a 1.3 million tonne of ammonia/urea per year plant in Gabon with an investment of \$290 million.
5. Indorama corporation (Indorama Eleme Fertilizer & Chemical limited) announced investment of \$1.8 billion in a fertilizer and methanol plant in Port Harcourt, Nigeria. The fertilizer plant would produce 1.4 million tonne per year of nitrogenous fertilizers with a capital cost of \$1.2 billion.<sup>102</sup>



### 3.5.2.1 Fertilizer in Angola

Angola imports all of its fertilizer and has experienced wide swings in demand as a result of market price fluctuations. Angola consumes ~6,000 tonne of urea a year, and this demand is small at 1.3 kg Urea/ha compared to other African countries around 20 kg Urea/ha. The following figure shows historical fertilizer consumption for Angola.



**Figure 53. Fertilizer demand in Angola**

Item	Imports (tonne)
Urea	1962
Ammonium nitrate	2791
Ammonium sulphate	5886
MAP/DAP	41
NPK < 10kg	1050
NPK >10kg	9833
Other N&P	18
Other <sup>xi</sup>	51
Superphosphate	425

**Table 19. Angola fertilizer imports in 2010**

Angola is a much less developed market for urea due to relatively low use of land, in part due to the civil war which led to many inhabitants to move from the rural areas to the city and the large number of landmines still not removed. There are significant opportunities to expand fertilizer use, and the production of an ammonia/urea plant has been on the government agenda since the early 1980s. Given Angola's current low demand for fertilizers, most output would have to be sold abroad, and the plant would require a very low gas price to be economic on the highly competitive international fertilizer market.

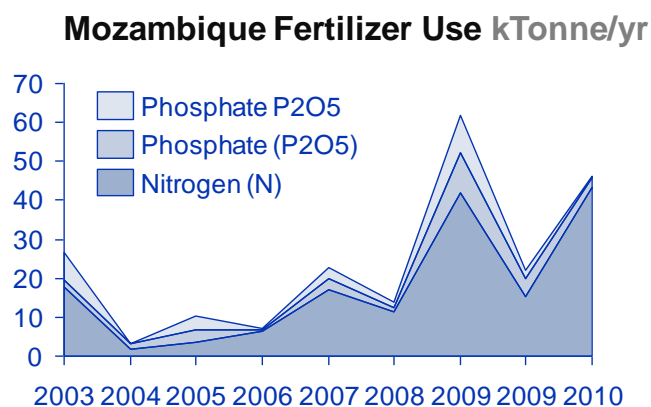
In 2011, a group of Japanese firms won a \$1.3 billion contract to build a first-of-its-kind plant in Angola using locally produced natural gas in the Zaire Province, 300 km north of Luanda. Production is anticipated to start 2015, and the plant would be capable of producing 660,000 ton of ammonia and 580,000 ton of urea a year. Half of the ammonia would be exported, while all urea would be shipped domestically. It is uncertain if this project will move forward, and due to low demand in

<sup>xi</sup> Including Potassium chloride/sulphate/nitrate, and other PK compounds

Angola the project is expected to focus on export via ships. In this respect Mozambique offers a better environment for a urea plant that serves regional demand.

### 3.5.2.2 Fertilizer in Mozambique

Mozambique has experienced considerable growth in its fertilizer demand over the past decade despite high prices and relative scarcity from depending on imports. It does not make any of its own fertilizer, but imports much of the region’s growing fertilizer demand through its Beira Port. Mozambique consumed 50,000 tonne of fertilizer in 2010, and forwards approximately 200,000 tonne of fertilizer through its Beira Port to Malawi, Zimbabwe, and Zambia. The figure below shows Mozambique’s current domestic consumption of fertilizer.

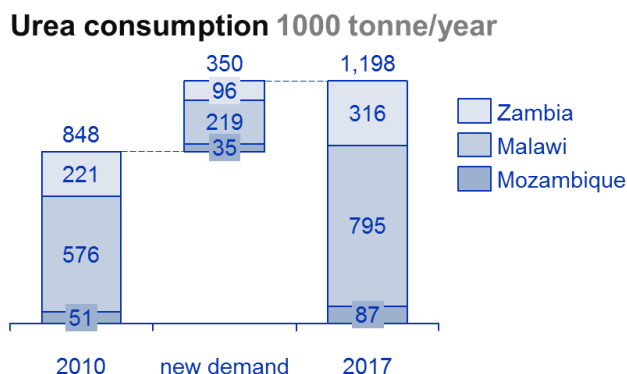


**Figure 54. Fertilizer demand in Mozambique**

Fertilizer demand of Malawi and Zambia is large and consistent, and because it is imported, it will benefit from more local urea production in Mozambique. These demands are the principal outlet for Mozambique produced urea.

There remains significant room for fertilizer use growth in Mozambique as currently only 6 kg of nitrogen is applied to each hectare (kg/ha) of cultivated land while neighboring countries apply around 16 kg/ha, and first world nations use more than 200 kg/ha. The region could grow towards 20 kg/ha use for optimal crop growth, which anticipates a doubling of current demand. In Mozambique, sugar cane and tobacco account for 90% of fertilizer demand. For reference South Africa applies ~30 kg/ha of urea, and the Netherlands uses ~280 kg/ha.

Urea demand is projected to grow significantly with total Mozambique consumption rising from 51,000 tonne in 2011 to 87,000 tonne in 2017, while those of its neighbors Zambia and Malawi grow similarly for a collective increase from 848,000 tonne in 2011 to 1,198,000 tonne in 2017. The figure below illustrates the growth in urea demand.



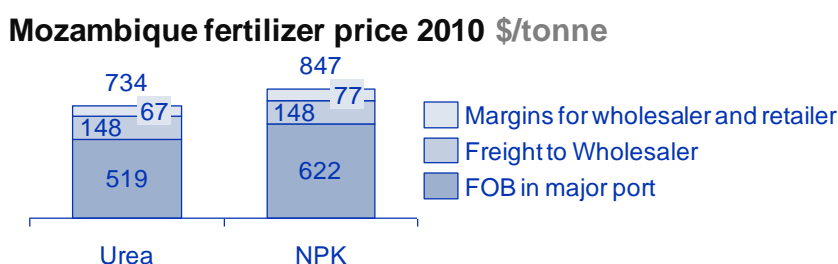
**Figure 55. Urea demand forecast for Mozambique and its surrounding countries**

This is driving discussions around a 630,000 tonne/yr facility by Sumitomo and Toyo Engineering that would supply Mozambican, Zambia, and Malawi consumption. Given the location of Zambia, Malawi and the huge gas reserves in Mozambique the most logical location for a fertilizer facility is in the northern part of Mozambique, close to gas reserves and transportation links to neighbors and global markets.

### 3.5.2.3 Prices in Mozambique

The Mozambique Fertilizer Company imports nitrogen, potash, and phosphates from South Africa, blends it in Chimoio near Beira Port, and sells their product within the region. The facility can blend 55,000 tonne/yr with one 8 hr shift per day. Urea, ammonium sulphate, and lime ammonium nitrate were sold by the Mozambique Fertilizer Company in February 2012 for \$588, \$529, and \$441 per tonne respectively, which were high prices relative to global markets, but about half the price of three competing commercial fertilizer importers that provide urea and other final fertilizer products.

Mozambique’s urea and NPK price in 2008 was \$519 and \$622 per tonne respectively in Beira Port, but an additional \$225-235 per tonne is added to these FOB prices for transport and margins to get to whole sale prices of 734 and 847 per tonne respectively. The figure below shows this build up.



**Figure 56. Retail fertilizer prices in Mozambique**

The retail price of NPK fertilizer at the local level can be much higher at \$1,600 per ton due to severe limitations in its availability, high costs associated with the small volumes utilized, and competition for delivering the urea to inland countries of Zambia and Malawi. Recently the retail prices of urea and NPK have been from \$800-\$1200 per tonne.

### 3.5.3 Capex, Opex, Pricing, Gas netback value

Natural gas accounts for a significant share of urea's production cost, and is almost all of the marginal production cost. The producer cost curves shown below suggest a marginal cost of production of \$250-\$320 per ton of urea would be the floor to prices the next few years. In addition the SADC region would be cushioned by about \$40 per tonne freight transport savings. Since urea prices have regularly exceeded \$500 per tonne in the SADC region, there is significant opportunity to create value. New plants are coming online in Africa and the Middle East to benefit from rising fertilizer plants, and these facilities threaten this price floor if fertilizer demand collapses.

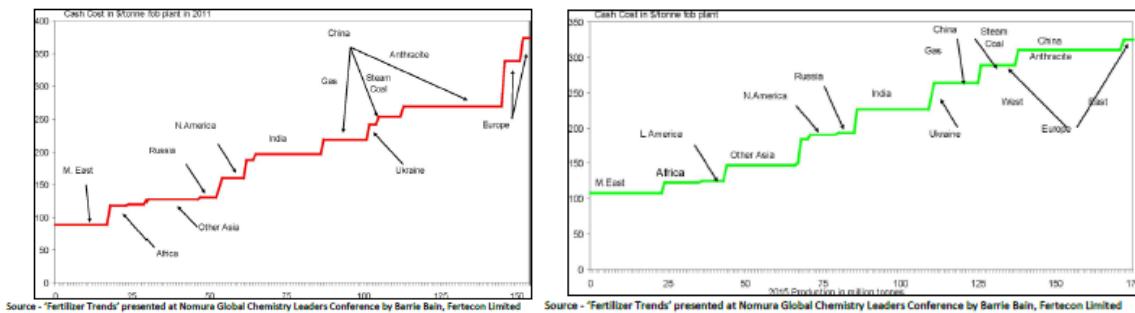


Figure 57 Marginal cost of urea production globally in 2011 and 2015

The cost to construct a urea plant is expected to be higher in Mozambique and Angola than in other developed countries due to a lack of infrastructure and absence of expertise around such facilities. Still there are several proposals to build a plant if gas is made available at an acceptable price. To evaluate the value of gas to such projects, a net back analysis is performed to calculate the value of natural gas under assumed urea prices, production facility costs, and financing requirements. The netback value provides the maximum natural gas price in order for the produced fertilizer to compete in the global market.

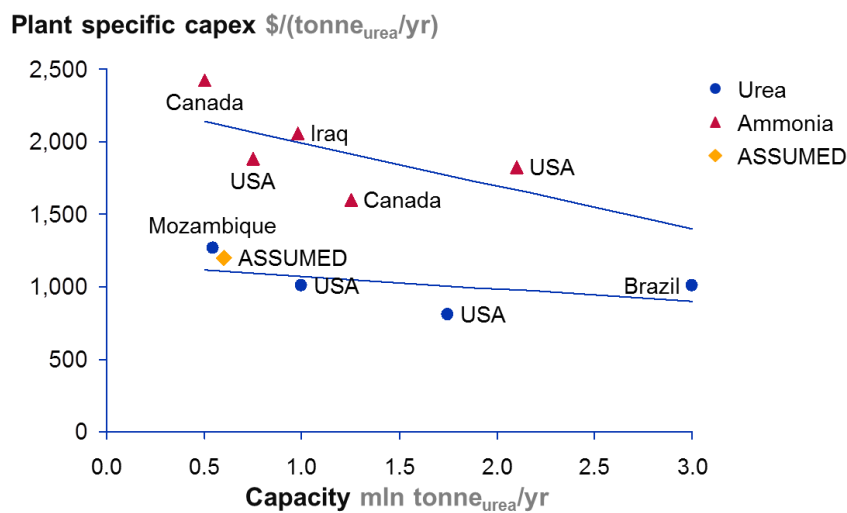


Figure 58. Capital cost of urea and ammonia plants

Using these figures, the following parameters are used in the net back calculations for Urea:

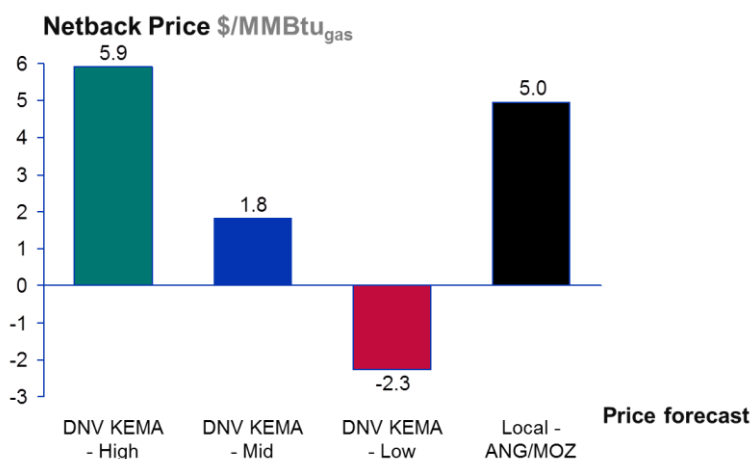
Plant parameter	Value	unit
Plant capacity	600,000	tonne/year
Capacity factor	90%	%
Annual gas consumption	17.7	Bcf/year
Gas intensity	32.7	MMBtu/tonne
Specific capex	1,200	\$/tonne/year
Specific O&M	38	\$/tonne/year
Total capital cost	720,000,000	\$
Annual O&M cost	22,800,000	\$/year
Construction time	3	year

**Table 20. Parameters for urea plant project**

The plant is assumed to take 3 full years to construct, but its economic lifetime is set at 20 years.

As mentioned previously the two primary sources for global urea price forecasts differ in their expectations with the IEA forecasting rising prices, and the World Bank projecting declining prices. The relative impact is significant to the netback value of gas, and so DNV KEMA is using a moderate scenario to calculate the netback value with the IEA and World Bank scenarios serving as high and low sensitivities. The price assumed has a \$43 per ton freight charge deducted from it to reflect the added cost of getting the urea to market.

The analysis suggests a natural gas netback price of 1.8 \$/MMBtu would justify undertaking the project, while higher than required returns would be achieved at lower natural gas prices. Under the IEA urea prices the netback value rises to 5.9 \$/MMBtu of natural gas, and under World Bank projects the netback value lowers to a negative -2.3 \$/MMBtu as illustrated below. In the situation where local prices prevail, which is a moderate scenario overall, the netback value is 4.9 \$/MMBtu. The netback value of natural gas is heavily dependent on the assumed urea price.



**Figure 59. Netback price for natural gas used to make urea**

The sales price under the local scenario excludes the \$43 per ton shipping charge to get to market. The proposed facilities are expected to be built primarily to support local urea demand, and secondarily to supply to the global market, so this charge penalizes the facility which will essentially be creating a new regional market hub around it. Furthermore the present prices of urea in the SADC region are consistently \$200 per tonne greater than the other hub prices, which creates an opportunity to either charge a premium for urea, or significantly reduce its price to end users.

Such a facility will be relatively low in the production merit order, and thus is expected to continue operating at lower urea prices, though its profitability will be impacted. To reduce financial risk and benefit from potential upsides it is suggested that governments partially set the sale price of natural gas to these customers by the value of the resulting commodity. This accomplishes three important items to ensure a successful project:

1. Commodity producer is ensured of their returns if a commodity price collapse occurs,
2. Likewise the government is ensured to capture some of the benefit from rising commodity prices
3. By ensuring the project moves forward, direct and indirect jobs are created independent of any government revenue resulting from the project

### **3.5.4 Risks & Abatements**

Three trends combine to potentially diminish the upside of domestic fertilizer production. Foremost is that population growth is slowing, and as a result the excess fertilizer capacity could increase and put downward price pressure on global prices due to marginal producer shifts. Fortunately there should always be ~\$50 per ton urea of value to capture from avoiding shipment of urea to Mozambique or Angola.

Secondly, the genetic modification of crops could enhance plants ability to fix nitrogen which could further diminish the need for nitrogen fertilizers. These advances appear inevitable, but it is not clear that countries will allow such crops as already there is significant resistance to their use in Europe and other parts of the developed world.

Thirdly, mandates to recycle waste streams from waste water treatment plants could provide a significant source of nitrogen to agriculture at low cost as the process would be performed the auspices of water treatment, and not fertilizer production. The likelihood of these materials being directed to energy crops is high, but there are challenges to using such material on agriculture fit for human or animal consumption due to the presence of complicated contaminants with unknown effects to human health.

International fertilizer project developers filed requests to Mozambique for gas supply, mainly serving export markets, totaling 65 Bcf/yr for a duration of 20 to 25 years. The requested prices range from 1- 3.2 \$/MMBtu.<sup>17</sup> Though these projects may be considered uncertain as the global economic development drives them, these project developers might also be incited to develop domestic projects and serve as an example for Angola.

### 3.6 Methanol

Methanol is a global commodity primarily produced from natural gas and, in China, from coal. End uses are categorized into chemical and energy as follows for:

1. Chemical derivatives, such as formaldehyde (in pharmaceuticals, wood, automotive industry), acetic acid (to produce fleece, adhesives, paints), dimethyl terephthalate (for recyclable plastic bottles), or methyl chloride (in silicones)
2. Energy applications, such as blending in gasoline, as a fuel for domestic heating and cooking, to produce DME (dimethyl ether) for LPG blending, or production of MTBE and olefins

#### 3.6.1 Global Market Outlook

##### 3.6.1.1 Demand

Two-thirds of the World’s methanol is used for the production of chemical derivatives, whereas the remainder is used for energy related applications. In 2012, global methanol demand was ~51 million tonne, excluding methanol produced in integrated methanol-to-olefin factories. This represents a year-on-year growth of 5% compared to 2011. The largest share of growth came from Asia, and primarily China, which saw an increase in both end use applications. The Asia Pacific region uses 70% of global methanol, and China accounts for 75% of this demand.<sup>103</sup> China remains a net importer of methanol despite new coal-to-methanol-to-olefins or methanol-to-olefins factories coming on-stream in 2012. The latter type is supplied by the merchant methanol market whilst the former occasionally sources methanol on the merchant market to supplement its own methanol production.

Methanol demand is expected to continue growing at a rate of just under 17% per year, driven by the gap between the price of crude oil compared to natural gas and coal, which leads to an increase in fuel-blending. Chinese growth is expected to keep increasing due to various fuel-blending standards currently being implemented, and because the production of olefins from methanol is competitive to the production of olefins from naphtha at current crude oil prices. Other countries have standards for fuel-blending in place, or are currently conducting fuel-blending trials, which is driving their growth. As shown in the figure below, North East Asia (i.e. mainly China) is expected to primarily drive global growth in demand for methanol.

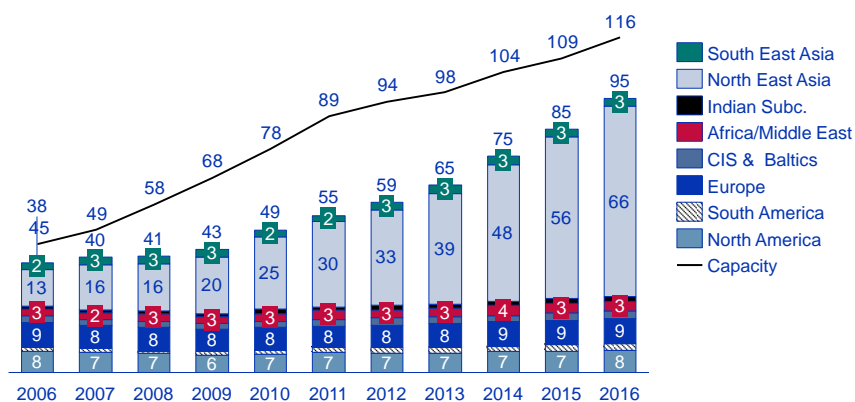


Figure 60 Methanol demand by region and supply (MTPA)<sup>104</sup>

### 3.6.1.2 Supply

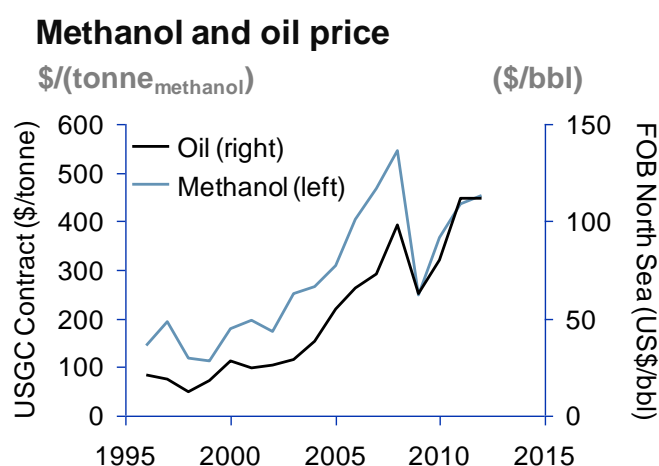
As mentioned above, supply additions took place in China, but it remains a net importer. Other supply additions are shown in the next table. Iran considers building 14 methanol plants to add ~4 million tonne/yr capacity. However, sanctions are likely to postpone these projects.

Country	Site	2010	2011	2012	2013	2014	2015	2016
Canada	Methanex, Canada		0.47					
	Pandora Methanol			0.85				
	Geismar I, Louisiana, US					1.00		
United States	Geismar II, Louisiana, US							1.00
	Channelview, Texas, US				0.80			
	Beaumont, Texas, US			0.70				
Venezuela	Metor 2, Venezuela	0.85						
Azerbaijan	Azmeco				0.70			
Russia	JSC Ammonly							
	ZAO Ural Methanol Group							
Iran	Kharg 2					1.40		
Oman	Salalah Methanol	1.30						
Egypt	EMethanex		1.26					
India	GSFC				0.165			
Brunei	Brunei Methanol	0.85						
New Zealand	Motunui, New Zealand				0.70			
	Waitara Valley, New Zealand					0.70		
China	Multiple projects	11.05	7.77		4.20	3.60		
Global	All projects	14.05	9.50	2.42	5.70	6.70	0.0	1.00

Methanex annual report 2012, Ministry of Energy and Energy Affairs

**Table 21. Methanol supply additions in 2012 and expected outside of China<sup>103,105</sup>**

Methanol prices are influenced by global supply and demand characteristics, but due to its use, marginal demand and price is influenced by crude oil prices, which it tracks closely as shown below:

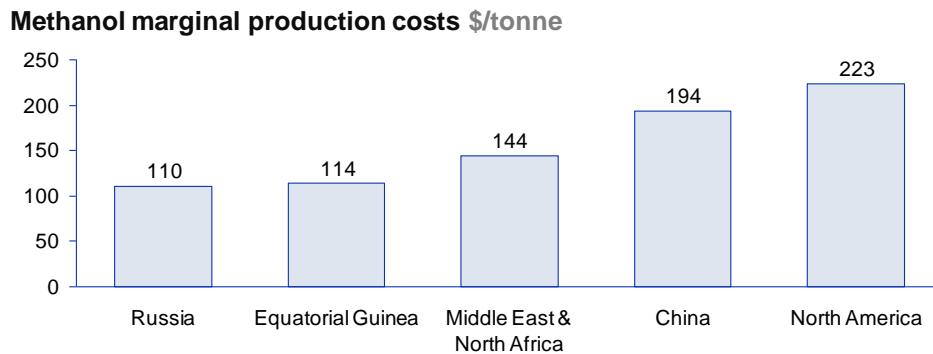


**Figure 61. Relation between oil prices and methanol prices<sup>106</sup>**

Overall, methanol prices in 2012 to Asian consumers were fairly stable between \$355-375/tonne. Southern Chemical Corporation (SCC), one of the largest importers and a market leader of methanol

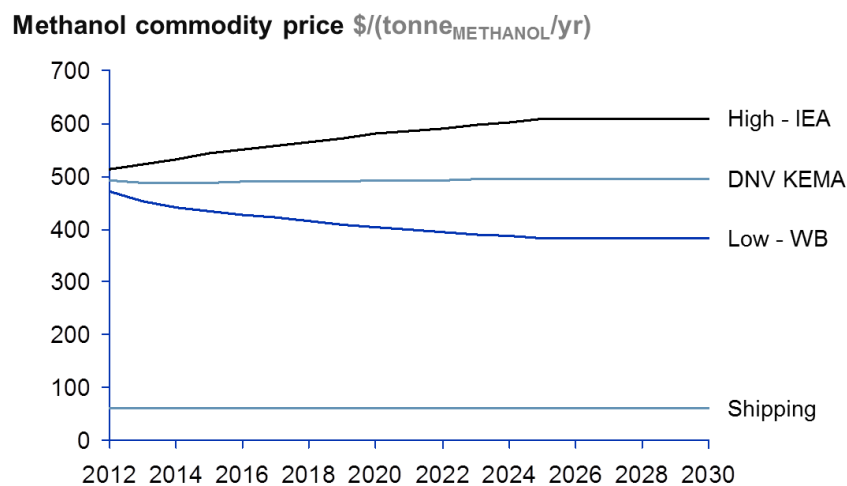


sales and distribution in North America, posted an average contract price for the US of ~\$450/tonne. In contrast, SCC contract prices were just under \$200/tonne in mid-2009 as a result of the financial crisis. The world’s largest Methanol producer, Methanex, realized an average price of \$382/tonne in 2012 compared to \$374/tonne in 2011. Production costs for methanol are considerably below its market price, and due to high capacity underutilization, these low costs reflect a high barrier to entry and resulting risk for new production facilities seeking a return on their investment.



**Figure 62. Industry methanol production cost curve<sup>107</sup>**

Price forecasts for methanol are provided by the World Bank, IEA, and IHS. The forecasts diverge with the IEA forecast being higher than World Bank, and the IHS forecast starting lower compared to both IEA and World Bank, but approaching the average of both series in the long-run. DNV KEMA supports a more moderate and flat price forecast to reflect relative loose market dynamics from underutilized capacity. The following forecasts are used in the netback analysis for methanol:



**Figure 63. Methanol price forecasts (\$2013)**

These prices represent the price paid in Asian markets, and the corresponding shipping charge to these destinations of \$60 per tonne is deducted from the received revenue. The high and low price scenarios are based on IEA and WorldBank forecasts respectively. Values are shown below:

Methanol price (\$2013/Tonne)	2013	2014	2015	2016	2017	2018	2019	2020	2025
High - IEA	523	533	543	550	558	565	573	580	608
DNV KEMA	488	487	489	489	490	490	491	492	495
Low - WB	453	441	434	428	421	415	409	403	382
Shipping	60	60	60	60	60	60	60	60	60

Table 22. WorldBank and IEA Methanol price forecasts

### 3.6.2 Methanol Use and Pricing in Africa

African and Middle Eastern combined demand is only 5% of global demand and expected to drop in relative terms due to high growth in Asia. Absolute demand is expected to remain at current levels or slightly higher. With a share of 72%, methanol demand is highest in South Africa.

Division of African methanol demand % by region

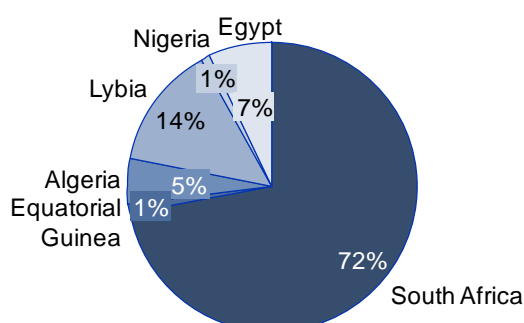


Figure 64. African methanol demand by country<sup>108</sup>

In 2011, net export from the African continent was 1.99 million MTPY of methanol which is expected to rise to 2.65 million MTPY in 2016.<sup>104</sup> As a result of its limited demand, methanol seems to be more suitable for export to Asia Pacific than for own consumption.

One possible way to increase the use of methanol in Mozambique and Angola is to approve the introduction of methanol fuel blending. Methanol fuel blending is widely applied in China and retail pumps sell low level blends (e.g. M15 = 15% methanol) in many parts of the country. In this way, China uses its abundant coal resources to create methanol and reduce its dependence on gasoline imports. As both Angola and Mozambique import refined oil products (elaborated on in the Gas-To-Liquids section), methanol fuel blending could directly reduce their imports.

Within the SADC region, only South Africa has its own methanol production facilities. The facility has a capacity of 140,000 tonne/yr and is owned and operated by Sasol in Sasolburg. Several other facilities have been proposed in Mozambique and Tanzania as displayed in the following table:

Investor country	Site	Gas use (MMcf/d)	Gas use (Bcf/yr)	Gas Price (\$/MMBtu)	Lifetime (Yr)
Canada (Wentworth)	Palma, Mozambique or Mtwara, Tanzania	140	46.05		25
Japan	Palma, Mozambique	77	25.3	4.07	20
Japan	Palma, Mozambique	n/a	n/a	n/a	n/a
India	Palma, Mozambique	129	42.4	1.00	30
Germany	Palma, Mozambique	1425	468.1	2.00	25
South Korea	Palma, Mozambique	n/a	n/a	n/a	n/a

**Table 23. Proposed Methanol plants in Mozambique and Tanzania<sup>109</sup>**

The most remarkable project is proposed by the Germany company GigaMethanol BV, which aims to build and operate the world’s largest and most efficient methanol plant in Mozambique. Its capacity is proposed to be ~7 MTPA or about 15% of global supply and is expected to cost around \$3 billion. Furthermore, the plant is expected to turn part of the methanol into gasoline, which could satisfy some of Mozambique’s domestic gasoline demand. Gasoline accounts for around 40% of the \$600 million that Mozambique spends each year on purchasing fuel. Around 2,000 construction workers will be needed to build the plant.

Other facilities in Africa producing methanol are geared towards the North American and European markets. For example, the existing facility of Atlantic Methanol in Equatorial Guinea mainly exports to these regions. Furthermore, the \$700 million and 0.85 million MTPA Delta Methanol plant in Nigeria proposed by the Gulf of Guinea Oil Exploration company is said to export mainly to Europe.

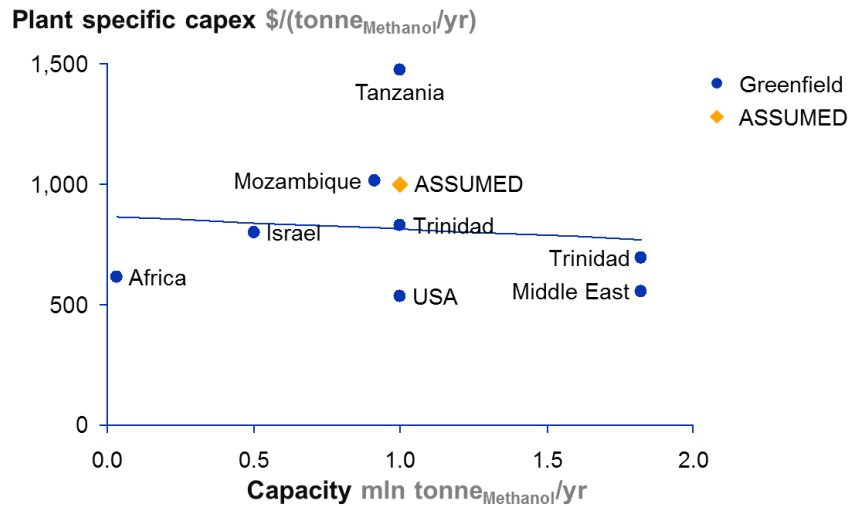
### 3.6.3 Capex, Opex, Pricing, Gas netback value

Capital costs represent the largest share of methanol production costs, accounting for ~50% of costs. Although strongly dependent on actual gas prices, natural gas may represent only 15% of the total costs associated with methanol production, which is equal to the other operating costs. Shipping is accountable for the remaining 20%.

Capacities of large scale methanol plants have increased from 2,500 TPD (0.875 MTPA) in the 1990’s to 5,000 TPD (1.75 MTPA) today in order to take advantage of economies of scale. Also, larger plants ranging from 10,000 TPD (3.5 MTPA) to even 20,000 TPD (~7 MTPA) are being considered.

A natural gas based methanol plant consists out of three main sections: the first section reforms natural gas into synthesis gas. In the second section, synthesis gas reacts to form methanol. In the third section, the methanol produced in the second sections is purified to reach the desired purity. The first section is most capital intensive, representing ~60% of total capital expenditures.

Estimates for capital costs for a methanol plant vary considerably between different sources. Fleish et al.<sup>110</sup> use a figure of \$600/TPY of output for a world-scale plant located in the Middle East, whereas Methanex<sup>106</sup> estimates replacement values for its existing plants in the range of \$800 to \$1,050/TPY. The latter is thus a typical figure for the Americas and New Zealand. Due to this disparity between estimates, we have researched costs of existing plants to find that most projects are within the \$600-900/TPY range. Notable exceptions are Tanzania, which includes urea production as well, and Iranian plants with considerably lower investment projected costs.



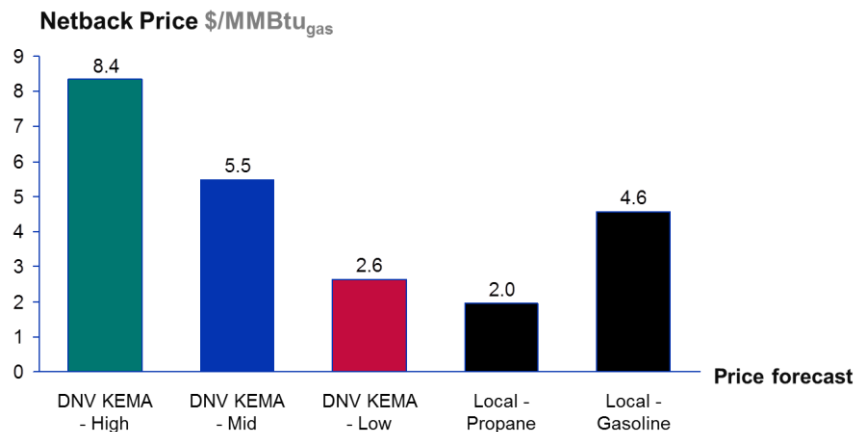
**Figure 65. Specific capital expenditures for methanol plants**

We estimate that a 1.65 MTPA facility would cost close to \$1.5 billion, which is in the upper range of the other projects. The foreseen cost escalation compared to other projects is mainly caused by the lack of infrastructure compared to other countries, where either the country has a well-developed infrastructure as a whole, or where these plants are located in dedicated industrial cities. The following parameters are used for calculating netback values:

Plant parameter	Value	unit
Plant capacity	1,000,000	tonne/year
Capacity factor	90%	%
Annual gas consumption	30.2	Bcf/year
Gas intensity	33.6	MMBtu/tonne
Specific capex	1,000	\$/tonne/year
Specific O&M	40	\$/tonne/year
Total capital cost	1,000,000,000	\$
Annual O&M cost	40,000,000	\$/year
Construction time	3	year

**Table 24. Parameters for Methanol plant project**

Natural gas netback values are found to be from 2.6-8.4 \$/MMBtu under the three scenarios. When price is set by local propane and gasoline values, a netback of 2.0-4.6 \$/MMBtu is reasonable.



**Figure 66. Netback price for natural gas used to make methanol**

The local propane and gasoline displacement scenarios excludes the \$60 per ton shipping charge to get the methanol to Asian market. The proposed facilities are expected to be built primarily to support Asian demand, but will also result in a new regional market hub around it.

### 3.6.4 Risks & Abatements

First of all, Southern Africa has been indicated as a suitable place to produce methanol. It has dry, sweet gas on tide water and direct sea access to the most important Methanol markets in Asia. Furthermore, methanol can be used to substitute imported fuels for satisfying local demand. Also, land and labor costs are relatively low in Southern Africa<sup>111</sup>.

However, there are specific challenges for developing methanol plants in Africa. A methanol plant in Southern Africa would be a greenfield project with little existing physical infrastructure to leverage. Also, many countries in Southern Africa lack the legal framework and government policy that enable project financing. Furthermore, petrochemicals experience is relatively underdeveloped, which is exacerbated by a shortage of trained construction and operations personnel. If Gigamethanol does invest in the large methanol plant it proposed, it is doubtful that Mozambique could accommodate two methanol plants. Also, it may be better to diversify natural gas use in this case in order to reduce potential risks that may occur due to bearish methanol market.

### 3.7 Gas-to-Liquids

As the name suggests, Gas-to-Liquids (GTL) technologies can transform natural gas into liquid fuels. Most technologies to turn natural gas into liquid fuels are based on producing synthesis gas, but the most widely applied ones for both large and small-scale applications are based on the Fisher-Tropsch (F-T) process. The F-T process consists of three steps:<sup>112</sup>

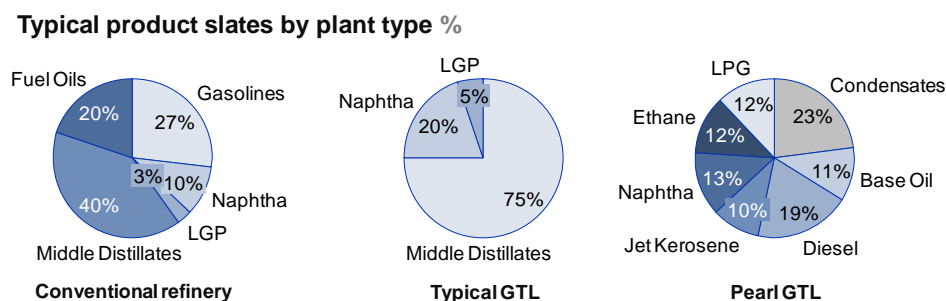
1. **Synthesis gas (syngas) production** of mainly carbon monoxide and hydrogen from natural gas (methane). The methane molecule is broken in parts by either steam reforming, partial oxidation or a combination thereof called autothermal reforming, with the latter technique usually applied in large-scale plants.
2. **Catalytic (F-T) synthesis** in a Fisher-Tropsch reactor to transform syngas into long-chained hydrocarbons (syncrude).
3. **Cracking** syncrude, the intermediate product from the previous step, is performed to produce various end products such as diesel, naphtha and oil-based lubricants. The final mixture of different end products can be adjusted in this final step to supply those products with the highest demand and most value.

GTL plants can, to some extent, adjust the F-T reactor to produce different product mixes. Currently, most GTL projects aim for a product mix consisting of mainly middle distillates, such as sulfur-free diesel and jet fuel, combined with some naphtha, base oils and paraffin. For example, Shell’s Pearl GTL plant in Qatar, the world largest, produces the following products:<sup>113</sup>

Product	Application
<b>Gasoil</b>	Can be blended with conventional diesel resulting in cleaner burning and lower emissions.
<b>Naphtha &amp; Normal Paraffin</b>	Naphtha has a higher paraffin content that helps plastic manufacturers produce more plastic. The normal paraffin is used in the detergent industry and is similar to oil-derived paraffin.
<b>Base oil</b>	For lubricating vehicle engines, gearboxes and transmissions.
<b>Kerosene/jet fuel</b>	Used for cooking, lighting and dry-cleaning and as a clean jet fuel.

**Table 25. Product slate of Qatar’s Pearl GTL plant**

The figure below compares a typical GTL product mix with that of a conventional refinery.<sup>xii</sup>



**Figure 67. Comparison of typical products from refinery and GTL plants**

<sup>xii</sup> Pearl GTL pretreats wet gas before using it as feedstock for the production of syngas. This treatment results in other products such as condensates and LPG.

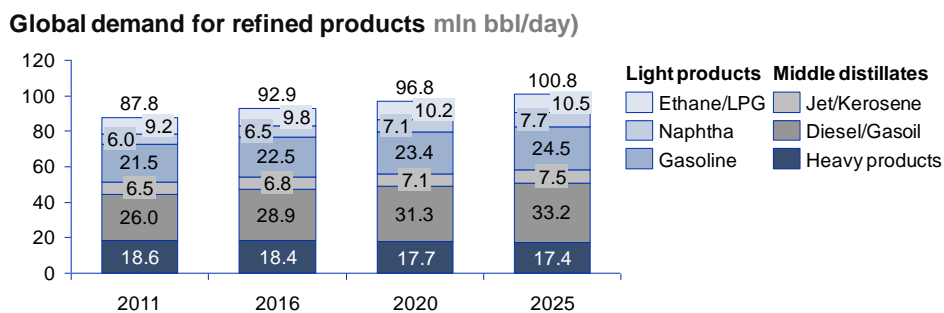
### 3.7.1 Global Market Outlook<sup>114</sup>

#### 3.7.1.1 Demand

As GTL results in (derivative) oil products, the relevant market to assess is the oil market. More specifically, given the resulting products of the GTL process, the middle distillates: jet fuel, kerosene, diesel, gasoil, and light products: naphtha and gasoline are of primary interest.

In 2011, total global demand for oil products stood at 87.8 million barrels per day (mb/d). The middle distillate had a combined demand of 27.1 mb/d of which 20.6 mb/d were diesel/gasoil and 6.5 mb/d for kerosene/jet fuel. Demand for light products was somewhat similar with 27.5 mb/d distributed over naphtha (6.0 mb/d) and gasoline (21.5 mb/d).

Towards 2020, global demand is expected to grow to 96.8 mb/d (+1.1% per annum) of which diesel/gasoil will contribute just under one-third at 31.3 mb/d, gasoline with 23.4 mb/d, followed by naphtha and jet fuel with 7.1 mb/d each. Demand is expected to further increase to 100.8 mb/d of oil products in 2025, or about 1% per year from 2020 onwards. Again, demand will be highest for diesel/gasoil with 33.2 mb/d, following by gasoline (24.5 mb/d) and naphtha (7.7 mb/d) and jet fuel/kerosene (7.5 mb/d). See figure below:



**Figure 68. Global demand for oil products**

The incremental demand for gasoil/diesel is expected to be greatest with an increase of over 7 mb/d between 2011 and 2025. This demand is mainly driven by an increase in the transport sector. On the other hand, naphtha is expected to witness the fastest growth on a percentage basis at 1.7%/yr mainly driven by growth in demand in the Asia-Pacific region.

Similar to gasoil/diesel and naphtha, demand for gasoline is expected to grow as well. However, with 3 mb/d additional volumes, demand will be less than half of the demand for gasoil/diesel. Notably, demand growth for gasoline is unevenly distributed across the world. Demand for gasoline in North America is expected to decline, whereas it is expected to stabilize in Europe, while the Asia Pacific region is envisaged to witness significant demand growth.

Industrialized countries are anticipated to witness a stable or declining demand for oil-related products in the long-term. Conversely, demand in developing regions is project to grow at 1.2 mb/d towards 2020 and 1.0 mb/d from 2025 onwards. In total, a modest overall growth in demand combined with a high growth in untraditional emerging demand centers is expected.

### 3.7.1.2 Supply

GTL products compete with products derived from crude oil. As such, distillation capacity additions at conventional refineries are important to market dynamics. In the following figure, the distillation capacity additions per region are provided up to the year 2016. Capacity additions will be most significant in developing regions, which coincides with where highest demand growth is expected. Moreover, capacity additions are predominantly expected in Asia (e.g. China and India), although other noticeable additional capacity will be built in the Middle East and Latin America as well. Total added distillation capacity towards 2016 is expected to equal 7.2 mb/d.

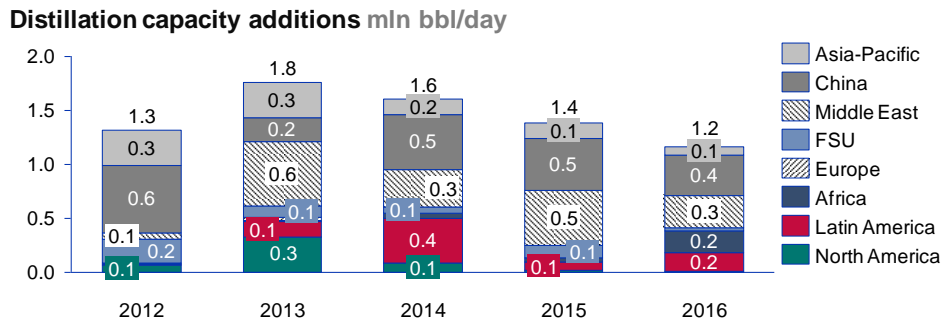


Figure 69. Distillation capacity additions from existing projects<sup>xiii</sup>

Part of the new additions above will be offset by capacity closures. Refinery closures are difficult to estimate as they may happen within a very short time frame (weekly basis) and recent years have been turbulent in this respect. OPEC reports that over the last three years, around 4 mb/d of refining capacity has been permanently mothballed. Projected additional refinery capacity is expected to be in excess of the increase in demand even when taking into account closures.

The long-term outlook for refinery capacity and demand is shown below.<sup>115</sup> The figure shows the projected cumulative global demand growth and projected distillation capacity additions to 2025. These have been divided into known projects (i.e. that will be built) and new units. New units are further additions (major new units and de-bottlenecking) required to balance supply and demand.

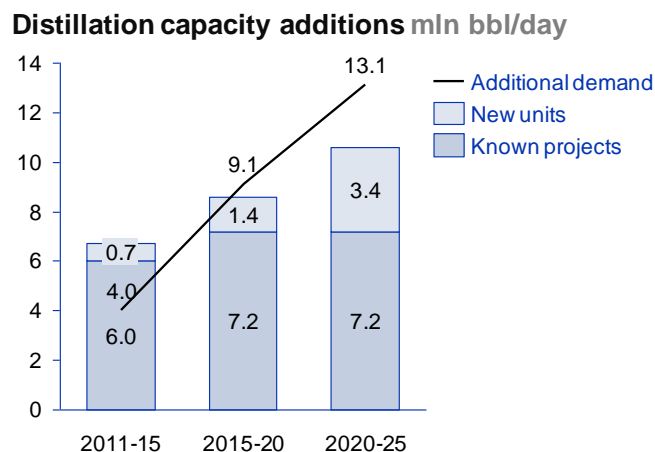


Figure 70. Additional demand and distillation capacity additions from known and new projects

<sup>xiii</sup> Figures are rounded; total capacity additions add up to 7.2 mb/d.



From 2015 to 2025, new distillation capacity of 10.6 mb/d is expected. More than half of this capacity, 7.2 mb/d, is accounted for by projects already known to be completed before 2016. In addition, de-bottlenecking existing plants through 2015 (denoted under new units) will add another 0.7 mb/d. Therefore, the annually required additional distillation capacity from new units is expected to equal 0.25 mb/d from 2011 to 2025.

Besides additions from conventional refineries, new GTL capacity must be considered as well. The table below shows that the total additional GTL capacity for which firm commitments have been made may add up to 0.17 mb/d; not even 2% of planned conventional refinery additions.

Plant	Country	Operator	Timing	Capacity (bbl/d)	Investment (Bln \$)
<b>Escravos</b>	Nigeria	Chevron/NNPC	2013	34,000	8.4
<b>Oltin Yo'l</b>	Uzbekistan	Sasol/UNG/Petron	2017	38,000	4
<b>Sasol Louisiana</b>	US	Sasol	2018/19	96,000	11 – 14
<b>Total</b>				168,000	

**Table 26. Planned large-scale GTL plants**

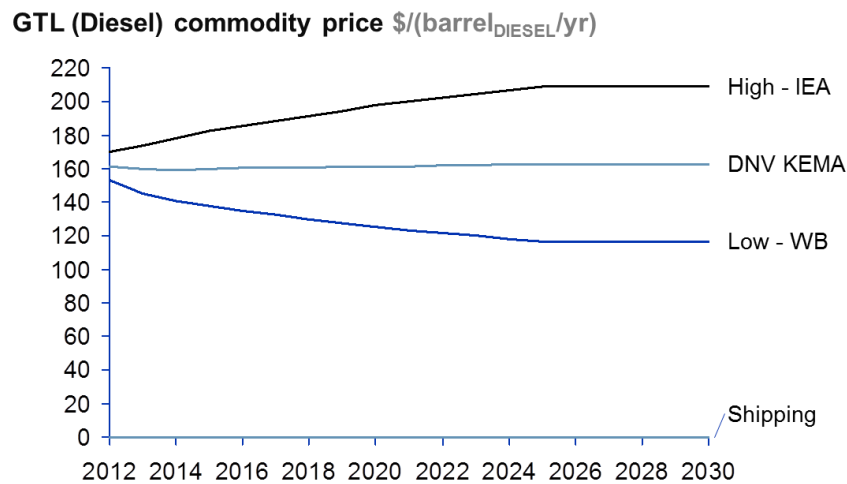
GTL products compete with products derived from oil, which prices are in turn closely correlated to that of crude oil. Therefore, the prices of interest for GTL products are crude oil prices. Some recent price forecasts from the IEA, World Bank, and EIA are provided in the following table:

Oil price forecast (\$2011/bbl)	2013	2015	2020	2025	2030	2035
<b>IEA forecast</b>		116	129	139	146	152
<b>World Bank forecast</b>		97	88	80	73	67
<b>EIA forecast</b>	97	96	106	117	130	145

**Table 27. Oil price forecasts<sup>65</sup>**

Out of the three, IEA (International Energy Agency) estimates for oil prices are the highest. In the long-term, EIA's (Energy Information Administration) forecasts are fairly comparable to IEA's, although this only occurs for estimates between 2030 and 2035; in the short-run, estimates by EIA are considerably lower. Both the estimates by EIA and IEA follow a similar upward trend in contrast to the estimates by the World Bank, which foresees a steep drop in oil prices.

Price forecasts for product diesel sale price are provided by the World Bank and the IEA. DNV KEMA supports a moderate and flat price forecast between these two to reflect a perspective that supports new oil projects continuing to be developed at today's price levels. The following forecasts are used in the netback analysis for Gas-To-Liquids diesel price:



**Figure 71. Diesel (GTL) price forecasts (\$2013)**

These prices represent the price paid on global markets, and the corresponding shipping charge to these destinations of \$0 per tonne is chosen to reflect the use for these refined products directly within the SADC region. The high and low price scenarios are based on IEA and WorldBank forecasts respectively, and are shown below with the DNV KEMA perspective:

Diesel price (\$2013/bbl)	2013	2014	2015	2016	2017	2018	2019	2020	2025
High - IEA	174	178	182	185	189	192	195	198	209
DNV KEMA	160	159	160	160	161	161	161	161	163
Low - WB	145	141	138	135	133	130	127	125	116
Shipping	0	0	0	0	0	0	0	0	0

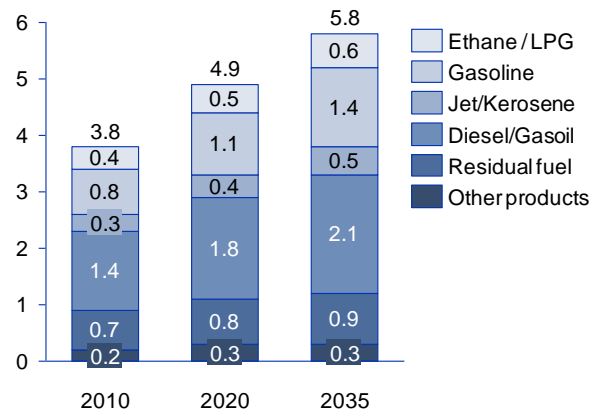
**Table 28. WorldBank and IEA Diesel (GTL) price forecasts**

### 3.7.2 Oil-product Use and Pricing in Africa

Currently, demand for refined oil-products in Africa is less than 5% of global demand. However, we expect demand to grow at an average rate of 2.7% through 2015, and slowing down after 2015 to 1.2% per yr. In terms of volume, this will only represent a cumulative increase of less than 2 mb/d towards 2035. This translates to an average annual volume increase of less than 0.1 mb/d. In 2035, total African demand for refined oil-products is not likely to top 6 mb/d.

More specifically, we expect diesel to add most to the volume increases and we anticipate it to contribute around 0.7 mb/d between 2010 and 2035, while gasoline grows with 0.5 mb/d. We expect demand growth for other products such as LPG and residential fuel oil to stay below 0.2 mb/d.

**Africa refined product demand mln bbl/day**



**Figure 72. Demand for refined petroleum products by type**

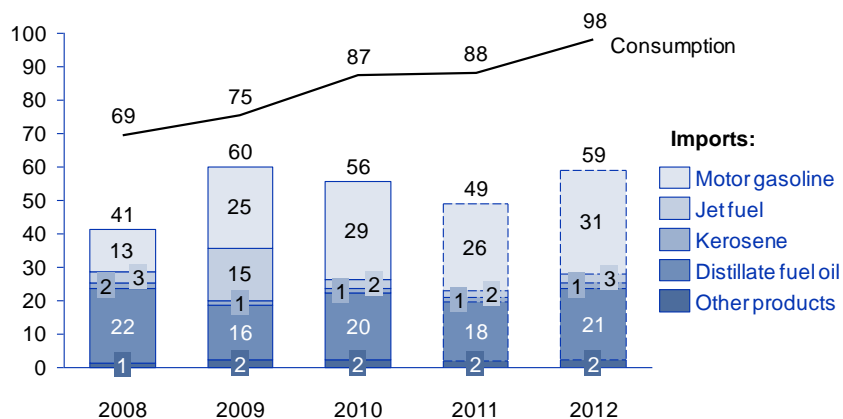
### 3.7.2.1 Angola

Angola is a member of OPEC and the second largest in terms of oil production and proven reserves in Sub-Saharan Africa only topped by Nigeria. According to the IMF, its net oil export revenues stood at \$64.4 billion and accounted for 98% of the Government’s revenues in 2011.

Angola has one refinery in Luanda, Fina Petroleos de Angola, and has a processing capacity of just 39,000 b/d of crude oil. However, Angola currently hosts the largest refinery project under construction in Africa. The Sonaref refinery near Lobito expected to be commissioned in 2016 was designed to produce 120,000 b/d initially before eventually reaching full 200,000 b/d capacity. Crude oil will be supplied from domestic fields such as Kuito Crude and Dalia Crude. This oil will be used to produce a mixture of unleaded gasoline, diesel, jet fuel, illuminant oil, LPG and smaller quantities of sulfur and petrocake. The specifications of these products match the requirements for the expected export markets in Europe and the US.

Although being a large oil producing country, Angola is heavily dependent on imports of refined products, for example for diesel engines on which all industries and even individual houses rely on. Consumption of refined products is relatively low due to low economic activity, but is increasing. In 2011, consumption of oil products stood at approximately 88,000 b/d from 75,300 b/d in 2009.<sup>116</sup>

**Angola refined product supply and demand kbbl/day**



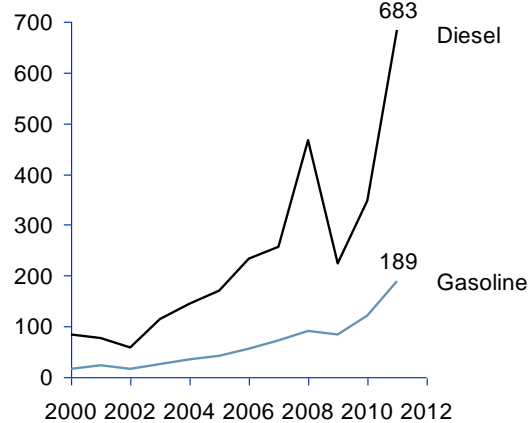
**Figure 73. Consumption and imports of refined oil products in Angola**

Although dependent on imports, transportation fuel prices are among the lowest in the world due to subsidies on fuel provided by the state. Diesel is subsidized 40 ¢/liter and gasoline by 60 ¢/liter by the state. Total spending on fuel subsidies by the Angolan government equaled \$6 billion in 2012 or roughly 90% of its public investment spending.

### 3.7.2.2 Mozambique

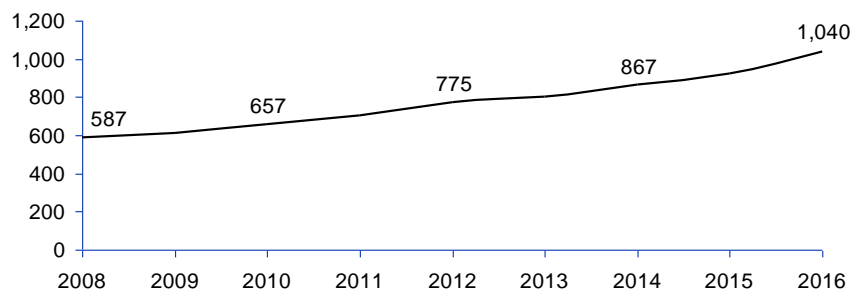
Mozambique does not have any significant crude oil reserves as of January 2013. Mozambique currently imports all refined oil products used within the country. For 2011, total imports were estimated at 19,580 b/d. The chart below depicts Mozambique’s historic import value for diesel and gasoline. Combined, Mozambique spent around \$870 million imported diesel and gasoline in 2011.

**Mozambique diesel and gasoline imports mln \$**



**Figure 74. Value of Mozambique imports for diesel and gasoline<sup>117</sup>**

**Mozambique fuel (white products) imports mln litres/yr**



**Figure 75. Imports of ‘white products’ in Mozambique<sup>xiv, 118</sup>**

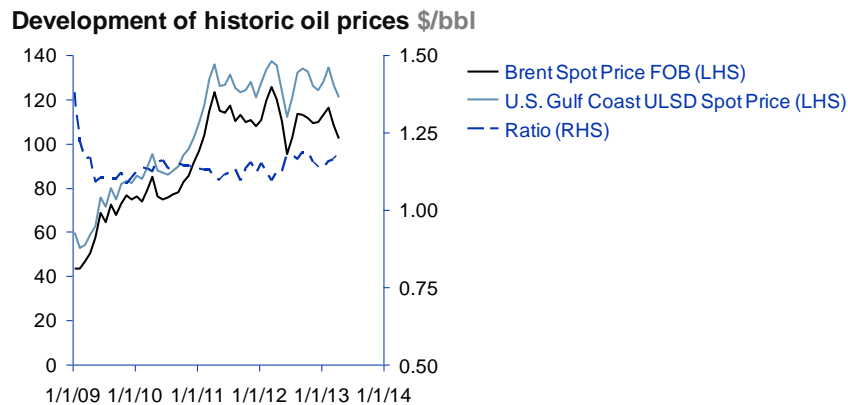
In Mozambique, two oil refinery projects are being considered to process imported crude: Ayr Petro Nacala Refinery and Oilmoz. The Ayr Petro Nacala Refinery has recently been revived by the Saudi Radyolla Group after being tabled due to the economic crisis in 2008. In 2007, the Texas-based oil company Ayr Logistics was intending to invest \$5 billion to establish a 300,000 b/d of refinery. The second proposal, Olimoz, is said to have a capacity of 350,000 b/d with construction to begin in the summer of 2013 at an investment cost estimated at \$12 billion.<sup>119</sup> Half of the refining capacity is said to be earmarked for domestic consumption, which seems to be quite a lot for Mozambique (in 2011,

<sup>xiv</sup> White products are liquefied petroleum gas (cooking gas), gasoline, kerosene, and diesel

total imports were just under 20,000 b/d). In addition, exports to Uganda and South Africa are questionable as both countries are planning their own refinery facilities.

### 3.7.3 Capex, Opex, Pricing, Gas netback value

Products produced by GTL plants compete with refinery oil products which are usually strongly influenced by benchmark crude oil prices. GTL products are priced with small premium over these refinery products to reflect their superior quality. The following chart shows historic prices for crude oil and ultra-low sulfur diesel (ULSD) and shows that, on average, ULSD is traded at 113% of crude prices during the last 3 years.



**Figure 76. Correlation between crude prices and ULSD**

The viability of GTL depends on the disparity between natural gas prices and oil prices. In general, the ratio between natural gas prices (in US\$/MMBtu) and crude oil prices (in US\$/bbl) should be around 25 in order for greenfield GTL-projects to be economically feasible<sup>120</sup>. In other words, with crude oil prices at around 100 US\$/bbl, netback prices for natural gas used in GTL is approximately 4 US\$/MMBtu. However, actual netback values will be calculated further on in this chapter.

Historic GTL projects have always been accompanied by large investments and unplanned escalation of investment costs. We have assessed investment cost for GTL plants based on realized projects and planned projects. In the next figure, the specific costs for GTL projects are given, and the typical costs for a GTL plant are estimated at \$150,000 per barrel of GTL product per day. This is higher than EIA's estimate of overnight capital costs of \$90,000 per barrel of GTL product per day used in their Annual Energy Outlook of 2013, which we believe to be quite optimistic given past projects.

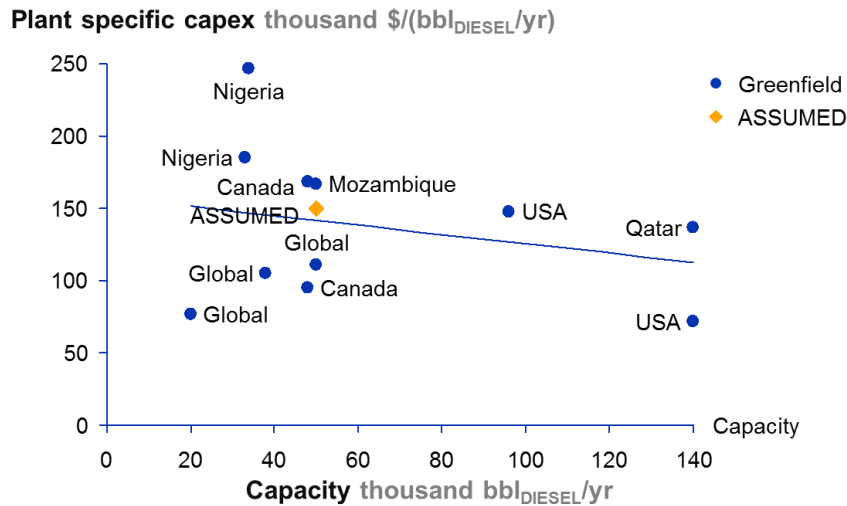


Figure 77. Specific capital expenditures for GTL plants (\$2013)

Given the above, we use the following parameters for the netback analysis:

Plant parameter	Value	unit
Plant capacity	50,000	bbl/day
Capacity factor	90%	%
Annual gas consumption	159.3	Bcf/year
Gas intensity	9.7	MMBtu/bbl
Specific capex	150,000	\$/bbl/day
Specific O&M	3,300	\$/bbl/day
Total capital cost	7,500,000,000	\$
Annual O&M cost	165,000,000	\$/year
Construction time	5	year

Table 29. Parameters for Gas-To-Liquids plant project

Natural gas netback values are found to be from 4.2-12.9 \$/MMBtu under the three scenarios. When price is set by local diesel and gasoline values, a netback of 7.6-8.2 \$/MMBtu is reasonable.

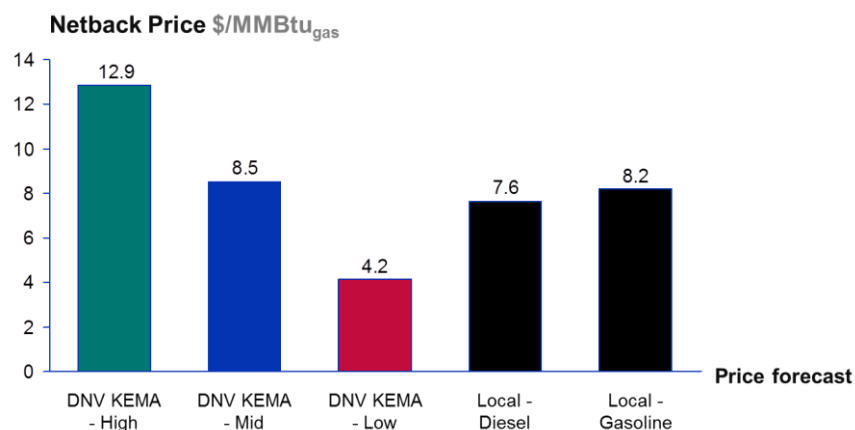


Figure 78. Netback price for natural gas used in GTL (refined products)

No shipping charges are deducted from revenue as the proposed facilities are expected to be built primarily to support local and regional demand.

### 3.7.4 Risks & Abatements

The risks associated with GTL in Angola and/or Mozambique does not merely result from country specifics. Currently, GTL has not been widely implemented on an industrial scale and most of the industrial scale GTL projects that did materialize have faced large budget overruns. This is risk is magnified by the capital intensity of a GTL project. As discussed, we estimate capital costs of a 50,000 b/d GTL plant to be around of \$7.5 billion. It is questionable whether Angola and Mozambique are able to raise these amounts of capital.

Besides high capital costs, GTL plants use complex technology, held by only two companies Sasol and Shell, and requiring trained operations personnel. It will take time for Mozambique and Angola to acquire and develop such skilled labor. Arguably, a GTL plant is the technologically most complex compared to the other industries reviewed in this assesment.

It should also be acknowledged that these large projects benefit from well-developed infrastructure extending from roads and harbors to airports and hotels, etc. Currently Mozambique and Angola struggle to accommodate these. For example, it seems rather unlikely that Luanda airport can accommodate all flight movements necessary to bring in the construction workers (which can run into tens of thousands at a single moment as was the case for Shell's GTL plant in Qatar). In relation to this, other generic aspects are required as well, such as permits, regulation, possibly quarantine, and a significant amount of civil servants to make this all happen. All in all, such an approach requires a clear vision (e.g. Ras Laffan Industrial City in Qatar) and central planning by a strong government. In Australia, central planning did not happen for many years to the detriment of their projects. Another good example of strong governmental planning is the US Gulf Coast where cracking, methanol synthesis, and GTL are located close together and share suppliers.

More general, GTL plants are mainly viable in cases where there is a large disparity between gas and oil prices. In this sense, the viability of a GTL is dependent on the price of oil. Low future oil prices, exacerbated by oversupply in distillation capacity, are detrimental to the GTL business case.

Besides competition from worldwide and regional distillation capacity, GTL in Southern Africa could be faced with coal-to-liquids competition from inside the country. Plans have been made to build a coal-to-liquids facility using low quality coal feedstock (which cannot be exported) from the Tete province in the northwest where one of the world's largest untapped coal reserves are located. The CTL project is envisaged to produce 65,000 bbls per day (3.5bn litres per year) consisting of 20,000 bbls petrol and diesel and 45,000 bbls jet fuel. This project is expected to create 2,500 direct jobs.

## 3.8 Aluminum

Aluminum is a high-strength, light-weight, industry diversified, and readily recyclable material. Although aluminum is not a free element in nature, it is the most ample metallic element available in the earth's crust; at roughly 8%, it follows behind only oxygen and silicon. Industries such as transportation, building and construction, food and beverage packaging, transmission of electricity, machinery and equipment are dependent on a consistent aluminum supply.

However, its high-energy requirements prove an impeding force to aluminum manufacturing; an estimated 17.4 MWh<sub>e</sub>/tonne of aluminum produced. This said, the metals high-energy manufacturing is offset by low-energy recyclable attributes. The recycling of aluminum uses only 5% of the energy needed to produce aluminum from bauxite.

The global aluminum market is described below, followed by observations on aluminum use and pricing in Africa. We then discuss Capex, Opex, Pricing and Gas netback values for selected projects, and list risks this sector faces along with potential abatements.

### 3.8.1 Global Market Outlook

The global aluminum industry consists of five major segments:<sup>17</sup>

- Bauxite mining (with its primary component alumina, aluminum oxide)
- Alumina refining
- Primary aluminum production
- Secondary aluminum production
- Aluminum semi-fabricators:
  - Aluminum sheet, plate and foil manufacturing
  - Aluminum extrusion, tube, cable, and wire manufacturing

Primary aluminum production is electricity intensive. Smelter efficiencies currently range between 13 and 17.5 MWh<sub>e</sub> per ton aluminum.<sup>17</sup>

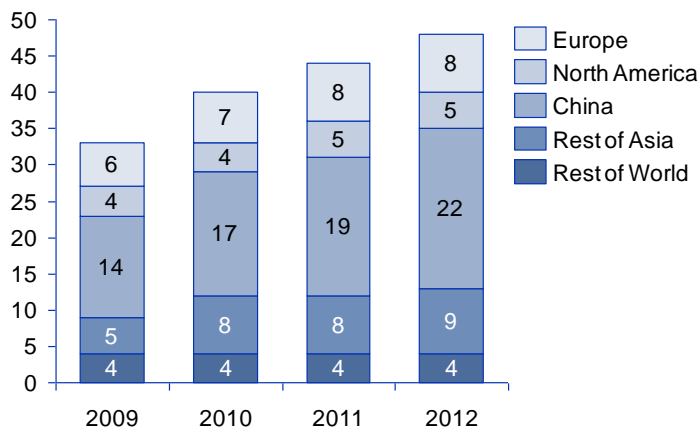
#### 3.8.1.1 Aluminum production and consumption

In 2012 more than 232 smelters producing primary aluminum were present worldwide. The combined installed production capacity of these plants exceeded 56 million ton of primary aluminum. Historically, the majority of smelters were located in Europe and North America, whereas nowadays most smelters are located in Asia. Likewise, a slight increase has been shown in the share of African smelters.

The global consumption of primary aluminum reached 48 million ton in 2012, of which China was the largest consumer. China steadily increased consumption levels from 2009 to 2012, an amount roughly equivalent to 8 million tonnes of aluminum per year. Global players such as Europe and North America showed modest growth rates in consumption during the same time period. The following figure shows the respective demand developments.



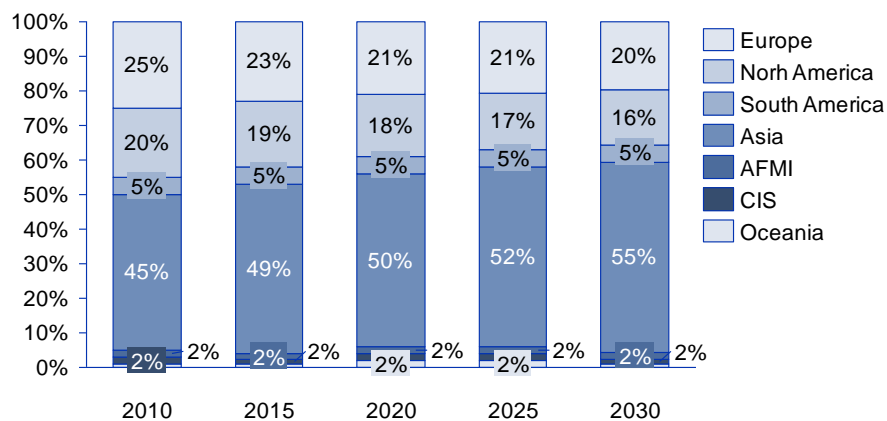
**Global primary aluminum consumption mln tonnes<sub>aluminum</sub>/yr**



**Figure 79. Historical development of the global consumption of primary aluminum<sup>17</sup>**

The total global aluminum consumption (consisting of primary and secondary aluminum) is projected to more than double and reach 87 MTPA by the year 2030. Accordingly, the average annual demand growth rate will be around 3.3 percent until 2030.<sup>120</sup> Currently, Asia is the biggest consumer of aluminum followed by Europe and North America. As shown below, Asia will continue to increase its global share of primary aluminum consumption through 2030.

**Global primary aluminum consumption % by region**

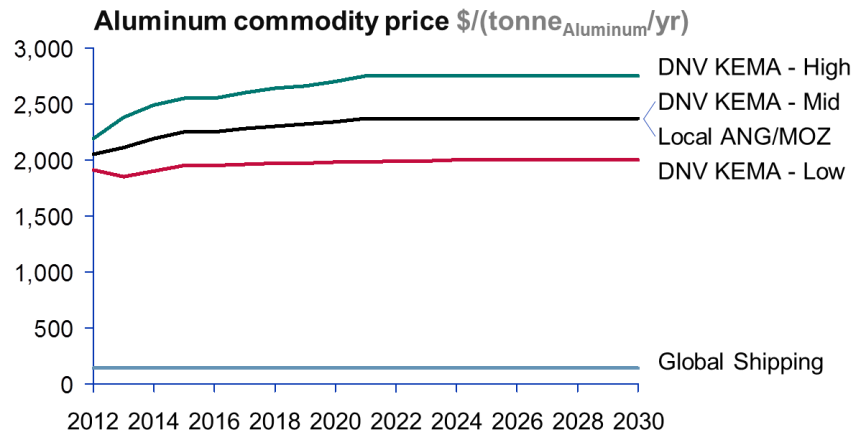


**Figure 80. Regional distribution of aluminum demand from 2000 to 2030<sup>121</sup>**

Due to recycling (and increasing use of secondary aluminum) the annual production of primary aluminum has decreased. In 2012 annual primary aluminum production amounted to roughly 46 MTPA and is expected to increase to some 60 MTPA by 2030. Accordingly, 27 MTPA (or ~30%) of secondary aluminum will be produced to assist in meeting global demand.

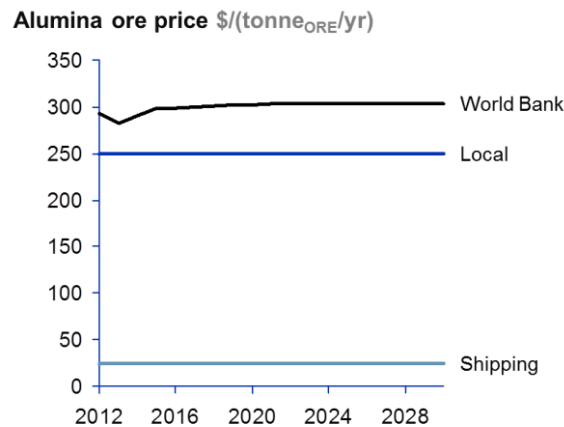
### 3.8.1.2 Aluminum prices

In 2011 the early price average for nominal aluminum amounted to roughly \$2,500 per tonne. According to the World Bank's most recent forecast, real aluminum prices are expected to reach \$2,140 per tonne by 2025. The following figure illustrates the price development:



**Figure 81. Projected real global aluminum prices (\$2013)<sup>122</sup>**

To assess the netback value, assumptions on alumina prices are made and shown below. The WorldBank price forecast is used for all cases except the local case in which a domestic supply is assumed which is priced including delivery:



**Figure 82. Alumina ore price forecasts**

### 3.8.2 Aluminum Use and Pricing in Africa

Currently six African countries (Cameroon, Egypt, Ghana, Mozambique, Nigeria and South Africa ) have aluminum smelting facilities, with South Africa accounting for half of the primary aluminum production. In 2010 South Africa produced around 850 thousand tonnes of primary aluminum.

### Primary aluminum production kTonnes<sub>aluminum</sub>/yr

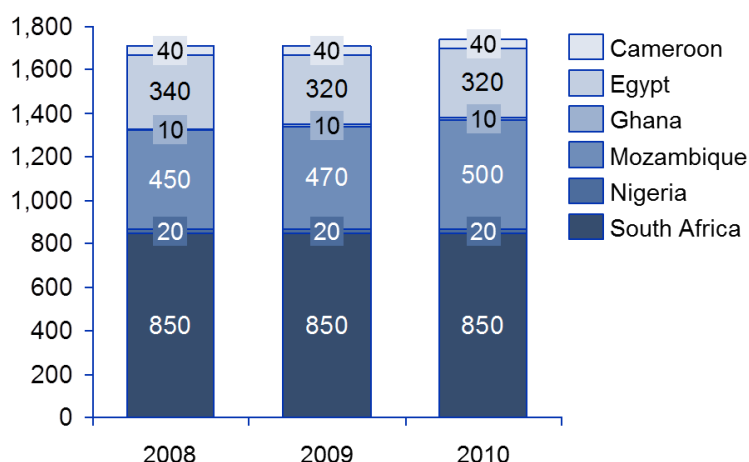


Figure 83. Production of primary aluminum in African countries<sup>123</sup>

#### 3.8.2.1 Mozambique Aluminum

Mozambique produces about 30 percent of the total primary aluminum production in Africa, thus being the second largest producer in the continent. Most of the produced aluminum is exported outside of Africa. The Mozal plant is the only production facility within the country with a total production capacity of 560,000 ton (509,000 tonne) per year. Direct natural consumption levels from the plant equated to only 1.1 Bcf in 2011. The average annual power consumption of the smelter amounts to 8,350 GWh which, if it were supplied by gas-fired plants, amounts to a gas use of 57 Bcf/yr.<sup>xv</sup> Thus, meeting the energy needs entirely by natural gas would require a gas input of 111 Bcf per million tonne aluminum. Further expansion plans for the Mozal plant are currently on hold unless additional electricity supplies become available.<sup>17</sup>

#### 3.8.2.2 Angola Aluminum

Currently, three aluminum projects are under investigation in Angola.<sup>124</sup> The first, located in southern Angola, stems from a memorandum of understanding signed in 2009 between the Angolan government and Norsk Hydro, which suggests the development of a 750 to 1,000 MW<sub>e</sub> hydroelectric power plant. The second project is located in the Soyo region and is also pursued by a Norwegian developer.

At the end of 2011, Alcoa announced the signing of a memorandum of understanding with the government of Angola to explore the development of a 750,000 MTPY aluminum smelter which uses electricity from hydroelectric facilities. Angola has committed to allocate 1,300 MW<sub>e</sub> of firm power generation capacity to the aluminum industry. If the project moves forward, the smelter will begin production in 2020.

<sup>xv</sup> Assuming an electrical efficiency of 50% of the gas plant.

### 3.8.3 Capex, Opex, Pricing, Gas netback value

The following financial cornerstones characterized the first phase of the Mozal plant in Mozambique:

- A \$1.34 billion private and public sector partnership project for the original capacity of 240,000 ton primary aluminum per year<sup>xvi</sup>
- Provided over \$400 million in foreign exchange earnings
- Increased Mozambique’s GDP by an additional 7%

In 2011 first phase capital costs amounted to \$7,022 per ton aluminum. ICF International lists an investment project yielding capital costs of \$6,932 per ton aluminum, which is significantly higher than Mozal plant figures.

A recent project in India announced by Vedanta shows total capital expenses of \$5,650 million for a 1.25 million ton smelter and 1,980 MW<sub>e</sub> power plant. Capital costs for the aluminum smelter alone amounts to \$3,650 million (equaling 2,600 \$/ton). A second project by Vedanta shows total capital costs of \$2,000 million for a 325,000 ton smelter and 1,200 MW<sub>e</sub> power plant. Capex for the aluminum smelter amounts to \$900 million (equaling \$2,714 per ton/yr). Furthermore, Rusal is involved in a Russian project with capital expenses for an aluminum smelter totaling \$2,100 million and a capacity of 600,000 ton of aluminum per year (yielding specific capital costs of \$3,430 2011 USD equivalent per ton). Within a similar range, Emkay Research mentions capital costs of \$2,500 to \$2,700 per ton aluminum for new projects in 2011. Mozambique lists higher capital expenses than all abovementioned projects, indicating that investment costs, similar to power plant projects, are higher in Africa. Comparing costs of African projects to those observed in the Middle East<sup>125</sup> show similar high-cost investments. The following table compares capital costs for various regions worldwide.

Region/Country	Capital cost range (2011\$/ton)
Africa (Mozambique)	5,360 – 7,022
India	2,600-2,900
Russia	3,430
Middle East (Qatar)	7,483
Middle East (Saudi Arabia)	6,130

**Table 30. Comparison of CAPEX for aluminum smelters for various regions**

<sup>xvi</sup> Meanwhile the plant got extended and produces 560,000 ton primary aluminum.

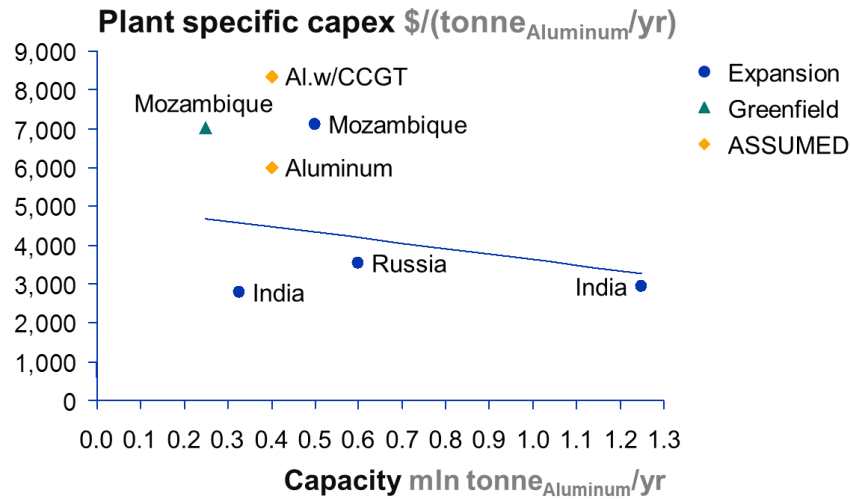


Figure 84. Capital cost ranges for aluminum smelters (\$2013)

Plant parameter	Aluminum only	Aluminum w/CCGT	unit
Plant capacity	400,000	400,000	tonne/year
Capacity factor	97%	97%	%
Annual gas consumption	8.9	44.2	Bcf/year
Gas intensity	23	114	MMBtu/tonne
Specific capex	6,000	8,340	\$/tonne/year
Specific O&M	225	264	\$/tonne/year
Total capital cost	2,400,000,000	3,336,000,000	\$
Annual O&M cost	90,000,000	105,600,000	\$/year
Construction time	3	3	year

Table 31. Parameters for Aluminum plant project w/ and w/o CCGT

The netback price is unfavorable under all circumstances due to the high price of alumina and the relatively small use of natural gas which puts all of the forecasted profits onto a very small amount of gas. The netback price range is from -26 to 6 \$/MMBtu of natural gas under the four pricing scenarios as shown below. The netback is from -6 to 1 \$/MMBtu when a CCGT power plant is included because the losses are spread over a much larger gas consumption.

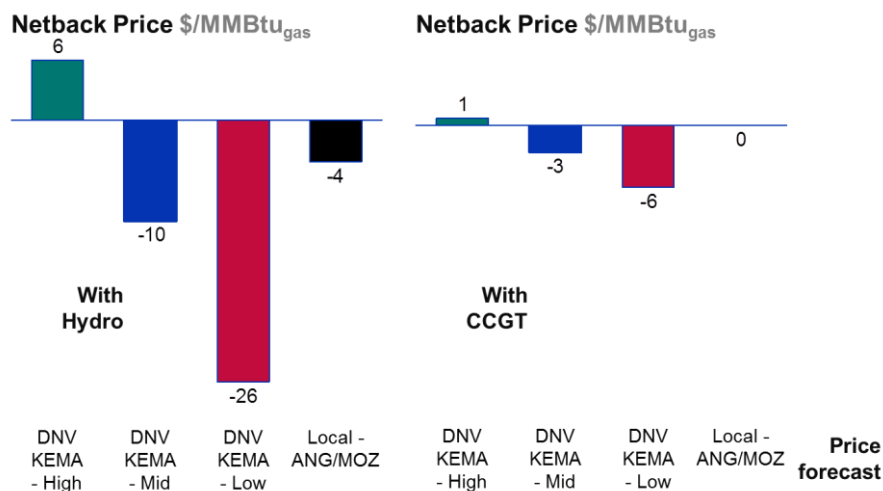


Figure 85. Netback price for natural gas used for aluminum

## 3.8.4 Risks & Abatements

### 3.8.4.1 Angola

Angola currently does not have any primary aluminum production facilities. Local input resource availability would be key to guarantee competitiveness. Besides, the availability of cheap power is critical for sector competition. As such, gas-fired plants would compete with hydro-units, whereas the latter provides cheaper total generation costs.

For both countries, total annual gas input (also taking into account gas-fired electricity production) to the aluminum industry would be rather limited with roughly 104 Bcf per million ton aluminum.

### 3.8.4.2 Mozambique

Mozambique has potential to meet a larger portion of the global primary aluminum demand – primarily due to significant demand growth rates. Low production costs are critical to capture larger market shares. As the inputs bauxite and alumina are currently imported, this represents a competitive constraint. As electricity costs represent more than a third of total aluminum production costs, cheap electricity generation resources are essential. In general, aluminum offers an attractive business case as it is a high value-added good. Nonetheless, due to global economic uncertainties, significant market risks prevail. Future demand centers will be located in Asia, which puts geographically challenged producers at a disadvantage.

## 3.9 Steel

In this section we focus on iron and steel. Steel prices, mainly due to dips in the steel demand caused by the financial crisis, are expected to stay rather stable during the same period. The World Bank foresees steel prices to decrease by 8% from 2012 to 2035<sup>xvii</sup>.<sup>126</sup> Below we will provide a brief overview on the global market outlook, followed by observations on iron and steel use and pricing in African continental, regional and country contexts. We will then discuss capex, opex, pricing and gas netback values for selected projects, list risks and abatements the sectors face and assess SME opportunities and regulatory specifics.

### 3.9.1 Global Market Outlook

Iron and steel production consists of the making of iron and steel and the manufacturing of steel products. In regards to making iron, the two main processes consist of blast furnace (pig iron) or direct reduced iron. The two main processes correlated with making steel are an oxygen furnace or an electric arc furnace. Steel is mainly produced in large integrated steel mills, which both produce iron and, in turn, steel. Production quantities range in millions of tonne. However, mini mills are much smaller in size, typically producing in the range of hundreds of thousands of tonnes, using scrap iron or direct reduced iron as inputs.<sup>17</sup>

#### 3.9.1.1 Gas use

Natural gas can be used in the following processes in an integrated steel mill.<sup>17</sup>

- Pellet heater
- Blast furnace with coke and natural gas
- Blast oxygen furnace
- Continuous case heater (for primary finishing)
- Batch furnace (for secondary finishing)
- Batch anneal process (for heat treating)

These processes would require about 4.7 MMBtu of natural gas per ton of output in an integrated steel mill, out of a total energy consumption of 17.4 MMBtu/ton, with the remaining energy coming from coke. On the other hand, a mini mill would consume a total of around 5.5 MMBtu energy and around 1 MMBtu of natural gas per ton of steel produced.<sup>17</sup>

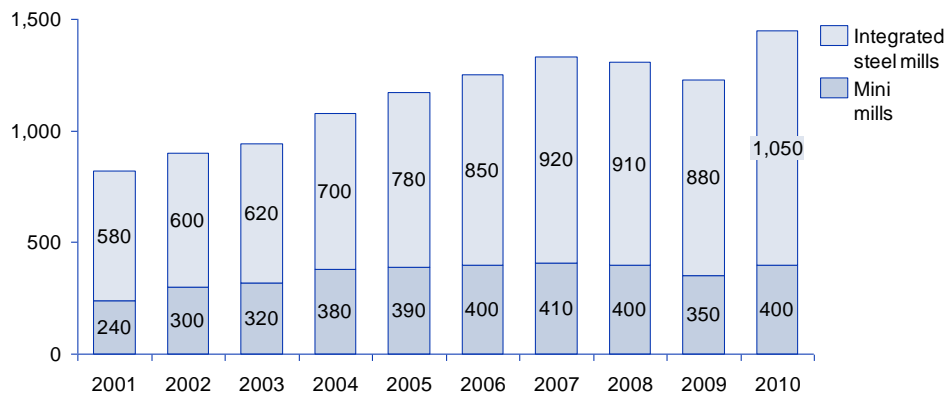
#### 3.9.1.2 Iron and steel production and consumption

In 2011, around 1,500 million ton of steel were produced globally. Two-thirds of the global production stemmed from large integrated mills. The following two figures show the development of global steel production, production by mill size and distinguish steel production per country. China is the largest producer of steel, accounting for almost half of steel produced globally, followed by Japan, the United States, India and Russia.

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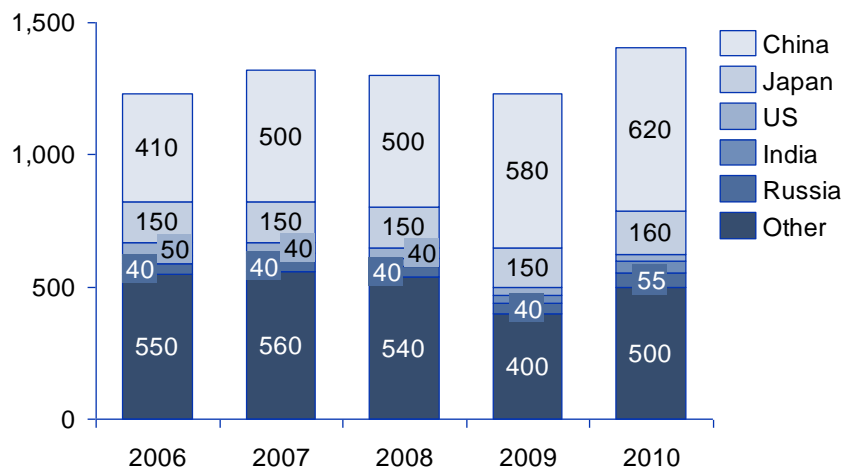
<sup>xvii</sup> More specifically, prices decrease between 2012 and 2017 and increase thereafter.

**Global steel production development mln tons<sub>Steel</sub>/yr**



**Figure 86. Global steel production in integrated vs. mini mills<sup>17</sup>**

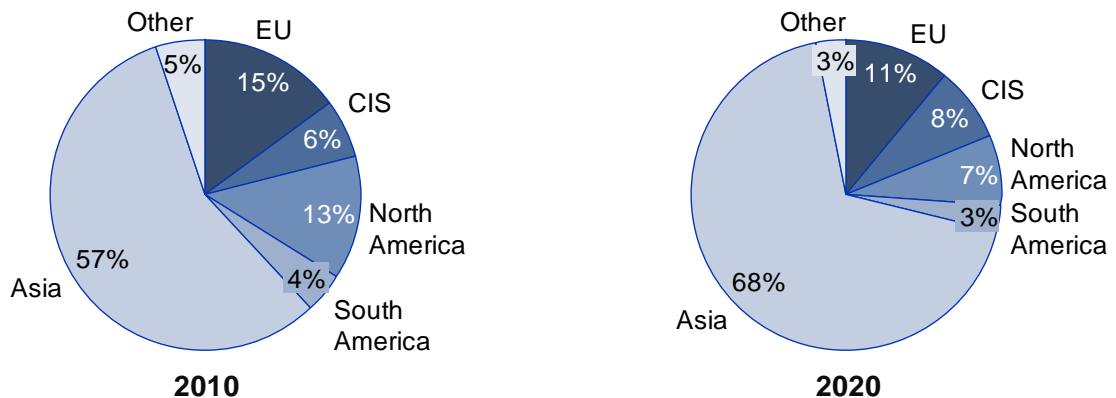
**Global steel production development mln tons<sub>Steel</sub>/yr**



**Figure 87. Global steel production per country<sup>17</sup>**

The annual demand for steel is expected to increase by an average of roughly 3.5% per year during the next two decades.<sup>17</sup> By 2020, Asia is expected to consume around two-thirds of the global steel demand; therefore, decreasing the share of steel demand for all remaining regions, except CIS.

**Steel demand breakdown and forecast % by region**



**Figure 88. Regional mix of steel demand in 2010 and 2020<sup>17</sup>**



Accordingly, global production of steel is expected to exceed 2 billion ton by 2020. Similar to demand, the majority of the additional production is expected to be in Asia. China is expected to produce roughly 50% of global steel production.<sup>17</sup>

### 3.9.1.3 Iron and steel prices

Global steel prices (measured in real terms) have increased significantly over the last ten years. After a short decline until 2015 (due to global economic and financial crisis), prices are expected to increase gradually but with lower growth rates than observed in the last ten years. Price development trends for steel closely resemble those of iron ore.

## 3.9.2 Steel Use and Pricing in Africa

The combined steel consumption of all African countries amounts to only 1.7% of global steel demand. The development of steel product imports in African countries from 2001 to 2010 is provided below. Algeria and Egypt are the largest steel importers in Africa.

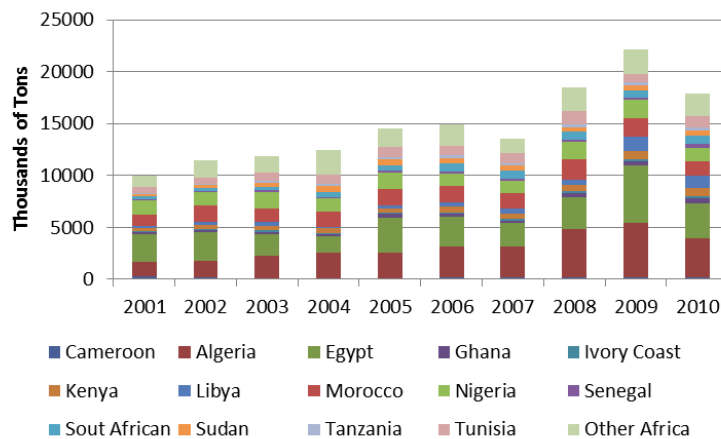


Figure 89. Imports of steel products in African countries<sup>17</sup>

South Africa is the largest producer of (crude) steel in Africa, followed by Mauretania and Egypt. Countries such as Algeria, Congo, Nigeria and Tunisia have much smaller domestic production capacities. The following figure shows the respective steel production quantities:

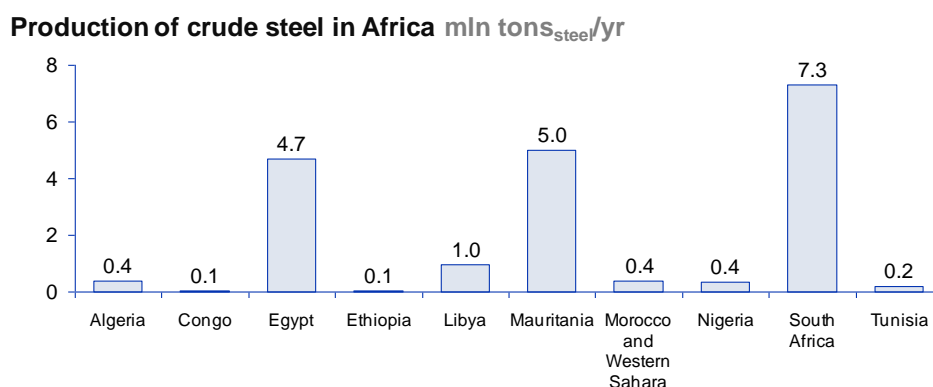


Figure 90. Production of crude steel in African countries<sup>17</sup>

The current annual production volume of crude steel in Sub-Saharan Africa emerges solely from South Africa, totaling 7.1 million tons. In October 2012, the sale price for hot rolled steel coils equated to \$647/ton.

### 3.9.2.1 Mozambique

Mozambique currently has no operational iron or steel production facilities, although the country is endowed with an iron ore resource base. An existing plant in Mozambique (production capacity of 35,000 ton/yr) is no longer operational and plans for a second plant (production capacity of 400,000 ton/yr) have been put on hold due to the global financial crisis and the associated drop of steel prices. However, a steel tube factory with a production capacity of 200,000 ton/yr remains in operation.<sup>18</sup>

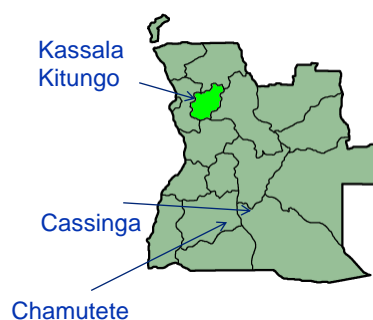
Jindal, the Indian steel major, and the Mozambican government are negotiating a potential plant in the Tete region. Furthermore, an iron and steel project, which was re-evaluated and promoted by the Ministries of Industry and Trade of both Mozambique and South Africa, if realized, could be supplied with natural gas from the Pande field and iron ore from Phalabora.<sup>xviii</sup> The plant would have a production capacity of 2 million ton of steel.

Given Mozambique's large domestic resources, we accordingly expect new steel plants to have a production capacity of at least 1 million ton/yr.

### 3.9.2.2 Angola

According to the Medium Term Plan of 2009-2013 of the Angolan Ministry of Industry published in 2008, several feasibility studies have been carried out for new steel plants. Due to local iron ore and manganese deposits, the best locations have been realized in Namibe, Luanda, Soyo, Kassala Kitungo, Cassinga and Chamatute. Cassinga is expected to deliver 20 million ton of iron ore per year. However, current domestic production of iron ore remains non-existent. Through a public/private partnership, production is expected to start by 2015. Locations are illustrated in the map below. One ton of conventional steel produced in a blast oxygen furnace typically requires 1.6 to 3 ton of iron ore, depending on the ore content. Given domestic ore resources in Angola, this implies an upper ceiling of 6.7 to 12.5 million ton of steel production. As the iron ore production is currently under development, we expect new steel plants to have a production capacity of 1-2 million ton/yr. This follows from initial iron ore production levels of around 3 million ton/yr. Annual iron ore production levels of 20 million ton are foreseeable in later years, ton which allows for the expansion of existing steel plants.

As mentioned above about 4.7 MMBtu of natural gas would be required per ton of output in an integrated steel mill, implying an annual gas consumption of 4.7 Bcf for a 1 million ton/yr plant.

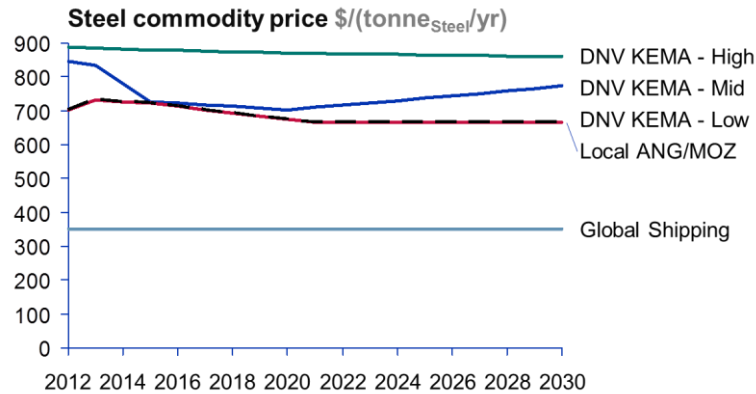


**Figure 91. Select iron ore and manganese deposits in Angola<sup>15</sup>**

<sup>xviii</sup> In regards to steel plants, coal is important; such plants are better suited in Mozambique than in Angola (due to large coal resources).

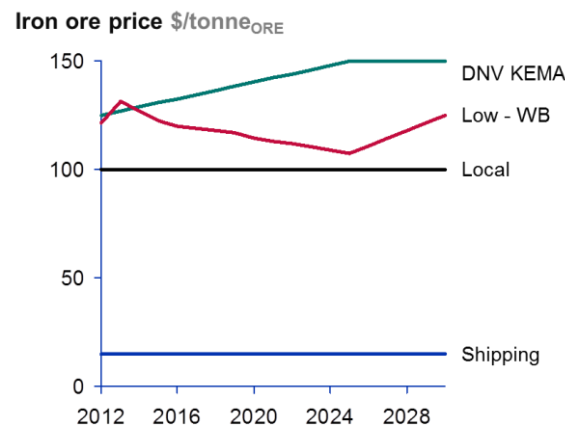
### 3.9.3 Capex, Opex, Pricing, Gas netback value

To assess the netback value, assumptions on iron ore, steel and coal prices, and typical investment projects are based on the World Bank, IEA and DNV KEMA analysis. The following figure and table lists the assumptions for steel, iron ore and coal prices.



**Figure 92. Projections for global steel prices (\$2013)**

To assess the netback value, assumptions on iron ore prices are made and shown below. The WorldBank price forecast is used for all cases except the local case in which a domestic supply is assumed which is priced including delivery:

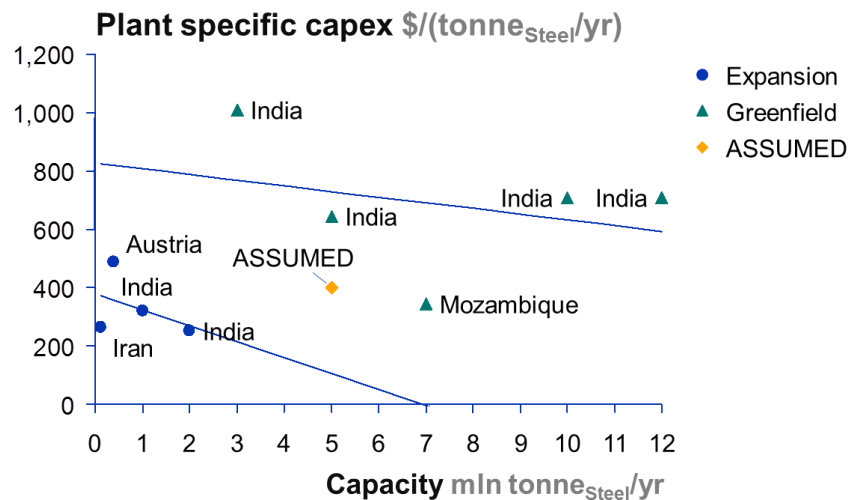


**Figure 93. Iron ore price forecasts**

Plant parameter	Value	unit
Plant capacity	5,000,000	tonne/year
Capacity factor	80%	%
Annual gas consumption	58	Bcf/year
Gas intensity	14.5	MMBtu/tonne
Specific capex	400	\$/tonne/year
Specific O&M	60	\$/tonne/year
Total capital cost	2,000,000,000	\$
Annual O&M cost	300,000,000	\$/year
Construction time	3	year

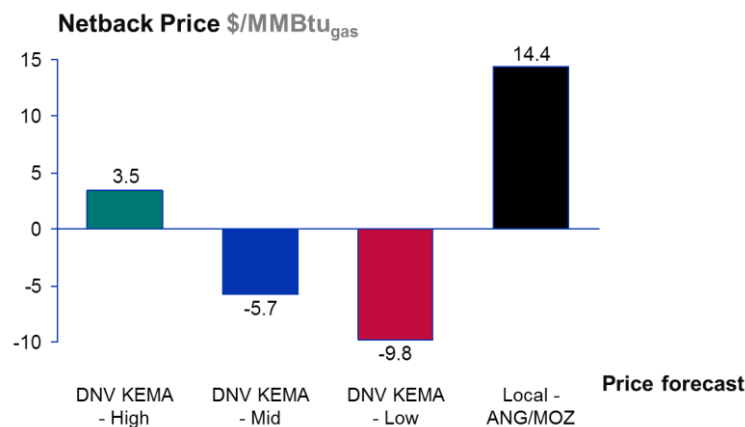
**Table 32. Parameters for steel plant project<sup>17,15</sup>**

According to Metals Consulting International, steel plant projects in Austria and Iran show capital expenses of \$475 and \$255 per ton/yr capacity, respectively. Whereas, Indian expansion projects announced by JSW Steel and Tata Steel show capital costs equivalent to \$245 and \$336 per ton/yr of steel produced, respectively. Greenfield projects by Tata Steel foresee capital expenses in the range of \$627 to \$980 per ton/yr of steel produced.



**Figure 94. Capital costs for integrated steel mill expansion and Greenfield projects**

Natural gas netback values are found to be from 3.5 to negative -9.8 \$/MMBtu under the three scenarios, largely due to high shipping costs to Asian markets and relatively low steel prices. When price is set by local needs, a very positive netback of 14.4 \$/MMBtu is achieved.



**Figure 95. Netback price for natural gas used for steel**

The local scenario excludes a \$350 per ton shipping charge to get the steel to market. The proposed facilities are analyzed in the low-mid-high scenarios for global export to meet Asian demand, but will also be able to serve local needs. No shipping charges are deducted from the local scenario as the proposed facility is then expected to be built primarily to support local and regional demand.

### 3.9.4 Risks & Abatements

Similar to Mozambique, Angola has the natural resources available to build up and maintain a steel industry. From a capital cost perspective, the Angolan case would presumably face more challenging

economics since Greenfield projects are more expensive. However, Angola has the advantage to have substantial local ore deposits. Nonetheless, these iron ore deposits are currently being developed with an expected production of only 3 million ton by 2015. This would limit the size of new steel plants to a production capacity of roughly 1 million tons.

The gas consumption related to iron and steel consumption is small, whereas the main inputs are iron core, coking coal and scrap steel. As global demand for steel is expected to increase, Mozambique export potentials look promising since domestic production facilities exist, which are currently mothballed. Most importantly, local availability of coal and iron ore resources is essential. The state of the global economy and associated market prices are essential for the performance of iron and steel plants (which brings about significant market risks). However, African demand is likely to increase which offers regional opportunities for domestic steel production. Energy and labor are key production factors which eventually allow Mozambique to gain a competitive position in the regional and global market.

Gas use in general is limited for integrated steel production (about 5 Bcf per 1 million ton of steel). The iron and steel industry fails to be a neither critical nor valuable use of natural gas. Since gas inputs are rather low and its transport distances can be long if plants are located near ore and/or coal sources, it is more important to have coal and ore available.

### 3.10 Cement

The most often used cement is Portland cement which is produced from limestone, silica, alumina, and iron ( $\text{CaCO}_3$ ,  $\text{SiO}_2$ ,  $\text{Al}_2\text{O}_3$ , and  $\text{Fe}_2\text{O}_3$ ). In addition there can be small amounts of the undesirable contaminants magnesium oxide, sulfur and alkalis. A typical raw mixture contains 80% calcium carbonate and 12.5% silica. Cement is produced by pyro-processing limestone along with shale, clay and further additives. The resultant clinker is then mixed with gypsum, and ground into a fine powder to form cement. Herein we provide a brief overview on cement use and pricing in Africa, discuss capex, opex, pricing and gas netback values, and then list sector risks and abatements.

#### 3.10.1 Global Market Outlook

Cement production and consumption occurs on a local-regional level as cement has the lowest added value to weight ratio for any industrial processed product. Thus global trade is limited, and reserves must be close to market. Fortunately the raw ingredients are available all over the world.

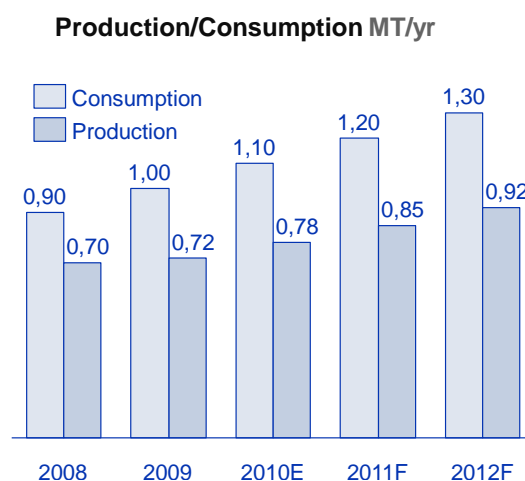
Globally, coal and coke supply 75% of the primary energy required for cement production, while natural gas contributes less than 5% of the energy required. In locations where natural gas is used for cement, coal and coke are often procured as backup in case gas is not always available.

#### 3.10.2 Cement Use and Pricing in Africa

Total cement production in Sub Saharan Africa was 56.6 MTPA in 2011 with Nigeria, Kenya, Angola, Tanzania, South Africa, Zambia and Zimbabwe being the largest producers.

##### 3.10.2.1 Cement in Mozambique

In 2010, Mozambique consumed ~1.1 million ton of cement, and demand is growing due to local infrastructure investments across the country. Currently, Mozambique imports cement from Pakistan and China to meet domestic demand. Moreover, the gap between domestic consumption and production is widening as illustrated below. While cement consumption increased 44% from 2008 to 2012, domestic production only increased 31%, causing imports to increase by 90%.



**Figure 96. Yearly domestic consumption and production of cement in Mozambique**

Most cement demand (62%) is in the South of the country near the capital Maputo. The central part around the city Beira makes up for 23% of domestic demand, and demand in the North corresponds to 15%, though this is expected to increase in line with upcoming industrial growth.

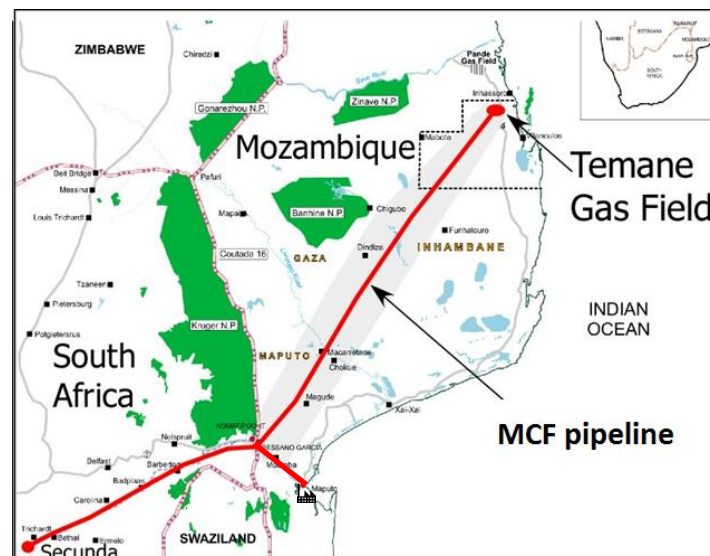
Currently, three cement factories are located in the South of Mozambique around Maputo, and an additional three factories are under construction by Chinese investors which will triple domestic production capacity from 0.9 to 2.7 mln ton/yr. The following table shows these new facilities technical and financial information.

Place	Investment (mln\$)	Capacity (Tons)	Company
Magude	78	500,000	Africa Great Wall Cement
Maputo	72	800,000	China International Fund's
Boane	100	550,000	GS Cimento

**Figure 97. New cement production facilities in Mozambique<sup>127</sup>**

Mozambique is endowed with significant limestone deposits with reserves estimated at several hundred million tons, which yields a good potential for increasing domestic production and decreasing imports.<sup>128</sup> Additionally, gypsum reserves have been discovered which can displace gypsum imports to potentially allow increased domestic input to cement production.<sup>129</sup>

Coal is predominately used as fuel for cement production kilns. However, there is one project where coal is replaced by natural gas (“Matola Gas Company Fuel Switch Project”). This factory in the south operated by Cimentos de Mocambique uses 1.5 Bcf/yr of gas instead of less expensive coal for environmental reasons. The cement factory is supplied off of the MCF pipeline to South-Africa.



**Figure 98. Gas supply for the Matola cement coal to gas fuel switch project**

### 3.10.2.2 Cement in Angola

Currently, two cement plants are operating in Angola. The Nova Cimangola is the largest one and consumes about 7 Bcf of natural gas per year. It is located near Luanda and the onshore Kwanza field. A second plant operated by Secil Angola is located in Libito, and owned by the government and the Portuguese Secil group who plan to build another factory. This would increase their production capacity from 280,000 ton to 1.8 million ton/yr.

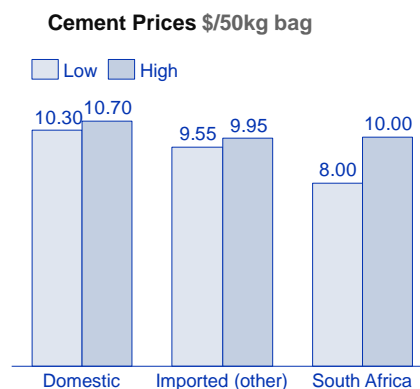
According to Secil, the current cement demand of the Angolan economy ranges from 4-5 million ton/yr, which justifies the new factory. The investment of \$180 million will be spent in two phases, with the new plant being operational three years after the beginning of its construction.<sup>130</sup>

In 2010 the 2<sup>nd</sup> largest Brazilian cement group (Inter cement) started building a 1.6 million ton/yr cement plant in Angola. Moreover, Angola plans to refurbish existing plants and build additional new ones to increase total output to 7.5 million ton/yr by 2015.

### 3.10.2.3 Prices

Cement prices in West Africa have increased steadily from 107 to 153 \$/tonne from 2004-2008, and have risen further to 190-230 \$/tonne in 2012.<sup>15</sup> Africa thus shows above average prices compared to global cement prices of ~\$100/tonne, most notably due to local supply shortages.

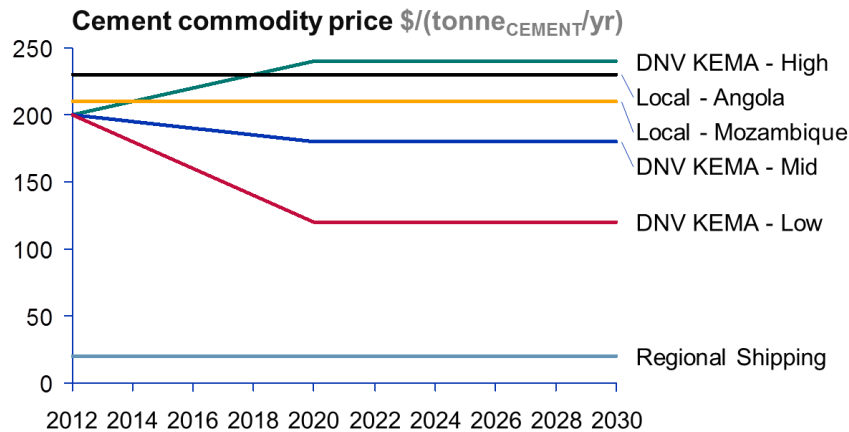
Cement prices in Mozambique are higher compared to prices in West Africa. Imported cement is at this moment cheaper than domestic cement, though this is related to quality risks, bulk purchasing economies, and higher distribution costs. Currently, cement prices from domestic production trade at 206-214 \$/tonne (10.3-10.7 \$/50 kg), whereas import prices range from 191-199 \$/tonne. As a comparison, prices in South Africa range from 180-230 \$/tonne, with Angola around 230 \$/tonne.



**Figure 99. Cement prices in Mozambique and South Africa**

The DNV KEMA assumed cement price forecast is shown below, and is based on the assumption that recent supply shortages will be alleviated by cement factories under construction, but that prices will not decrease significantly due to continued demand at this price to meet growth. The high and low cases are provided to account for either of these forces not balancing the other. Local cases for Angola and Mozambique are run at their current cement prices to reflect a potentially static market.





**Figure 100. Cement price forecast**

Again, the DNV KEMA price forecast assumes the product is shipped regionally to meet wider demand where competition from other sources may occur, thus a shipping fee is removed from the actual revenue received by the plant. In the local cases there is no shipping charge deducted.

### 3.10.3 Capex, Opex, Pricing, Gas netback value

The netback analysis is less relevant for cement as the natural gas input is limited to a maximum of 3 MMBtu/tonne cement.<sup>17</sup> In the following we summarize recent activities with respect to cement production in Angola and Mozambique and compare capital cost of cement production facilities.

#### 3.10.3.1 Angola and Mozambique

A planned 1.5 million ton cement production facility expansion in Angola is reported to require an investment of \$180 million, or a specific capex of 120 \$/ton/yr cement production capacity.

In Mozambique, a recent project by Cimentos de Mocambique with annual production capacity of 240,000 ton of clinker and 400,000 ton of cement reported costs of 450,000 EUR with a plant lifetime of 20 years.<sup>131</sup> This corresponds to a specific capital cost of 146 \$/ton/yr capacity. The three African projects mentioned previously with 500-800k ton/yr capacity are estimated to have specific capital costs of 160, 92, and 187 \$/ton/yr cement capacity.

In both Angola and Mozambique, these costs are considered low where additional infrastructure investments (exceeding \$10-20 million) are often needed to exploit limestone quarries. Furthermore, low local labor costs have minimal savings as experienced people and supervisors must be brought in from abroad, and about half the required equipment is imported anyway. An ongoing project in Peru is now estimated to cost \$200-240 million for an 800,000 tonne/yr facility (250-300 \$/tonne/yr).

#### 3.10.3.1 Global comparison

Global company announcements yield similar Capex ranges. For example, recent Indian projects show Capex of 94 \$/ton (JK Lakshmi Cement) to 140 \$/ton (Ultra Tech). According to the European Cement Association, capital costs of new plants in Europe are around 182 \$/ton/yr capacity.<sup>132</sup>

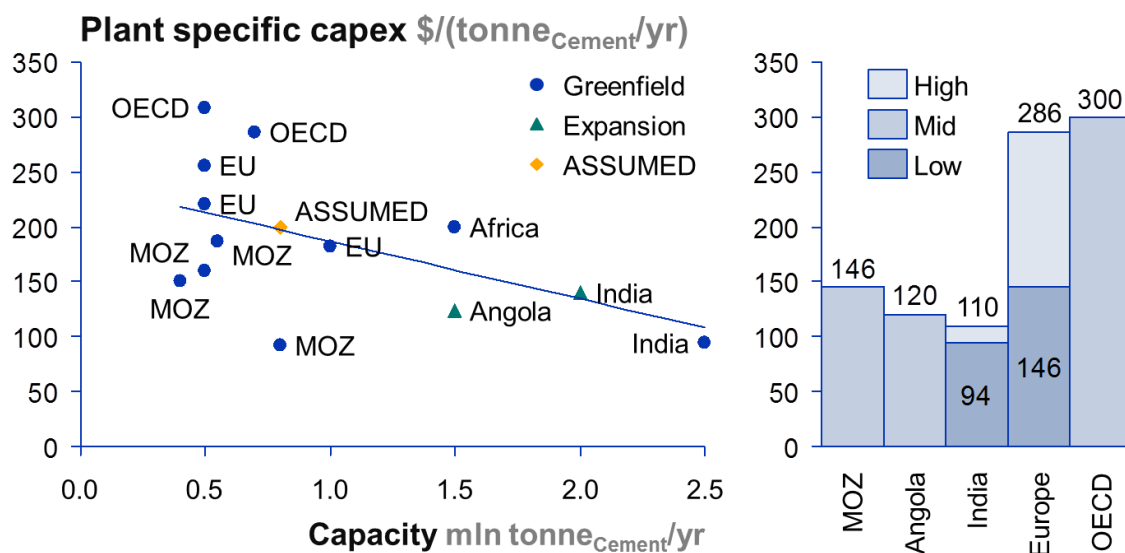
However, higher cost figures are also mentioned in the literature. The IEA<sup>133</sup> records investment costs of 300 \$/ton/yr and the European Cement Research Academy<sup>134</sup> mentions investment costs of 146 and 286 \$/ton/yr for a 2 and 0.5 million ton/yr plant respectively.

In India a number of mini-cement plants have been installed which are characterized by lower capital costs (30-35 \$/tonne capacity).<sup>135</sup> However, plant operation is less efficient and thus OPEX of mini-plants are significantly higher than those of large-scale cement plants. The following table summarizes the capital costs for the mentioned worldwide regions.

Region/Country	Capital cost range (\$/ton)
ANG/MOZ	120-146
India	94-110
Europe	146-286
OECD	300

**Table 33. Comparison of CAPEX for large scale cement plants for various regions**

Cement plant capital costs are shown below verses their capacity along with the regional averages.



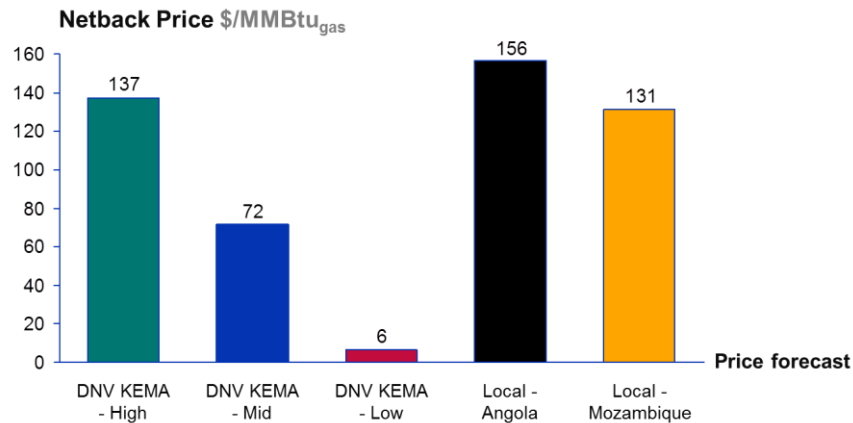
**Figure 101. Capital cost ranges for cement plant projects**

A moderate sized cement plant is assumed for the netback analysis with a 800,000 tonne/yr capacity and average capital costs due to lower labor rates in Mozambique and Angola balancing the higher costs from these undeveloped markets. In general, the relatively simple nature of constructing a cement plant is expected to lead to lower capital costs as experience grows.

Plant parameter	Value	unit
Plant capacity	800,000	tonne/year
Capacity factor	90%	%
Annual gas consumption	2.4	Bcf/year
Gas intensity	3	MMBtu/tonne
Specific capex	200	\$/tonne/year
Specific O&M	60	\$/tonne/year
Total capital cost	120,000,000	\$
Annual O&M cost	48,000,000	\$/year
Construction time	2	years

**Table 34. Parameters for cement plant project**

The netback price is very favorable under all circumstances due to the high profitability of cement plants and the relatively small use of natural gas which puts all of the forecasted profits onto a very small amount of gas. The netback price range is from 6-156 \$/MMBtu of natural gas under the four pricing scenarios as shown below.



**Figure 102. Capital cost ranges for cement plant projects**

In actual practice the value of natural gas will be priced to coal with a relatively small (~\$1/MMBtu) premium as it allows simpler and cleaner kilns over coal alternatives. Considering imported coal costs ~\$4.25/MMBtu (\$125/tonne), this puts the total netback value of delivered natural gas to cement at ~\$5/MMBtu. Mozambique’s local coal resources are likely to result in a much lower delivered coal price of ~\$2/MMBtu which corresponds to a cement netback value of \$3/MMBtu. By comparison a natural gas fired cement plant in Peru is paying ~\$4/MMBtu for its gas today.<sup>136</sup>

### 3.10.4 Risks & Abatements

The Mozambican outlook for the cement industry is good as domestic demand is increasing and local resources are available for domestic production. As cement is a locally traded product and neighboring countries (especially South Africa) have increased their domestic cement industry, prospects for the Mozambican industry will largely depend on national developments.

Similar remarks apply to Angola where domestic demand is met by imports, though a new facility is expected to start operating soon. As there is no technical advantage of using gas in cement manufacturing, gas will need to be competitive with coal, petcoke, and other alternatives to play a role in the energy supply of the cement industry.

While gas use for cement plants is limited, cement is a critical base material for economic growth. As such, alternative uses of gas offer a higher monetary value to the government, but clearly cement provides a basis for expanding the local economy (e.g. as input for the buildings sector and SMEs). Gas use in cement will only be taken into consideration when gas infrastructure is already planned to be built in the neighborhood. Hence, it acts as a spin off and not as anchor project.

## 4 Domestic Small Medium Enterprise impact

Here we describe the impact of natural gas industries on the small and medium enterprises (SME) and the domestic economy of Angola and Mozambique. We start with an introduction on the SME sector for these two countries, and follow with descriptions of each natural gas industries creation of direct and indirect jobs, as well as induced jobs. We also elaborate on steps for the local workforce to become involved in construction and/or operation of the respective industries.

Medium enterprises are defined as 10-99 employees, small include less than 10 employees (1-9), and when noted, the micro enterprises employee less than 6 employees (1-5).

### 4.1 Angola SMEs

Angola's average GDP growth rate exceeded 10% per year during the last decade due largely to the oil, gas, and diamond industries. The expansion of these industries has created spillover effects for the commercial and service sectors (i.e. financial and SME related activities). For sustained private SME sector activity though, energy supply – and especially electricity supply – remains, besides many others, a critical barrier to further expansion as this accordingly translates into high energy costs. In 2012, manufacturing and (public and private) services contributed ~30% to the country's GDP.<sup>137</sup>

Roughly 60% of the employed population work in SMEs with 5-19 employees, 23% in SMEs with 20-49 employees and 5% worked in SMEs with 50-99 employees. Thus, 88% of the employed population in Angola worked in enterprises with less than 100 employees. The remaining 12% of employees worked in enterprises with 100+ total employees. With respect to job creation, 77% of newly created jobs emerged in SMEs with 5-19 employees, 10% in SMEs with 20-49 employees, and 20% of net new jobs were created in businesses with a total of 50-99 employees. Slightly larger enterprises (100-250 employees) actually cut jobs by 7%.

The business development is very dynamic as 26% of the workforce works in enterprises which were established within the last two years and 53% worked in businesses established within the last five years.<sup>138</sup> In 2012, 41% and 72% of new jobs were created in businesses younger than two years and five years respectively.<sup>138</sup> Unemployment is estimated to be 25%.

Thus, although the contribution to the national GDP mainly stems from the oil and gas industry which is characterized by relatively low direct employment, the Angolan SME sector is important for the formal employment of the domestic workforce. In line with economic growth rates, the sector is in a dynamic state with young and small business creating the majority of new jobs.

Key sectors identified for the larger economic development, and thus enablers for further SME activities, are financing, oil, gas, mining, infrastructure services (telecommunication, construction, electricity and water, transport), agriculture, hospitality, retail, and beverages. In parallel, improved and transparent governance and regulatory frames are needed to embrace this development.

The Government aims to further stimulate Micro, Small and Medium sized Enterprises (MSMEs) by providing fiscal and tax incentives. One law specifies that 25% of the value of public procurement should target MSMEs. As many smaller-scale economic activities are not formalized within enterprises, the Government hopes to stimulate formal business development with such initiatives.

In 2012, public expenditures of \$1.8 billion were announced to support SME sector growth over a multi-year time horizon. Access to micro-finance is seen as critical to facilitate MSMEs.<sup>137, 15</sup>

Furthermore, the Government requires oil companies to hire local workforce and procure partly from local businesses. In addition to the above mentioned facilitators, training programs and knowledge transfer are beginning to foster local capacity arising from the SME sector.<sup>139</sup>

## 4.2 Mozambique SMEs

Almost 80% of total enterprises are micro scale companies with small and medium sized enterprises showing comparable numbers. The following figure shows the split of SME enterprises and turnover by region, as well as the share of enterprises and employees by enterprise size.

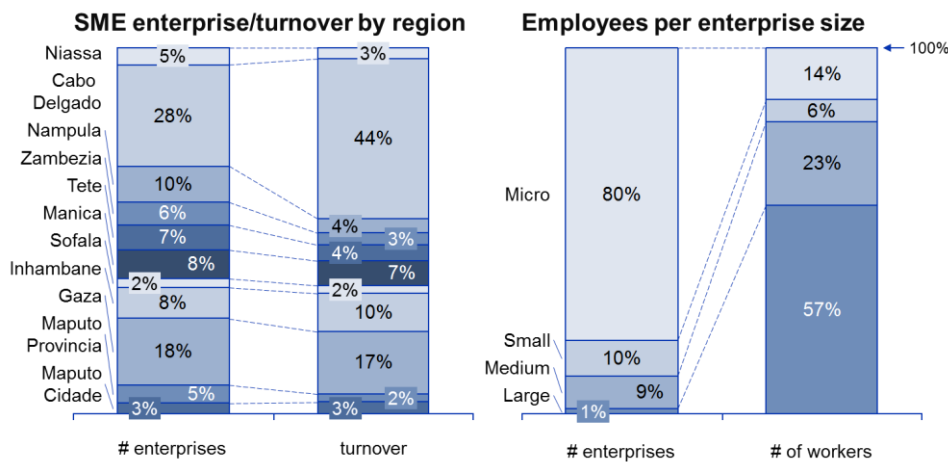


Figure 103. Mozambique SMEs by region and size<sup>140</sup>

A regional breakdown shows Cabo Delgado, Gaza, and Nampula account for 54% of the enterprises and 71% of the total SME turnover.<sup>140</sup> The majority (57%) of employees are in companies with more than 100 employees. The following figure shows each sectors number of enterprises vs. their share of total turnover. Sectors with fewer enterprises often have larger employee bases.

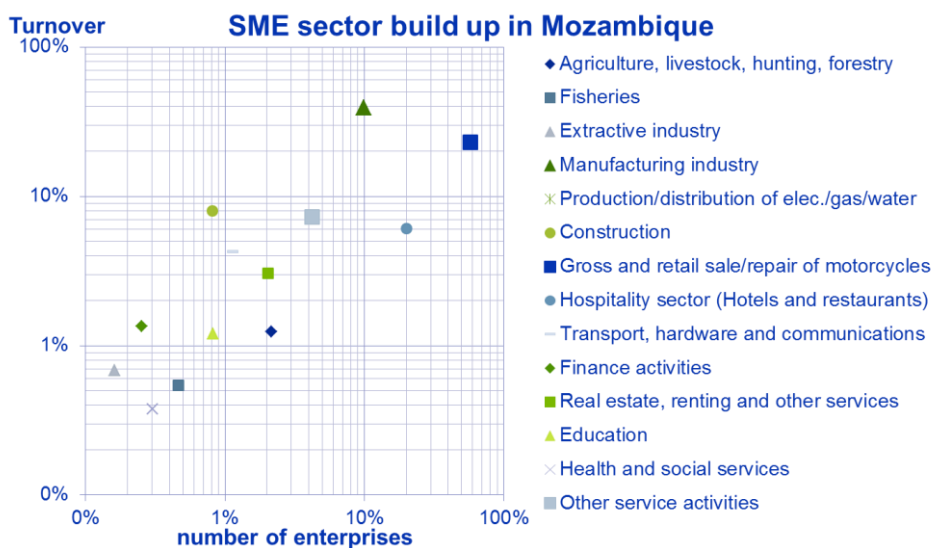


Figure 104. Mozambique SME sector details<sup>140</sup>

Regarding economic activities, commerce is the dominant activity (16,357 enterprises, or 57.4% of the total SME), followed by the hospitality sector (5,739 enterprises or 20.2%) and the manufacturing industry (2,828 enterprises or 9.9%). However, the manufacturing industry contributes most to the total turnover (39.2%).<sup>140</sup>

We estimate around 400 Mozambicans are working in the gas based industry in Mozambique. The breakdown of this workforce across sectors and experience level is in the following table.

Estimated number of Mozambicans working in the Gas Based Industry and competency					
	Sector	Basic Level	Medium level	High Level	Total
Production & Maintenance	Exploration and Production	46	24	7	77
	Transportation and Distribution	60	24	15	99
	Power Generation	35	23	6	64
	Manufacturing Industry	52	24	7	83
	<b>sub-total</b>	193	95	35	323
Commercial & Services	Exploration and Production	3	9	3	15
	Transportation and Distribution	4	12	4	20
	Power Generation	3	8	3	13
	Manufacturing Industry	3	10	3	17
	<b>sub-total</b>	13	39	13	65
<b>TOTAL</b>		206	134	48	388

**Table 35. Estimated number of Mozambicans working in gas based industry<sup>141</sup>**

In addition to the current workers, there were almost 12,000 graduates in 2010 with an education that could fit into the gas based industry. These values are summarized in the table below.

Number of graduates in 2010	Basic Level	Medium level	High Level	Total
<b>Production &amp; Maintenance</b>	2018	715	395	3128
<b>Commercial &amp; Services</b>	1829	1281	5618	8728
<b>Total</b>	3847	1996	6013	11856

**Table 36. Number of graduates in studies useful for gas based industries<sup>142</sup>**

The gas based industry is in competition with other industries and employers in Mozambique, so only part of this potential is available for the gas industry. It should be noted that especially the ~3,000 graduates from the studies related to production & maintenance are of most importance to become part of the future workforce in the gas based industry.

### 4.3 Impact of industries on SME and domestic economy

Industrial projects create direct jobs for their construction and operation (engineers, laborers, operators), indirect jobs to support the direct jobs (regulators, deliveries, manufacturers), and induced jobs from the direct and indirect jobs (hotels, restaurants, retail, schools). Specific direct, indirect, and induced jobs created by each industry are shown in the following charts:

### Direct/Indirect Jobs #/bcf/year

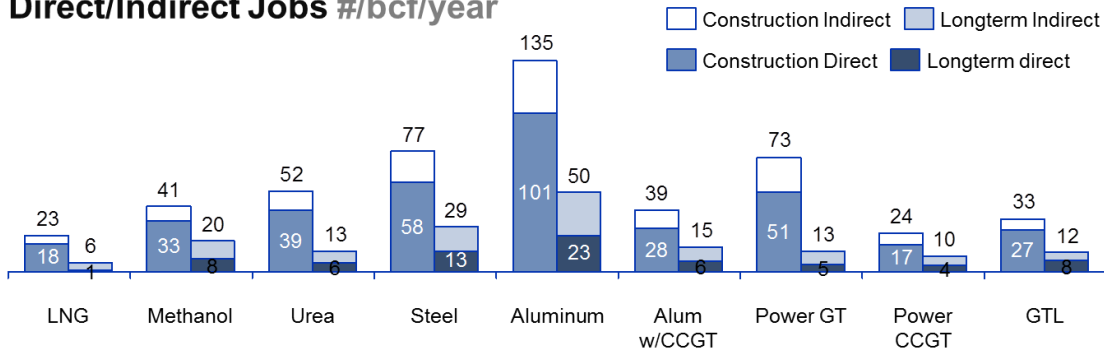


Figure 105. Specific direct and indirect jobs by industry

### Induced Jobs #/bcf/year

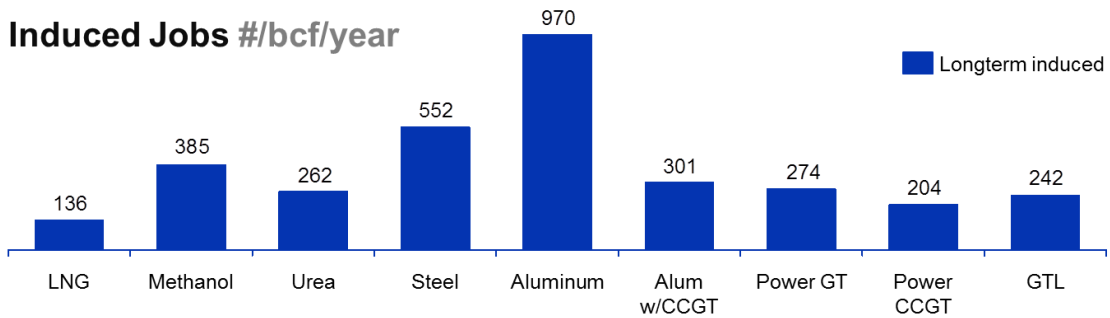


Figure 106. Specific induced jobs by industry

Direct, indirect, and induced jobs created by each facility are shown in the following charts:

### Direct/Indirect Jobs #/year

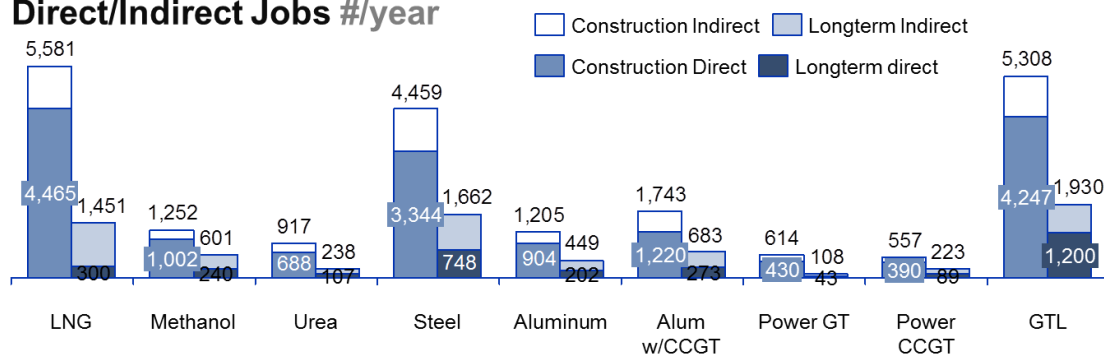
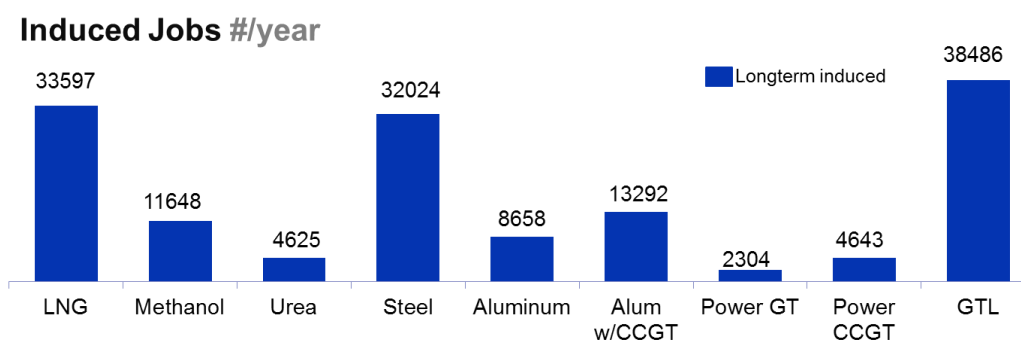


Figure 107. Direct and indirect jobs by industrial facility



**Figure 108. Induced jobs by industrial facility**

The above values are put in a table to facilitate comparison:

	LNG	Methanol	Urea	Steel	Alum.	Al. w/CCGT	Power GT	Power CCGT	GTL
Gas consumption (Bcf/year)	248	30	18	58	9	44	8	23	159
<b>Total jobs/year per assumed facility</b>									
Construction Direct	4465	1002	688	3344	904	1220	430	390	4247
Construct. indirect	1116	250	229	1115	301	523	184	167	1062
Longterm direct	300	240	107	748	202	273	43	89	1200
Longterm indirect	1151	361	131	914	247	410	65	134	730
Longterm induced	33597	11648	4625	32024	8658	13292	2304	4643	38486
<b>Jobs per Bcf/year gas demand</b>									
Construction Direct	18	33	39	58	101	28	51	17	27
Construct. indirect	5	8	13	19	34	12	22	7	7
Longterm direct	1	8	6	13	23	6	5	4	8
Longterm indirect	5	12	7	16	28	9	8	6	5
Longterm induced	136	385	262	552	970	301	274	204	242

**Table 37. Direct, indirect, and induced jobs by gas industry<sup>143</sup>**

The most significant SME impact is expected to come from improved electricity reliability and new access to gas. Power plants will drive pipeline expansion as energy is 3-10x cheaper to deliver as gas in a pipeline vs. electricity in wires, hence power plants prefer to be collocated with the electric load they serve. The pipelines to power plant make gas available over a broader region and open up small industrial and domestic uses, as well as the chance to replace LPG and biomass with natural gas. The opportunity for small combined heat, power, and cooling presents to serve new and existing buildings represents a large domestic opportunity.

Large industrial projects are best co-located next to the natural gas landing point and existing/new transport infrastructure (ports, rail heads). People will migrate for direct and induced employment opportunities, thereby creating opportunity to build new areas with well-thought urban planning measures. Steel and aluminum plants are best located near ore and hydroelectric reserves, and may be of sufficient demand to justify the construction of pipelines, that then has the spillover effect mentioned above to SMEs. Specific information and/or examples on the eight different industries are provided for in the sections below.



### 4.3.1 LNG

The question is to what extent a large gas project established by, usually, international oil companies and focused on exports may provide opportunities for SME. In order to address this question, a good example may be Peru, where Latin America's first LNG export terminal was started up in 2010.<sup>144</sup>

Although about 7,000 construction workers are required during the construction of a liquefaction plant, it only provides permanent work for approximately 200 employees. However, it was reported that about 30,000 jobs were created during the construction period due to inter-linkage between other economic sectors.<sup>145</sup> In addition, another way was sought to have the LNG plant make a further positive contribution to the local businesses. The result was a two-year program focused on increasing business opportunities in the towns in close proximity to the LNG terminal.

One of the activities under the program consisted of training and skill-building courses to the local business community based on an analysis of the SME's needs. Furthermore, a subsequent trade fair connecting local participants to large corporations resulted in \$2 million of new sales. All in all, about 50 local SME's have experienced at least 20 percent revenue growth as a result of the program.

### 4.3.2 Power Generation

The National Directorate of Industry in Mozambique lists in its 2008 Strategy for Development of SME that in 2004 only 0.1% of all SMEs had their activities within the power, gas and water production and distribution sector. These 26 companies, out of which 17 are medium sized, generated 3.8% of the total turnover of the Mozambican SME sector.

Based on interviews and an analysis of the existing industry, DNV KEMA estimates that 78 Mozambicans are employed in the power generation sector, 64 of which having maintenance, production or operational functions. Of these 64 employees, 35 perform a basic level job, 23 a medium level and 6 a high level activity. 14 employees serve a commercial, legal or other service function. Regarding the latter, 3 employees perform a basic level job, 8 a medium level and 3 a high-level function. Integrated industrial facility development projects for Mozambique show that 15,000 jobs emerge during construction of a refinery and gas fired power plant, of which 2,000 being permanent ones. This comprises also SMEs supporting the industrial activities itself. We estimate that 5-10% of the jobs are related to the power plant, so about 300 jobs (incl. SMEs) would emerge per GW of built and installed gas power plant capacity.

### 4.3.3 Fertilizer

While fertilizer does not provide the highest netback value for natural gas, the development impact of them can be significant if institutions are put in place to facilitate their constructive use. The fertilizer value chain in Africa involves multiple players to get fertilizer to farm end-users that are impacted by government policies, institutional regulations, physical geography, and infrastructure concerns. Typically fertilizer is manufactured internationally and then shipped to African ports. This fertilizer is often already mixed into a final product, but can also be sent as the ingredients urea, potash, and phosphates for final blending in country.

Importers procure the materials through tender or direct negotiation and pay for the commodity, freight, and insurance. The Port Authority and clearing agents handle the fertilizer on arrival and its customs clearance. Large transporters move the fertilizer to warehouse operations further inland,

most often by truck, but also by rail when feasible. Small transporters deliver fertilizer to wholesale and retail agrodealers where it is stored, repackaged, and distributed to farmers. Agrodealers are often responsible for marketing their product and educating the farmer on its preferred use. Banks provide credit to all parties, but most significantly to the importer.

Direct jobs are created along the value chain to make and distribute the fertilizer, but the greatest benefit comes from a population of farmers who know how to seasonally and regionally use fertilizer on different crops to increase production and manage the lands. This base of the economy supports the expansion of other sectors by providing food security and allowing higher margins for relatively poor farmers. Many countries subsidize or set their fertilizer prices to expand their use, but this can lead to heavy economic burdens and the misuse of a devalued product. Farmers must be educated on the use of fertilizer to avoid economic waste and environmental damage.

It is advised that Angola and Mozambique pursue a market pulled approach in which urea and fertilizer mixing plants are built to meet local demand in parallel to a broader campaign to educate farmers on the best use of fertilizer. This will effectively reduce import burdens while avoiding competition on international markets where new urea capacity from lower cost gas sources has and is expected to come online in the coming decade. Angola and Mozambique are able to profit from international fertilizer sales, but they will not be the lowest cost producers and should concentrate on fostering local demand, as the netback analysis suggests other exports are more profitable.

#### **4.3.4 Methanol**

Based on existing methanol plants, we foresee that operating a methanol plant provides direct employment for roughly 200 people. For example, Methanex owns two methanol plants in New Zealand, Motunui and Waitara Valley. The Waitara Valley plant is idle, but expected to be made operational. Currently, Methanex employs 165 employees in New Zealand and contributes more than \$45 million/year to the local economy. Recommencing the Waitara Valley plant will employ up to 500 contractor jobs and 30 fulltime jobs when operational again. Also, The Brunei Methanol Company formed in 2006 currently employs ~190 employees of which 96% of are Bruneians; some of them have undergone overseas training in Japan or other countries. Japanese technical specialists have been providing in-house mentoring and assistance.

In contrast to the above though, the methanol plant in Equatorial Guinea produces approximately 1 million metric tonne/yr of methanol and employs over 450 employees worldwide. This includes three vessels and terminals in Europe and the US however.

Part of the construction work of a methanol plant can be carried out by local companies as was done during the construction of the Azmeco methanol plant in Azerbaijan. Around 75% of the construction work involved in building the Azmeco plant was carried out by local construction and engineering companies with the involvement of foreign experts.

Methanol is used for a large variety of other chemical products as was explained in the beginning of the section. Therefore, various spin-off companies using methanol as feedstock can be developed.

### 4.3.5 Gas-to-Liquids

GTL could reduce Angola’s and particularly Mozambique’s dependency on fuel imports which it currently faces. Apart from methanol production, which could reduce this burden by allowing for fuel blending, GTL is the only option able to achieve this.

Due to its complexity, a GTL plant provides relatively many direct jobs. Estimates by Sasol for its Louisiana-based GTL project indicate that around 1,200 direct jobs could be created; for its Canadian GTL project, Sasol estimates more than 500 new permanent jobs. Although technologically challenging, about 95% of the people working in Shell’s Bintulu GTL plant in Malaysia are local people. Also, the workforce of Sasol’s ORYX plant consists of about 30% of Qatari.

Apart from these permanent jobs, construction jobs are required as well. In the culmination of the Pearl GTL project in Qatar, approximately 50,000 workers were present on-site. Although part of this workforce could be provided by the countries themselves, many of these workers will come from all over the world. As all of them require accommodation, food, etc., it is clear how local SME’s may benefit from this.

The complexity of the GTL plant makes it unlikely that local companies will be able to supply the necessary components such as the GTL catalyst which is highly advanced material.

### 4.3.6 Aluminum

Angola has 150,000 artisanal and small-scale mining enterprises (ASM) with an estimated 900,000 dependants. Compared to large-scale mining (LSM), ASM is commonly acknowledged to create far more jobs per invested amount of money. The following table lists the minerals and metals mining activities in Angola.

Category	Specific resources produced
Precious materials	Diamonds, Gold, Silver, various gemstones
Metallic minerals	Uranium, Nickel, Chromium, Bauxite, Copper, Lead, Iron ore, Zinc
Industrial minerals	Phosphate, Granite, Marble, Salt, Gypsum, Lignite, Mica, Peat, Manganese

**Table 38. Minerals and metals being mined in Angola<sup>146</sup>**

From a resource base the buildup of a national aluminum industry using domestic inputs would thus be possible in Angola. Similar to Angola, Mozambique also has the resource base to expand its domestic aluminum industry solely based on domestic inputs.

For both countries direct employment for primary aluminum production would be in the range of ~0.004 employees/ton aluminum. Indirect employment, part of which would induce jobs in the SME sector, would amount to ~0.01 employees/ton aluminum.<sup>xix</sup> Accordingly, a national production capacity of 1,000,000 ton primary aluminum could create 4,000 direct and 10,000 indirect jobs.

### 4.3.7 Iron and Steel

Evidence from the Brazilian steel industry shows that 0.003 direct and indirect jobs are created per ton of crude steel produced.<sup>147</sup> Thus, a steel industry with an annual production capacity of 1,000,000 ton generates 3,000 direct and indirect jobs.

<sup>xix</sup> Numbers account for existing aluminum plants operated by Rio Tinto Alcan and DUBAL.

Building up a national steel industry clearly provides opportunities for local economic development. As mentioned, the creation of direct and indirect jobs within the region where plants are erected arise. Companies are expected to hire employees from surrounding communities and contribute to the local population's capacity.

#### 4.3.8 Cement

According to realized projects in Nigeria and India, approximately 0.001 direct jobs per ton cement production capacity are created whereas 0.004 indirect jobs per ton are created. As such, a cement plant with a 1,000,000 ton production capacity creates 1,000 direct and 4,000 indirect jobs.<sup>148</sup>

With regards to indirect jobs, cement production operations generate additional employment mainly in the areas of supplying bags for packing, contracting of services within the cement factory and developing distribution networks (incl. transport of bagged cement). About two-thirds of the jobs added are for unskilled labor, one-third is for skilled workforce.<sup>148, xx</sup>

#### 4.3.9 General remarks

The contribution to the domestic economy differs between the industries. From the experience in comparable projects in other countries we can learn that the relative contribution of local workforce is heavily dependent on the complexity of the respective industry. This is applicable for the construction as well for the operation. In the section on GTL we have mentioned that about 95% of the people working in Shell's Bintulu GTL plant in Malaysia are local people, but we have to bear in mind that it has taken between 15 and 20 years to arrive at this level.

To estimate the contribution of local workforce during operation we have to take into account that education of people towards the right skills in all cases requires a certain time lag, as education programs have to be made and students have to attend these education programs for a couple of years. If education would start directly from final investment decision (FID), construction time and education of the first operational people can go alongside. Furthermore, training on the job is required to become experienced in the specific industry.

For GTL as most complex industry GTL and learning from the Shell experience, we expect it will last fifteen years before 80-90% of the workforce for operation will consist of local people, while for Cement already from the beginning 70% of the operating people can be local, given the large share of unskilled labor. We would consider LNG, Methanol and Fertilizer plants as quite comparable and from the Brunei example we derive that a local workforce of 80-90% should be possible after around seven years. We consider Power, Steel and Aluminum to be between Cement and the last category. We therefore expect a local workforce of 80-90% to be possible after around 4 years.

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<sup>xx</sup> Skilled workforce includes, e.g. truck drivers, administrative and managerial staff, etc.

## 5 Regulatory & Financing

This section distinguishes the regulatory framework and financing of the gas sectors of Angola, Mozambique, Tanzania, South Africa, The Netherlands and Qatar. The last four countries are provided for a regional and global perspective. A regional comparison of the gas regulatory framework in southern Africa and a global comparison on best practices relevant to the gas industry are provided after the country details. In closing global, regional and local financing is discussed and compared before a summary and recommendations are provided for Angola and Mozambique on regulatory and finance issues addressing the eight natural gas industries.

### 5.1 ANGOLA<sup>xxi</sup>

The majority of gas production in Angola is associated with oil, resulting in a large degree of gas flaring (some 140 Bcf in 2011<sup>149</sup>). The government declared flaring reduction as an important goal in petroleum policy, although significant drops in flaring have not been realised yet. Angola LNG has emerged as an essential project to facilitate continued offshore oil development and natural gas commercialization, while maintaining gas flaring reductions. The project's first LNG cargo departed in June 2013 towards Brazil.

The Ministry of Petroleum (MINPET) is the executive agency responsible for petroleum (and bio-fuel) policy definition and control (Presidential Decree No. 239/12, of 4 December 2012). In addition, Sonangol E.P. is the national and sole concessionaire for oil and gas sectors, responsible for the exploration and production of oil and gas in Angola. Sonagas (Sonangol Gas Natural), a branch of Sonangol E.P., extends to natural gas. Due to the lack of expertise to operate in the exploration industry until the mid-1990s, Sonangol E.P. associated with international oil companies (IOCs) for oil exploration and production in all concessions. Angola's policy has been to encourage the upstream private sector to focus on oil, while gas monetization projects in the country have been mostly ignored (except for the LNG project).

The Ministry of Energy and Water (MINEA) is the executive agency mainly responsible for the country's energy policy (Presidential Decree No. 246/12, of 11 December 2012). The latest energy strategy, the Angolan National Energy Security Policy and Strategy (NESPS), covers the power, oil and gas sectors alike (Presidential Decree No. 256/11, of 29 September 2011). The overarching goal, at least for the petroleum sector, is the Angolanization of the sector (i.e. to capture the wealth for Angola and promote local entrepreneurship). Meanwhile, large investments planned for the oil and gas sector should be secured. There is a need to reinforce investments in gas reserve exploration and development, which the government aims to achieve by ensuring (i) a transparent regulatory framework (specific gas concession rights, clarification of functions in the value chain, etc.), and (ii) a legal framework for transportation and processing activities. The NESPS sets forth several priority initiatives for the oil and natural gas subsectors<sup>150</sup>:

The Petroleum Fund, an Oil Fund launched in October 2012 (by means of Presidential Decree No. 48/11, of 9 March 2011), was amended by Presidential Decree No. 57/11, of 30 March 2011 and Presidential Decree No. 24/12, of 30 January 2012 for the purpose of promoting project development investments in Angola or abroad, water and energy sectors, as well as other strategic

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<sup>xxi</sup> DNV KEMA appreciates earlier comments and reviews by law firm Miranda Correia Amendoeira & Associados on this chapter.

sectors. The fund will receive inflows from an “Oil Fund” equivalent to the sale value of 100,000 barrels of oil per day<sup>151</sup>; at current oil prices, around \$3 billion/yr.

### 5.1.1 Upstream – exploration & production

The exploration and production of oil and gas is governed under the Petroleum Activities Law (Law No. 10/04, of 12 November 2004), including its secondary legislation (e.g. Decree No. 39/00, of 10 October 2000 on Environmental Protection for the Petroleum Industry; Decree No. 1/09, of 27 January 2009, which approved the Petroleum Operations' Regulations; Law No. 26/12, of 22 August 2012 on Transportation and Storage of Crude Oil and Natural Gas), as well as by the individual oil production sharing agreements (PSAs) and other contracts entered into between international oil companies (IOCs) and Sonangol E.P. The Petroleum Activities Law forbids flaring of gas unless special conditions are met; MINPET gives permission on a case by case basis. Until the mid-2000s the ministry routinely gave such permission, but now a "zero-flare" policy applies for new fields, while existing fields are subject to flaring reductions.

In general, the PSAs state that gas surpluses associated with oil production is the property of the Angolan State (the cost of transportation is part of recoverable costs). Moreover, under the Model PSA non-associated gas discovered within the contract area is the exclusive property of the Angolan State and will be developed and approved at the risk and account of Sonangol E.P. However, gas project agreements relative to the Angolan state have consisted of Risk Service Contracts (RSC) rather than production sharing agreements<sup>xxii</sup>.

The Petroleum Taxation Law (Law No. 13/04 of 24 December 2004) established several taxes and fees applicable to oil and gas in Angola, thus being applicable to PSAs and/or RSCs<sup>xxiii</sup>:

- A Petroleum Income Tax (PIT) is levied on taxable income from petroleum exploration, development, production, storage, sale, treatment and transport, and from wholesale trading of products. Tax-deductible costs are specified in detail for PSAs, partnerships and RSCs. If the company operates under a PSA, the tax rate is 50%, otherwise the tax rate is 65.75%;
- A Petroleum Production Tax (PPT or sometimes also described as a royalty) of 20% is levied on quantities of natural gas measured at the wellhead, deducted from the quantities consumed in kind by petroleum operations. Reduced rates (10%) may apply to production in marginal fields, and in areas defined as difficult-to-reach, including offshore depths exceeding 750 meters. The PPT can be paid in kind or in cash. A PPT is not imposed under a PSA;
- The Petroleum Transaction Tax (PTT or windfall profit tax) is computed on taxable income, which takes into account several adjustments in accordance with the tax law. The tax rate is 70%. This tax is deductible for the computation of PIT. Deduction of a production allowance and an investment allowance is possible on the basis of the specific petroleum agreement. PTT is not imposed under a PSA.

<sup>xxii</sup> Risk-service contracts differ from PSAs in that profits (cash) are shared between the IOC (private investor) and state party instead of oil. As with PSAs, in risk-service contracts ownership of the resource remains with the state and risk and cost remain with the investor. In a RSC the IOC is typically seen more as a subcontractor of Sonangol E.P., while in a PSA its position is more of a partner.

<sup>xxiii</sup> For a detailed overview of the oil and gas fiscal regime in Angola see Ernst&Young, Global oil and gas tax guide 2012.

- A Surface Fee (SF) is computed on the concession area or on the development areas whenever provided within the relevant petroleum agreement. The surcharge shall be the Angolan currency amount equivalent to \$300 per km<sup>2</sup> and is due by partners of the state concessionaire. This surcharge is deductible for PIT purposes.
- A levy for the training of Angolan personnel is imposed on oil and gas exploration companies as well as production companies<sup>xxiv</sup>, and on service companies that contract with E&P companies for more than one year. Angolan companies owned by Angolan nationals with capital fully or more than 50% are not subject to this levy. Also excluded from this levy are i) foreign companies that supply materials, equipment and any other products, ii) services providers and entities engaged in the construction of structures or similar, that execute all or most of the work outside Angola, and iii) entities with a corporate objective which has no strict connection to the oil industry.

Under Presidential Legislative Decree No. 3/12, of 16 March 2012 (Decree on Incentives to Angolan Petroleum Companies), Angolan national petroleum companies may benefit from, amongst others, a Petroleum Income Tax rate reduction from 50% or 65.75% to a rate equivalent to that in force for Industrial Tax, in case of PSAs or other petroleum contracts, respectively.

The Angola LNG Project has been considered public interest; hence special incentives have been granted under Decree-Law No. 10/07, of 3 October 2007 (last amended by Presidential Legislative Decree No. 4/12, of 10 May 2012<sup>152</sup>) for taxes, customs and foreign exchange controls, and others.

### 5.1.2 Downstream – large scale gas-based industry

One of the strategic objectives of Sonangol E.P. is to promote the development of an industrial park in the Soyo region, thus attracting investments in gas utilization projects such as petrochemical and energy generation. In the Angola LNG Project, the supply of 125 MMSCF per day of treated gas is reserved for an ammonia plant project. The growth of the industrial park based on natural gas is subject to the success of Sonagas investments in Angolan natural gas reserve exploration and development.

Law No. 30/11 of 13 September 2011 defines the differential treatment regulation of Micro, Small and Medium Enterprises (MSMEs), as well as conditions for special benefit and incentive access. Pursuant to the terms of the Law, the Government is to create programs aimed at providing MSMEs with (a) tax and financial incentives; (b) organizational and vocational training; and (c) programs to foster innovation and technological capabilities. MSMEs are also provided with support in the form of simplified incorporation, licensing and tax procedures, in addition to being exempted from administrative fees and charges on share capital increases. Financing is made available to MSMEs through credit lines with subsidized interest rates, while their tax burdens are lightened by a reduction in the number of taxes levied under the Industrial Tax Code. With the law being enforced on 2 January 2012, MSMEs interested in applying for the benefits and incentives made available have one year from the beginning of the next fiscal year to apply for the necessary certification.<sup>153</sup> Law No. 30/11 was further regulated by Presidential Decree No. 43/12, of 13 March 2012.

<sup>xxiv</sup> US\$0.15 per barrel for production companies as well as companies engaged in refinery and processing of petroleum; US\$100,000 per year for companies holding a prospecting license, and; US\$300,000 per year for companies engaged in exploration activities.

### 5.1.3 Starting a foreign business in Angola<sup>154</sup>

It takes 12 procedures and 263 days to establish a foreign-owned limited liability company (LLC) in Luanda, Angola. This is longer than the Sub-Saharan Africa average. LLCs (Sociedades por Quota) must have at least 2 shareholders. The 4 additional procedures required exclusively of foreign companies add 195 days to the establishment process. A foreign company must translate the parent company's documents into Portuguese and certify them in the country of origin. In addition, a foreign company must obtain an investment project approval from the National Agency for Private Investment (ANIP). A New Private Investment Law (Law No. 20/11, of 20 May 2011, NPIL), which repealed the former regime, introduced some substantial changes to the investment process, notably: (i) the minimum foreign investment amount has been raised to \$1 million per investor in order for the investors to be able to repatriate dividends from their local operations; and (ii) all foreign investment projects processed through ANIP must be subject to the negotiation of an investment contract with the Angolan State. The simplified "prior declaration" regime that existed under the previous legislation has been revoked. Under the new rules, an investment project should be submitted along with the following additional documents: (i) technical, economic and financial feasibility study; (ii) environmental impact study; and (iii) proposed draft Investment Contract to be entered between the investors and the Angolan State, represented by ANIP. Although the NPIL allows for the foreign investment to be made outside its framework (investments lower than \$1 million), in such case, the relevant project will not qualify as a private investment operation, but rather as a mere foreign exchange operation, subject only to licensing by the Banco Nacional de Angola (BNA). As such, no prior approval from ANIP is required, but the foreign investor will not benefit from the rights conferred under the NPIL (notably tax and customs incentives, and the right to repatriate profits or dividends).

Main laws: The New Private Investment Law (Law No. 20/11, of 20 May 2011); The Tax and Customs Incentives Law (Law No. 17/03, of 25 July 2003); The Companies Law (Law No. 1/04, of 13 February 2004).

### 5.1.4 Accessing industrial land in Angola<sup>155</sup>

According to Article 15 of the Constitutional Law of Angola, all land is originally property of the Angolan state. Private land is not common, although it does exist. The state grants lease rights to investors, but the state usually retains ownership of the land. While it is legally possible for a company to own or lease private land, the more common option is to lease public land. The transfer of public land to another party is possible, but depends on authorization from the relevant official. There are time limits and certain conditions that limit the possibility of transfer. For example, the holder must use leased land for a minimum of 5 years. The intention is to thwart land speculation. There are certain limits on the amount of land that may be leased. For land greater than 2 hectares in urban areas and 5 hectares in rural ones, a ministerial grant may be required.

Main laws: Land law; Land Law Regulations; Civil Code; Real Estate Registry Code; Notary Code; Real Estate Tax Code; Real Estate Lease Law and Civil Government Ordinances.

### 5.1.5 Midstream – access to transport

The regulatory framework for gas transport, distribution and supply is hardly developed since there is no real downstream natural gas market as yet. In 2012, the Law on Transportation and Storage of



Crude Oil and Natural Gas (Law No. 26/12 of 22 August 2012) was enacted. It defines the rules and procedures for undertaking crude oil and natural gas transportation and storage activities connected with petroleum operations carried out under the Petroleum Activities Law. The transportation of hydrocarbons to international markets and other specific situations fundamentally related to oil exploration and production are excluded from the scope of the law. The new rules impose licensing requirements for the activities covered by the Law, and set the fees to be paid by license holders as well as the fines that may be assessed for breaches of the Law provisions. The maximum validity periods for licenses for the construction and subsequent operation of oil and natural gas pipelines and storage facilities are addressed, as are rules on the ownership of their infrastructure and their use by third parties. Finally, the new law also includes rules on public tenders for the hiring of transportation and storage services by Sonangol E.P., its associates, and any other entity wishing to acquire those services.<sup>156</sup>

Various technical regulations on domestic gas distribution, transportation and storage have been approved throughout the years.

### 5.1.6 Downstream – pricing

Not covered in Angolan legal or regulatory framework.

### 5.1.7 Financing

Currently, the upstream natural gas activities in Angola are centred around the Angola LNG project, which is a marketing joint venture between state company Sonangol (50%) and affiliates of Chevron (23.6%), Total (8.8%), BP (8.8%), and ENI (8.8%). “Stand alone” natural gas production is not developed yet, due to the mainly associated nature of gas with oil production. IOCs are only allowed to have a minority equity stake in (oil) exploration and production blocks. Finance required for midstream and downstream activities may be shared between public and private sectors, however Sonangol and Sonagas have the upper hand until recently.

	Activity	Financial parties
<b>Upstream</b>	Exploration & Development	Sonangol / IOC
	Production	Sonangol / IOC
	Bring onshore	Sonangol / IOC
	Processing	Sonangol / IOC
	LNG liquefaction	Sonangol / IOC
<b>Midstream</b>	Transmission infrastructure	Public (Sonagas)
	Large gas-based projects	Public (Sonagas)
<b>Downstream</b>	Distribution infrastructure	Public / Private

**Table 39. Angola financing parties by activity**

## 5.2 MOZAMBIQUE

Since 2004, gas is produced at the onshore Pande and Temane fields (Inhambane province) by Sasol and exported to South Africa via the ROMPCO pipeline. Part of the production is handed over to the Mozambique state as production taxes in kind, while the remaining is sold as commercial gas for markets in Mozambique. Gas is sold in Mozambique through:

- ENH, which distributes gas in Vilanculos and the Bazaruto islands;

- Matola Gas Company, which supplies certain industries in Matola and suburban Maputo;
- AUTOGAS S.A., which distributes compressed natural gas (CNG) for use in vehicles in Maputo and Matola.

Part of the commercial gas is sold to the Central Térmica de Ressano Garcia S.A, jointly owned by Aggreko and Sanduka Group, for power generation at the Ressano Garcia Gas Power Station (107 MW<sub>e</sub> capacity) inaugurated in July 2012.

The gas sector in Mozambique is regulated by the National Petroleum Institute (INP - Instituto Nacional de Petroleo) in cooperation with the Ministry of Mineral Resources (MIREM), and by the Ministry of Energy (ME). The INP is the regulatory authority responsible for managing the petroleum resources of Mozambique for the benefit of society. It ensures that petroleum exploration and production operations are conducted in accordance with the laws, regulations and best practices. The Ministry of Energy is responsible for energy policy, most notably for electrical energy, renewable energy sources and fuels, including the distribution activities of natural gas and other petroleum products.

The Mozambican natural gas strategy is officially laid down in Resolution No. 64/2009 on the strategy to develop a gas market and gas sector in Mozambique. The strategy is established along the following lines:

- Priority to be given to the use of Royalty Gas in kind for projects that are difficult to establish solely on a commercial basis, but with high impact on the development of the country;
- Avoiding the establishment of monopolies and conflicts of interest, while promoting diversified ownership within gas distribution networks;
- The Government to develop a knowledge base on the potential of gas utilization in Mozambique and promote economic viable projects;
- Avoiding the holding of proven reserves for unreasonable time periods by concessionaires and potential gas users, on an exclusive basis, and only for purposes of feasibility studies;
- Ample dissemination of proven gas reserve discoveries, as well as tariffs and regimes for third party access in gas transportation;
- Promoting the participation of Mozambican entrepreneurs in the natural gas industry;
- Approval of gas sales agreements by the Government and in selecting alternative buyers, consideration should be given to the price, priority of substitution of liquid fuels and manufacturing of products for domestic consumption as well as other local value added projects and the social and economic development consideration of Mozambique.

The promotion of employment linked to the development of small and medium-sized enterprises (SMEs) is a key element in Mozambique's Action Plan for Reducing Poverty (PARP 2011-14). Together with agriculture, SMEs traditionally generate significant employment. Currently the SME sector accounts for 42.8% of employment in the country and has been growing roughly 7% each year. However, overall SME growth is constrained by lack of access to affordable capital, heavy red tape and a poor business climate. Moreover, the high amount of low-skilled laborers within the labor force remains a significant issue both for employers who are unable to engage qualified laborers, as

well as entrepreneurship. Thus, the SME sector will require a significant investment and reform by the government<sup>157</sup>.

### 5.2.1 Upstream – exploration & production

Petroleum operations (exploration, production and transport of oil and gas) in Mozambique are governed by the Petroleum Law 3/2001, of (21 February 2001<sup>xxv</sup>, which gradually has been supplemented by various Decrees and Regulations in different operational areas (e.g. access to acreage, environmental protection, etc.). The Petroleum Law establishes that participation in upstream activities is subject to concessions. Moreover, it contains the policy statement which states the development of petroleum resources should contribute to the economic and social development of the country, further stating that the State has the right to participate in any project.

The Petroleum Operations Regulations (Decree No.24/2004, of 20 August 2004) sets out the process and criteria for awarding concessions for the upstream<sup>xxvi</sup> activities covered by the Petroleum Law and the terms on which contracts are awarded. The regulations establish natural gas exploration, production, transmission and processing rules, defining management, planning and operational requirements, health and safety obligations and emergency provisions. It establishes a third party access regime for natural gas transmission pipelines, which needs to be further detailed with operational procedures and tariff methodology.

A new draft Petroleum Law is available and currently discussed but envisages no drastic changes. Changes focus on infrastructure, unconventionals, and the provision that 1% of gas extracted must be channelled to local communities near the production site.<sup>158</sup>

Upstream petroleum activities are to be carried out under an Exploration and Production Concession Contract (EPCC), which combines features of contracts (e.g. production sharing agreements) and concessions. The INP website provides an example EPCC. Key fiscal and economic terms in the EPCC consist of:

- Petroleum Production Tax (PPT); which is a royalty charged to the production of gas and oil. By law (Decree 4/2008) the PPT level is set at 6% for natural gas (and 10% for oil). The collection of the PPT can be in cash or in kind; where it is paid in cash, it is calculated on the basis of agreed contract prices in the case of natural gas as set out in the Gas Sales Agreement. It is believed that the PPT on Rovuma (Anadarko/ENI) is 2%, on Pande/Temane (Sasol) 5% and 6% on other developments<sup>159</sup>.
- Cost recovery and production sharing. "Disposable gas" is calculated as production minus the PPT. Part of "disposable gas" is defined as "cost gas" and can be sold by the concessionaire to recover their costs (recoverable costs are defined in detail). The rest is "profit gas", which shall be shared by the government and the concessionaire according to a scale varying with the value of the R-factor (the recovery factor determined by the ratio of cash inflows over capital expenditures). The government take starts low and eventually grows to about 50%.<sup>160</sup>

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<sup>xxv</sup> Gas distribution and supply are not part of the Petroleum Law.

<sup>xxvi</sup> The construction and operation of oil and gas pipelines are also regarded as upstream activities, and thus subject to concession contracts.

- In addition, production bonuses apply, to be paid by the concessionaire in US dollars for the various production tranches. These payments do not count as recoverable costs.
- The methods to value gas (and oil) are also provided for in the EPCC. However, the exact determination is very unclear. It states that the value of natural gas produced within the EPCC is based on the prices (per GJ) of all gas delivered and produced in Mozambique and prices of alternative fuels (to natural gas) for large-scale industrial consumers, including power generators. The prices within a commercial gas sales agreement between the government and the concessionaire shall not be higher than the value determined in the EPCC.
- A five year exemption for custom duties and value added tax (VAT) related to the import of materials, equipment, etc. to be used in gas production (according to Petroleum Fiscal Incentives Law 13/2007).
- Special application of corporate income tax (IRPC), which is normally 32% on profits.

In 2011, the "Mega Projects Law" (Law on Public-Private Partnerships (PPP), Large Scale Projects (LSP) and Business Concessions (BC), Law 15/2011, of 10 August 2011) was adopted. This law enables the GoM to take an equity interest of at least 5% in projects exploiting natural resources in Mozambique. Further, it requires the offer for sale to the Mozambican people of shares in the capital of the project company via the Stock exchange.

The Government of Mozambique is currently effectuating its right to take an equity share in coal projects: it took a 5% share in the Moatize project (Vale) in 2012 and intends to take a similar stake in the Benga project (Rio Tinto)<sup>161</sup>. For gas, the National Enterprise of Hydrocarbons ENH (Empresa Nacional de Hidrocarbonetos, 100% state owned) is the mechanism through which the government participates in gas exploration projects, typically for 15% and capped at 25%<sup>162</sup>. For example, ENH holds a 10% interest in the offshore area 2/5 (Rovuma basin) of Statoil/Tullow. Moreover, the state (20% directly and 70% via ENH) is also involved in the Mozambican Company of Hydrocarbons CMH (Companhia Moçambicana de Hidrocarbonetos). CMH was established as a public company to develop and participate in the Natural Gas Project in the Pande and Temane fields, operated by Sasol. CMH holds a 25% share in this project, Sasol 70% and IFC 5% (International Finance Corporation)<sup>xxvii</sup>.

In January 2013, the Ministry of Mineral Resources announced that all concession holders are contracted to commit a proportion of their gas production to the domestic market. This domestic market obligation (DMO) could put economic pressure on projects depending on price level for the DMO.<sup>163</sup>

### 5.2.2 Downstream – large scale gas-based industry

The Investment Law (No. 3/93, of 24 June 1993), the related Decree (No. 14/93, of 21 July 1993) and the Code of Fiscal Benefits (Decree No. 16/2002, of 27 June 2002) favor greater participation, complementarities and equal treatment of domestic and foreign investments. The fiscal benefits available for undertakings approved under the Investment Law include, among other:

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<sup>xxvii</sup> Via Companhia Moçambicana de Gasoduto CMG (Mozambican Company of Gastransport), the state is also involved in the transportation of gas from the Pande/Temane fields to Ressano Garcia at the border with South Africa (ROMPCO).

- Total exemptions of Customs duties and VAT on import of construction materials, equipment and accessories;
- Exemption on company tax (IRPC at 32%), for the first 5 to 10 years and reduction of IRPC on a reducing scale for a number of years, depending on whether the undertaking has an industrial free zone (IFZ) status, and its location inside an IFZ area.

The process of obtaining an industrial license is governed by the Industrial License Regulations (approved by Decree 39/2003), under the supervision of the Minister of Trade and Industry. However, for production of petroleum products or similar (liquid fuels) a production license must be obtained from the Minister of Energy (Decree No. 45/2012, of 28 December 2012). A concession for power generation is obtained from the Minister for Energy under the Electricity Law, (Law No. 21/1997) and subsidiary regulations, including the regulations on concessions for electricity production, transport, distribution and trade, approved by Decree No. 8/2000.

### 5.2.3 Starting a foreign business Mozambique<sup>164</sup>

It takes 12 procedures and 34 days to establish a foreign-owned limited liability company (LLC) in Maputo, Mozambique. This is faster than the regional average for Sub-Saharan Africa. A foreign company establishing itself in Maputo is not required to seek an investment approval unless it wants to avail itself of investment incentives offered by the Investment Promotion Centre (CPI). It will, however, need to authenticate the parent company's documentation in the Mozambican embassy or consulate in its country of origin. In addition, foreign companies that engage in retail and wholesale trade qualify as foreign-trade operators and must obtain a foreign-trade operator card from the Ministry of Trade and Industry. This card takes 7 days to obtain. Registration with the Legal Entities Registrar Office of Maputo takes 1 to 2 days. The required documents are available online, but cannot be submitted online. Any company in Mozambique may freely open and maintain bank accounts in foreign currency. The minimum paid-in capital requirement of MZM 20,000 (~\$740) was abolished by Law No. 2/2009, of 24 April 2009. Instead, said law stipulates that shareholders may now decide on the proper capital of the company. The minimum investment value necessary to take advantage of any guarantees and fiscal benefits is \$50,000 for foreign investments.

Main law: Commercial Code Decree No. 2/2005, of 27 December 2005; Commercial License Regulation Decree No. 49/2004, of 17 November 2004; Regulation on Legal Entities Registry Law No. 1/2006, of 3 May 2006; The Investment Law No. 3/93, of 24 June 1993; Regulations on the Investment Law Decree No. 14/93, of 21 June 1993, with changes approved by Decree No. 36/95, of 8 August 1995; Regulations of the Exchange Law Notice No. 5/GGBM/96; Labor Law No. 23/2007, of 1 August 2007.

### 5.2.4 Accessing industrial land in Mozambique<sup>165</sup>

In Mozambique, all land is considered property of the state and therefore cannot be sold. The available option for foreign companies seeking to acquire land in Maputo is the lease of publicly held land<sup>xxviii</sup>. Foreign companies may lease land provided they have an authorized investment project as provided by Mozambique's investment law and the company is established or registered in Mozambique. The process of leasing land requires negotiations with the relevant public authority

<sup>xxviii</sup> The land use title or Direito de Uso e Aproveitamento the Terra (DUAT) for an economic activity is subject to a maximum term of 50 years (can be extended by equal periods at the request of the title holder).

and members of the surrounding community in which the land is located and consequent approval from both the public authority and community members. Land may be leased for a maximum of 99 years. Approval is required from the provincial governor to lease land of up to 1,000 ha. For areas between 1,000 and 10,000 ha authorization by the Minister of Agriculture is required. For greater amounts of land, approval must be sought from the Council of Ministers. Lease contracts offer the lessee the right to subdivide or sublease the leased land, subject to approval by the relevant authority. Most land-related information can be found in the cadastre (provincial land registry service).

Main laws: Land Law No. 19/97, of 1 October 1997; and its regulation (Decree No. 66/98, of 8 December 1998).

### 5.2.5 Midstream – access to transport

At the downstream level, the regulatory framework for distribution, supply and pricing of gas is less developed (there is no primary legislation governing the distribution and supply of gas). Gas transport pipelines are governed by the aforementioned Petroleum Law and Petroleum Operations Regulations. The construction and operation of a gas pipeline either is part of the exploration and production concession contract, or, if it is not covered by such EPCC, is covered by a separate gas pipeline concession contract (Article 13 and 14 of the Law). The regulations (Article 21) require non-discriminatory third party access to oil and gas pipelines on reasonable commercial terms. Moreover, in case of insufficient capacity the pipeline operator shall increase capacity if the pipeline user is willing to pay for it or, if commercial and operational terms cannot be agreed, the matter shall be settled by an independent authority.

### 5.2.6 Downstream – pricing

The main concession contracts currently in place in the transmission and distribution of Mozambican natural gas are for<sup>xxix</sup>:

- The transportation of gas from the Pande/Temane fields to Ressano Garcia at the border with South Africa, awarded to the Republic of Mozambique Pipeline Company (ROMPCO);
- The transportation of gas from Ressano Garcia to Matola, awarded to Matola Gas Company (approved by Decree No. 43/2002);
- The distribution of gas in the area of Matola, also awarded to Matola Gas Company (approved by Decree No. 44/2002);
- The distribution of gas in North Inhambane Province, awarded to Empresa Nacional de Hidrocarbonetos (ENH) (approved by Decree No. 30/2009); and
- The distribution of gas in the Maputo City and Marracuene Districts, awarded also to Empresa Nacional de Hidrocarbonetos (ENH), ( approved by Decree No. 31/2009);
- AUTOGAS operates in the distribution of CNG for use as vehicle fuel on the basis of a license issued by the Minister of Energy, under Decree No. 45/2012, of 28 December 2012. This decree of the Council of Ministers, (which supersedes and revokes Decree No.63/2006, of 26 December

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<sup>xxix</sup> Source: IPA. Domestic natural gas and condensate market study for Mozambique – Final report. September 2009.

2006, on the same subject), establishes the regime for production, storage, transportation, distribution, import and export of petroleum products, the natural gas used as fuel in the transport sector, being defined as petroleum product under application of this regulation.

Some of these concessions were agreed prior to the development and publication of the Regulations for the Distribution and Trade of Natural Gas (Decree No. 44/2005, of 29 November 2005). These regulations assign responsibility for regulating the distribution and trade of gas to the Minister of Energy and set out the framework for gas distribution concessions. Moreover, they provide that once new retail pricing arrangements are developed in accordance with these regulations, Decree No. 46/98 will be repealed<sup>xxx</sup>.

By means of Ministerial Order (No. 210/2012, of (12 September 2012), the Minister of Energy has approved the Regulations for Determination of Maximum Supply Prices of Natural Gas. The new Regulations lay down the rules for assessing the maximum reference price of natural gas, to be charged by concessionaires of natural gas distribution, in the supply to end users, including for commercial or industrial purposes. The National Directorate of Fuels (NDF, part of ME) has to approve the reference price.<sup>166</sup> These new regulations repeal Decree No. 46/98 and also establish the maximum end user price and retail margin, as well as the price review formulas for compressed natural gas (CNG).

### 5.2.7 Financing

Upstream natural gas activities in Mozambique are largely financed by international oil companies, except for some minority equity participation by the state company ENH. The Mega Projects Law (e.g. applicable to LNG projects) requires ENH to participate on at least a 5% level. Finance required for midstream activities may be shared between public and private sectors. It is likely that the transmission infrastructure needed for midstream activities will mainly be covered by public sources, whereas private investors are willing to support large gas-using projects.

	Activity	Financial parties
<b>Upstream</b>	Exploration & Development	IOC
	Production	IOC
	Bring onshore	IOC
	Processing	IOC
	LNG liquefaction	IOC / ENH
<b>Midstream</b>	Transmission infrastructure	Public / Private
	Large gas-based projects	Private
<b>Downstream</b>	Distribution infrastructure	Public sector

**Table 40. Mozambique financing parties by activity**

<sup>xxx</sup> Decree No. 46/98 sets out some principles for retail prices to power producers and domestic, commercial and small industrial gas consumers (gas prices to large customers are negotiated between buyer and seller). The decree contains a mixture of high level principles, more detailed provisions for price indexation and review, and specified prices for supply in the districts of Vilankulos, Govuro and Inhassoro near the gas production areas in the province of Inhambane. (Source: IPA. Domestic natural gas and condensate market study for Mozambique – Final report. September 2009.)

## 5.3 TANZANIA

Natural gas discoveries of about 22 Tcf (P1) to 67 Tcf (P2) have been made from both onshore and offshore basins. The deep sea discoveries have indicated a new era in the exploration for petroleum in Tanzania and the region at large.

The beginning of chapter 4 in the first draft of the *Natural Gas Policy of Tanzania* (October 2012) reads: “The existing Legal and Regulatory framework for energy sector does not address comprehensively the governance of the natural gas industry. As a result of significant discovery of natural gas deposits, there will be tremendous increase of upstream, midstream and downstream activities. These require enactment of specific legislation to address the situation.”<sup>167</sup>

The draft *Natural Gas Policy of Tanzania* indicates that the state is reviving its development plans, as illustrated by expected changes in natural gas legislation. Anticipated changes in investment terms include increasing royalty rates, the introduction of a signature bonus or signing fee, and the implementation of international industry standards, including new sector-specific regulations and requirements (especially around HSE requirements). Tanzania is also considering the creation of a sovereign wealth fund to help channel hydrocarbon revenues into development and savings for future generations.

In addition to the Natural Gas Policy, a new gas legislative package is in preparation in Tanzania, consisting of the Gas Utilization Master Plan, The Natural Gas Bill (produced from the Gas Supply Bill 2009), The Petroleum Policy, and The Upstream Act. However, the development of this package is delayed, partly due to political issues and unrest.

Currently the oil and gas activities, including commercial and regulatory roles, are carried out by the Tanzania Petroleum Development Corporation (TPDC) on behalf of the government (Ministry of Energy and Minerals). The authority for the downstream gas industry is the Energy and Water Utilities Regulatory Authority (EWURA), also coordinated by the Ministry.

### 5.3.1 Upstream – exploration & production<sup>168</sup>

Petroleum exploration and development in Tanzania is governed by the Petroleum (Exploration and Production) Act 1980. This Act vests title to petroleum deposits within Tanzania in the State and is designed to create a favorable legal environment for exploration by oil companies.

The Act expressly permits the Government to enter into a petroleum agreement under which an oil company may be granted exclusive rights to explore for and produce petroleum. Tanzania's Model PSA serves as the basic document for negotiations between foreign oil companies, the Government and TPDC. It sets out the terms under which exploration and production can take place. Although the terms closely mirror those incorporated in earlier PSAs concluded in Tanzania, the Government's flexible approach allows for the negotiation of the important issues (such as Area, Work Program and Economic terms etc.) within the framework of PSAs. The Government's objective is to negotiate terms with the oil industry which are fair and balanced, bearing in mind the usual risks associated with exploration and the State's legitimate desire for revenues as owner of a depleting, non-renewable, natural resource. The Government seeks to encourage the development of small and marginal discoveries, obtain a higher share of profits from the more attractive fields, and satisfy national objectives such as the transfer of petroleum skills and the acquisition of more data.



The Model PSA also applies to natural gas, however an addendum to the existing PSA may be agreed in order to facilitate the commercialization of natural gas found in Deep Sea operations in the Contract Area. Up to June 2012 there were 26 PSAs signed with 18 oil exploration companies. Some key terms in Tanzania's Model PSA are:

- There is an option for TPDC to participate in development whereby it will contribute to Contract Expenses. The MPSA provides for TPDC to negotiate a participating interest at 20% of the Contract Expenses, excluding Exploration (and Appraisal) expenses. TPDC's Profit Gas Share will then be increased by the rate of the participating interest, and the Oil Company's Share will be reduced accordingly;
- TPDC's share of Profit Gas increases from 60% at low production rates (<20 MMscf per day or 7.3 Bcf/yr), to 85% at production rates above 100 MMscf per day (or 36 Bcf/yr). These rates are somewhat different for Deep Sea gas operations;
- The Oil Company shall be subject to Tanzanian taxes on income derived from Petroleum Operations (according to the Income Tax Act 2004). The Model PSA clearly states that each party (TPDC and Oil Company) has to pay its own Income Tax to the government. The Corporate Income Tax level is 30%;
- Petroleum royalties are administered and collected under the Petroleum Act 1980. Royalties are collected by the TPDC and are paid to the central Government as follows:
  - For onshore projects: 12.5%
  - For offshore projects: 5%
- The PSAs provide for payment of Additional Petroleum Tax (APT) calculated on the basis of a development area in accordance with the provisions of the PSA. APT is calculated for each year of income, it may vary with the real rate of return earned by the company on the net cash flow from the development area in question. The APT due must be paid in cash at the time and in the manner that the commissioner of income tax may reasonably require. The tax rate for the APT is either 25% or 35%. It should be noted that the APT has not yet been introduced in practice, but the requirement is retained in the relevant PSAs entered into by oil and gas exploration companies with the Government of Tanzania;
- All equipment and material etc. imported for use in petroleum operations can be imported free of all duties and import taxes and can be re-exported free of any export duty or tax. Expatriates enjoy similar privileges in respect of their personal effects;
- The Model PSA envisages good faith negotiations upon the discovery of natural gas in order to reach an agreement on its development, production and sale. In appropriate circumstances the Minister will extend the appraisal period;
- The oil company may freely assign its rights and obligations to an affiliate providing the performance of the oil company obligations will not be adversely affected. Assignment to third parties requires the prior consent of government, not to be unreasonably withheld (several such assignments have in fact occurred in recent years).

As already indicated above, a new legislative package for gas is being developed in Tanzania, which includes likely amendments to the Petroleum Act, as well as the Petroleum Policy and Upstream Act, both addressing the upstream sector.

In September 2012, the Ministry announced its intention to review all of the 26 PSAs. The purpose of the review is “procedural” in nature, and will be conducted for the purpose of developing the Policy rather than with a view to renegotiating contracts. Later in the same month, the Ministry also released a statement confirming it has decided to postpone any new offshore licensing rounds until the Government has published the Policy and the Bill.

### **5.3.2 Downstream – large scale gas-based industry**

Downstream petroleum activities are governed by the National Investment (Promotion and Protection) Act, 1990, and qualify for the incentives and guarantees provided for in the Act. The purpose of the National Investment Act is to establish rules for governing investment in Tanzanian enterprises, particularly foreign capital. However, this legislation is general and not specifically directed towards large scale gas-based industry.

EWURA regulates the downstream industry, including power generation, transmission and distribution and issuing licenses. Although currently there is only one independent gas supplier, the EWURA is mandated to foster competition. To this end, the EWURA will not restrict the right to purchase gas from the TPDC or any other third party. However, the ability of an investor to purchase gas from the TPDC is subject to any purchasing restrictions contained in the particular gas sales agreement.<sup>169</sup>

Gas produced from Songo is utilized for power generation (currently ~26 Bcf/yr) and as fuel to cement manufacturing kilns and small captive power plants (TCC and Urafiki Textiles). 36 industries in Dar es Salaam are also connected to the gas pipeline and use gas for boilers and furnaces. Recently the use of compressed natural gas (CNG) into vehicles and buildings has been introduced. The combined industrial use of gas is approximately 4 Bcf/yr, but due to limited power demand in the Southern Regions of Lindi and Mtwara, only 0.7 Bcf/yr from the Mnazi Bay field is used to generate circa 12 MW<sub>e</sub> of electricity.<sup>170</sup>

Recent protests and violence over Tanzania’s decision to construct a pipeline to pump natural gas from Mtwara to Dar es Salaam<sup>xxxii</sup> illustrates political (and regulatory) difficulties to develop a gas-based industry in Tanzania. The people of Mtwara argue that the power from gas should be produced in Mtwara and distributed countrywide.

### **5.3.3 Starting a foreign business in Tanzania<sup>171</sup>**

It takes 14 procedures and 38 days to establish a foreign-owned limited liability company (LLC) in Dar es Salaam. This is slower than the average for Sub-Saharan Africa. Domestic as well as foreign-owned LLCs must have at least 2 shareholders. In addition to the procedures required of domestic companies, a foreign-owned LLC must authenticate the parent company’s documents abroad. If the company wants to engage in international trade, it must obtain a trade license from the Ministry of

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<sup>xxxii</sup> The 532km pipeline (to cost \$1.225 billion upon completion) would transport gas to Dar es Salaam for producing 2780 MW<sub>e</sub> of electricity. It is a joint project between a Chinese company and TPDC. It is expected to be completed by 2015.

Industry and Trade. The Tanzania Investment Centre (TIC) offers fast-track service to establish a business in Tanzania. A foreign company is not required to obtain an investment approval in Tanzania, unless it decides to apply for TIC's incentive certificate to benefit from tax incentives. The business registration documents are available online. Foreign companies are free to open and maintain bank accounts in foreign currency. There is no minimum capital requirement for foreign-owned LLCs unless the project is registered with TIC, in which case the minimum capital is \$300,000.

Main laws: The Companies Act, Cap 212 (R.E. 2002); The Business Licensing Act, Cap. 208 (R.E. 2002); Income Tax Act, No. 11 of 2004; Value Added Tax Act, Cap 148 (R.E. 2002); The Tanzania Investment Act, Cap. 38 (R.E. 2002).

### **5.3.4 Accessing industrial land in Tanzania<sup>172</sup>**

In Tanzania, all land is publicly held, and the president acts as trustee. Foreign entities are prohibited from owning land, except in the following circumstances: as a right of occupancy for purposes of investment approved under the Tanzania Investment Act; as a derivative right for purposes of investment approved under the Investment Act; or as an interest in land under a partial transfer of interest by a citizen for purposes of investment approved under the Investment Act in a joint venture. Land may be leased for a maximum duration of 99 years. Lease contracts offer the lessee the right to sublease, subdivide, or mortgage the leased land or use it as collateral, subject to the terms of the contract. In the case of publicly held land, approval may be required from the Commissioner of Lands. There are regulations that govern the amount of land that may be leased. Most land-related information can be found in the registry.

### **5.3.5 Midstream – access to transport**

The Gas Supply Bill 2009 (Gas Bill) is not yet enacted and is awaiting parliamentary approval and Presidential assent. Once passed, the Gas Bill will provide for the regulation of transportation, liquefaction, re-gasification, storage, distribution, supply, import, export and trade in natural gas. The Gas Bill is intended comprehensively to redefine the regulation of the Tanzanian natural gas sector. It specifically states that the EWURA will, in consultation with the Tanzania Bureau of Standards, the Occupational Safety and Health Authority and the National Environmental Management Council, develop and carry out a program of gradual adoption and adaptation of prevailing international standards of the petroleum industry. This suggests that there will be new sector-specific regulations made, which may create new requirements in the fields of public health, safety and the environment.

### **5.3.6 Downstream – pricing**

Downstream gas pricing is virtually non-existent and in fact not part of the regulatory and legal framework in Tanzania. Pricing for the large-scale gas based industry sector is determined by the PSAs. In general, the activities calling for economic regulation include investigation of market abuse, monopolistic infrastructure tariff review, and efficiency levels of investment. Application for tariff and tariff formulae is detailed in the Tariff Application Guidelines, 2009, which are however directed towards electricity tariffs. Competition is between natural gas and alternative fuels such as coal, jet fuel, and heavy fuel oil. It is the duty of EWURA to protect all stakeholders.

### 5.3.7 Financing

Much of the upstream gas activities in Tanzania will need to be financed by international oil companies, although the State company TPDC may negotiate a minority participating interest of 20% of the upstream contract expenses (production). Finance required for midstream and downstream activities will have to be covered mainly by public sources, although the private sector may have an interest when the infrastructure is needed for their marketing and sales activities.

	Activity	Financial parties
<b>Upstream</b>	Development & Exploration	IOC
	Production	IOC / TPDC
	Bring onshore	IOC
	Processing	IOC
	LNG liquefaction	IOC
<b>Midstream</b>	Transmission infrastructure	Public / Private
	Large gas-based projects	Private
<b>Downstream</b>	Distribution infrastructure	Public / Private

**Table 41. Tanzania financing parties by activity**

## 5.4 SOUTH AFRICA

South Africa's energy situation is mainly based on its synthetic fuels industries and coal reserves. It has very limited and declining natural gas reserves, but potentially large shale gas resources, most of which are located in the Karoo Basin. Natural gas production (offshore) is supplied to the Mossel Bay GTL plant via an offshore pipeline. Natural gas imports from Mozambique are used to supply Sasol's operations at the Secunda CTL plant and to some gas-fired power plants.

South Africa's upstream oil and gas sector is dominated by the state-owned company Petroleum Oil and Gas Corporation of South Africa (PetroSA). It operates all upstream oil and gas assets, along with the GTL plant in Mossel Bay. Sasol is another major player in South Africa's energy industry and operates the Secunda CTL plant.

South Africa has a well-developed gas regulatory and legal framework in place. The National Energy Regulator (NERSA) is a regulatory authority for electricity, piped gas and petroleum pipeline industries and responsible for implementing South Africa's Energy Plan. The Gas Act, 2001 (Act No. 48 of 2001) and Petroleum Pipelines Act, 2003 (Act No. 60 of 2003) provide the basis for oil and gas regulation.

The Integrated Resource Plan 2010 (IRP2) released by the Department of Energy makes provision for gas-fired power generation, which provides the most likely source of demand for gas in South Africa. The Gas Infrastructure Plan dates back to 2005.

### 5.4.1 Upstream – exploration & production

The Petroleum Agency South Africa (PASA) promotes the exploration for onshore and offshore oil and gas resources and their optimal development on behalf of the government. The Mineral and Petroleum Resources Development Act (MPRDA) of 2002 applies to upstream oil and gas exploration and production. It gives the State custodianship of mineral resources on behalf of the people of South Africa.

The fiscal regime that applies in South Africa to the upstream oil and gas industry consists of a combination of corporate income tax (CIT) and royalties (the latter was implemented on 1 March 2010 by the Mineral and Petroleum Resources Royalty Act (the Royalty Act)). Royalties are capped at 5% for gas resources at the inlet of the refinery or plant.

The current CIT rate may not exceed 28% (to which must generally be added a 5% secondary tax (STC) on dividends declared) and 31%, respectively for residents and non-residents, under the Tenth Schedule to the Income Tax Act (No. 58 of 1962). For a non-resident that derives its oil and gas income solely by virtue of an OP26 right,<sup>xxxii</sup> the tax rate may not exceed 28%.

In recognition of the need for oil and gas companies to have certainty as to the tax treatment of future revenues, and in conformity with international practice, the minister of finance may enter into a fiscal stabilization contract with an oil and gas company. Such a contract binds the State and guarantees that the provisions of the Tenth Schedule, as of the date that a particular oil and gas right is acquired, apply and that the contract may not be amended for the duration of the oil and gas company's right (or any renewals thereof and of any conversions from exploration to an initial production right).

The draft Mineral and Petroleum Resources Development Act (MPRDA) Amendment Bill<sup>xxxiii</sup>, which was published for public comment in December 2012, indicates some far-reaching changes in the future, including the possibility of creating a regulatory environment to enable and facilitate exploration for and production of shale gas. The PASA has issued companies technical cooperation permits (TCPs), which authorize research into shale gas potential<sup>xxxiv</sup>. However, companies are awaiting approval to convert their TCPs to exploration licenses now. In its current form, the Amendment Bill leaves much uncertainty. Such uncertainty will exacerbate rather than improve the difficulties that exist with the current regulatory regime and may further damage investor confidence in the petroleum industry. Some of the key amendments proposed by the Bill are given by Peter Leon<sup>173</sup>. For example, the Bill grants the State a right to a free carried interest in all new exploration and production rights in the petroleum industry, with an option for the State to acquire a further interest through a designated organ of state or a state-owned entity. A "free carried interest" refers to a share in the annual profits derived from the exercise of an exploration or production right, without the State being expected to make any contribution towards capital expenditure. Moreover, there are a number of sections in the Bill in terms of which the Minister is granted the power to determine important issues by Ministerial regulation. There is a strong argument that the discretion afforded to the Minister by the Bill is overbroad.

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<sup>xxxii</sup> Before November 2006, oil and gas exploration and production revenues were taxed in accordance with the provisions of the mineral lease known as OP26, and not in terms of the 1962 Income Tax Act. Subject to a number of variations between leaseholders, OP26 created a fiscal stability regime. When the Mineral and Petroleum Resources Development Act of 2002 became effective, it became necessary to terminate the provisions of OP26 (notwithstanding that they were guaranteed to existing leaseholders for the duration of their leases). For years of assessment commencing on or after 2 November 2006, the Tenth Schedule of the Income Tax Act (No. 58 of 1962) was introduced.

<sup>xxxiii</sup> The Bill purports to amend the MPRDA as if the Mineral and Petroleum Resources Development Amendment Act, 2008 (the Amendment Act) is in force, although the Amendment Act has never been brought into effect. It is thus necessary to read the Bill together with the MPRDA and the Amendment Act to understand the proposed changes properly.

<sup>xxxiv</sup> There are five major shale gas developers holding exploration blocks under TCPs: Royal Dutch Shell, Falcon Oil and Gas, Sasol / Chesapeake / Statoil, Sunset Energy, and Anglo Coal.

### 5.4.2 Downstream – large scale gas-based industry

Current demand for natural gas in South Africa is mainly for the GTL and chemicals industries. Sasol has exclusive rights to the transmission and distribution network for gas imported from Mozambique for 10 years until 2014. It has more than 500 industrial customers and gas traders, but also satisfies the demand from the following local gas distributors:

- Egoli Gas, operating in and around Johannesburg, servicing 7,500 industrial and residential customers;
- Spring Lights Gas, operating in KwaZulu-Natal, servicing industrial customers; and
- Novo Energy, operating in Gauteng, supplying commercial and residential customers.

Therefore, the domestic gas market mainly consists of GTL plants and industrial users; the lack of an extensive transmission and distribution network is seen to be a significant barrier to increasing commercial and residential demand. In addition, concerns relative to the security of gas supply have induced reliance on electricity among the energy intensive industry.

A key barrier, irrespective to infrastructure or reserves, remains the failure to adopt a credible and constructive industry development plan for natural gas. Only about 3% of primary energy is provided by natural gas, the South African Government recognizes this and understands natural gas can contribute to the solution given a carbon constrained environment. The Government has stated its support to increase its natural gas share within the total energy mix. However, incentive support, tax breaks, industry support or development plans remain absent. The Gas Act is targeted to encourage South African gas industry developments. Its objectives are listed below:

- a) Promote the efficient, effective, sustainable and orderly development and operation of gas transmission, storage, distribution, liquefaction and regasification facilities and the provision of efficient, effective and sustainable gas transmission, storage, distribution, liquefaction, regasification and trading services;
- b) Facilitate investment in the gas industry;
- c) Promote the development of competitive markets for gas and gas services;
- d) Promote access to gas in an affordable and safe manner.

The Gas Act was based on international norms and best practices found in economies with developed gas industries. The risks associated with investing in the industry (security of supply, regulatory barriers, potential lack of demand, etc.) have been considered to strive to detour such roadblocks from occurring in South Africa<sup>174</sup>.

All license applications are given careful consideration by NERSA to prevent speculative applications that may result in market foreclosure and establishing barriers to entry. NERSA demonstrates its commitment by denying licenses to companies such as Gigajoule (see below) and Unigas, where the lack of supply contracts and contractually committed customers, generic gas specifications and uncertainties related to the capital structures influenced the regulator's decision.

### 5.4.3 Starting a foreign business in South Africa<sup>175</sup>

It takes 8 procedures and 65 days to establish a foreign-owned limited liability company (LLC) in Johannesburg. This is slower than the regional average for Sub-Saharan Africa. In addition to the procedures required of domestic companies, a foreign company establishing a subsidiary and wishing to engage in international trade must obtain a trade license from the Department of Trade and Industry, which usually takes 38 days. An authorized dealer (one of the 4 biggest commercial banks in South Africa) must endorse as “nonresident” the parent company’s share certificate for shares held in the subsidiary. This process takes 5 days. The business registration documents are available online, but the application process is not yet available online. In South Africa, no regulatory restrictions on the composition of the board of directors or on the appointment of managers exist. The Broad-Based Black Economic Empowerment (BBBEE) initiative, while not enforceable, affects the type of business a company may be entitled to engage in. BBBEE urges companies to have meaningful representation of previously disadvantaged groups. If a foreign company is involved in import and export transactions as well as services, it is allowed to hold a Customer Foreign Currency (CFC) account. Only authorized dealers may initiate transactions on a CFC account. Foreign currency accruals from exports may be held in the CFC account for a maximum of 180 days, during which the amount can be set off against an import transaction. At the end of the 180-day period, any unutilized balance must be converted to rand. There is no minimum capital requirement for South African companies, only a nominal fee of \$1.

Main laws: Companies Act 61 of 1973 as amended; Exchange Control Regulations issued by the South African Reserve Bank as promulgated by Government Notice R1111, of 1 December 1961 and amended up to Government Notice No. R.885 in Government Gazette No. 20299, of 23 July 1999; Income Tax Act 58 of 1962; Value Added Tax (VAT) Act 89 of 1991; Environmental Act 1998; Consumer Protection Act 68 of 2008; Human Resources/Labour Law Labour Relations Act 66 of 1995; Unemployment Insurance Fund Act 63; Pension Fund Act 24; Employment Equity Act 55; Skills Development Act 97 of 1998; Occupational Health and Safety Act 85 of 1993; Collective agreement with applicable labor unions for sector.

### 5.4.4 Accessing industrial land in South Africa<sup>176</sup>

Foreign companies seeking to acquire land in the Johannesburg region have the option to lease or buy privately or publicly held land. Private land can be bought through negotiations with the owner. Buying public land is a more complex process. It requires negotiating with the public body holding the land, obtaining approval from the relevant authority, and complying with a number of statutes limitations on the power of public authorities to lease land. Lease contracts of privately held land offer the lessee the right to subdivide, sublease, or mortgage the leased land or use it as collateral, subject to the terms of the contract. There are no restrictions on the amount of land that may be leased. There is no statutory maximum duration for leases. Land-related information can be found in the land registry and cadastre, which are linked and coordinated to share data. Johannesburg has a land information system (LIS) and geographic information system (GIS) in place.

Main laws: Deeds Registries Act No. 47 of 1937.

### 5.4.5 Midstream – access to transport

The Gas Act provides that third parties must have access on commercially reasonable terms to uncommitted capacity in transmission pipelines, distribution networks and storage facilities. However, currently there is no uncommitted capacity in existing infrastructure and therefore only limited competition. Sasol has exclusive rights to the transmission and distribution network for gas imported from Mozambique for 10 years until 2014. The Mozambique Gas Pipeline Agreement (predating the Gas Act) is actually treated in a separate section of the Gas Act.

A license from NERSA is required to construct or operate a gas transmission or distribution facility. The majority of operating licenses is held by Sasol. The lack of an extensive transmission and distribution network is seen to be a significant barrier to increasing the demand from commercial and residential customers.

Gigajoule Africa has existing operations in neighboring Mozambique. It jointly owns Matola Gas Corporation with the Mozambican Government and operates more than 100 km of transmission and distribution pipelines. The company has been actively pursuing opportunities in South Africa and has made an unsuccessful license application to NERSA for the supply of natural gas to the Western Cape. Gigajoule proposed the introduction of what it termed a “virtual pipeline” system, making use of centralized compressed natural gas facilities from where gas could be distributed to industry and households.<sup>177</sup>

### 5.4.6 Downstream – pricing

Due to insufficient competition in the market, NERSA sets maximum gas prices to protect customers (mandated by the Gas Act)<sup>178</sup>. Given the limited number of players in the market, and the dominant position of Sasol, there is currently minimal gas-on-gas competition.

### 5.4.7 Financing

The upstream gas sector in South Africa is dominated by the national company PetroSA. There is limited potential for IOCs in the upstream sector. Currently, large gas-based projects (such as the GTL plant) are government financed. Finance required for midstream and downstream activities will have to be covered mainly by public sources, although the private sector may have an interest upon necessary infrastructure for their marketing and sales activities.

	Activity	Financial parties
<b>Upstream</b>	Development & Exploration	PetroSA / IOC
	Production	PetroSA / IOC
	Bring onshore	PetroSA / IOC
	Processing	PetroSA / IOC
	LNG liquefaction	n.a.
<b>Midstream</b>	Transmission infrastructure	Public
	Large gas-based projects	Public / Private
<b>Downstream</b>	Distribution infrastructure	Public

**Table 42. South Africa financing parties by activity**



## 5.5 NETHERLANDS<sup>179</sup>

The system in which the Dutch gas sector is organized is referred to as the 'Gas Building' (Gasgebouw). The Gas Building was erected following the discovery of the Groningen field. A concession for the Groningen field was granted in 1963, to Nederlandse Aardolie Maatschappij (NAM), a 50/50 joint venture of Shell and ExxonMobil, under the condition that NAM would enter into a partnership (the Maatschap Groningen) with a State participation company, currently named EBN (formerly known as: Energie Beheer Nederland). In this public/private partnership, EBN has a 40% financial share and NAM 60%, although the voting rights are 50/50. The Maatschap Groningen entered into a gas sales agreement with N.V. Nederlandse Gasunie (Gasunie), another joint venture of Shell and ExxonMobil (each 25%) and the Dutch state (10% directly plus 40% via EBN) for the entire gas production from the Groningen field. Gasunie was made responsible for the marketing and distribution of the gas. This way, production and marketing of the Groningen gas was coordinated to the maximum extent. This public/private system of central marketing has been applied ever since to the Groningen gas production in the Netherlands.

The Small Field Policy (SFP) became the regulatory framework to optimize production from the 'small fields' (i.e. smaller than the Groningen field) and to maintain the valuable aspects of the Groningen field as long as possible. The SFP guaranteed producers that their gas would be purchased directly by a creditworthy party (Gasunie) against market based prices.

In 2005, the activities of Gasunie were split up. The commercial activities went to a new company, GasTerra, in which the Dutch state (50%) and Shell and ExxonMobil (each 25%) are the shareholders. High pressure gas transmission is the statutory responsibility of Gasunie Transport Services (GTS), a subsidiary of 100% state-owned Gasunie.

As from 2000, the legal framework for the SFP has been laid down in the Gas Act. GasTerra purchases all gas produced from the Groningen field taking into account production from the 'small fields'. Furthermore, GasTerra must (at the request of the holders of a Dutch production license) purchase gas produced from the small fields against reasonable conditions and prices; however these holders of Dutch production licenses are free to sell the gas to anyone else, at will. The market-based price that GasTerra is required to pay is reflected in the so-called Normative Buying Price (Norm Inkoop Prijs or "NIP"). Conceptually, the NIP gas price mechanism attempts to provide a proxy for GasTerra's end user market by deriving a price based on competitive fuel in the industrial sector (heavy fuel oil) and residential market (gasoil) in both the domestic (Rotterdam pricing point) and export markets. In recent years, prices at gas hubs (Zeebrugge, NBP and TTF) have grown to become the most important factors in the NIP formula, to the detriment of the oil indicators

### 5.5.1 Upstream – exploration & production

The Mining Act, complemented by the Mining Decree and the Mining Regulation, forms the legal basis for exploration and production activities relating to minerals in the Netherlands. Minerals under the surface of the Netherlands (including the continental shelf) are owned by the Dutch State. Ownership of the minerals is transferred to the license holder(s) at the production of the minerals under a production license issued by the Dutch Ministry of Economic Affairs (MEA). A production license will be granted if the minerals within the area for which the license will apply are deemed economically producible. The license will specify the validity period and the applicable period. The delineation of this area is indicated on the surface in Blocks and is done in such a manner that the

activities can be carried out in the optimum possible manner from a technical and economical point of view.

The MEA may grant a license for exploration, production or storage. License requirements for exploration are, amongst others, financial and technical capabilities and a development plan satisfactory to the MEA. If the holder of an exploration license demonstrates the commerciality of a gas reservoir, he may apply for a production permit, which in most cases will be automatically granted to him as the current holder of the exploration license for the area concerned. Upon the granting of a production license, a license holder is exclusively entitled to production in the license area. Ownership of the gas transfers from the State to the license holder at the well-head.

The Mining Act prescribes Dutch State participation in offshore exploration licenses for 40% via its 100% state-owned participation vehicle EBN. Licensees are obligated to enter into an agreement of cooperation with EBN that stipulates the allocation of rights and obligations and the attribution of costs in accordance with the respective interests. Except in the event that the State may conclude that participation in a production license may inflict a financial loss, the State will participate via EBN in all offshore and onshore production licenses.

The Dutch State derives value from natural gas development and production in a variety of ways. Apart from corporate income tax, the State charges certain taxes directly to the license holder, such as surface duties (offshore exploration license or production license), royalties relating to the amount of natural gas produced (production license) and the 50% State Profit Share (production license). Also, the State derives value through its indirect participation (via EBN) in production, through its 50% stake in gas marketing company GasTerra and through the TSO (GTS, 100% state owned).

### **5.5.2 Downstream – large scale gas-based industry**

When developing the Dutch gas marketing strategy in the 1960s, the idea was that nuclear energy would soon enter the market and thus the newly found Dutch natural gas had to be marketed and commercialized quickly. With a 25-year-ahead view on domestic gas use, the remainder of gas reserves became available for export. In 1965, within a period of 6 months, some 1,200 km of gas pipeline was put into the ground and consumers were 'educated' about the advantages of natural gas via advertising campaigns. The competitiveness of several industries increased due to the availability of relatively cheap natural gas. For example, Dutch horticulture in greenhouses (heated by natural gas) could develop and flourish.

The fast switch of the Dutch economy to the use of natural gas<sup>xxxv</sup> was particularly supported by the marketing of natural gas based on the market value principle, which establishes that the price of gas should be equivalent to (or a little below) the price of alternative fuels such as oil. Therefore, it was established that the price of Dutch gas had to be linked to oil, both for the domestic market as well as for export.

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<sup>xxxv</sup> Within a period of 5 years 1.7 million old gas appliances (based on city gas from cokes) were replaced and 1 million natural gas connections were refurbished.

### 5.5.3 Midstream – access to transport

A statutory distinction is made between transportation pipelines and production pipelines, the latter being the pipelines that forms a part of the production installations and that are used for the transportation to a processing plant, storage facility or landing facility. Pursuant to the Gas Act, general competition (antitrust) law is applicable to access gas production pipelines on the Dutch part of the continental shelf, excluding the pipelines used within a specific oil or gas production project. Access to these pipelines is not regulated, but is arranged for contractually.

The national high pressure transmission network is owned and operated by GTS. Regional gas networks are operated by 12 regional network operators. Third party access to the transmission and distribution networks is regulated in conformity with the Gas Act and based on regulated tariffs.

Network operators are subject to regulated terms and maximum tariffs (CPI – X) set by the regulator Dutch Authority for Consumers and Markets (ACM). Network operators must provide the necessary information for efficient network access and has the statutory task to connect its network with the network of other network operators and to provide information about connections between networks, the use of the networks and the allocation of transport capacity. Network operators, gas storage companies and LNG companies must refrain from any form of discrimination among the system users. TPA to Dutch transport and distribution networks is regulated and supervised by ACM.

### 5.5.4 Downstream – pricing

Gas pricing for end-users in the Netherlands is market based. With a substantial number of gas suppliers active in the market, the consumer has various options to choose his supplier and agree on terms and conditions, including prices, for gas delivery. Wholesale gas trading is completely liberalized, with the Title Transfer Facility (TTF) being the virtual market place at which gas on the Dutch network can be traded.

### 5.5.5 Financing

State participation company EBN participates in gas exploration and production, usually for 40%, except when the State concludes that participation may inflict a financial loss. GasTerra (50% state owned) purchases all gas produced from Groningen, and it must at the request of the holders of a Dutch production license purchase gas produced from the small fields from on- and offshore against reasonable conditions and prices. Since the liberalization of the gas market, including the unbundling of network related activities, the transmission and distribution infrastructure is financed by the public sector through regulated tariffs.

	Activity	Financial parties
<b>Upstream</b>	Exploration & Development	IOC / EBN
	Production	IOC / EBN
	Bring onshore	IOC / PPP / EBN
	Processing	IOC / PPP
	LNG liquefaction	n.a.
<b>Midstream</b>	Transmission infrastructure	Public sector
	Large gas-based projects	Private / Public / PPP
<b>Downstream</b>	Distribution infrastructure	Public sector

**Table 43. Netherlands financing parties by activity**

The Dutch state profited enormously from the marketing of natural gas; some 70% annually (and some years even more) of total natural gas income was added to the State treasury i.e. general public finances, which accounted for 16% to 17% of total State income in some years. Only in the 1990-ies a dedicated fund was legally established (FES – Fund Economic Structure) from which (infrastructure) projects are financed, such as railway tracks, environmental measures and scientific research. In 2011 the FES fund was abolished and natural gas state income again flows into general funds.

In the 1970s, increasing natural gas revenues (also from exporting gas) strengthened the Dutch currency which resulted in more expensive exports and making the Dutch manufacturing industry less competitive. This mechanism or ‘Dutch disease’ as it is called, may be a threat to natural resources-rich countries (amongst others).

## 5.6 QATAR<sup>180</sup>

Qatar began exporting LNG only in 1997. Qatar’s LNG sector is led by Qatargas Operating Company Limited and RasGas Company Limited. These are purely operating companies. They do not own the LNG facilities or the LNG itself. There are specific joint venture companies that own one or more of the LNG trains and the corresponding LNG.

Qatar Petroleum (QP) controls all aspects of Qatar’s upstream and downstream oil and gas sector. Offshore fields are mostly operated by international oil companies via production sharing agreements (PSAs). Qatargas is the state-owned LNG producing company (the largest in the world), with an annual LNG production capacity of 42 million tonne/yr (MTPA). RasGas is a joint stock company established in 2001 by Qatar Petroleum (70%) and ExxonMobil (30%), with 35 MTPA LNG production capacity.

The moratorium on new upstream gas developments has been extended to 2015. Qatar’s gas industry is currently in a period of consolidation. The focus has shifted to increasing domestic supply for the various mega-projects Qatar has planned (including the hosting of the football World Cup in 2022), and on more value-added aspects of the hydrocarbon sector, such as petrochemicals.

### 5.6.1 Upstream – exploration & production

Law No.( 3) of 2007, regarding the Exploitation of Natural Resources and its Sources (the Natural Resources Law) states natural resources (including natural gas) are deemed the public property of the State. The Ministry of Industry and Energy regulates Qatar’s natural gas policy subject to the ultimate control of the Emir of Qatar.

Law No. (10) of 1974, concerning the Establishment of Qatar Petroleum (the QP Law), states QP manages upstream, midstream and downstream oil and gas operations on behalf of the Government of Qatar. QP acts as the State’s investment arm in the oil and gas sector.

The right to explore, develop and produce petroleum is typically granted by way of a production sharing agreement (PSA, either for exploration and production or for development and production) entered into with QP on behalf of the State of Qatar. A development PSA (DPSA) will be more usual in circumstances where there is a mid/downstream component integrated into the development of the project, which will typically be the case for gas projects. For example, Shell’s Pearl GTL project was done under a DPSA.

Emiri Decree Law No. (15) of 2007 (the Tasweeq Law) established the Qatar International Petroleum Marketing Company Limited (Tasweeq) to market and sell "Regulated Products". These comprise of, for example, refined products, condensate, LPG, and sulphur. Crude oil and natural gas (including LNG and GTL products) are excluded.

Qatar's Investment Law Regulating the Investment of Foreign Capital in Economic Activities (Law No. (13) of 2000, Foreign Investment Law) imposes certain restrictions and prohibitions on foreign investment in Qatar. However, in many cases, these will be irrelevant to investment in the gas industry. Article 12 specifically states that the Foreign Investment Law will not apply to:

- Companies and individuals assigned by the State to extract, exploit or manage the natural resources by virtue of a particular concession or agreement except to the extent it does not contradict the provisions of the special agreement or concession contract; or
- Companies incorporated by the government, or in which the government participates.

Despite this, it will be usual for the government, typically acting through QP, to take a majority interest in a gas project. QP typically owns about 70% of the shares in each of the RasGas and Qatargas train companies. In Barzan, however, QP owns over 90%.

The State of Qatar typically derives value from natural gas development through:

- A share in or right to offtake production (via QP);
- Equity participation at the mid/downstream phase (via QP);
- Royalties; and
- Taxation.

Subject to the terms of the individual PSA the approval of the State is generally required prior to the transfer of natural gas development rights or interests.

It is possible as a matter of Qatari law to "mortgage" or "pledge" (depending on the translation) the right to receive a debt. Generally, it is also possible to assign contractual rights. In an EPSA or DPSA, it would be usual to see detailed provisions regulating any such right to pledge, assign or otherwise make a grant of security having similar effect.

Participants are obliged to comply with the framework of State environmental, health and safety laws and regulations.

Generally speaking, industrial projects in Qatar must seek approval from certain regulatory entities, such as the Ministry of Environment. For example, under Law No. (30) of 2002 on Environmental Protection (the Environmental Protection Law) and the Executive Regulations pursuant to Ministerial Decision No. (4) of 2005, all plans for public and/or private development projects must be submitted to the Ministry for approval.

The Environmental Protection Law requires that all organizations undertaking activities in the field of exploration, drilling, extraction, production, refining and processing of crude oil shall follow international standard specifications with regard to methods and ways of safe operation in all

matters related to the storage and transportation of petroleum, petrochemicals and gas, as well as to the disposal of water and other dispensable substances while avoiding loss of petroleum or gas.

Law No. (4) of 1983 Concerning the Exploitation and Protection of Aquatic Life in Qatar states that plant, laboratory and factory waste, sewage water, chemical and petroleum substances, ship oils or any other liquids that may cause harm to aquatic life may not be discharged into fishing water or internal water without the written approval of the competent department.

### **5.6.2 Downstream – large scale gas-based industry**

Qatar's focus on natural gas development tends to be integrated large-scale projects linked to LNG exports or downstream industries that use natural gas as a feedstock. Therefore, foreign company involvement has favored international oil companies with the technology and expertise in integrated mega-projects, including ExxonMobil, Shell, and Total. However, QP has maintained a majority share in most of its gas projects, in particular via Qatargas and RasGas.

Qatar reoriented its gas prioritization, granting first allocation rights to domestic projects, followed by LNG export projects, pipeline exports, and GTL production. In fact, Qatar's domestic gas consumption has been rising steadily and this is a primary concern. Qatar does not want to bind itself to a multitude of long-term gas export contract and risk the dire prospect that fast paced industrialization may leave it unable to supply domestic needs. Because of rapid industrial expansion, Qatari officials estimate that the country's gas demand will sharply increase over the next decade.

The domestic power generation sector constitutes Qatar's single most gas-hungry sector. The Qatar General Electricity & Water Corporation (Kahramaa) ruled against raising electricity tariffs, because the issue of power tariffs is politically sensitive. Qatari citizens receive water and power free of charge, which is one of the main reasons why demand has been increasing rapidly. Fear of inflation is factored into this decision to not raise electricity prices, and Kahramaa is continuing to supply free of charge. Instead the government has set a monthly ceiling for household consumption for Qatari nationals, whereby if their power usage increases beyond the ceiling, end-user nationals are charged. As with many of Qatar's other megaprojects, the principle reason behind its frenetic development of the power sector is to supply the enormous amounts of electricity needed to fuel the country's energy intensive industries, which are undergoing significant expansion and require a consistent power supply.

Although Qatar only began exporting LNG in 1997, heavy government emphasis on this sector — both in terms of generating investments and attracting foreign investors — contributed to the rapid development of Qatar's LNG capacity. Qatar's LNG sector is dominated by Qatargas and RasGas. RasGas is 70% owned by QP and 30% by ExxonMobil, while the Qatargas consortium includes QP, Total, ExxonMobil, Mitsui, Marubeni, ConocoPhillips, and Shell. Each venture has an individual ownership structure, although QP owns at least 65% of all the above ventures.

Qatar is one of only three countries — with South Africa and Malaysia being the others — to have operational GTL facilities. Qatar's Oryx GTL plant (QP 51%, Sasol-Chevron GTL 49%) came online in 2007, but due to initial problems, was not fully operational until early 2009. At full capacity, the Oryx project uses about 330 MMcf per day (or 120 Bcf/yr) of natural gas feedstock from the Al Khaleej field to produce 30,000 bbl per day of GTL.

The Pearl GTL project (QP 51%, Shell 49%) is expected to use 1.6 Bcf per day (or 580 Bcf/yr) of natural gas feedstock to produce 140,000 bbl per day of GTL products as well as 120,000 bbl per day of associated condensate and LPG. Pearl GTL commenced production early in 2011 and the first shipments of gasoil were sent out in June 2011. The plant achieved full capacity in October 2012. In addition to being the largest GTL plant in the world, the Pearl project is also the first integrated GTL operation, meaning it will have upstream natural gas production integrated with the onshore conversion plant.

Qatar's petrochemical industry is also growing at an extremely fast pace, which places additional demand on the country's gas reserves. Qatar's interest in petrochemical expansion is predicated on the need for a diversified, value-added downstream industry sufficiently stable to withstand the constant fluctuations of the international oil and gas market.

The government is actively informing and helping industrial investors, e.g. by publishing an industrial magazine, and industrial directory and an investor's guide for obtaining a plot of industrial land.<sup>181</sup>

### **5.6.3 Midstream – access to transport**

Gas pipelines within Qatar typically transport gas from source to specific industrial projects. They will usually be integrated into and form part of a wider project, although QP may in some cases own the relevant interconnecting pipelines. There is no independent gas transmission or distribution network in Qatar, thus there is no specific regulation of transportation terms. There is only limited integration and interconnection of gas transmission pipelines. In contrast, Qatar has invested massively to establish its own fleet of more than 50 LNG carriers. These vessels are owned by Nakilat (Qatar Gas Transport Company).

Approvals for the construction and operation of oil and gas pipelines and associated infrastructure are required from the Ministry of Energy and Industry, and the Ministry of Environment, which are responsible for preparing guidelines of specifications on the conditions of environmental safety and management of waste resulting from the transportation of oil and gas. Municipal and Civil Defense approvals for construction and operation may also be required depending on the scope of the project. But given QP's statutory role, it is unlikely any independent entity will be successful in obtaining any such authorizations.

As the State ultimately owns all land in Qatar, the construction of natural oil and gas transportation pipelines or associated infrastructure requires a grant of rights from the State. The State possesses the power of compulsory acquisition to facilitate land access. Emiri Decision No. (13) of 1988 regarding Compulsory Acquisition for Public Benefit permits expropriation in the public interest. In the event that private property (real estate) is expropriated or nationalized, a payment of compensation has to be made to the affected party.

There are no standard rights for new customers to compel or require the operator/owner of a natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate new customers. In practice, it is likely that there will be a high degree of coordination given the major role that QP plays in all oil and gas projects (subject to the rights of joint venture partners and/or lenders, if applicable).

Qatar’s competition law is set out in the Law on the Protection on Competition and Prohibition of Monopolistic Practices (Law No. (19) of 2006) (Competition Law). It prohibits a variety of anti-competitive behavior including price manipulation, product hoarding, as well as dumping and collusion over the sharing or division of markets. It also sets up an Anti-Monopoly and Competition Committee to hear claims of alleged breach of the Competition Law and to consider mergers, acquisitions and joint ventures that may lead to one or more persons exercising “control” of a market. If such transactions contribute to “economic progress”, the Competition Law does not apply. In addition, the Competition Law will not apply to governmental acts, or the acts of any organization, entity or company controlled or supervised by the State. That may well limit its direct relevance to the oil and gas industry.

### 5.6.4 Downstream – pricing

Qatar is one of those countries heavily subsidizing energy in their domestic market. The country typically charges their population less than a third of international prices for fuel (including gas) and electricity (or indeed supply is even free of charge).<sup>xxxvi</sup> As for natural gas: Qatar’s fast growing power generating sector is entirely built on gas-fired technology.

### 5.6.5 Financing

The government, acting through QP, typically has a majority interest in a gas project. QP owns about 70% of the shares in each of the RasGas and Qatargas LNG train companies. But QP’s equity participation can also be higher than 70% (e.g. in Barzan QP owns over 90%). Also, in the large industrial projects such as GTL plants, QP has a majority (51%) stake. Transmission of gas is an integrated part of a wider project, although QP may in some cases own the relevant interconnecting pipelines. There is no independent gas transmission or distribution network in Qatar.

	Activity	Financial parties
<b>Upstream</b>	Exploration & Development	QP / IOC
	Production	QP / IOC
	Bring onshore	QP / IOC
	Processing	QP / IOC
	LNG liquefaction	QP / IOC
<b>Midstream</b>	Transmission infrastructure	QP
	Large gas-based projects	PPP
<b>Downstream</b>	Distribution infrastructure	QP

Table 44. Qatar financing parties by activity

## 5.7 Regional competitiveness of regulatory framework

The purpose of this section is to compare the regulatory and legal frameworks in Angola and Mozambique with those in Tanzania and South Africa, with a view on the attractiveness for foreign investors to do business in the respective countries’ gas sectors. Thus, the competitive advantages of one country over the other in relation to gas regulations and procedures are addressed. The comparison is based on the country descriptions and on some external publications on the topics. Below we distinguish between the upstream and midstream sectors, and the downstream sector. The comparison on financing is addressed separately (see section 5.9).

<sup>xxxvi</sup> Fattough, B. and L. El-Katiri. Energy Subsidies in the Arab World. Arab Human Development Report – Research Paper Series, 2012.



	Rank 1 <sup>st</sup>	Rank 2 <sup>nd</sup>	Rank 3 <sup>rd</sup>	Rank 4 <sup>th</sup>
<b>Upstream regulation</b>	MOZ	TAN	SA	ANG
<b>Midstream regulation</b>	MOZ	TAN	SA	ANG
<b>Downstream regulation (gas distribution)</b>	SA	MOZ	TAN	ANG
<b>Downstream regulation (business)</b>	SA	TAN	MOZ	ANG
<b>Financing</b>	SA	TAN	MOZ	ANG

**Table 45. General ranking of countries on regulation and financing**

### 5.7.1 Upstream and midstream

According to the Global Petroleum Survey 2012 by the Fraser Institute<sup>xxxvii</sup>, Tanzania, Mozambique and South Africa are more attractive for investors than Angola based on the All-Inclusive Composite Index<sup>xxxviii</sup>. Of these four African countries, Tanzania and Mozambique are the most attractive, however Mozambique’s position deteriorated considerably since the previous survey year (2011), possibly due to “evolving resource nationalism, lack of consistency in the legal regime and reluctance to grant stabilization.” On the other hand, Tanzania is labeled as a “friendly government approach to investment.”<sup>xxxix</sup>

The Fraser Institute also ranked countries based on the Regulatory Climate Index, which reflects the scores assigned to countries for the following six factors:

- The cost of regulatory compliance;
- Uncertainty regarding the administration, interpretation, and enforcement of regulations;
- Uncertainty concerning the basis for and/or anticipated changes in environmental regulations;
- Labor regulations, employment agreements, and local hiring requirements;
- Regulatory duplication and inconsistencies;
- Legal system fairness and transparency.

A relatively high value on the Regulatory Climate Index indicates that regulations, requirements, and agreements in a country constitute a substantial barrier to investment, resulting in a relatively poor ranking. Mozambique is ranked highest (position 68) of the four African countries under consideration, closely followed by Tanzania (70); both in the mid-section of the Fraser Institute’s ranking list of all countries. Angola and South Africa are ‘performing’ less on the Regulatory Climate Index, with ranks 108 and 115 respectively.

Since the implementation of the Petroleum Law in 2001, Mozambique has built up a solid regulatory framework for the upstream gas sector. Gas transport pipelines are also governed by the Petroleum

<sup>xxxvii</sup> Fraser Institute’s 6th annual survey of petroleum industry executives and managers regarding barriers to investment in upstream oil and gas exploration and production in various jurisdictions around the globe.

<sup>xxxviii</sup> The survey was designed to capture the opinions of managers and executives regarding the level of investment barriers in jurisdictions with which their companies were familiar. Respondents were asked to indicate how each of 18 factors influence company decisions to invest in various jurisdictions. An All-Inclusive Composite Index is derived from the scores of these 18 factors and provides a comprehensive assessment of each jurisdiction.

<sup>xxxix</sup> Remarkably, both Qatar and the Netherlands scored highest in their respective regions (Middle East and Europe) on relative attractiveness for investment as measured by the All-Inclusive Composite Index.

Law. The construction and operation of a gas pipeline either is part of the exploration and production concession contract, or by a separate gas pipeline concession contract. However, in light of growing gas prospects and finds, and thus of the increasing number of parties entering the sector, changes to the Petroleum Law have been drafted (a key change is the provision that 1 percent of gas extracted must be channeled to local communities near the production site). Moreover, capital gains tax rates have recently been changed. Mozambique should be aware of the unsettling impact that regulatory changes can have on investors.

Tanzania is still developing its regulatory framework for the gas sector. The Petroleum (Exploration and Production) Act of 1980 is outdated given the recent gas finds. The provisions of the Act and related regulation are considered to not specifically deterring investments upstream. The government's flexible approach, which allows for PSA framework negotiations, is appreciated by investors. Nevertheless, a new legislative package is in preparation, including increasing royalty rates and introducing a signature bonus or signing fee. The package also includes the Gas Supply Bill providing for the regulation of transportation, liquefaction, re-gasification, storage, distribution, supply, import, export and trade in natural gas. The development of the whole package is however delayed, partly due to political issues and unrest. Moreover, the governmental intention to review all existing PSAs and postponement of new offshore licensing rounds added to the uncertainty in the sector.

The less attractive situation in Angola is mainly driven by the fact that natural gas and its value has been ignored for a long time (also due to the associated nature of gas finds in Angola). Upstream regulations dictate that all surplus gas left after oil production and all non-associated gas discovered is the exclusive property of the State (Sonangol). This may have helped built up technical knowhow and skills within the state company, but is seriously detrimental to foreign investors and international oil companies (IOCs).

Although South Africa has the Mineral and Petroleum Resources Development Act 2002 in place, the regulatory embedding for the gas industry is not particularly considered as investor-friendly. On the one hand this has to do with the relatively small and declining gas volumes, the strong position of the synthetic fuels industry and coal reserves and the involvement of the State in those industries. On the other hand however, recently proposed changes in the regulatory regime leave much uncertainty. Such uncertainty will exacerbate rather than improve the difficulties that exist with the current gas regulatory regime and may further damage investor confidence in the industry. Moreover, the majority of operating licenses in gas transmission and distribution is held by Sasol while there is no uncommitted capacity available.

### **5.7.2 Gas distribution regulation – downstream**

In Angola, various technical regulations on domestic gas distribution, transportation and storage have been approved throughout the years. Gas transportation and storage are governed by a new law (2012), imposing licensing requirements and operational rules and use by third parties. However in the absence of any gas pipeline transportation and distribution activity by other parties than Sonangol, the law mainly serves a theoretical goal. At the same time real downstream gas distribution and pricing regulation does not exist in Angola.

The construction and operation of a gas pipelines in Mozambique either is part of the exploration and production concession contract, or, if it is not covered by such EPCC, is covered by a separate gas pipeline concession contract. The regulations require non-discriminatory third party access to gas pipelines on reasonable commercial terms, and provide rules for capacity increase. Various transmission and distribution concession contracts are in place in Mozambique. Maximum regulated end user prices and retail margins can be charged by gas distribution concessionaires (as an integrated capacity and commodity price as it seems). However, such pricing arrangements have not yet been developed by the Minister of Energy.

In Tanzania, the gas supply bill still is not enacted but would provide for regulation of gas transport, distribution, storage and supply (amongst other issues). It mainly seeks to adopt and adapt to prevailing international technological and safety standards in the gas sector. Downstream gas distribution and pricing is non-existent in Tanzania and thus not regulated.

The gas act of South Africa provides for third party access to uncommitted capacity in gas transport and distribution networks. However, there is no such capacity and the majority of operating licenses is held by Sasol. Maximum gas prices are set by the regulator since there is no real competition in the market (limited number of players).

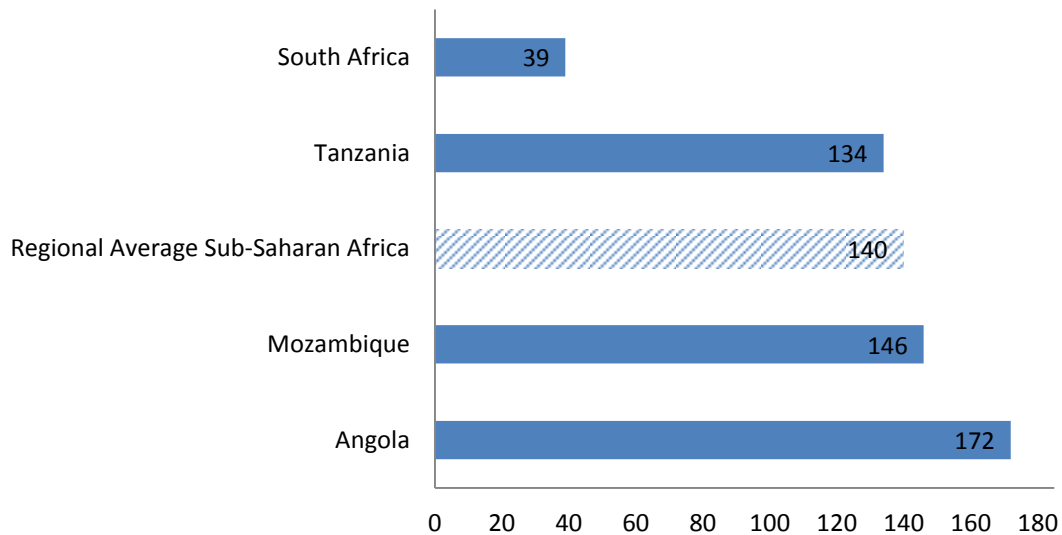
### **5.7.3 Business regulation – downstream**

The Doing Business report (2013)<sup>182</sup> evaluates business regulatory practices applying to domestic small and medium-size companies, covering 10 indicator sets and 185 economies. Two areas of business regulations are distinguished:

- Complexity and cost of regulatory processes: starting a business, dealing with construction permits, getting electricity, registering property, paying taxes and trading across borders;
- Strength of legal institution: getting credit, protecting investors, enforcing contracts and resolving insolvency.

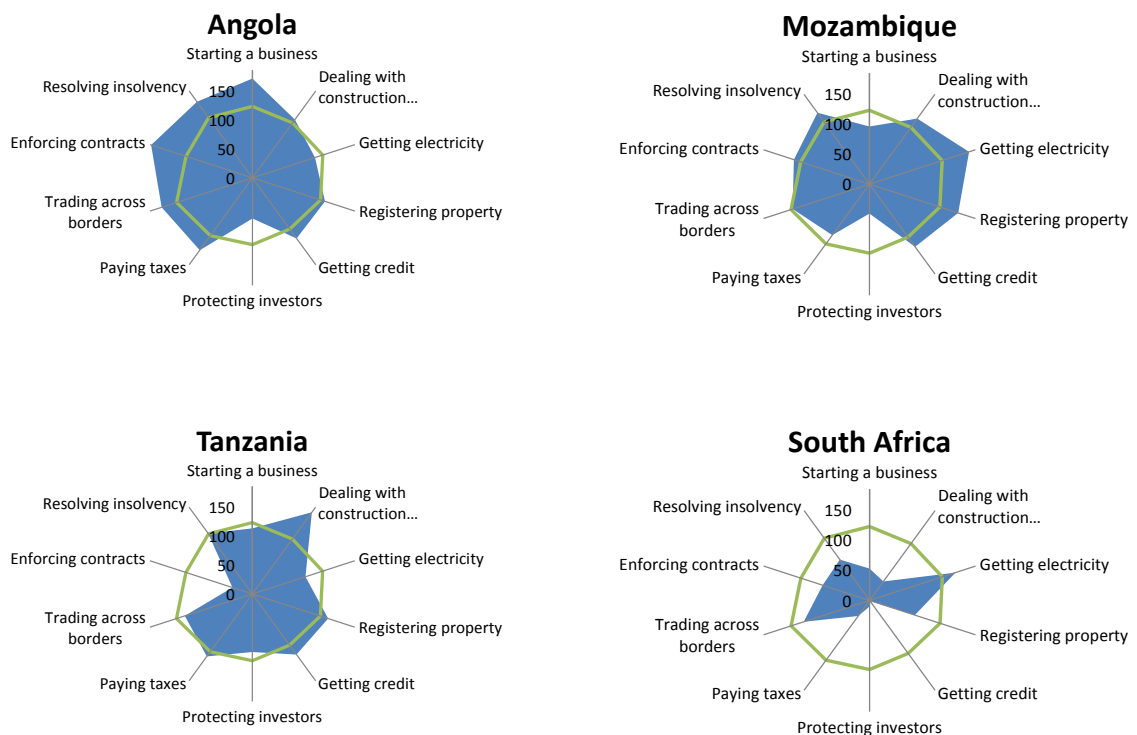
One of its main findings since 2003 is that business regulatory practices have been slowly converging as economies with initially poor performance narrow the gap with better performers. Among the 50 economies with the biggest improvements since 2005, the largest share (a third) is in Sub-Saharan Africa.

In respect to the overall ranking on the ease of doing business, South Africa is in the top-50 of 185 countries. Tanzania and Mozambique are ranked around the Sub-Saharan Africa regional average, while Angola scores rather low.



**Figure 109. How selected countries rank on the ease of doing business (Source: World Bank)**

A more detailed analysis of the ease of doing business in the selected African countries can be found in the specific Doing Business 2013 country reports. These provide, for example, rankings and details on each of the 10 indicators and the development over time for each indicator gives an overview of the ranking on each of the doing business indicators for our selected African countries (thus, the higher the figure, the lower the position on the ranking list, represented by more ‘blue’ and a worse situation). The solid green line represents the ranks for the Sub-Saharan Africa regional average.



**Figure 110. How selected countries rank on doing business indicators (Source: World Bank)**

The figures reveal that setting up businesses (e.g. gas using small scale businesses or larger industrial gas-based companies) will be easier in Tanzania and South Africa than in Angola and Mozambique.

## 5.8 Global comparison - Best practices

The purpose of this section is to distill regulatory best practices for the natural gas sector in Angola and Mozambique. The focus will be on the regulatory and legal framework in 'example' gas countries - the Netherlands and Qatar – that might be appropriate for Angola and Mozambique. Of course, country specific circumstances will be accounted for. In particular, Qatar may serve as example upon the consideration of LNG exports, whereas the Netherlands is/was more focused on domestic gas market development (incl. pipeline export, and cross border trade).

### 5.8.1 Upstream

The development of the gas production and use both in the Netherlands and Qatar is characterized by overall coordination by the government, while providing private initiatives, sufficient room to manoeuvre and grow. Back in the 1960s the Dutch government was very keen on making the switch to natural gas use (moving away from other fossil fuels) and at the same time entering into long term gas export relationships. They had a clear idea and plan on which gas volumes could be marketed domestically and which volumes would be available for export in the long-run. Gas prices were set in par with (or just below) the price of alternative fuels so that natural gas would be the fuel of choice for domestic gas users, meanwhile the producers of gas (Shell and Exxon and the Dutch State) would earn enough profits to stay above margin and further develop the sector. Still today, the Dutch State is involved in gas production through the (minority) participation of EBN in gas exploration and production in the Netherlands, in order to secure revenue for the Dutch State and to guarantee the security of supply of natural gas.

Qatar has an even more centralized approach towards gas developments, not only under upstream sector consideration, but also with respect to industrial projects and infrastructure. The rapid development of Qatar's LNG capacity was and is heavily driven by the government emphasis on the sector (by generating investments and attracting foreign investors). The Qataris focus on integrated large-scale projects linked to LNG exports and downstream industries that use natural gas as a feedstock. The government of Qatar has clearly prioritized domestic projects enabling to serve industry (e.g. in terms of providing input for large plants such as fertilizer, GTL and methanol). Subsequently LNG export was developed further and the power sector is growing fast, i.e. building gas-fired power generation plants. State company Qatar Petroleum (QP) has a crucial role in this strategy; it ensures that the State gets maximum benefit from its gas resources by engaging directly or indirectly in all activities that would add value to these resources. QP's objective is to maximize the oil and gas contribution to the national wealth of the State of Qatar, i.e. to provide the state with a reliable cash flow, to build an internationally competitive business and technical expertise, to maximise the employment (and develop them to the competence level of the leading IOCs), and to meet national oil and gas demand in a cost-effective way. Foreign company involvement has favoured international oil companies with the technology and expertise in integrated mega-projects, however, with QP maintaining a majority share in most of its gas projects.

## 5.8.2 Midstream and downstream

Since the liberalisation of the gas markets in Europe and the Netherlands, transmission and distribution of gas is a regulated activity performed by independent public TSOs and DSOs. However, prior to liberalisation, the Dutch gas transport pipelines have been developed mainly via public / private partnerships, and occasionally purely as private initiative. The planning and regulatory framework of gas transmission and distribution infrastructure was mainly related to dedicated gas using industry and power generation and to the marketing of gas to small domestic users.

Gas pipelines within Qatar typically transport gas from source to specific industrial projects. They are usually be integrated into a wider project, and QP may in some cases own the relevant interconnecting pipelines. There is no independent gas transmission or distribution network in Qatar. In contrast, Qatar has invested massively to establish its own fleet of over 50 LNG carriers, which are also State owned (by Nakilat, Qatar Gas Transport Company).

## 5.9 Financing

Investments required for developing the gas sectors in Angola and Mozambique fall naturally into three value chain segments (as also indicated by ICF's Natural Gas Master Plan for Mozambique). In the 6 country reports we have also distinguished those segments:

- Upstream exploration, development and production of gas, including transporting the gas ashore, processing and if applicable liquefaction of gas into LNG for export;
- Midstream transmission of gas, mainly involving investments into the required infrastructure, as well as the large scale gas-using projects (e.g. petrochemical, GTL, etc.);
- Downstream distribution of gas to end-users. The focus here is on distribution infrastructure (not on financing different types of gas using activities).

Securing finance for the downstream developments can only be successful when the midstream and upstream sectors are being developed and financed. Thus, there is a natural sequence for investing and financing.

Various sources of capital to finance the different segments are available (see also ICF):

- Global capital markets
- Public financial sources
- Local financial sector and banks
- International donors

### 5.9.1 Global capital markets

Since Angola and Mozambique probably lack creditworthiness to have direct access to the global financial markets, the countries will mainly have to rely on international oil companies (IOC) which bring in their own financial sources (both internal and external). However, IOCs are only willing to make investments when they can expect sufficient revenue and profit in return. Therefore, it is crucial that IOCs can negotiate proper contracts (production sharing agreements or risk sharing contracts in the case of Angola, and exploration and production concession contracts in the case of

Mozambique). IOCs may have deep pockets, but they can only be reached when risks attached to gas development and production projects can be mitigated and a proper return on investment is estimated. The declared exclusive State property rights (Sonangol) for natural gas seems a major barrier for IOCs to invest in gas developments in Angola, as well as dictates that oil developments are the main driver for investments.

### 5.9.2 Public financial sources

Public financial sources will mainly depend on direct and indirect taxes, which in general may be assumed as insufficient sources for the governments of Angola and Mozambique to fund gas developments. However, the government take (royalties, profit gas, taxes, etc.) of gas developments may be a solid source for financing further gas projects, and may even be required for the State's equity share of the national oil and gas companies in gas development and production.

### 5.9.3 Local financial sector

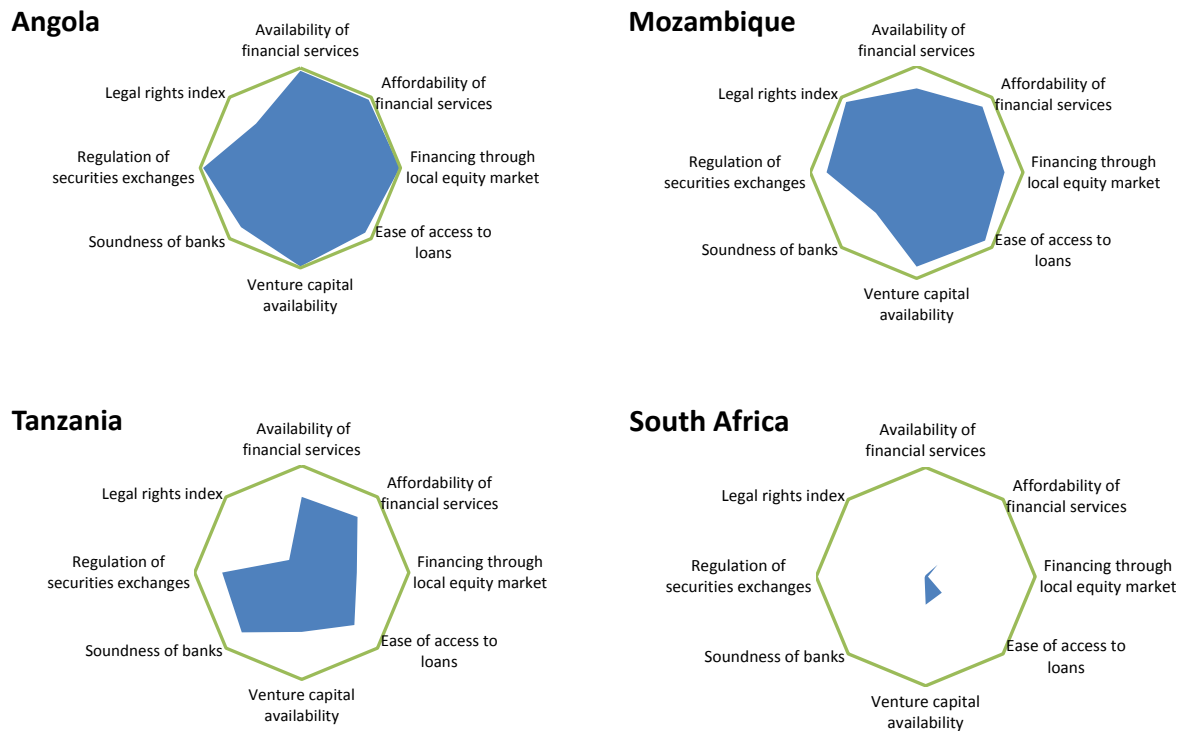
According to the Global Competitiveness Report 2012-2013 of the World Economic Forum<sup>xl</sup>, access to financing is indicated as the most problematic factor for doing business in Mozambique (followed by corruption, inadequate supply of infrastructure and inefficient government bureaucracy). In Tanzania, access to financing is perceived as the second most problematic factor for doing business (corruption is most problematic). When zooming in on the financial market development – one of the pillars for the global competitiveness index – it immediately becomes clear that financing is a difficult issue in both Mozambique and Tanzania, whereas South Africa scores very well on financing. Angola is not evaluated in the 2012-2013 Global Competitiveness Report; therefore figures of the 2011-2012 report are used here for Angola, revealing that financial markets are poorly developed in the country.<sup>183</sup> The figure below provides an overview of the rankings for the four countries on the following eight financial market development indicators:

1. Availability of financial services: Does the financial sector in your country provide a wide variety of financial products and services to businesses?
2. Affordability of financial services: To what extent does competition among providers of financial services in your country ensure the provision of financial services at affordable prices?
3. Financing through local equity market: How easy is it to raise money by issuing shares on the stock market in your country?
4. Ease of access to loans: How easy is it to obtain a bank loan in your country with only a good business plan and no collateral?
5. Venture capital availability: In your country, how easy is it for entrepreneurs with innovative but risky projects to find venture capital?
6. Soundness of banks: In your country, how easy is it for entrepreneurs with innovative but risky projects to find venture capital?
7. Regulation of securities exchanges: How would you assess the regulation and supervision of securities exchanges in your country?
8. Legal rights index: Degree of legal protection of borrowers and lenders' rights.

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<sup>xl</sup> <http://reports.weforum.org/global-competitiveness-report-2012-2013/#=>

The green solid line indicates the maximum possible rank of 144 (142 for Angola) for each indicator.



**Figure 111. How selected countries rank on financial market development indicators (Source: World Economic Forum)**

Local financial institutions have an important role especially in the development of midstream and downstream activities in the gas sector. Smaller businesses and industrial gas users, as well as equity required for transmission and distribution infrastructure projects, are likely to rely (partly) on loans and project financing through local banks, etc. Tanzania and notably South Africa seem to have leading positions here when compared to Angola and Mozambique. However, Mozambique could leverage on its ongoing cooperation with South Africa in the ROMPCO and Pande-Temane project.

#### 5.9.4 International financial institutions

International financial institutions such as the World Bank (including IDA, IBRD, IFC, etc.), the African Development Bank and IMF play an important role in financing economic developments and capacity building in Africa. Furthermore, these institutions can advise and assist the local governments to establish the most appropriate framework for a solid gas-based industry.

#### 5.9.5 Comparison and recommendations on financing

At the various levels of the gas value chain, main financial players currently active in the African countries considered are summarized in the table below. Deep involvement is clearly present for State companies throughout entire value chain in both Angola and South Africa. The financial strategy in Mozambique and Tanzania has mainly been to attract international oil companies to their upstream gas developments, with some (minority) State company involvement. Moreover, private parties are usually associated with the financial initiative to large-scale projects in Mozambique and Tanzania (and partly in South Africa).



	Activity	Angola	Mozambique	Tanzania	South Africa
<b>Upstream</b>	Production	Sonangol / IOC	IOC	IOC / TPDC	PetroSA / IOC
	Processing	Sonangol / IOC	IOC	IOC	PetroSA / IOC
	LNG liquefaction	Sonangol / IOC	IOC / ENH	IOC	n.a.
<b>Midstream</b>	Transmission	Public	Public / Private	Public / Private	Public TSO
	Large projects	Public	Private	Private	Public / Private
<b>Downstream</b>	Distribution	Public / Private	Public	Public / Private	Public

**Table 46. Summary of financial players by type of activity**

State participation in upstream gas production is a common mechanism to attract foreign investors and create revenue for the country. A question remains, should this be majority (such as in Qatar and Angola) or minority state participation (Netherlands and Mozambique)? For IOCs it is crucial that they can rely on some reasonable revenue and profit stream from their gas developments. DNV KEMA holds the opinion that a state minority share is more appropriate (since there are alternative ways to get additional state revenue from developing the gas market), although the example of Qatar also seems to work. However, in Qatar the revenues are solely based on gas exports; domestic marketing of gas seems a profit-loss business (due to subsidized electricity and fuel prices). Moreover, Qatar exploited its huge alternative (oil) resources to build up their economy (cross-subsidization between oil and gas).

Angola and Mozambique require a dedicated gas transport infrastructure plan in order to bring natural gas from the production facility to the market. The financial sources required for these infrastructure investments may partly depend on the establishment of larger gas intensive projects. In most countries the gas transport infrastructure is publicly owned, either because of third party access requirements to a natural monopolistic network (e.g. the Netherlands), or due to exclusive capacity rights to gas operators who have been or are developing large gas-based projects (power plants, GTL, fertilizer, etc.), which for example is the case in Qatar. Since the gas transport infrastructure still needs to be developed in Angola and Mozambique (at least for a large part), public financial guidance seems required, while at the same time closely cooperate with (private) parties willing to invest in large gas-based projects. However, for each specific project (which remains undefined) the strategic and financial choices may vary.

## 5.10 Summary and recommendations

In this section we provide a summary, as well as recommendations, for Angola and Mozambique on regulatory and finance issues. After a general overview we will address the eight natural gas industries in connection to their logical position in the gas value chain: upstream, midstream or downstream.

### 5.10.1 General overview

DNV KEMA comes to the following summarizing statements and recommendations:

- Stable and transparent regulation is essential to any economic development. It provides confidence to investors and reduces investment risks;
- Existing regulations in both Angolan and Mozambique have been driven by specific developments, such as the Angola LNG project and the Sasol export project. The Angola LNG

project has been considered public interest, hence special incentives for taxes and customs and exchange controls have been granted under specific law. Recently, somewhat more generalized regulation has been introduced, in particular in Mozambique;

- In order to make (quick and pragmatic) step changes in developing the large, centralized gas using projects, it seems wise to rely on negotiated contracts between the government and project partners at first – of course within the existing regulatory framework and policy;
- Financing for investments in the upstream E&P, LNG, transmission infrastructure and large gas-based projects should be secured first, before downstream developments are considered;
- The legislative frameworks should cover and adopt various technical and safety standards (offshore, pipeline, chemical plant, etc.), preferably based on international practices. Moreover, a safety governance structure (apply, maintain, control, etc.) should be in place;
- The Qataris focus on integrated large-scale projects linked to LNG exports and downstream industries that use natural gas as a feedstock. The government of Qatar has clearly prioritized domestic projects enabling to serve industry (e.g. in terms of providing input for large plants such as fertilizer, GTL and methanol). Given the huge gas resources this is especially a relevant finding for Mozambique;
- The official Mozambique gas strategy gives priority to the use of Royalty Gas in kind for projects that are difficult to establish solely on a commercial basis, but with high impact in development of the country. Thus, high impact projects (e.g. SMEs) and local jobs created may be supported. In addition there is the provision that 1% of gas extracted must be channeled to local communities near the production site. However, the latter provisions could negatively impact the business case for gas production projects;
- Both Angola and Mozambique have established the basics for third party access to natural gas transport infrastructures. However, they need to be further detailed with operational procedures and tariff methodologies;
- In general the governments of Angola and Mozambique should seek to encourage transparency (e.g. requiring all upstream operators to provide detailed data on a regular basis (e.g. regarding gas quality indicators and components from the different wells));
- Some South African regulations provide examples for Angola and Mozambique not to copy (i.e. ‘negative’ recommendations):
  - Important regulatory and policy issues should not be left to the sole discretion of just one Minister or other governmental official;
  - A constructive industrial development plan for natural gas in Angola and Mozambique is critical (which has been lacking in South Africa). Especially for Angola, this seems to be an important recommendation, as until now gas developments have been rather ‘accidental’ or opportunistic (associated gas and LNG focused on international market);
  - It is not wise to just copy and paste gas regulations from countries with well-developed gas industries where more or less normal market forces are in place. In South Africa, risks associated with investing in the industry (security of supply, regulatory barriers,

potential lack of demand, etc.) have hindered the development of a gas industry notwithstanding seemingly proper gas regulations.

### **5.10.2 LNG - upstream**

Developing an LNG industry is closely linked to upstream gas production and development, and thus to upstream gas regulation.

Angola has clearly chosen to have a large governmental involvement with majority stakes in gas projects. The example of Qatar shows that this may very well serve the LNG sector if the government assumes a coordinating and prioritizing role. However, the financial burden on Angola of such strategy may be too high while foreign investors and IOCs have difficulties entering into dedicated gas E&P and LNG projects. For IOCs it is crucial that they can rely on some reasonable revenue and profit stream from their gas developments. The declared exclusive state property rights for natural gas in Angola seem a major barrier for IOCs to invest in gas exploration and development in the country.

A relatively sound regulatory framework is in place in Mozambique to guide investments in LNG. However, unsettling governmental announcements and rumors (e.g. reserving a proportion of production to the domestic market; increasing the share of state participation) lead to agitation and uncertainty for investors.

There are no specific capital gains taxes in Mozambique and Angola. Fee levels have been negotiable and not transparent. It is recommended to address capital gains taxes in the legal frameworks of both countries. This will especially become important when projects advance towards production (and more M&A activity is expected).

Mozambique should think about provisions for cross-border cooperation with Tanzania regarding LNG (integrated LNG hub creating economies of scale).

### **5.10.3 Power generation - midstream**

Currently gas transport pipelines are governed by upstream regulations in Angola and Mozambique. In Mozambique, the construction and operation of a gas pipeline either is part of the exploration and production concession contract, or by a separate gas pipeline concession contract. In Angola, the construction and operation of natural gas pipelines and storage facilities are subject to licenses and their use by third parties is addressed, although Sonangol is currently the sole user.

Mozambique requires a concession for power generation from the Minister of Energy under the electricity law.

The planning of gas transport infrastructure co-jointly with the planning of gas-fired power generation (and large gas-using projects in general) is of major importance to Angola and Mozambique. Commitment of (private) project partners in power generation requires access to stable and secure gas and thus to gas transport infrastructure. State involvement (coordination, planning, financing) in developing the infrastructure seems inevitable, while developing and exploiting power plants and a gas-based industry may be left (partially) to private companies.

We recommend relating the planning and regulatory framework of gas transmission and distribution infrastructure to dedicated gas-fired power generating projects (and other large gas-using projects in general). Since the interface between power and gas systems is important for the business case of the power plant, the regulations should take an integrated view on the development of gas and power infrastructure.

We recommend independent ownership and operation of gas transport infrastructure in Angola and Mozambique. In the short- to mid-term it would enable exclusive capacity rights required to large gas based projects such as power plants. In the long-run, when the domestic gas market is further developed, it enables third party access to the network.

#### **5.10.4 Fertilizer, methanol and GTL - midstream**

Reliable water and electricity supplies, as well as constant and reliable gas availability at reasonably (predictable) gas prices are key preconditions for operating a large chemical plant. Thus, such chemical projects would want to contract for water, electricity and gas supply capacity and commodity.

Skilled labor is crucial for complex chemical plants such as methanol and GTL. Due to a lack of experience and know how locally, this would need to be imported from abroad. It implies that getting foreign employees on board should be supported by the regulations in Angola and Mozambique, while at the same time local training is supported to develop a knowledge base.

Similar to the electricity infrastructure, also the transport infrastructure for selling fertilizer, methanol and liquid products need to be considered.

Private land is not common in Angola and Mozambique, thus land necessary for chemical projects must to be leased.

An industrial license (from the Minister of Trade and Industry) is required in Mozambique for industries (fertilizer, metal, cement). For the production of petroleum products (methanol, GTL) a concession should be obtained from the Minister of Energy. Investment incentives are offered to approved investment projects.

Also in Angola, only officially approved investments can benefit from certain tax and investment incentives.

#### **5.10.5 Aluminum, iron & steel, cement and SMEs - downstream**

The local financial institutions have an important role especially in the development of midstream and downstream activities in the gas sector. Smaller businesses and industrial gas users, as well as equity required for transmission and distribution infrastructure projects, are likely to rely (partly) on loans and project financing through local banks, etc. However, the local financial sectors in Angola and Mozambique are still poorly developed.

Mozambique could leverage on its existing gas distribution initiatives and the ongoing cooperation with South Africa in the ROMPCO and Pande-Temane project.

Subsidizing gas use in the domestic market as is done in Qatar does not seem a good idea to follow in Angola and Mozambique. In the short-term it may help to develop domestic gas demand, albeit at

substantial public costs, but in the mid- to long-term the market distortion would negatively affect economic and environmental developments. Gas price according to market value, as has been adopted in the Netherlands while developing their gas market, seems a better example for Angola and Mozambique. It may help to establish a gas market, both domestically as well as export, and create revenue for gas producers.

For the downstream distribution of gas, regulation is lacking in Angola and only basically available in Mozambique. Domestic gas use (e.g. SMEs) and cement can only truly develop when a firm regulatory basis for the downstream sector is in place.

## 6 Forward plans

### 6.1 Potential build-up of the large gas based industry

Here we recommend pathways for building-up Angola and Mozambique's natural gas industry. We provide two indicative build-ups for each country related to their assumed reserves presented in chapter 2. Each build-up program consists of two phases: The first includes the most promising gas industries. In the second, we consider further growth of first phase industries and new industries which may be enabled from the first phase's experience and serve to diversify the gas industry.

#### 6.1.1 First Phase

Based on the netback analysis and the description of the industries we conclude the **first phase** should involve a combination of the following three industries: LNG, Power Plants, and Urea.

**LNG** is an important anchor project, but it is not the best use of country resources to spur domestic development. Still it is a necessary component of the development because it provides significant revenue while building up a skills base to do more complicated projects. This justifies the significant investment in gas infrastructure required to develop the resources and bring them to market.

**Power plants** should be developed as often as need to stabilize the grid and grow demand as new hydroelectric facilities are built. This limits gas used for electric power and the resulting revenues, but makes gas available for other uses. If hydroelectric facilities are slow to develop additional gas power plants can be built to ensure a reliable electric supply.

**Urea** is an important project to Mozambique and Angola to develop their domestic economies, and Mozambique is in a clear position to create great value from its natural gas by building a urea plant. There is significant urea demand in the SADC region which Mozambique is well positioned to serve. Based on this regional demand and the corresponding local prices, we see a netback value in the neighborhood of LNG and power. We do not recommend building urea plants in this region for global export as the corresponding netback value is very low or even negative.

#### 6.1.2 Second Phase

For the **second phase** we propose additional units of the three industries mentioned above in combination with Methanol, Gas-to-Liquids, Steel and Cement production facilities.

**Methanol** does not compete with LNG in terms of the netback analysis, but we see opportunity for the country from a diversification perspective. As there is presently a lack of local expertise for this industry, we recommend it to start up at least three years after first LNG. As it is vulnerable on global markets in the near term with large oversupply we would recommend vertical integration, so the buyer of methanol takes a stake in the gas production, or agrees to long term supply contracts from the producer to ensure security of future revenue. It is also encouraged to develop local beneficial uses for methanol, which could include its use as an energy carrier.

**Gas-to-Liquids** (GTL) is the most complicated facility that requires a deep base of local expertise to be built economically. The recent experiences in Qatar should be followed to better understand the cost to construct such a facility in Mozambique and Angola. A Gas-to-Liquids facility would serve a tight global market, but it is a high risk project that should be deferred until local expertise is proven.

A LNG and possibly a methanol plant would be good learning experiences towards building a Gas-to-Liquids facility. Mozambique would be able to sell products to its domestic consumers, but Angola produces significant amounts of oil for export, so any Gas-to-Liquids products there would be destined for export markets. Thus a GTL facility is not recommended in Angola as it would compete for limited gas supplies that could be put to better use in other industries for domestic growth.

**Steel** production should be considered in Mozambique if ore reserves prove economical as expected. The netback value was not as high as LNG and the global market is oversupplied, but steel is an important industry that allows a lot of expansion in the manufacturing and construction sectors. Natural Gas is competing with coal to be the most economical fuel, so on this basis natural gas may not be needed. A decision in Angola can be deferred until economical iron resources are validated.

**Cement**, like steel production, can readily utilize coal resources that are available in Mozambique and to a lesser extent in Angola via regional trade. From a netback perspective cement is not that promising. However, from an environmental perspective gas use in cement production is preferred above coal. This environmental perspective was the background for the fuel switch in 2008 for the cement factory in Mozambique.

From a netback perspective we see no ground for gas use in **aluminum** production. As hydro sources are available in the region generally aluminum smelters will be delivered with hydro generated power. As shown in the industry section the gas use in aluminum production is only substantial if the electricity used is generated by gas. Implicitly this gas use is already been taken into account when describing the Power generation.

Given the country specifics with respect to the local demand and resources of raw material, as described in chapter 2, we see different market potential for the different industries in Mozambique and Angola. These market potentials, without taking restrictions to gas resources into consideration, are provided in the table below.

Period	Industry	Mozambique	Angola	Determining factor for size
<b>Total by ~2020</b>	LNG	35 MTPA	5 MTPA	Gas resource base Local demand Regional demand/expected supply
	Power	0.5 GW <sub>e</sub>	1 GW <sub>e</sub>	
	Urea	0.6 MTPA		
<b>Total by ~2030</b>	LNG	70 MTPA	10 MTPA	Gas resource base
	Power	3 GW <sub>e</sub>	2 GW <sub>e</sub>	Local/regional demand
	Urea	2 MTPA	1 MTPA	Regional demand/expected supply
	Methanol	5 MTPA	5 MTPA	Asian demand
	GTL	200k bbl/d	None	Local/global demand
	Cement	2 MTPA	4 MTPA	Local demand/expected supply
	Steel	4 MTPA	1 MTPA	Coal and ore availability

**Table 47. Market potential in Mozambique and Angola**

For each of the four indicative build-up programs we do not fully allocate the gas resources. The remainder of the resources can for instance be used in sectors with smaller gas uses: SME,

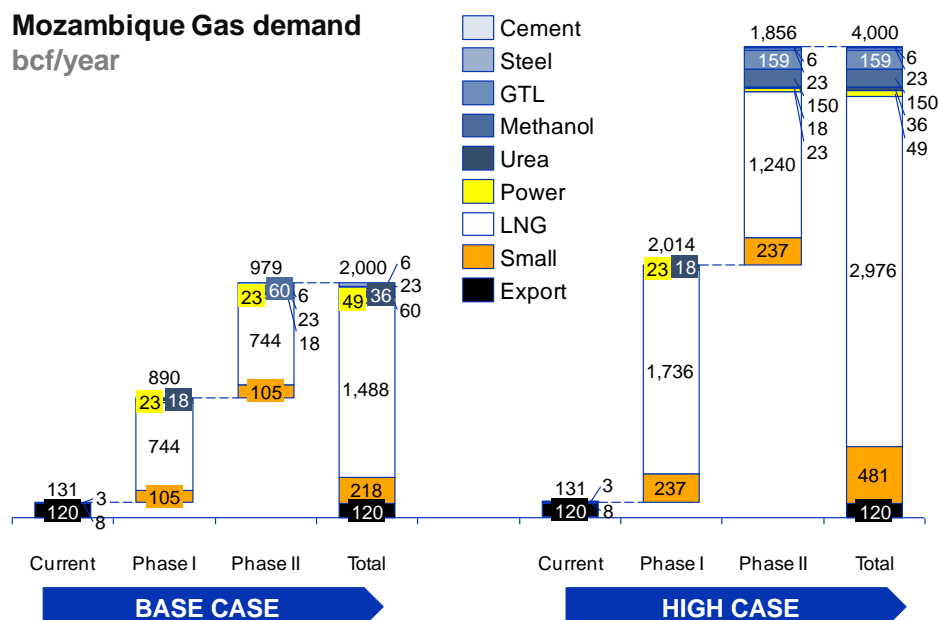
commercials, residential and transport. As this is not part of the scope of this study we do not elaborate further on these amounts.

The four indicative build-up programs, taking into account the market potential as well as the available gas resources, are given in the table below.

Country		Mozambique		Angola	
Case description		Base case	High case	Base case	High case
Current use		Export Sasol Domestic use	Export Sasol Domestic use	LNG 5 MTPA + liquids	LNG 5 MTPA + liquids
1 <sup>st</sup> Phase to ~2020	LNG	15 MTPA	35 MTPA	1 GW <sub>e</sub>	5 MTPA
	Power	0.5 GW <sub>e</sub>	0.5 GW <sub>e</sub>		
Added in 2 <sup>nd</sup> Phase to ~2030	Urea	0.6 MTPA	0.6 MTPA	0.6 MTPA	2 GW <sub>e</sub>
	LNG	15 MTPA	25 MTPA		
	Power	0.5 GW <sub>e</sub>	0.5 GW		0.6 MTPA
	Urea	0.6 MTPA	0.6 MTPA		
	Methanol	2 MTPA	5 MTPA		4 MTPA
	GTL		50k bbl/d		
	Cement	2 MTPA	2 MTPA		1 MTPA
	Steel	2 MTPA	2 MTPA		

**Table 48. Indicative build-up programs**

A graphical representation of the corresponding yearly gas uses is given in the chart(s) below.



**Figure 112. Mozambique natural gas demand pathway**



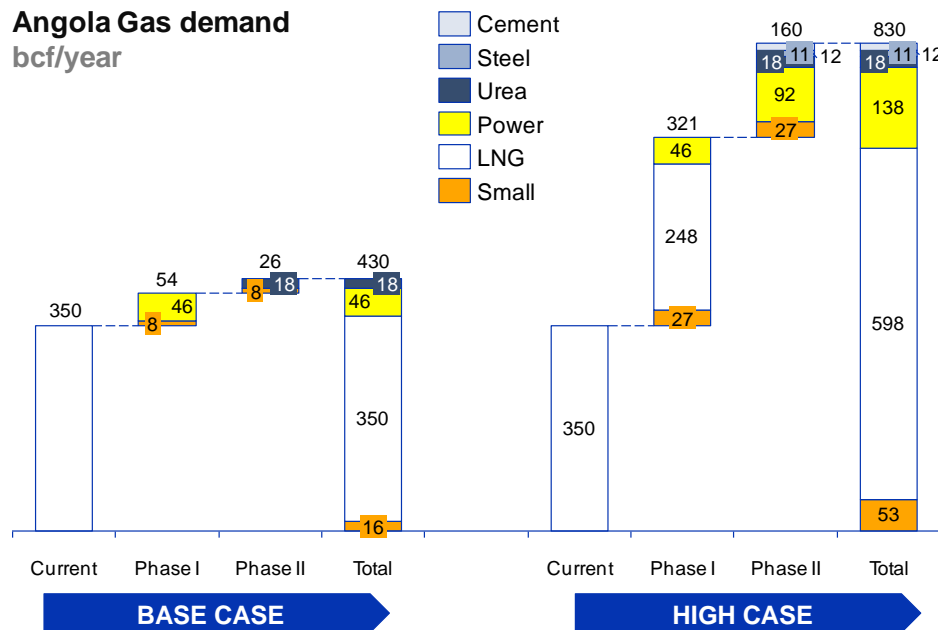


Figure 113. Angola natural gas demand pathway

### 6.1.3 Mozambique

With respect to Mozambique we assume in the 1<sup>st</sup> phase the three most promising industries: LNG, Power and Urea. We differentiate in the amount of LNG for the base case (3 trains) and the high case (7 trains), in both cases an amount more or less half of the total resource base. In the 2<sup>nd</sup> phase we add the other industries as explained above. Given its complexity we only assume a GTL plant in the high case. The amount of LNG and Methanol differs for the two scenarios, while for steel and cement the amounts are assumed the same, as gas amounts are relatively small. The non-allocated volume is slightly above 10% of the assumed resource base.

The location of the gas based industries is a point of attention. The Pande and Termene gas fields and new discoveries in that area contain sufficient reserves to maintain exports to South Africa and to develop gas use in the Matala region, for a power plant, a fertilizer factory and a local distribution network. Possibilities to enhance production are limited and will have an adverse effect on the lifespan of the project. Bringing gas from the northern reserves to the southern part of the country is a cost intensive operation. There is some doubt whether a gas pipeline to Maputo is feasible given the distance of 2,500 km. Bringing gas to the southern region first and then converting into methanol or GTL is questionable. From an economic point of view it makes more sense to do this conversion near the landing point of the gas. However from a country macro-economic viewpoint, to enhance industrial activity other regions, large distance gas transport may be considered. This may be by pipeline, however transport as LNG and building a LNG receiving terminal in the southern part of the country may be considered.

The impact on SME and local economy can be calculated for the two building schemes. By multiplying the impact per industry as provided for in chapter 4 with the number of industries in the respective building schemes results in the number for direct, indirect and induced jobs during construction and operation. The results are summarized in the table below.

# jobs	Base Case			High Case		
	1 <sup>st</sup> Phase	2 <sup>nd</sup> Phase	Total	1 <sup>st</sup> Phase	2 <sup>nd</sup> Phase	Total
<b>Construction direct</b>	15,000	18,000	33,000	32,000	34,000	66,000
<b>Construction indirect</b>	3,800	4,700	8,500	8,200	8,800	17,000
<b>Long term direct</b>	1,100	1,900	3,000	2,300	4,400	6,700
<b>Long term indirect</b>	3,700	4,800	8,500	8,300	9,000	17,300
<b>Long term induced</b>	110,000	150,000	260,000	240,000	290,000	530,000

**Table 49. Direct, indirect and induced jobs Mozambique**

### 6.1.4 Angola

With respect to Angola the amount of additional gas available in the base case is limited, given the allocated volumes to the ALNG plant in Soyo. There is only room for Power and Urea, not for additional LNG. In the high case we see room for only one additional train of LNG, while taking Power, Urea, Cement and Steel at maximum market potential for Angola. The non-allocated volume is around 5% of the assumed resource base. Given the large dependence on the Asian market for Methanol we did not put Methanol into the package. However, in case of increasing domestic resources, it is one of the options to take into consideration. Given the current location of reserves and the power demand centre in the capital Luanda, we recommend to consider a ~300 km gas pipeline connection from Soyo to Luanda. Such a pipeline is the logical option for expansion of the distribution network if more gas becomes available for domestic users. Given the recently built facilities, Soyo is the preferred place for bringing new gas resources to shore. Only if gas is discovered in blocks far south, a new coastal facility for LNG, petrochemicals or treatment for domestic consumers should be taken into consideration.

The impact on SME and local economy can be calculated for the two building schemes. By multiplying the impact per industry as provided for in chapter 4 with the number of industries in the respective building schemes results in the number for direct, indirect and induced jobs during construction and operation. The results are summarized in the table below.

# jobs	Base Case			High Case		
	1 <sup>st</sup> Phase	2 <sup>nd</sup> Phase	Total	1 <sup>st</sup> Phase	2 <sup>nd</sup> Phase	Total
<b>Construction direct</b>	780	690	1,470	5,200	2,900	8,100
<b>Construction indirect</b>	330	230	560	1,500	1,100	2,600
<b>Long term direct</b>	180	110	290	500	700	1,200
<b>Long term indirect</b>	270	140	410	1,400	1,000	2,400
<b>Long term induced</b>	9,300	4,700	14,000	43,000	30,000	73,000

**Table 50. Direct, indirect and induced jobs Angola**

## 6.2 Recommendations

In this section we provide our recommendations that will support the pathways for the gas based industry in Angola and Mozambique as described in section 6.1. In our first part we will provide recommendations that are valid for both Angola and Mozambique. Thereafter we will differentiate in country specific recommendations.

## 6.2.1 Recommendations for both Angola and Mozambique

### 6.2.1.1 Regulatory framework

- Stable and transparent regulation is key to any economic development. It provides confidence to investors and reduces investment risks.
- In order to make (quick and pragmatic) step changes in developing the large, centralized gas using projects, it seems wise to rely on negotiated contracts between the government and project partners at first – of course within the existing regulatory framework and policy.
- Important regulatory and policy issues should not be left to the sole discretion of just one Minister or other governmental official.
- In general the governments of Angola and Mozambique should seek to encourage transparency, e.g. requiring all upstream operators to provide detailed data on a regular basis (e.g. regarding gas quality indicators and components from the different wells).
- There are no specific capital gains taxes in Mozambique and Angola. Fee levels have been negotiable and not transparent. It is recommended to address capital gains taxes in the legal frameworks of both countries. This will especially become important when projects advance towards production (and more M&A activity is expected).
- The legislative frameworks should cover and adopt various technical and safety standards (offshore, pipeline, chemical plant, etc.), preferably based on international practices. Moreover, a safety governance structure (apply, maintain, control, etc.) should be in place.

### 6.2.1.2 LNG

- Developing an LNG industry is closely linked to upstream gas production and development, and thus to upstream gas regulation.
- LNG is a global market and new projects are being considered all around the world. Angola and especially Mozambique should bear in mind that this industry may show a boom-and-bust investment cycle. We have clear indication that traditional oil indexation will not hold in future. Innovative pricing and other terms and conditions may help to serve as well the producer with a reasonable return, the governments with reasonable tax income and the buyer with affordable prices in their market.

### 6.2.1.3 Power

- The planning of gas transport infrastructure co-jointly with the planning of gas-fired power generation (and large gas-using projects in general) is of major importance to Angola and Mozambique. Commitment of (private) project partners in power generation requires access to stable and secure gas and thus to gas transport infrastructure. State involvement (coordination, planning, financing) in developing the infrastructure seems inevitable, while developing and exploiting power plants and a gas-based industry may be left (partially) to private companies.
- We recommend relating the planning and regulatory framework of gas transmission and distribution infrastructure to dedicated gas-fired power generating projects (and other large

gas using projects in general). Since the interface between power and gas systems is important for the business case of the power plant, the regulations should take an integrated view on the development of gas and power infrastructure.

- Currently our build-up plans are related to local power demand only. Especially for Mozambique we recommend to consider gas based power export to South Africa, given the shortages in this neighboring country.

#### *6.2.1.4 Fertilizer, Methanol and GTL*

- The economics of building a urea plant and other fertilizer facilities in Mozambique and Angola should be investigated further to confirm:
  - The premium to build in these countries is valid to understand if reductions in actual capital costs could be achieved;
  - The supply-demand balance of the domestic fertilizer markets to estimate long term fertilizer price and volumes to the SADC region;
  - The availability of phosphate resources in Mozambique and other close locations.

The above could further improve the economics and justify a broader development of indigenous fertilizer production.

- Skilled labor is crucial for complex chemical plants such as methanol and GTL. Due to a lack of experience and know how locally, this would need to be imported from abroad. It implies that getting foreign employees on board should be supported by the regulations in Angola and Mozambique, while at the same time local training is supported to develop a knowledge base. As methanol and GTL are part of our pathways for Mozambique, this recommendation is more applicable to Mozambique.
- Similar to the electricity infrastructure, also the transport infrastructure for selling fertilizer, methanol and liquid products need to be considered.

#### *6.2.1.5 Midstream transport*

- We recommend independent ownership and operation of gas transport infrastructure in Angola and Mozambique. In the short to mid-term it would enable exclusive capacity rights required to large gas based projects such as power plants. In the long run, when the domestic gas market is further developed, it enables third party access to the network.
- Both Angola and Mozambique have established the basics for third party access to natural gas transport infrastructure. However, they need to be further detailed with operational procedures and tariff methodologies.

#### *6.2.1.6 Downstream*

- Subsidizing gas use in the domestic market as is done in Qatar does not seem a good idea to follow in Angola and Mozambique. In the short term it may help to develop domestic gas demand, albeit at substantial public costs, but in the mid to long term the market distortion would negatively affect economic and environmental developments. Gas price according to market value, as has been adopted in the Netherlands while developing their gas market,

seems a better example for Angola and Mozambique. It may help to establish a gas market, both domestically as well as export, and create revenue for gas producers.

- For the downstream distribution of gas, regulation is lacking in Angola and only basically available in Mozambique. Domestic gas use, e.g. SME's and cement can only truly develop when a firm regulatory basis for the downstream sector is in place.

#### *6.2.1.7 Financing*

- Finance for investments in the upstream E&P, LNG, transmission infrastructure and large gas-using projects should be secured first, before downstream developments are considered. Anchor projects are needed for financing and LNG is the best candidate for that.
- It is not wise to just copy and paste gas regulations from countries with well-developed gas industries where more or less normal market forces are in place. In South Africa risks associated with investing in the industry (security of supply, regulatory barriers, potential lack of demand, etc.) have hindered the development of a gas industry notwithstanding seemingly proper gas regulations.
- The local financial institutions have an important role especially in the development of midstream and downstream activities in the gas sector. Smaller businesses and industrial gas users, as well as equity required for transmission and distribution infrastructure projects, probably have to rely (partly) on loans and project financing by local banks etc. The local financial sectors in Angola and Mozambique are however still poorly developed.

### **6.2.2 Recommendations for Angola**

- Angola has clearly chosen to have a large governmental involvement with majority stakes in gas projects. The example of Qatar shows that this may very well serve the LNG sector if the government assumes a coordinating and prioritizing role. However, the financial burden on Angola of such strategy may be too high while foreign investors and IOCs have difficulties entering into dedicated gas E&P and LNG projects. For IOCs it is crucial that they can rely on some reasonable revenue and profit stream from their gas developments. The declared exclusive state property rights for natural gas in Angola seem a major barrier for IOCs to invest in gas exploration and development in the country. We recommend abolishing these exclusive state property rights.
- A constructive industrial development plan for natural gas in Angola is key. Up till now gas developments have been rather 'accidental' or opportunistic (associated gas and LNG focused on international market), as general focus of Angola was and is on oil.
- We recommend to stimulate finding dry gas and to publish dry gas field discoveries. Abolishment of exclusive state property rights, as mentioned above, is key.
- We recommend having the focus on LNG, power generation and fertilizer first. If more gas becomes available, steel and cement industry come into the picture.
- As demand center for power is capital Luanda, we recommend considering a pipeline connection of ~300 km from Soyo to Luanda.

- Angola could extract value from a more complex fertilizer plant by importing phosphate rock from Morocco. Rail could also be used to collect it from closer locations if economic resources were developed.

### 6.2.3 Recommendations for Mozambique

- A constructive industrial development plan for natural gas in Mozambique is key, given the huge gas reserve base. A clear coordinated approach, which has been shown by the Qataris, may help to develop integrated large-scale projects linked to LNG exports and downstream industries that use natural gas as a feedstock. The government of Qatar has clearly prioritized domestic projects enabling to serve industry e.g. in terms of providing input for large plants such as fertilizer, GTL and methanol.
- A relatively sound regulatory framework is in place in Mozambique to guide investments in LNG. However, unsettling governmental announcements and rumors (e.g. reserving a proportion of production to the domestic market; increasing the share of state participation) lead to agitation and uncertainty for investors. We recommend the Government of Mozambique to reconsider this suggested provision.
- With respect to the industry we recommend focus on LNG, Power generation and fertilizer. In a second phase other large industries, such as methanol, steel, cement and GTL are recommended.
- Mozambique should think about provisions for cross-border cooperation with Tanzania regarding LNG (integrated LNG hub creating economies of scale).
- Mozambique could leverage on its existing gas distribution initiatives and the ongoing cooperation with South Africa in the ROMPCO and Pande-Temane project.
- As Mozambique has a huge length (over 3000 kilometers) implying transporting gas from the huge reserves in the north to the southern part of the country will require large investments and related high costs per Bcf gas transported. We recommend Mozambique to carefully consider the areas for the gas based industry. Instead of pipeline transport an LNG receiving terminal may be considered in the southern part of the country as well.

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