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Potential for regional use of East Africa's natural gas

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HIGHLIGHTS

- Significant reserves of natural gas have been identified in East Africa.
- Natural gas may support economic growth and low-carbon future in the region.
- Main applications include: power, cooking, transport, and fertilizer production.
- The economics of developing a gas transmission system across the region is discussed.
- East Africa's gas may be a very affordable energy source for the whole region.

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ABSTRACT

Recently, significant reserves of natural gas have been identified in Mozambique and Tanzania. These resources may support a pathway to both economic growth and a low-carbon future. This natural gas could be used locally for a host of different applications such as cooking, power generation, transportation and fertilizer production. The aim of this paper is to investigate how the potential future demand for natural gas across sectors and countries might impact the economic viability of an investment in a new regional transmission and distribution gas network in Eastern and Southern Africa. We analyze the economic viability by using future demand and pricing data inferred for biomass, charcoal, LPG and liquid fuels currently being used in the continent. The investment and transmission costs are assessed for various scenarios of transmission pipeline networks. Then, a detailed analysis for a gas transmission network across eight Eastern African countries is presented. Results suggest that the development of a regional gas pipeline network within the continent is an attractive investment (based on internal regional demand as well as co-benefits to economy, environment and health) that can complement LNG export, which is the dominant market option being considered to enable the large upstream investments.

1. Introduction

With increasing population, urbanization and economic growth expected, the energy demand in sub-Saharan Africa will likely drastically increase over the next decades. How to meet the growing energy demand in a sustainable manner and provide reliable and affordable energy services to support the economic development is a foundational challenge for the sub-continent. The focus of this paper is natural gas, which might play a significant role in sub-Saharan Africa's future energy mix. Currently, the use of natural gas in the region is very limited; in 2012, natural gas accounted for only 4% of total primary energy demand of sub-Saharan Africa [1]. Worldwide, natural gas is gaining more and more importance, and substantial capital investments in infrastructure are made at all levels [2].

Recently, significant recoverable resources of natural gas have been identified in Mozambique and Tanzania [3]. Large reserves of natural gas are now being exploited in: Nigeria, Algeria, Libya and Egypt (see Fig. 1) [6,7]. In East Africa, the recent gas finds in Mozambique and Tanzania could provide benefit to the whole region by using domestically a significant share of the production. Indeed, natural gas can be used for a host of different applications such as cooking, power generation, transportation and fertilizer production. For cooking, natural gas would be a great alternative to wood fuels, which causes indoor air pollution and health problems [8,9]. For industry, power generation and transport, natural gas could represent an interesting alternative to imported oil products.

While in Sub-Saharan countries the share of population living in rural areas is amongst the highest in the world, the high rate of urbanization [5] is changing the demographics at a rapid pace. Because it is generally more cost-effective to develop energy infrastructure in urban areas rather than in rural areas, the growing

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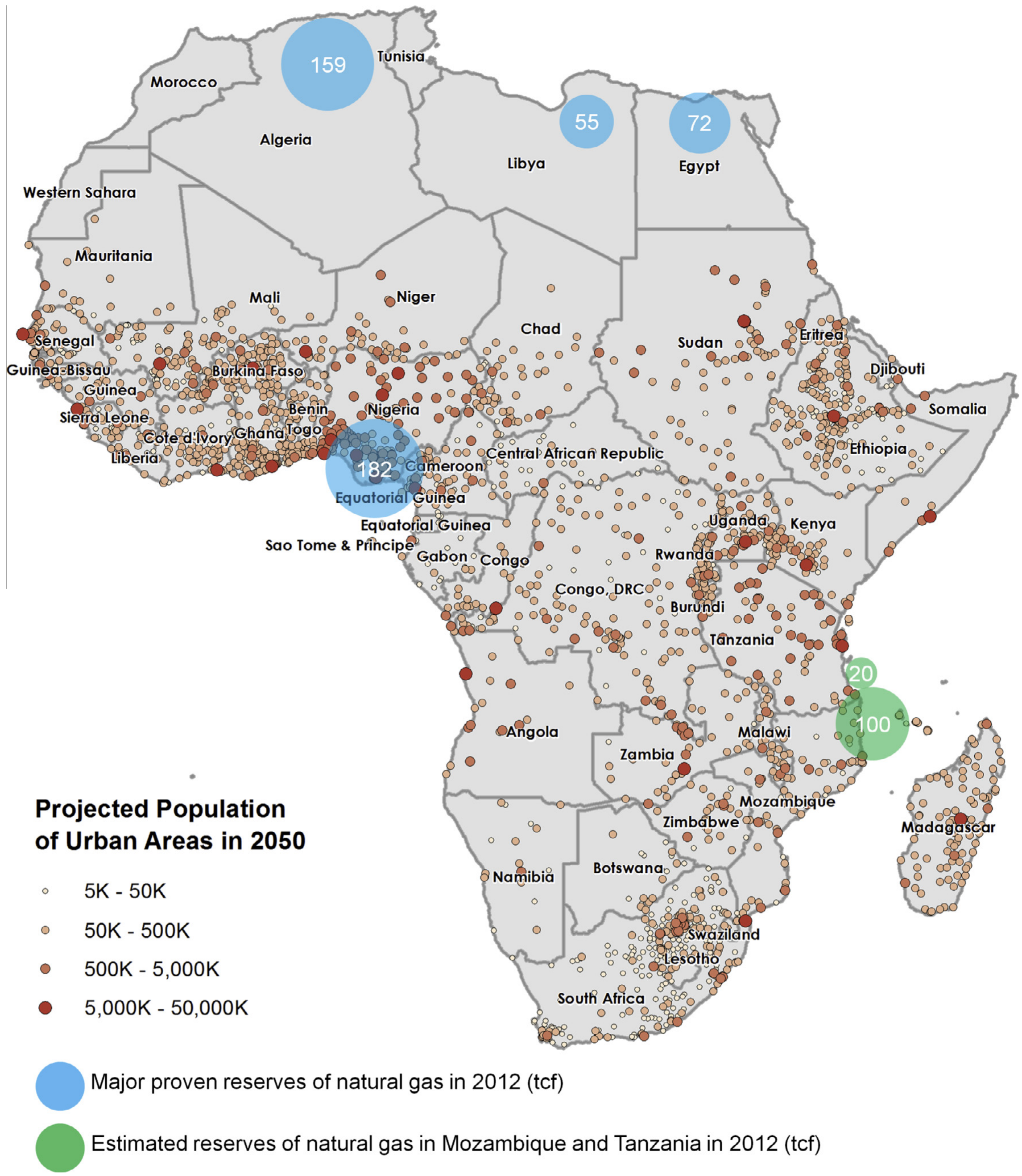

Fig. 1. Projection of the urban population in sub-Saharan Africa by 2050 [4,5], estimated natural gas reserves in Mozambique and Tanzania [3] and major proven natural gas reserves in Africa [6].

share of urban population tends to help increase the proportion of the population with access to modern energy services (although it is recognized that the quality of service is often sporadic, and definitions of "access" vary tremendously). A projection of the urban population in sub-Saharan Africa in 2050 is shown in Fig. 1. Western and Eastern Africa both exhibit areas with high densities of urban centers, which suggests that natural gas transmission networks could be economically viable in these regions. Fig. 2 shows the projected population of the major urban centers of Eastern Africa in 2050. In this paper we focus on Eastern Africa, because the question of how to best take advantage of the large potential recoverable resources of gas is still largely pending. In Western Africa, major gas producers, Nigeria and Equatorial Guinea, have long-term LNG export contracts already in place for the largest part of their production, which makes the scenario of drastically increasing the internal regional supply unlikely in the medium term.

The originality of this study is to examine the value proposition of using domestic natural gas at a large scale in a whole part of sub-Saharan Africa – East Africa – for energy needs in the different sectors, and to provide cost estimates and present a possible layout for a gas transmission system. The approach that we use here can be easily applied to other regions. It relies on simple models, an open-source software for network planning and publicly available data.

2. Current state of natural gas sector in sub-Saharan Africa

In 2011, the total production of natural gas in sub-Saharan Africa was approximately 1690 Bcf; the top gas producers were

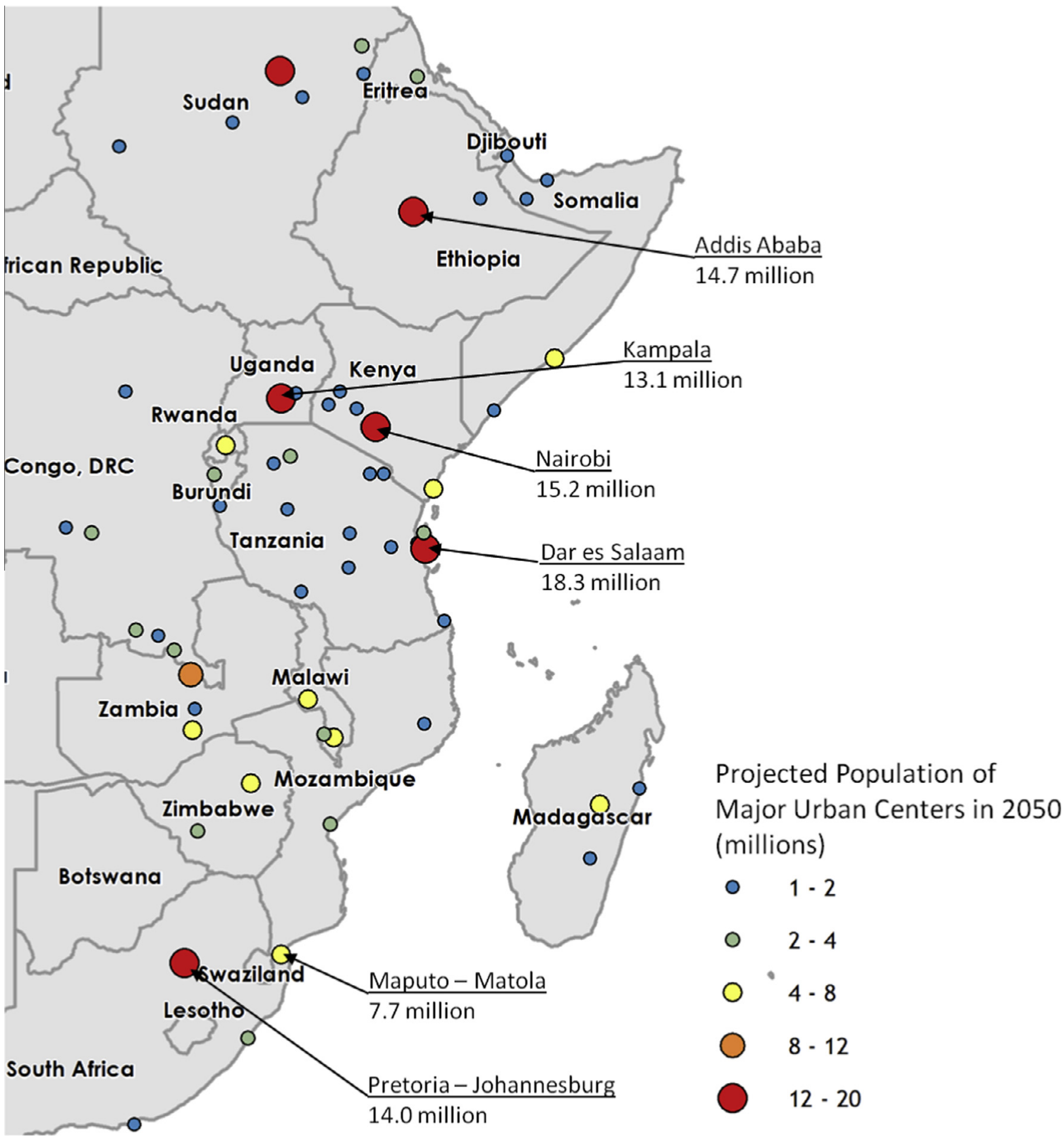

Fig. 2. Projection of the population of the major cities (metropolitan area) of Eastern Africa by 2050 [4,5].

Nigeria (66%), Equatorial Guinea (14%), Mozambique (8%), Ivory Coast (3%) and South Africa (3%) [10]. For comparison, in 2011 the two largest natural gas producers, the U.S. and the Russian Federation, produced 22,902 Bcf and 21,436 Bcf respectively, and the world total production was 116,230 Bcf [6]. Most of sub-Saharan Africa's production is exported as LNG. The remainder is used predominantly for power generation, except in South Africa, where natural gas is primarily used for GTL production. In Eastern Africa, Mozambique and Tanzania have produced natural gas for several years. In Mozambique, the current production is located onshore in the regions of Pande and Temane. In 2011, 135 Bcf of gas was produced in Mozambique, of which 117 Bcf was exported to South Africa (Secunda) via a pipeline of 860 km [11]. The Matola Gas Company (MGC) exploits a pipeline of approximately 70 km, which connects Matola to the bigger pipeline between Pande/Temane and Secunda (South Africa) [12]. This pipeline supplies around 9 Bcf/year of natural gas for industrial activities. MGC also delivers Compressed Natural Gas (CNG) by truck to customers in remote areas and provides gas to two refueling stations for natural gas vehicles. A new project in the region will allow one to supply gas consumers (at first, large consumers like hospitals and hotels) in Maputo and Marracuene [13]. Tanzania currently produces natural gas in two locations, Songo Songo Island and Mnazi Bay. The Songo Songo gas field delivers gas to Dar es Salaam via a pipeline of about 250 km. In 2011, the gas production was about 30 Bcf [11]. The gas produced at Mnazi Bay is used to supply the Mtwara Power Plant via a pipeline of about 27 km. A pipeline that will allow gas deliveries from Mnazi Bay to Dar es Salam is being constructed, and expected to be completed by 2014. Once the pipeline is commissioned, the production at Mnazi Bay should be increased to around 30 Bcf/year.

Recently, significant offshore gas resources have been indentified in Northern Mozambique and Southern Tanzania. The estimated recoverable reserves in 2012 were around 100 tcf for Mozambique and 20 tcf for Tanzania [3]. In sub-Saharan Africa, with very limited gas infrastructure and market, monetizing gas resources and the question of the best way to do it may be challenging [14,15]. For the new discoveries in East Africa, the majority

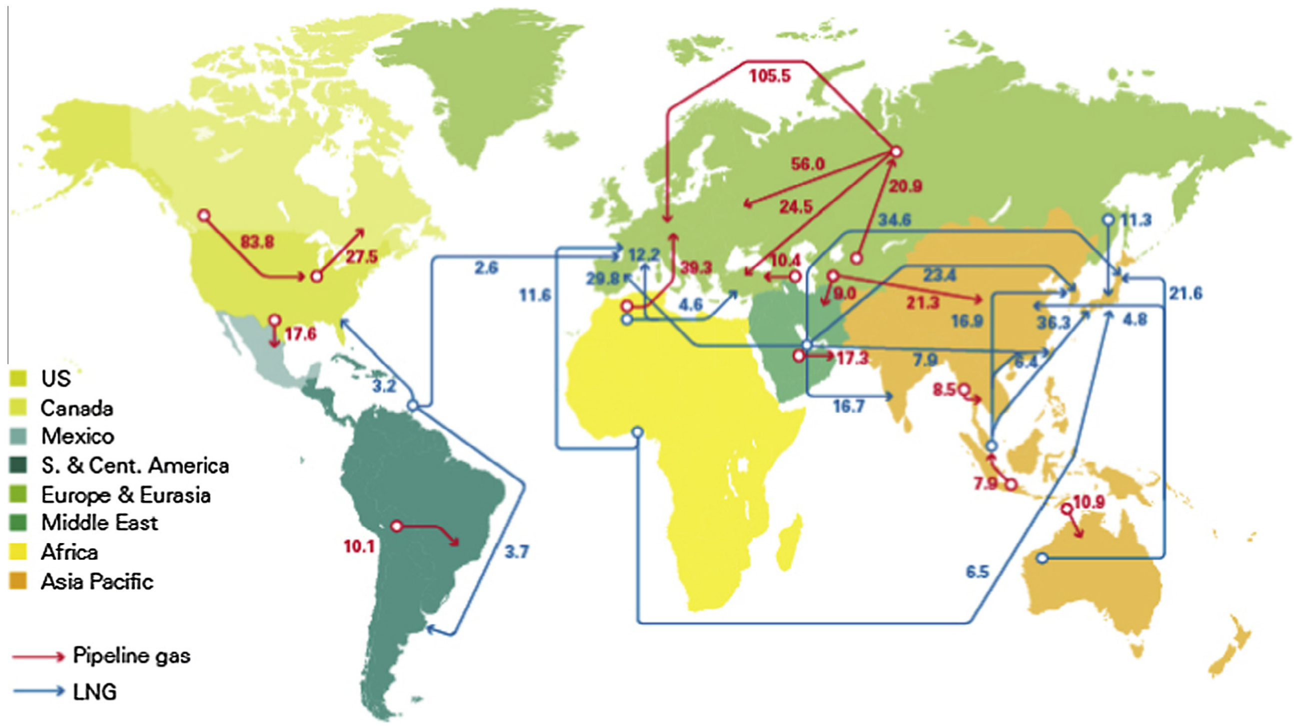

Fig. 3. Natural gas major trade flows worldwide, 2012 (billion cubic meters). *Source*: BP p.l.c. [6].

of the projects that have been proposed so far by the actors of the natural gas industry are associated with development of LNG export facilities. As the domestic demand is at this stage quite limited, LNG projects are seen to be able to generate revenues more rapidly. Looking at the trade flows of natural gas worldwide (see Fig. 3), one can naturally expect that East Africa's LNG exports would be intended to feed the Asian market. A comparison of delivered costs to Japan by Ledesma [3] shows that the price of East African gas would be very close to the ones of competitors (e.g., USA and Australia). ICF International [16] has studied several scenarios for Mozambique's natural gas, which include LNG export facilities as well as domestic fertilizer, GTL and Power plants in various amounts and locations. Currently, a feasibility study is also underway for a pipeline of 2600 km (estimated at $5 Billion) from the North of Mozambique to the South [17], which would also enable to increase the exports to South Africa.

3. Potential uses of natural gas

Natural gas is a very flexible resource that can be used for various applications. While its usage is limited in sub-Saharan Africa, it represents a significant portion of the primary energy consumption in most of the developed economies. For example, in the U.S., the share of natural gas in the energy mix was equal to 26% in 2011 and it is used in all sectors (see Fig. 4). Its usage as a vehicle fuel remains low in the U.S., but is gaining more and more importance in other regions of the world, especially in Asia. In the following sections, we focus on four applications particularly relevant for Eastern Africa. Our aim is to highlight the role that natural gas could play and to estimate the price at which it can represent a competitive alternative.

3.1. Cooking

The limited access to clean and modern cooking solutions in the developing world is widely recognized as a major issue [18,8]. The majority of the population in sub-Saharan Africa depends on traditional biomass (wood, charcoal and dung) for cooking. The proportion is exceeding 90% for the rural population [19]. Fig. 5 shows the shares of the different fuels for Eastern Africa. Different issues are linked to the use of traditional biomass such as the large health burden resulting from ingesting particulates and pollutants from the combustion of solid biomass fuels [21–24]. Efforts are pursued at different levels to promote both cleaner burning stoves as well as clean cooking fuels like LPG, biogas, ethanol and gelfuel [9,25]. Natural gas is an excellent candidate as clean cooking fuel, however it is less often mentioned as a solution for sub-Saharan Africa, since it requires dedicated infrastructure (distribution network) to be efficiently supplied to the end user.

To supply natural gas to residential users, a gas distribution network that connects the households to the city gate station has to be deployed. Such an infrastructure is economically viable in urban centers, but it is usually too expensive in rural areas. The penetration of natural gas as cooking fuel in urban areas will depends on its price compared to the alternatives. Table 1 shows a comparison of the cost of the two main clean alternatives and the three most used cooking fuels in Eastern Africa's urban areas. The different alternatives have specific efficiencies that have been taken into account to calculate a price for the same reference heat output, which is the heat output provided by one MMBtu of natural gas used in a standard cooking appliance. The cheapest fuels are charcoal ($18/MMBtu) and wood ($25/MMBtu), which explains why there are still largely used in urban areas. Kerosene ($41 – $62/MMBtu) is between 2 and 3 times higher than charcoal and wood depending on the country. Concerning the clean alternatives, LPG is close to the price of kerosene and electricity is in average cheaper. To allow for a large penetration of natural gas for cooking, its retail price has to be competitive with the cheapest alternatives, which are wood and charcoal, as well as electricity if its price for residential users is around $0.1/kWh or lower. Based on the numbers given in Table 1, we can assume that an affordable retail price for natural gas would be in the range of $15–25/MMBtu.

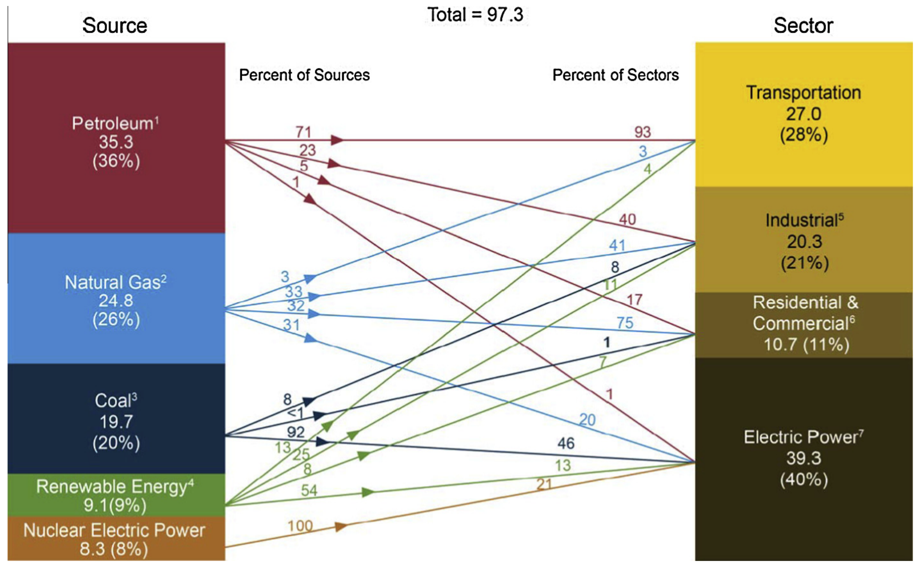

Fig. 4. U.S. primary energy consumption by source and sector, 2011 (Quadrillion Btu). *Source*: U.S. Energy Information Administration [11].

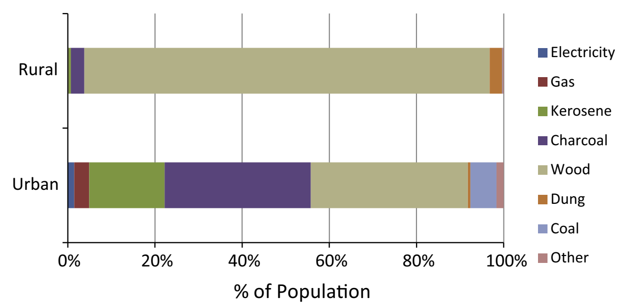

Fig. 5. Fuels used for cooking in Eastern Africa (Burundi, Ethiopia, Kenya, Malawi, Mozambique, Rwanda, Tanzania and Uganda). Based on data of fuels used by country (2003–2008) [20] and on population data for 2005 [5]. Gas includes LPG, natural gas, biogas and ethanol.

Table 1
Price comparison of cooking fuels in Eastern Africa. The *Natural Gas Equivalent Price* has been calculated assuming an efficiency for cooking of 60% for natural gas (same as that for LPG). LPG and Kerosene: retail prices in January 2012 reported by Kojima [26]. Charcoal and Wood: estimates by Daurella and Foster [27]. Efficiency for cooking: values reported by Barnes et al. [28]. (Data adjusted to 2013 U.S. dollars).

	Price	End-use efficiency %	Natural gas equivalent price $/MMBtu
Electricity	0.10–0.20 $/kWh	75	23–47
LPG	2.06–2.89 $/kg	60	47–66
Kerosene	0.82–1.26 $/L	35	41–62
Charcoal	0.18 $/kg[a]	22	18
Wood	0–0.13 $/kg[a]	15	0–25

[a] 0.18 $/kg for charcoal and 0.13 $/kg for wood are estimates of average retail prices in sub-Saharan Africa. A lower value of 0 is taken for wood as it is often gathered "for free".

The distribution costs to deliver natural gas from the city gate to houses are non-negligible. In India, where a certain number of distribution networks have been developed in the last decades, the average investment cost per household is of the order of $300 [29] when such investments are made as large-scale deployments within the entire city. Considering a repayment period of 30 years and an interest rate of 7%, and assuming an average gas consumption of 6.3 MMBtu/year per household,[1] an additional $3.8/MMBtu is needed to amortize the distribution infrastructure costs. Adding some O&M costs, an overall distribution cost of the order of $5/MMBtu seems a reasonable assumption. Therefore, the price at city gate should be $15/MMBtu or lower to ensure a retail price for residential customers that does not exceed $20/MMBtu.

3.2. Power generation

In sub-Saharan Africa the production cost of electricity is highly variable. Except South Africa, the power generation is essentially based on hydroelectricity and diesel generators. In general, where hydropower is predominant, the average cost of electricity is lower and where diesel has a large share, the average production cost is higher [31]. Fig. 6 shows the average cost of electricity production in 2005 for selected countries of Eastern and Southern Africa. With high economic and population growths, the electricity consumption in sub-Saharan countries is expected to increase drastically. Meeting this growing demand in a sustainable and affordable manner is an important challenge. Gas-fired generation can be a good complement to intermittent renewable sources (like solar and wind power), where on-demand renewable resources (like hydropower and geothermal energy) are limited. The gas-fired combined cycle power plant is the most efficient (in terms of energy and emissions) technology to convert a fossil fuel into electricity.

Fig. 7 shows the estimated electricity production cost (operating cost + capital cost) for a gas-fired Combined Cycle Power Plant (CCPP) as a function of the natural gas price. For comparison, in countries where power is generated predominantly with diesel engines, Eberhard et al. [31] report an average operating cost of about $0.32/kWh.[2] Assuming an overall electricity production cost for diesel generators of around $0.35/kWh and considering an average case (between « Worst Case » and « Best Case » of Fig. 7) for gas-to-power, a gas price below $48/MMBtu would allow one to produce electricity with a CCPP at a lower cost than from diesel. It has to be noted that $0.35/kWh is an extreme case. In its analysis, ICF

[1] Assumptions: useful energy per capita per year for cooking = 1 GJ [30]; efficiency of natural gas stoves = 60% (same as that reported for LPG stoves by Barnes et al. [28]); number of people per household = 4.

[2] Based on 2005 data from *Africa Infrastructure Country Diagnostic (AICD Power Sector Database), 2008.* (Value adjusted to 2013 U.S. dollars).

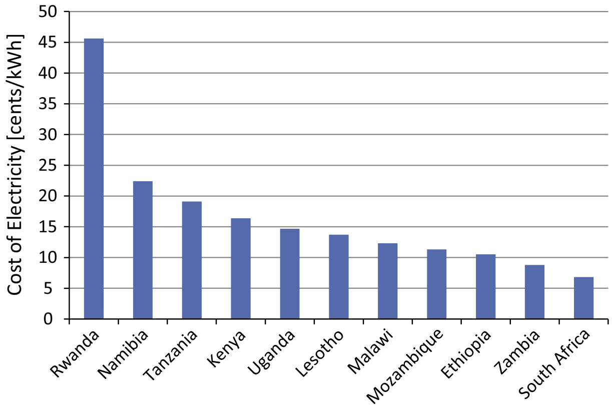

Fig. 6. Cost of electricity in selected sub-Saharan Countries in 2005 [32]. (Data adjusted to 2013 U.S. dollars).

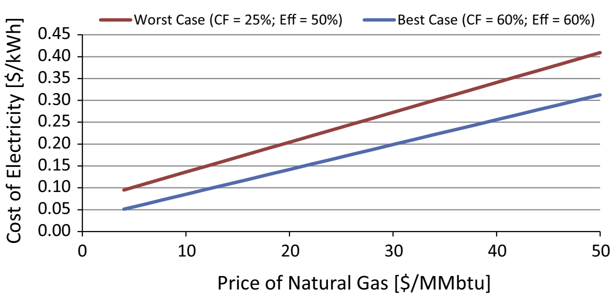

Fig. 7. Electricity production cost versus price of gas for a gas-fired combined cycle power plant, for two scenarios with different capacity factor (CF) and gas-to-electricity efficiency (Eff) values. Considered values for the calculation: CAPEX: 1100 $/kW; OPEX (excluding natural gas cost): 2.5% of the initial investment per year; Life time: 25 years; Interest rate: 10%.

International [16] has considered a market price of $0.12/kWh for electricity from natural gas in Mozambique; based on Fig. 7 and considering an average case, this corresponds to a gas price of $12/MMBtu.

3.3. Transportation

Compressed Natural gas (CNG) can be used as fuel for road transportation. Natural gas vehicle growth is particularly important in the Asia–Pacific region, where natural gas represents a cheaper alternative to conventional fuels (gasoline and diesel). An important advantage of natural gas over diesel and gasoline is a lower level of emissions (particles, CO_2, NO_x and SO_2). The drawback of CNG is that the range is about 3.5 times shorter when compared to gasoline or diesel for the same tank volume. The CNG vehicle requires a cylindrical tank pressurized at about ~3500 psi (240 bar).

In most of sub-Saharan countries, oil products are imported and the retail prices of diesel and gasoline are high. Hence, domestic natural gas could offer a competitive alternative. Fig. 8 shows the retail price of gasoline, diesel and LPG in selected Eastern African countries. Although LPG is only marginally used for transportation, it could be seen as an alternative to conventional fuels. Retail prices has been converted in $/MMBtu in order to allow the comparison with natural gas. In the US, the CNG price at refueling station is in average 25%[3] higher than the price at city gate. Assuming a similar ratio for Eastern African countries, the natural gas price at city gate should not exceed $25/MMBtu to $52/MMBtu, depending on the country (see Fig. 8), to represent a competitive alternative to conventional transportation fuels.

[3] Based on data of average natural gas price at city gate and for vehicles in the US from 1989 to 2011 reported by the U.S. Energy Information Administration (EIA).

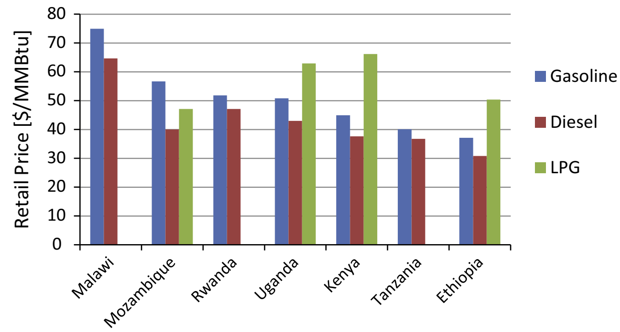

Fig. 8. Retail prices of fuels for transportation in selected Eastern African countries, in January 2012 [26]. (Data adjusted to 2013 U.S. dollars).

3.4. Fertilizer production

The crop yields in sub-Saharan Africa are very low compared to those in other developing regions. One of the main reasons is the low use of fertilizers [33]. In Sub- Saharan Africa in 2010, the average fertilizer use was 8 kg/ha, compared to 303 kg/ha in East Asia and 107 kg/ha in North America [34]. This low use of fertilizers is essentially due to the relatively high retail prices for the farmers. The supply of fertilizers relies on imports and the transportation costs (including ocean freight, port costs and truck transport) significantly impact the retail prices. The main nutrients provided by fertilizers are nitrogen (N), phosphorus (P) and potassium (K). The most often, nitrogenous fertilizers are produced using natural gas. The natural gas cost represents in average around 50% of the price of ammonia which is the main feedstock for producing nitrogenous fertilizer such as urea.

If affordable natural gas is available in sub-Saharan Africa, a domestic production of nitrogenous fertilizer could be developed, which would allow one to drive down the retail prices by reducing the transportation costs. Fig. 9 shows a comparison of the urea retail price for the last three years in different Eastern African countries and estimates of the retail price in the case of a domestic production.[4] It appears that a domestic production with a natural gas price as high as $15/MMBtu could supply urea at a very competitive cost ($570/ton) compared to imports. In 2010 – the most favorable year – the average price of urea was between $549/ton and $808/ton depending on the country. Considering these values and according to our assumptions for domestic production and distribution, the price of natural gas should be in the range of $14–24/MMBtu or lower to produce locally fertilizer that would be competitive with imports.

3.5. Maximum natural gas price by applications

Table 2 gives our estimates of the maximum natural gas price at city gate for the four applications we consider for Eastern Africa, based on the discussions of Sections 3.1–3.4.

- For cooking, with a price at city gate in the range of $10–20/MMBtu, the retail price for a residential user, including distribution costs, will reach about $15–25/MMBtu, which would be competitive with the cheapest alternative, such as charcoal or wood.

[4] For the domestic production, the distribution costs (from manufacturer to farmer) have been estimated based on the analysis of Wanzala and Groot [34], and Gregory and Bumb [39], and considering that the ocean freight and port costs are avoided and assuming that in average the domestic transport costs can be divided by 2 compared to the usual fertilizer supply chain (procurement from overseas fertilizer manufacturers). This results in distribution costs of around $115/ton.

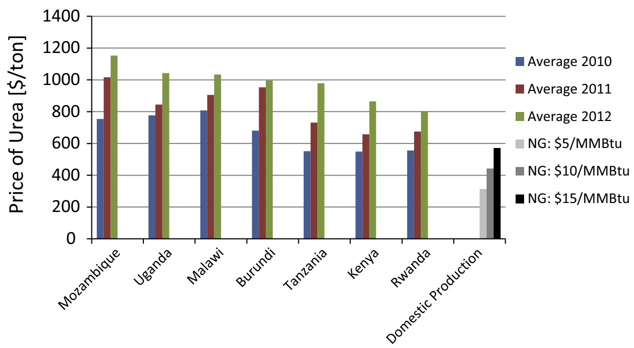

Fig. 9. Nitrogenous fertilizer (urea) retail price in Eastern Africa [35] and retail price estimates in case of domestic production for various natural gas (NG) prices. Urea production cost estimates based on a model from Yara [36] and data from Maung et al. [37] and Budidarmo [38]. Distribution cost estimates based on the analysis of Wanzala and Groot [34], and Gregory and Bumb [39]. (Data adjusted to 2013 U.S. dollars).

Table 2
Maximum natural gas price by applications. Author "stylized" estimates. (2013 U.S. dollars).

	Natural gas price at city gate ($/MMBtu)
Cooking	10–20
Power generation	12–48
Transportation	25–52
Fertilizer production	14–24

- Concerning power generation, if gas-to-power has to compete with diesel generators currently in use in sub-Saharan Africa, our estimates shows that the price of natural gas should be below $48/MMBtu (it corresponds to an electricity production cost of $0.35/kWh). We will consider here this value as an upper limit. As lower limit, we will use $12/MMBtu, which corresponds to the market price for electricity ($0.12/kWh) considered by ICF International [16] for its analysis. It has to be noted that power plants could be built near trunk pipelines to take advantage of a low natural gas price. As a large consumer and ideally located close to the city gate, it is assumed that a power plant would buy gas at the city gate price.
- Concerning transportation, in Eastern Africa the diesel retail price (cheapest transportation fuel alternative) is in the range of $31–65/MMBtu depending on the country (see Fig. 8). Therefore, the city gate price of natural gas should be below $25–52/MMBtu to be a competitive alternative (assuming that the retail price of CNG at refueling station is about 25% higher than the price at city gate).
- A gas price in the range of $14–24/MMBtu or lower would allow for the production locally of nitrogenous fertilizers for the domestic market that would be competitive with imports. As with power plants, fertilizer production should generally be developed close to trunk pipelines and city gates to take advantage of lower gas prices. It is assumed that the gas price for large fertilizer manufacturers would be very close to the city gate price.

4. Estimation of potential natural gas demand

For the purpose of proposing a natural gas transmission network in Eastern Africa, an estimation of the potential demand for the next decades has been performed. This work has been undertaken for the entire sub-Saharan Africa region. Even if the focus of this study is Eastern Africa, it is interesting to look at the potential natural gas demand at a larger scale. The methodology applied here is based on the projection of primary energy needs using the GDP per capita (PPP)[5] and the population as inputs. There exist different methods for projecting energy demands. Sözen and Arcaklioglu [40] used artificial neural networks to develop models for forecasting the energy consumption in Turkey. They obtained very good results using the GDP as input. Yu et al. [41] give a literature review of various methods. They developed a model for estimating the primary energy demand of China using a hybrid algorithm based on particle swarm optimization and a genetic algorithm. They used as inputs various factors such as GDP, population, economic structure, urbanization rate, and energy consumption structure. Here, we use a very simple approach, because we do not need a high level of accuracy; we just need a rough estimate of the potential demand for natural gas in order to estimate the costs of delivering it. We assume that the GDP per capita and the population are the main drivers of the primary energy consumption. It has to be noted that here we assess the aggregate natural gas demand in all sectors – not just for the four applications discussed in the previous section. Nevertheless, it is assumed that the fraction of the natural gas consumption that is not linked to these four main uses (cooking, power generation, transport, and fertilizer) is relatively modest.

For projecting the GDP per capita of the considered countries, we have assumed that the evolution of those developing economies can be modeled as a catching-up process [42]. In such process, the economic growth is higher when the GDP per capita gap with developed economies is larger. We used here the following model:

$$\frac{d(\ln \mathrm{GDP}_i)}{dt} = r(\ln \mathrm{GDP}_R - \ln \mathrm{GDP}_i) + \mathrm{GDPG}_R \tag{1}$$

where GDP_i is the GDP per capita of the considered developing country, GDP_R is the GDP per capita of a developed country used as a reference, GDPG_R is the GDP per capita growth rate of that developed country, and r is a constant that measures the speed of catching-up. In this model, the GDP per capita of the developing country tends asymptotically to that of the developed country. To calculate the GDP per capita of the developing country i at year t, the following discret formulation of the model given in Eq. (1) has been used:

$$\mathrm{GDP}_{i,t} = \mathrm{GDP}_{i,t-1} e^{[\mathrm{GDPG}_R + r(\ln \mathrm{GDP}_{R,t-1} - \ln \mathrm{GDP}_{i,t-1})]} \tag{2}$$

In our calculations, r has been set to 0.014 and we used the USA as reference with a GDP per capita growth rate (GDPG_R) equal to 1.5% per annum [43]. In Appendix A, a comparison between this model and historical data for various countries is shown.

The primary energy needs per capita (EPC) for a country i at year t is calculated using the following relation:

$$\mathrm{EPC}_{i,t} = \mathrm{GDP}_{i,t} I_t \tag{3}$$

where I_t is the energy intensity of GDP (kgoe/$) at year t. In our calculations, we assume that, in 2011 for the studied region, 1 kgoe corresponds to $5 of GDP (PPP) [44][6] and that the energy intensity is expected to improve due to efficiency measures. The energy intensity at year t is thus calculated as follows:

$$I_t = (1 - \epsilon) I_{t-1} \tag{4}$$

where ϵ is the annual rate of improvement of the energy intensity, assumed to be equal to 1.14% in our calculations.

In our scenario, it is assumed that *apriori* natural gas cannot be economically supplied to rural areas or small urban centers (<5000 inhabitants in 2000). Therefore, only the energy demands of bigger urban centers are considered. The population of each urban center

[5] In this work, we use the GDP adjusted to Purchasing Power Parity (PPP).

[6] According to the study of Suehiro [44] the energy intensities of GDP (PPP) of most of the countries were in the range of 0.07–0.29 kgoe/$ in 2004. For our calculations, we used a conservative value of 0.2 kgoe/$ (=$5/kgoe) for sub-Saharan Africa.

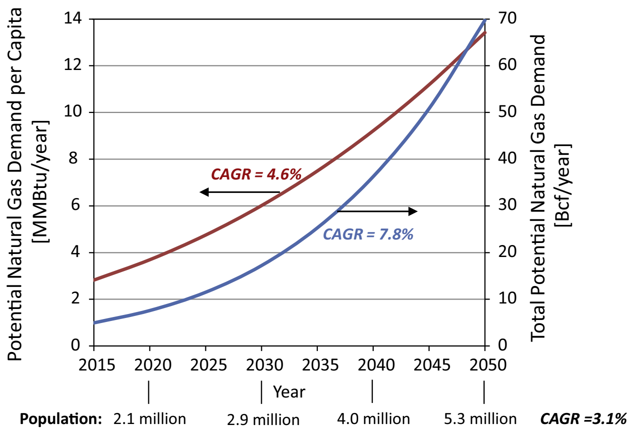

Fig. 10. Projection of the potential natural gas demand for Maputo (per capita and total). *CAGR = Compound Annual Growth Rate.*

has been projected using national growth rates reported by the United Nations [5]. Finally, the projected natural gas demand (NGD) of a urban center j in a country i at year t is given by

$$NGD_{j,t} = X_{NG} EPC_{i,t} POP_{j,t} \tag{5}$$

where $POP_{j,t}$ is the projected population of the urban center j at year t and X_{NG} is the share of primary energy needs that can be met with natural gas. In our calculations, we assume that X_{NG} is equal to 25%. For comparison, IEA is projecting the share of natural gas in the world's energy mix between 22% and 25% by 2035 [45].

The potential natural gas demand that is obtained with the methodology described here should be interpreted as the demand that might be reached if natural gas could be supplied to all urban centers at a competitive price. Using this methodology, the projected potential natural gas demand for sub-Saharan Africa is 6.5 tcf in 2030, 11.4 tcf in 2040 and 19.2 tcf in 2050. Fig. 10 shows, as an example, the projection of the potential natural gas demand for Maputo for the period 2015–2050. Due to the rapid population

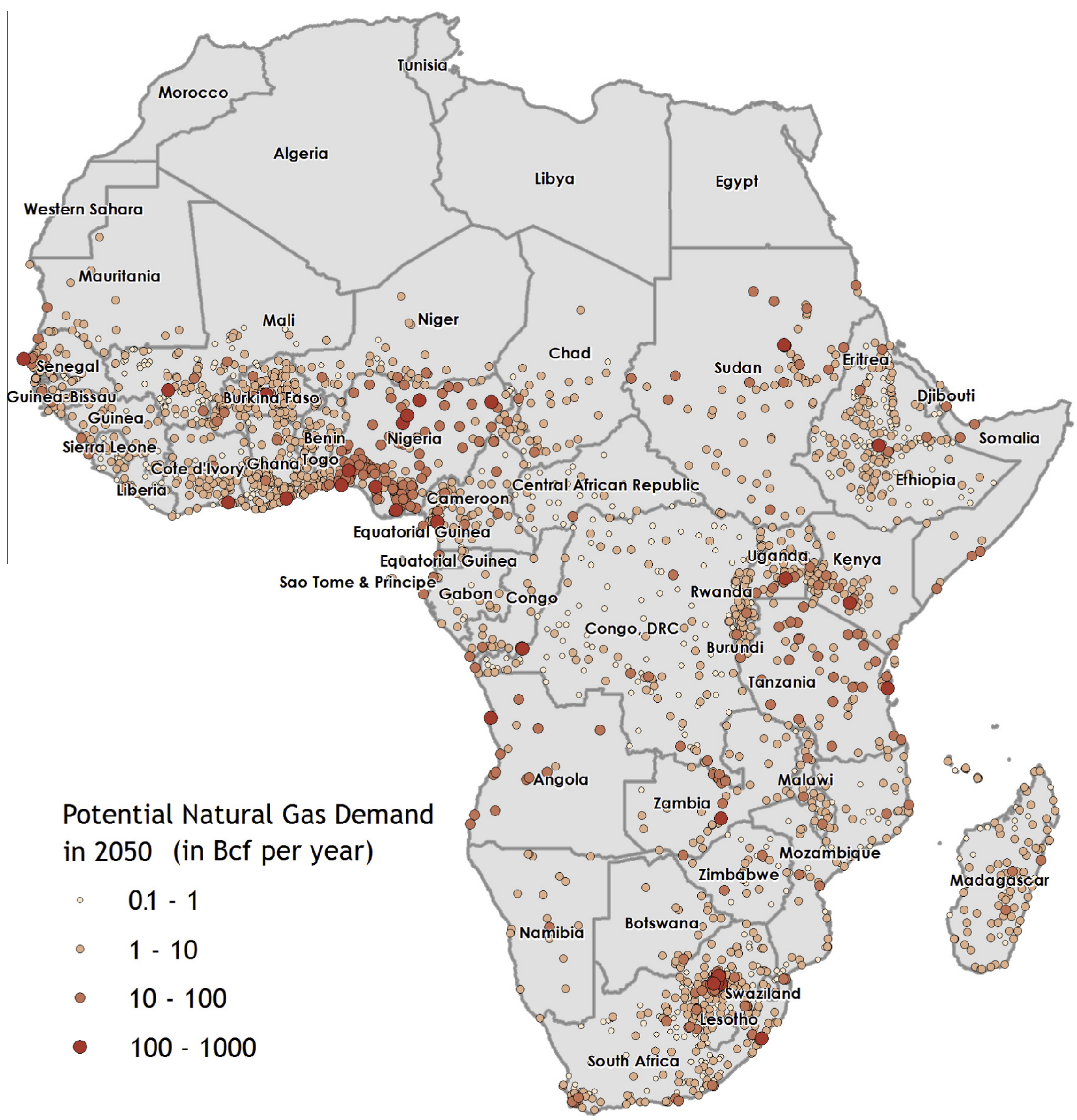

Fig. 11. Estimated potential natural gas demand in sub-Saharan Africa by 2050.

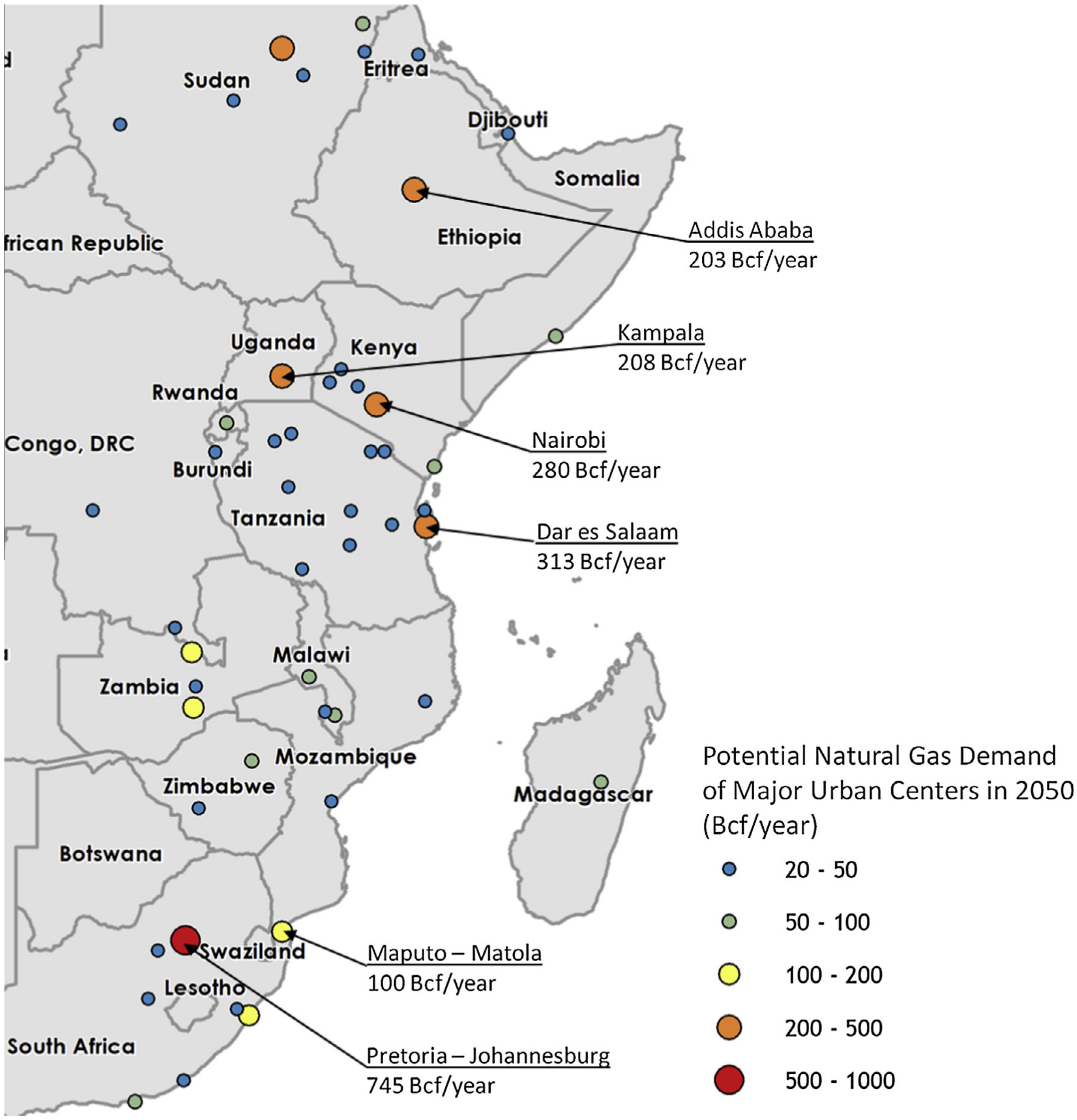

Fig. 12. Estimated potential natural gas demand of the major cities (metropolitan area) of Eastern Africa in 2050.

growth combined with high GDP growth, the projected potential demand exhibits an exponential trend. Figs. 11 and 12 show maps of the potential natural gas demand by 2050 for all urban areas of sub-Saharan Africa and for the major cities of Eastern Africa, respectively. The total potential demand in 2050 in Western Africa is about 8.4 tcf/year, and in Eastern and Southern Africa (together) it is about 8.1 tcf/year. Those numbers can appear very high compared to most of the current projections of natural gas consumption in Africa. For example, EIA [46] reports a projected consumption of natural gas for whole Africa (including large consumers like Algeria and Egypt) of 5.9 tcf in 2030 and 8.8 tcf in 2040, corresponding to 23% and 27% respectively of the projected total energy consumption. The discrepancy with our projection is essentially due to the difference in the projected primary energy demand. The model used here for projecting the primary energy demand, which takes into account population and economic growths, predicts an exponential trend, while most of the current projections assume a more linear growth. Our projection for the primary energy demand of urban areas of sub-Saharan Africa by 2040 is 1073 Mtoe/year, about 5.8 times the consumption in 2010. Although this energy demand growth may seem very high, it is in the same range as the consumption growths that have been observed during the last three decades in China and India. In the following, we will consider the projection presented here as the baseline assumption for the potential natural gas demand. The impact of the demand on the transmission costs is analyzed for a specific case in Section 5.4.3 (see « *Impact of Demand on Gas Cost* »).

The approach described in this section tends to overestimate the demand in smaller urban centers and underestimate the demand in the largest urban centers. Indeed, it can be assumed that most of the industrial activities and power generation will be concentrated close to the largest cities; in our model, the demand for the different sectors is aggregated and spatially distributed according to the distribution of the urban population. With the aim of conducting a first analysis of the viability of a natural gas transmission network in Eastern Africa, this approach is considered to be satisfactory.

5. Costs of supplying natural gas

The costs of supplying natural gas to consumers can be divided into three categories: production cost, transmission cost and distribution cost. In this work, we do not discuss the conditions and the cost for developing the production (including exploration and processing). For all scenarios discussed in the following, we assume that a sufficient volume of gas is available for the domestic market at a production cost of \$3/MMBtu [3]. Transmission refers to the transport of natural gas over long distances from production fields to consumption centers. Onshore, natural gas is usually transported through pipelines. The transmission cost highly depends on the distance from the production field and the transported volume. Distribution is the transport of gas from the transmission system to the end users. We suppose that the distribution costs would be roughly the same in all urban areas of the considered region. We have estimated that the distribution cost for residential users would be around \$5/MMBtu (see Section 3.1) and that for CNG would be approximately equal to 25% of the price at city gate (see Section 3.3). For big consumers like power plants or fertilizer plants, we assume that the distribution cost is negligible. In the following, we focus on the economics of developing a transmission system across Eastern Africa.

5.1. Pipeline cost model

Various options exist to model the capital and operating costs of a gas transmission pipeline system. Models based on the detailed design of the system (pipe diameter, pipe thickness, pressures, number of compressor stations, ...) are frequently used [47–49]. Here, we chose to use simpler models, as a high level of accuracy is not required. The following simple empirical model has been used to estimates the capital cost for natural gas transmission pipeline:

$$c_I = a_0 + a_1 Q_0^{0.5} + a_2 Q_0 \tag{6}$$

with
c_I: Unit capital cost of the pipeline (million \$/km).
Q_0: Pipeline capacity (Bcf/year).
a_0, a_1, a_2: Empirical coefficients to be tuned.

The unit capital cost c_I includes all components (pipes, compressor stations, city gate stations). The first term (a_0) represents the costs that are independent of the capacity, such as engineering, and right-of-way/land. The second term ($a_1 Q_0^{0.5}$) represents the costs that are roughly proportional to the pipe diameter,[7] such as the anticorrosive material. Finally the last term ($a_2 Q_0$) represents the costs that are proportional to the capacity, such as the compression capacity and the material (steel) for the pipes. It has to be noted that this model is very simple and that the capital cost can significantly vary from a project to another, for similar capacity and length, depending on topographic and terrain conditions. Also, it is difficult to obtain costing data for recent gas pipeline projects and to project future costs. In the last decades, the pipeline infrastructure costs were quite volatile and tripled between 1993 and 2007 [50]. Based on our research, we assumed the following values for the empirical coefficients of our model: a_0 = 0.4, a_1 = 0.11 and a_2 = 0.0012. The capital cost function corresponding to these parameter values is shown in Fig. 13, together with unit costs of recently completed pipelines

[7] The capacity is approximately proportional to the square of the pipe diameter (for given density and flow velocity).

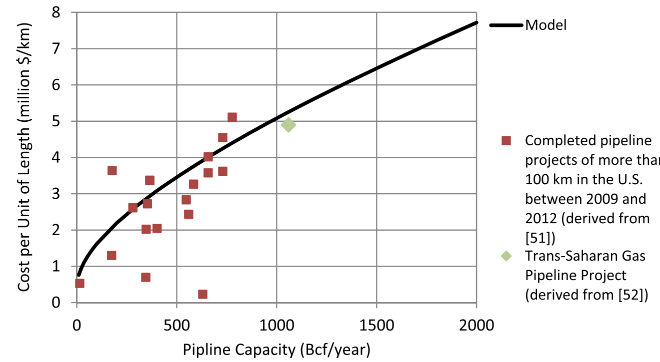

Fig. 13. Capital cost of natural gas transmission pipelines: model used for our calculations and data of real pipeline projects (adjusted 2013 U.S. dollars). (See above-mentioned references for further information.)

derived from data reported by EIA [51] and unit cost estimate for the Trans-Saharan gas pipeline project [52] (which should be a good indicator for the pipeline infrastructure costs that can be expected in our case). The data from EIA [51] corresponds to pipelines of more than 100 km completed between 2009 and 2012 in the US.

The used transmission cost model is expressed as follows:

$$c_T = \left(\left[\frac{(\mathrm{CRF} + \mathrm{MC}) c_I}{Q} + \mathrm{FC} \right] L \right) / 1.027 \times 10^6 \tag{7}$$

with
c_T: Transmission cost (\$/MMBtu).
CRF: Capital recovery factor (1/year).
MC : Ratio of annual maintenance cost to initial investment (1/year).
FC : Fuel cost for compression (\$/Bcf/km).
c_I: Pipeline unit capital cost calculated with Eq. (6) (\$/km).
Q: Average gas volume flow (Bcf/year).
L: Pipeline length (km).

The unit capital cost c_I is calculated using Eq. (6) with

$$Q_0 = (1 + m) Q \tag{8}$$

where m is the pipeline capacity margin. The capital recovery factor is calculated as follows:

$$\mathrm{CRF} = \frac{i(1+i)^n}{(1+i)^n - 1} \tag{9}$$

where n is the lifetime of the pipeline and i is the interest rate. Baseline assumptions for the different parameters of the transmission cost model are given in Table 3. The fuel cost for compression of \$150/(Bcf/year) is an average value estimated using a model described by Sanaye and Mahmoudimehr [48]. We assume that the annual maintenance cost is equal to 5% of the initial investment [47]. Fig. 14 shows the results obtained with this model and the parameter values given in Table 3, for a distance of 100 km, as well as transmission cost values derived from data reported by Ledesma [3], Cornot-Gandolphe et al. [53] and Jensen [54]. It can be noted that our model gives higher values than the ones derived from

Table 3
Baseline assumptions for the parameters of the pipeline transmission cost model.

Ratio of annual maintenance cost to initial investment	MC	5%
Fuel cost for compression	FC	\$150/(Bcf/km)
Pipeline capacity margin	m	30%
Pipeline lifetime	n	30 years
Interest rate	i	8%

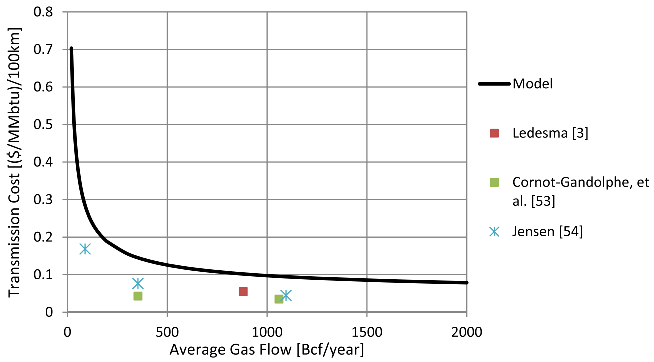

Fig. 14. Pipeline transmission cost: model used for our calculations and data collected from various sources (adjusted to 2013 U.S. dollars). (See above-mentioned references for further information.)

the other sources. This may be due to the fact that we probably consider here higher capital costs.

5.2. Methodology for network generation

Various approaches can be used to generate and optimize a pipe network. de Wolf and Smeers [55] used the bundle method for nonsmooth optimization to solve a problem of pipe dimensioning for a given network topology. Kabirian and Hemmati [56] proposed a comprehensive approach for the development of gas networks over a long-run planning horizon, which is based on an integrated nonlinear optimization model, and which uses a heuristic random search optimization method. Sanaye and Mahmoudimehr [48] used a genetic algorithm for the optimal design of a gas network. In their optimization problem, they considered a large number of parameters such as the network layout, the number of compressor stations, and the diameters of the pipes. Here, the Earth Institute's open-source geospatial network cost modeling and planning software, NetworkPlanner, has been used to generate optimized networks for different scenarios. The algorithm develops a minimum spanning tree network that connects a maximum of demand nodes (in our case, the urban centers) in the most cost-effective way. This approach has been used in several studies related to electricity planning in developing economies [57–59]. The main input for the software is a map of the nodes (urban centers) with their corresponding potential natural gas demand. The algorithm decides whether or not to connect a node depending on its associated potential demand and its distance from the other nodes. In NetworkPlanner, an average value is used for the pipeline unit capital cost ($/km); unlike in Eq. (6), at this step, the unit capital cost is a constant, not a function of the capacity.[8] Once the network has been generated, a Matlab script is used to compute the flow in each network segment, and then the capital and transmission costs using Eqs. (6) and (7). For all scenarios, it has been assumed that the production site is Palma, in Northern Mozambique. It has to be mentioned that in our model the cost assessment of the pipeline network does not include any cost associated with gas storage. Also, it has to be noted that here the network is optimized in terms of cost-effectiveness only. In reality, political aspects might very likely influence the network layout.

5.3. Impact of network size

In a first stage, the question of the number of countries that have to be included in the network to allow for an economically viable solution has been investigated. Scenarios have been generated for different set of countries. The largest set includes eight countries and the smallest one is Mozambique only. We have also generated an additional scenario which includes the largest set of countries (eight countries) plus significant exports (1300 Bcf/year[9]) to South Africa from Matola (Southern Mozambique).[10] This is motivated by the fact that South Africa is already importing gas from Mozambique and that the imported volume will very likely increase. For all scenarios, we considered a potential natural gas demand corresponding to our estimate for 2050 (see Section 4), the capital cost model show in Fig. 13, the parameter values given in Table 3 for the transmission costs and a production cost at Palma of $3/MMBtu [3]. Only urban centers with a delivered gas cost equal or below $10/MMBtu are included in the network. We assume that with a delivered cost at city gate of $10/MMBtu or lower, the price would be sufficiently low to enable a large penetration of natural gas (see Table 2). A comparison of the average gas cost at city gate and the investment for the different sets of countries is presented in Fig. 15. To develop a transmission network for the largest considered set of countries (8 countries) and with a significant export capacity to South Africa, an investment of about $57 Billion would be required and the average gas cost at city gate would be around $5.2/MMBtu. It can be noted that the average gas cost does not vary widely (only, between $5.0/MMBtu and $5.7/MMBtu) between the different scenarios. Therefore, the number of participating countries does not seem to be a significant criterion to determine the economic viability of a pipeline network. However, having an important consumer downstream in the network could have locally an important (positive) impact on the delivered gas cost. For example, when exports to South Africa are included (first scenario of Fig. 15), the gas cost in Maputo (Southern Mozambique) is relatively low – $5.5/MMBtu –, because Mozambique's capital city takes advantage of being located on a high-capacity pipeline segment which is highly cost-effective. When exports to South Africa are not included (2nd scenario of Fig. 15), the gas cost in Maputo increases to $8.2/MMBtu, because the infrastructure is developed for a lower gas supply, which is less cost-effective.

5.4. Detailed analysis for a set of eight countries

In the following, we have undertaken a detailed analysis for a set of eight countries (Mozambique, Malawi, Tanzania, Kenya, Uganda, Burundi, Rwanda and Ethiopia) with significant exports to South Africa[10] (first configuration in Fig. 15).

5.4.1. Baseline scenario

The baseline scenario (already briefly discussed above in Section 5.3) is based on our estimate of the potential natural gas demand for 2050 (see Section 4), the capital cost model show in Fig. 13, the parameter values given in Table 3 for the transmission costs and a production cost at Palma of $3/MMBtu [3]. The volume of natural gas that is exported from Matola to South Africa is assumed to be 1300 Bcf/year.[9] Only urban centers with a delivered gas cost equal or below $10/MMBtu are included in the network. As previously mentioned, with a delivered cost at city gate lower than $10/MMBtu, we assume that the gas price would be sufficiently low to ensure a large demand (see Table 2).

The optimal transmission network corresponding to this scenario is shown in Fig. 16. The total investment cost is approximately $57 Billion and the total gas supply is 4.2 tcf in 2050. For comparison, 8 LNG trains (total capacity = 40 MMtpa = 1.95 tcf/

[8] The current version of NetworkPlanner only allows to use a constant for the unit capital cost.

[9] This corresponds to approximately 11% of our projection of South Africa's total primary energy demand for 2050 (based on the method described in Section 4).

[10] We only considered the needed additional capacity to the border with South Africa.

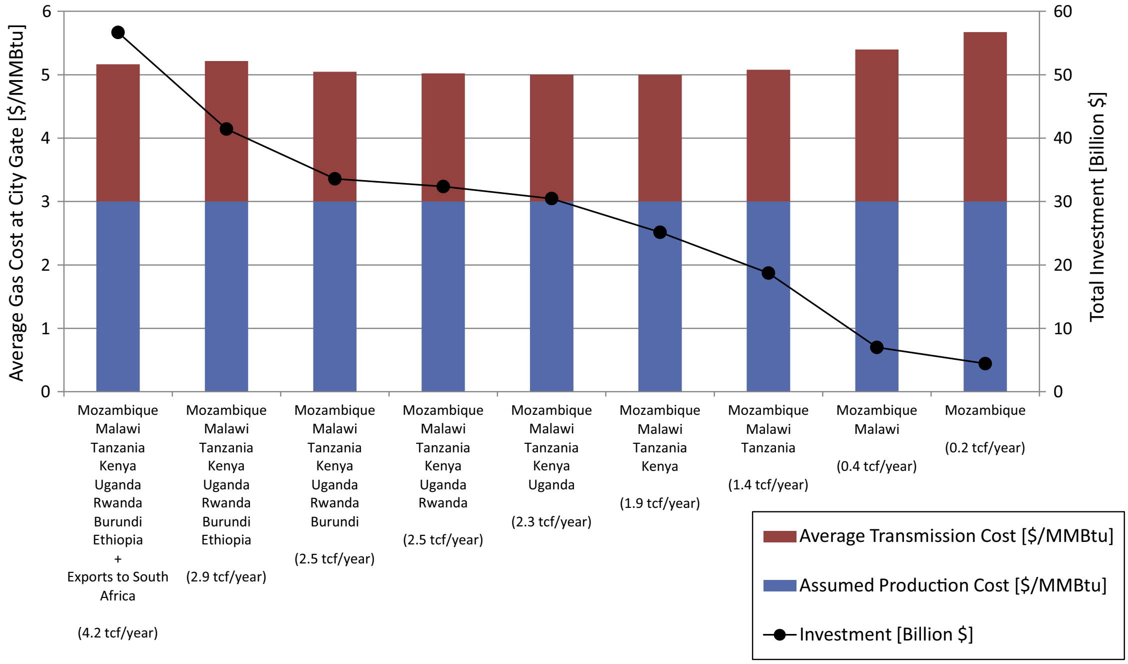

Fig. 15. Average gas cost at city gate and investment for various scenarios (various sizes) of gas pipeline network. The calculations are based on the estimated demand for 2050. The number in brackets indicates the annual volume of natural gas supplied for each scenario.

year), as proposed in Scenario #4 of ICF International [16], would cost about $43 Billion. For the proposed network, the average gas cost at city gate is $5.2/MMBtu and, for most urban centers, the gas cost is below $8/MMBtu. A preliminary rollout plan for this network is suggested (see Table 4). Three phases (2030, 2040, 2050) have been considered, with the corresponding potential gas demands. Figs. 26 and 27, in Appendix B, show the pipeline network at Phase I and Phase II, respectively. The pipeline segments are sized for the 2050 demand, therefore the gas costs in 2030 and 2040 are higher. However, in both Phases I and II, the gas cost at city gate is below $10/MMBtu for all served urban centers. The average gas cost at city gate decreases from $7.8/MMBtu in Phase I to $5.2/MMBtu in Phase III in 2050. The initial investment for Phase I is $31.9 Billion. For Phase II, an additional $14.2 Billion investment is required, and for Phase III (final network), $10.6 Billion.

5.4.2. High-cost scenario

In our model, a number of assumptions have to be made for the various parameters affecting the delivered gas cost. In this section, we present a high-cost scenario generated by considering less favorable values for the various parameters. Table 5 shows the differences with the baseline scenario. The pipeline network of the high-cost scenario is based on the network generated for the baseline scenario. The nodes for which the delivered gas cost is higher than $15/MMBtu are not taken into account; we assume that with a delivered cost at city gate higher than $15/MMBtu, the gas price would be too high and thus the demand would be too low (see Table 2). Fig. 17 shows the resulting network and the gas cost at city gate. In this scenario, Rwanda, Burundi and Ethiopia cannot be included in the gas network (delivered cost at city gate higher than $15/MMBtu). Table 6 gives the characteristics of the pipeline networks for both baseline and high-cost scenario. In the high-cost scenario, the cumulative length of the network is 7642 km, about half the one of the baseline case. The total gas supply is 52% lower for the high-cost scenario, because the considered demand per node is lower (−40%) and because fewer urban centers are connected. The average gas cost at city gate is two times higher for the high-cost scenario ($10.3/MMBtu) than for the baseline case ($5.2/MMBtu). Fig. 18 shows the gas cost at various locations for both scenarios.

5.4.3. Sensitivity analyses

The aim here is to assess how the delivered gas cost is affected by the different parameters. Based on the baseline scenario presented in Section 5.4.1 various scenarios have been calculated for different gas demands, capital costs, operating costs and planned capacities.

5.4.3.1. Impact of demand on gas cost. Gas demands 50% and 30% below the baseline case as well as 30% above it have been considered. The planned capacity (sizes of the pipes and compressor stations) is the same in all cases and corresponds to that of the baseline scenario. Fig. 19 shows the calculated gas cost at different locations and the average for the various scenarios. The results show that if the demand is 50% lower than expected, the gas cost in the main cities of the network remains below $10/MMBtu. For this case, the increase of the average gas cost is 35%. Of course, the impact is stronger for the farthest nodes for which the share of transmission cost in the cost build-up is higher. For example in Addis Ababa, if the demand is 50% lower, the gas cost at city gate is 45% higher. In the case of a demand 30% higher than expected, the average gas cost at city gate is around $4.7/MMBtu, about 8% lower than in the baseline case.

5.4.3.2. Impact of capital cost on gas cost. Our baseline scenario is based on the capital cost model shown in Fig. 13. As it can be seen in Fig. 13, in reality, the unit capital costs for pipeline projects of similar capacity can differ drastically depending on various parameters such as topographic and terrain conditions. Fig. 20 shows a comparison of the gas cost at city gate for the baseline scenario and for scenarios with unit capital costs 50% higher and 50% lower. When considering a capital cost 50% higher, the cost of gas still remains below $8/MMBtu in the major cities of the network. A change of 50% in capital cost leads to a change of 18% in average gas cost.

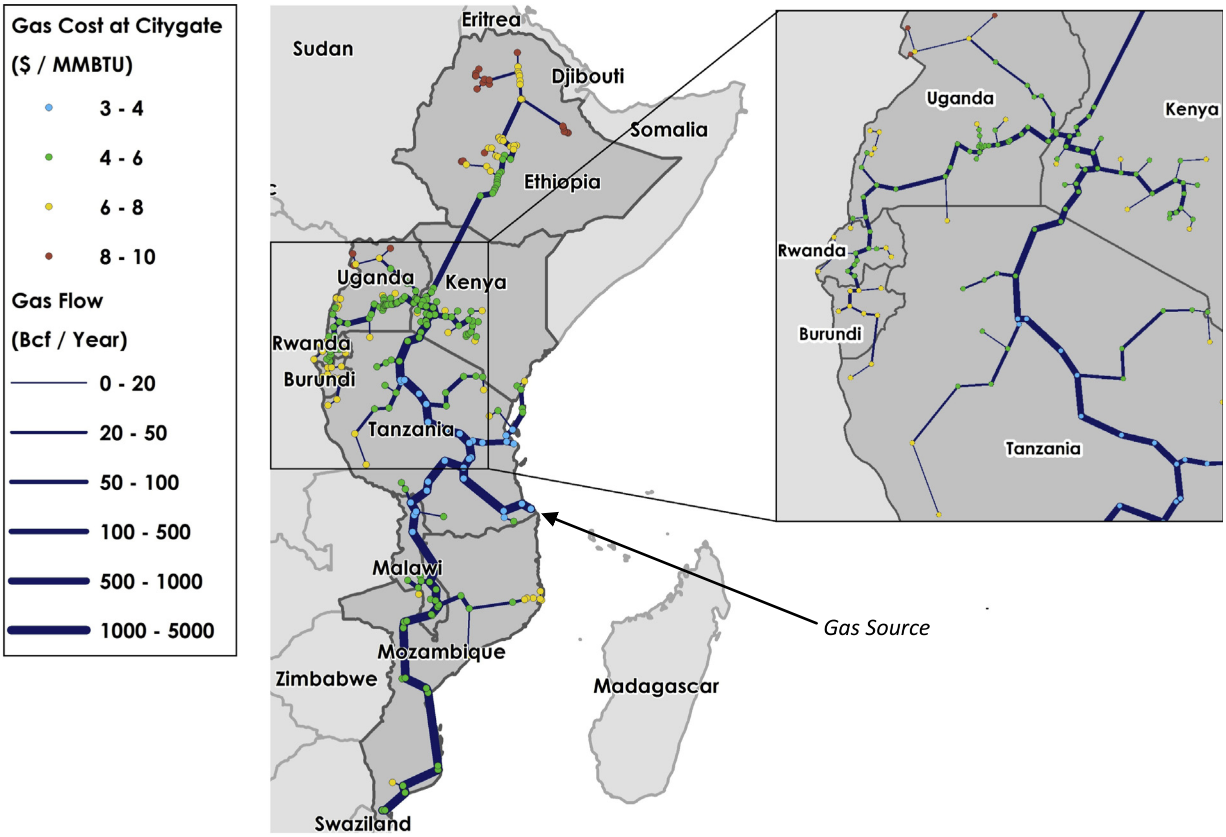

Fig. 16. Optimal transmission pipeline network and gas cost at city gate for the baseline scenario. Based on the estimated gas demand for 2050 and a gas production cost of $3/MMBtu. It is assumed that 1300 Bcf/year is exported from Matola (Southern Mozambique) to South Africa. The required investment is estimated at $56.7 Billion.

Table 4
Construction phases for the optimal transmission pipeline network shown in Fig. 16 (see Appendix B for maps of Phases I and II). Phase III corresponds to the final network in 2050.

	Phase I – 2030	Phase II – 2040	Phase III – 2050
Participating countries	Mozambique (part.) Malawi Tanzania (part.)	Mozambique (part.) Malawi Tanzania (part.) Kenya (part.) Uganda (part.)	Mozambique Malawi Tanzania Kenya Uganda Rwanda Burundi Ethiopia
Investment (Billion $)	31.9	+14.2	+10.6
Cumulative length (km)	4080	+3992	+6992
Average gas cost at city gate ($/MMBtu)	7.8	6.4	5.2
Gas consumption (Bcf/year)			
Mozambique	47	101	259
Malawi	28	72	166
Tanzania	113	436	955
Kenya		282	571
Uganda		139	416
Rwanda			130
Burundi			39
Ethiopia			360
Exports to South Africa	800	1000	1300
Total	987	2029	4197

5.4.3.3. Impact of operating costs on gas cost. For the baseline scenario, we assumed that the annual maintenance cost is equal to 5% of the initial investment and that the fuel cost for compression is $150/Bcf/km. At this stage it is difficult to have accurate estimates of those costs, which depend on various parameters (price of energy, cost of labor, ...) specific to the location of the pipeline. Fig. 21 shows a comparison of the gas cost at city gate for various operating costs scenarios. A change of 50% in overall

Table 5
Differences between the baseline scenario and the high-cost scenario.

	Baseline scenario	High-cost scenario
Demand	25% of the projected primary energy demand in 2050 + 1300 Bcf/year exported to South Africa	60% of the baseline scenario
Investment costs		
Capital cost model	Model shown in Fig. 13	140% of the baseline scenario
Pipeline sizing	Based on projected gas demand (25% projected primary energy) +30% capacity margin (pipeline utilization = 77%)	Same size as baseline scenario (pipeline utilization = 46%)
Transmission costs		
Annual interest rate	8%	15%
Annual maintenance cost	5% of the initial investment	7% of the initial investment
Fuel cost for compression	\$150/Bcf/km	\$200/Bcf/km

operating costs (maintenance and fuel costs) leads to a change of 10% in average gas cost.

5.4.3.4. Impact of planned capacity on gas cost. Three additional scenarios have been computed assuming that the network shown in Fig. 16 is developed for lower capacities. We considered capacities equal to 25%, 50% and 75% of that of our baseline case (total gas supply = 4197 Bcf/year). In each case, we assumed an average pipeline utilization of 77%. The four scenarios are compared in Fig. 22. The results show that when the network is developed for a capacity 75% lower than that of the baseline scenario, the needed investment is reduced by 51%. Because of economies of scale, when the planned capacity (and accordingly the demand, since we assumed the same pipeline utilization rate in all scenarios) decreases, the delivered gas cost increases. For example, with a capacity 75% lower than that of the baseline scenario, the average gas cost at city gate is 33% higher.

5.4.4. Estimates of natural gas consumption and needed investment by sector

Here, we present rough estimations of the natural gas consumption and needed investment by sector for our baseline scenario for eight countries (see Section 5.4.1) for the time horizon 2050. We assume that the main uses for the supplied natural gas will be cooking, power generation, transportation, and nitrogenous fertilizer production. Investments will be needed to develop those

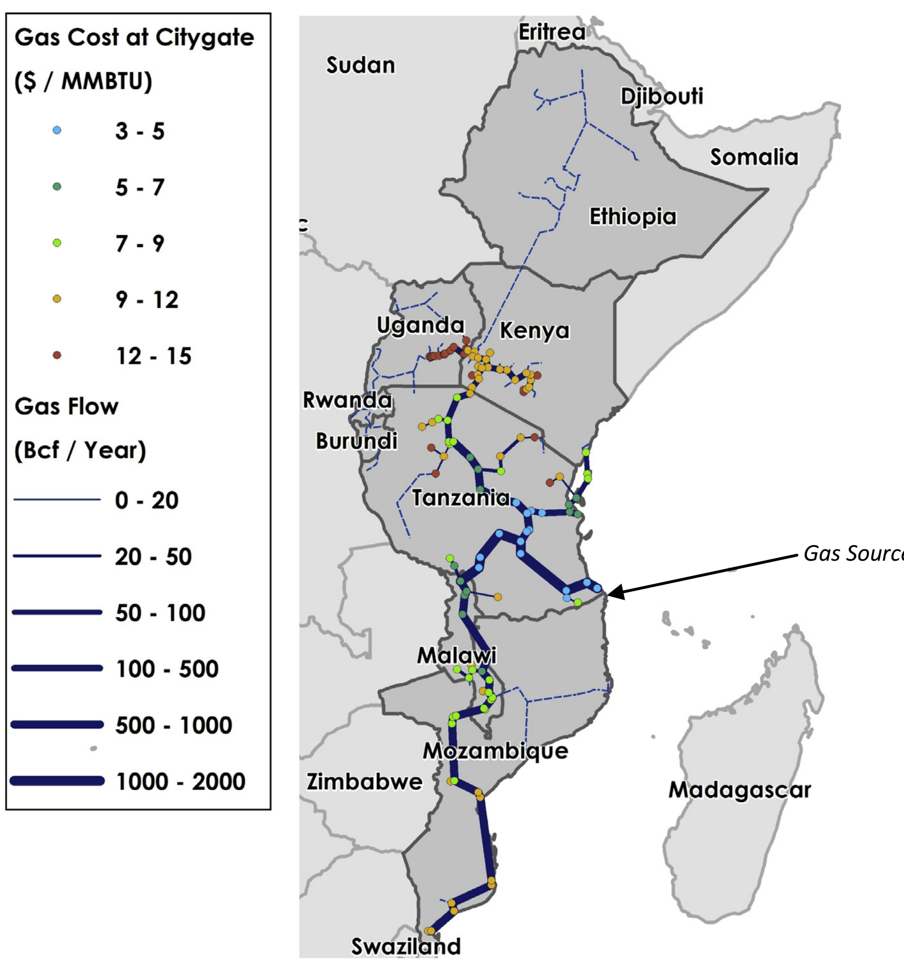

Fig. 17. Transmission pipeline network (solid blue lines) and gas cost at city gate for the high-cost scenario. The dashed blue lines indicate the additional network extensions of the baseline scenario. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

Table 6
Comparison of the pipeline networks of baseline and high-cost scenarios.

	Baseline scenario	High-cost scenario
Investment (Billion $)	56.7	64.0
Cumulative length (km)	15,064	7642
Total gas supply (Bcf/year)	4197	2004
Average gas cost at city gate ($/MMBtu)	5.2	10.3
Max. gas cost at city gate ($/MMBtu)	9.9	15.0

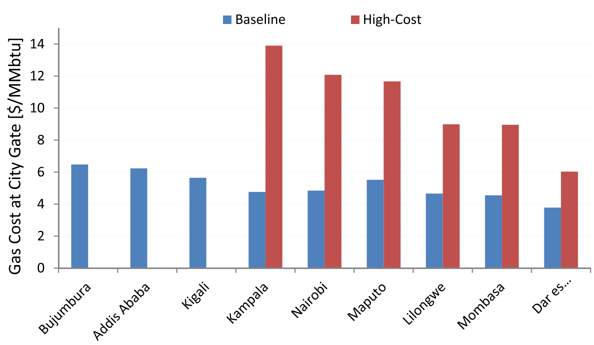

Fig. 18. Comparison of gas cost at city gate for the baseline and high-cost scenarios.

applications in the eight considered countries. For fertilizer production and power generation, plants will be built; for supplying gas to houses (mainly for cooking), distribution networks will be developed in urban centers; for transportation, CNG refueling stations will be built. Our estimates for the four main uses, as well as the assumptions used for our calculations, are given in Table 7. For cooking, we considered that 100% of the population living in urban centers connected to the transmission network (185 million people) uses natural gas for cooking. Assuming an access to electricity (percentage of the total population with access to electricity) of 75%, approximately 461 million people would benefit from gas-fired generation. We assumed that the population that benefits from natural gas for transportation is the population leaving in the urban centers connected to the transmission networks (185 million people). Concerning nitrogenous fertilizers, the whole population of the eight countries (urban + rural = 614 million) could benefit from a domestic production.

Power generation is the sector with the largest consumption of natural gas (39%). The total natural gas consumption for the four applications is 2444 Bcf/year. This is equal to 84% of the consumption obtained previously (see Table 4, 4197 [total supply] – 1300 [exports to South Africa] = 2897 Bcf/year) with our assumption that natural gas consumption is equal to 25% of the projected primary energy demand of the connected urban centers (see Section 4). This shows that our initial assumption for the gas demand (25% of the primary energy demand of the connected

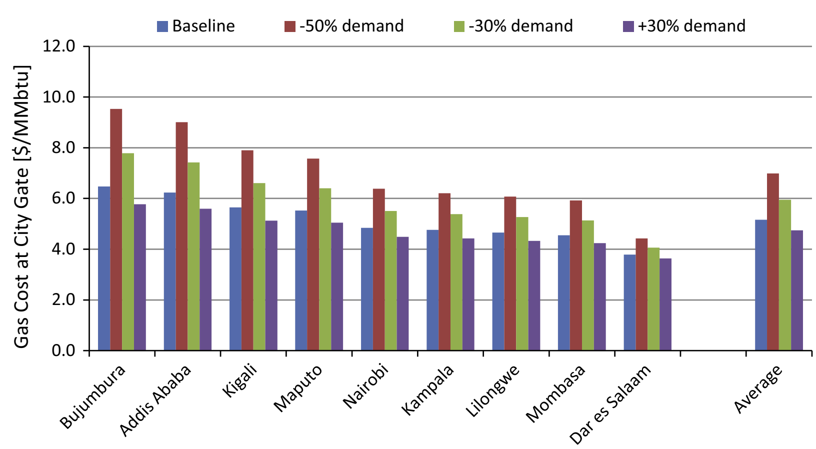

Fig. 19. Comparison of gas cost at city gate for various demand scenarios. In the baseline scenario, the overall gas demand is equal to 4197 Bcf/year. The additional scenarios correspond to gas demands 50% and 30% below the baseline case as well as 30% above it.

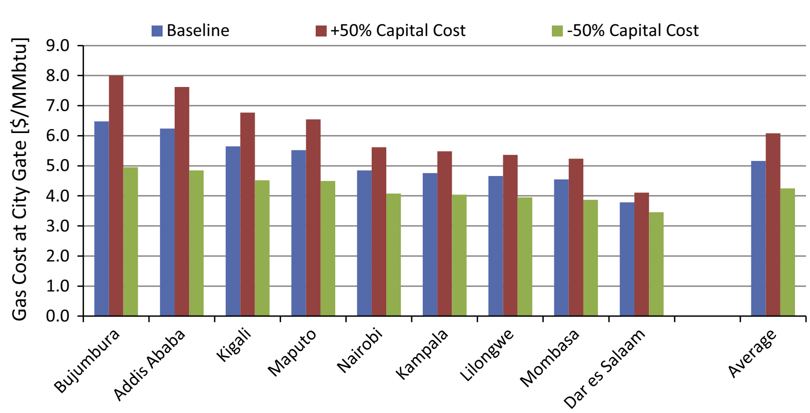

Fig. 20. Comparison of gas cost at city gate for various capital cost scenarios. In the baseline scenario, the capital costs correspond to the model shown in Fig. 13. The additional scenarios correspond to capital costs 50% higher and 50% lower.

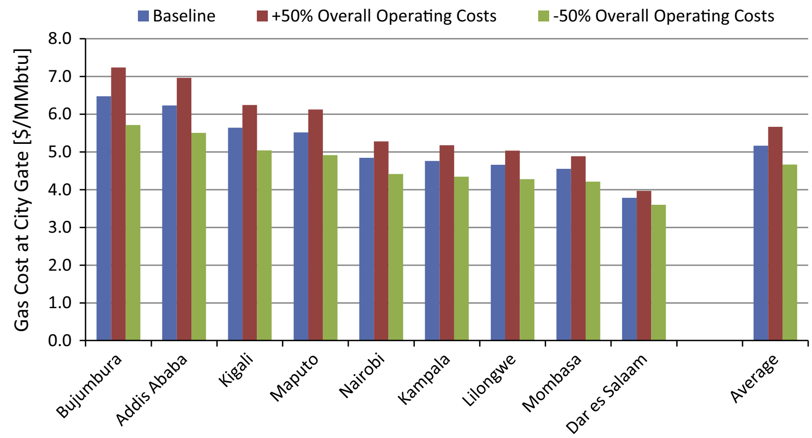

Fig. 21. Comparison of gas cost at city gate for various operating costs scenarios. In the baseline scenario, the annual maintenance cost is equal to 5% of the initial investment and the fuel cost is equal to $150/Bcf/km. The additional scenarios assume overall operating costs 50% higher (maintenance cost = 7.5% of initial investment and fuel cost = $225/Bcf/km) and 50% lower (maintenance cost = 2.5% of initial investment and fuel cost = $75/Bcf/km).

urban centers) is consistent with a bottom-up approach by sector as presented here. Also, besides the consumption for the four uses discussed in this analysis, one can expect an additional consumption for other industrial and manufacturing activities. The sectors that need the most important investments are power generation and fertilizer production, with $43.9 Billion and $33.2 Billion respectively. The development of distribution networks in 263 cities/towns to connect a total of about 46 million households would cost around $13.9 Billion. It has to be mentioned that besides the investments given in Table 7, additional investments will have to be made by final consumers (e.g., gas cook stoves, CNG vehicles or industrial gas boilers/burners). It is actually difficult to assess the part of the investments made by final consumers that is directly linked to natural gas and it is beyond the scope of this paper.

5.4.5. Comparison of potential profit: pipeline network vs. LNG

As previously mentioned, the projects that have been proposed so far by the actors of the natural gas industry are predominantly associated with LNG exports. The advantage of LNG exports is that the market is already developed. Moreover, the export infrastructure can be used to serve different consumers, which allows one to conclude short-term contracts and take advantage of the highest market prices. Currently, Asia is the region of the world with the highest LNG demand, followed by Europe. In 2012, Japan, South Korea, China, India and Taiwan imported a total of 8 tcf of LNG, representing 69% of the world LNG imports [6]. Given the relative proximity and the high market prices there, East Africa's LNG exports would primarily be intended to feed the Asian market. Landed prices of LNG in East Asia have been varying between $13/MMBtu and $20/MMBtu since the end of 2011 (see Fig. 23). However, it is not certain that LNG prices in Asia will remain such high in the long term. Before Fukushima disaster in 2011, the LNG prices in East Asia were close to the ones of the European market (see Fig. 23).

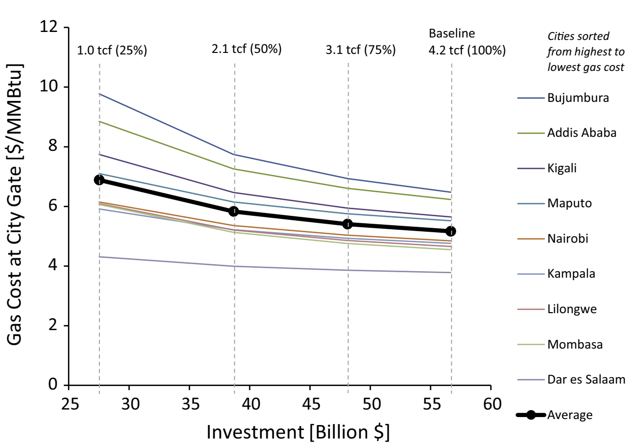

Fig. 22. Comparison of gas cost at city gate and investment for various planned capacities. In the baseline scenario, the planned capacity is based on our estimate of the potential gas demand for 2050 (gas supply = 4.2 tcf/year). The additional scenarios correspond to planned capacities equal to 25%, 50% and 75% of that of our baseline case. For each case, the pipeline utilization is assumed to be 77%. The values at the top of the dashed lines indicate the total gas supply.

While LNG gives flexibility in terms of served markets and might allow one to generate more rapidly large revenues, the risks associated with global price volatility are much more important than in the case of a regional gas pipeline network. With the development of shale gas, the U.S. might become a significant LNG exporter, which could drive down prices. Using existing LNG import infrastructure, the U.S. would be able to develop a number of export facilities at lower costs than in the case of greenfield projects, and thus could be a serious competitor for the Asian market [61]. In the longer-term, China's shale gas might also have a significant impact on gas pricing in Asia. Technically recoverable shale gas resources in China are estimated at 1115 tcf, the largest in the world [62]. If these resources can be exploited at sufficiently low costs, gas prices in Asia might drop. The World Bank [63] forecasts a progressive decrease of the price of LNG in Japan in the next decade, with a price of $10.5/MMBtu[11] in 2025, about $5.7/MMBtu less than in 2013.

For assessing the delivered cost of LNG in Japan, ICF International [16] has estimated the liquefaction cost at $3.3/MMBtu and the shipping cost at $1.5/MMBtu. For the same purpose, Ledesma [3] has considered a liquefaction cost of $4/MMBtu, a shipping cost of $2.2/MMBtu and additional infrastructure costs of $1.5/MMBtu. Based on those two sources and assuming a gas production cost of $3/MMBtu [3], the delivered cost of LNG in Japan might be in the range $8–11/MMBtu. For comparison, Ernst and Young [61] reports an estimated delivered cost of Mozambique's LNG in Japan at about $10.5/MMBtu. It has to be mentioned that the actual number will depend on several parameters such as the

[11] Value adjusted to 2013 U.S. dollars.

Table 7
Estimates of natural gas consumption and needed investment by sector for the baseline scenario for eight countries (Mozambique, Malawi, Tanzania, Kenya, Uganda, Burundi, Rwanda and Ethiopia) for the time horizon 2050.

	Assumptions	Population affected (Million)	Consumption (Bcf/year) (% of total consumption)	Total investments (Billion $)
Cooking – distribution networks within urban centers	• 100% of the population of the urban centers served by the transmission network uses natural gas for cooking • Average consumption per capita (in urban centers connected to natural gas): 1.58 MMBtu/year[a] • Average number of people per household: 4 (->46.3 million households) • Capital cost: $300/household[b]	185	285 (12%)	13.9
Power generation	• Total electric power consumption: 630 TWh/year[c] • Share of gas-fired generation: 25% (->157.5 TWh/year) • Average efficiency of gas-fired power plants: 55% • Average capacity factor of gas-fired power plants: 45% (->40 GW) • Capital cost: $1100/kW	461[d]	951 (39%)	43.9
Transportation – CNG refueling stations	• Average consumption per capita (in urban centers connected to natural gas): 3.6 MMBtu/year[c] • One CNG stations per 30,000 inhabitants (->6167 CNG stations) • Capital cost: $1.5 million/Station	185	648 (27%)	9.3
Fertilizer production	• Considered population: 100% (rural + urban) • 36 kg of urea per year per capita[c] (->22,104,000 t/years) • 26 MMBtu of natural gas per tonne of urea[e] • Capital cost: $1500/(t/year)	614	560 (23%)	33.2
Total			2444 Bcf/year	$100 Billion

[a] Assumptions: useful energy per capita per year for cooking = 1 GJ [30]; efficiency of natural gas stoves = 60% (same as that reported for LPG stoves by Barnes et al. [28]).
[b] Based on ICRA [29].
[c] See Appendix C for details on how these values have been estimated.
[d] Assumed access to electricity = 75%.
[e] Based on Yara [36].

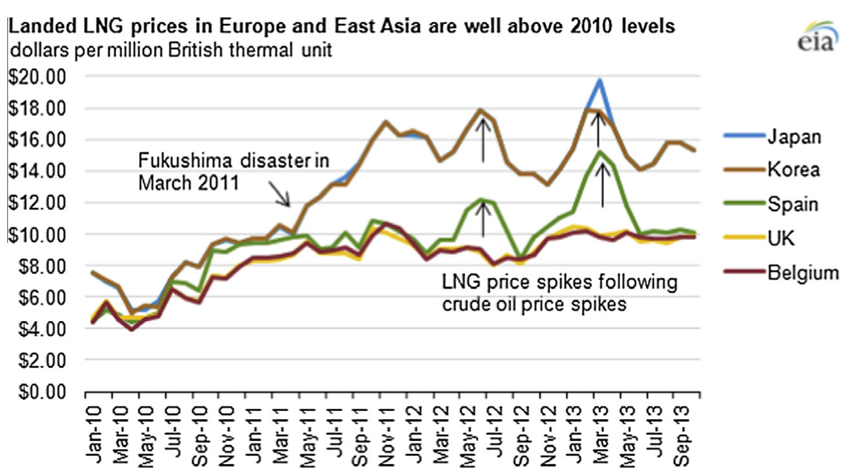

Fig. 23. Landed LNG prices in Europe and East Asia. *Source*: U.S. Energy Information Administration [60].

internal rate of return and the number of LNG trains. Indeed, with more LNG trains, the cost for the associated infrastructure will be relatively lower. Considering an average delivered cost of $9/MMBtu and a market price range of $11–16/MMBtu[12] for LNG in Japan, the profit is between $2/MMBtu and $7/MMBtu.

Assessing the potential profit for the case of a pipeline network in Eastern Africa is more complex than for LNG delivered in Japan. Indeed, the delivered gas cost at city gate varies across the network and it has to be compared to different prices depending on the applications. Fig. 24 shows the distribution of the gas cost at city gate across the network for the baseline scenario for eight countries and exports to South Africa (see Section 5.4.1). The blue line depicts the prices that would be applied if a $5 profit (comparable to the expected profit with LNG) is included. The ranges of maximum price at city gate for the various applications (see Table 2) are also given for comparison. The results show that for power generation and fertilizer production, there is a sufficient margin for profit almost anywhere in the network. Concerning cooking, a profit of $5/MMBtu might be acceptable. Finally, for transportation, there is a significant margin for profit in any case.

[12] The upper and lower values correspond approximately to the 2013 price ($16.1/MMBtu) and the 2025 price forecast ($10.5/MMBtu) for LNG in Japan given by The World Bank [63]. Values adjusted to 2013 U.S. dollars.

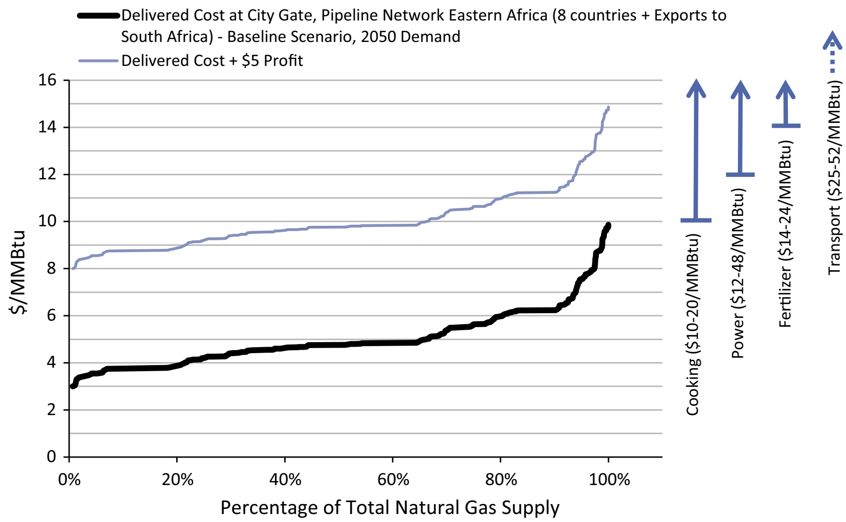

Fig. 24. Delivered gas cost at city gate across the network for the baseline scenario for eight Eastern African countries (thick black line). The blue line shows the delivered cost with an additional $5/MMBtu profit. Only the natural gas supply to the eight countries of the proposed pipeline network (Mozambique, Malawi, Tanzania, Kenya, Uganda, Burundi, Rwanda, and Ethiopia) is considered here; the exports to South Africa are not included. The ranges of maximum price at city gate for the different applications given in Table 2 are shown here for comparison. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

6. Discussion

6.1. A challenge for regional cooperation

Above, we discussed in details a scenario that includes eight countries of Eastern Africa. Obviously, such a project with an international scope will not come without risks and important challenges. To ensure its success, there must be a strong cooperation between the involved countries. Indeed, during the beginning of the project till the start of the operation, they will have to coordinate their spending and activities. After completion of the infrastructure, there will be also important challenges related to the operation of the network. Energy security issues will arise, since some countries will largely depend on other ones for their energy supply. A solid regulatory framework will have to be in place. The West African Gas Pipeline – involving Nigeria, Benin, Togo and Ghana – or the gas pipeline from Mozambique (Temane/Pande) to South Africa (Secunda) are smaller projects but still very encouraging examples of international cooperation in the field of natural gas infrastructure in sub-Saharan Africa.

6.2. Timing issues for supply and demand

In our approach, we analyze the delivered gas cost assuming a nominal gas supply. In reality, once the transmission network is completed, some time is needed for the demand to reach its nominal level. The consumptions of bulk consumers like fertilizer manufacturers and power plants can be relatively easily predicted and planned. On the contrary, the aggregated demand within urban centers for residential uses and transportation is much more difficult to predict and may increase relatively slowly. During this time period when the transmission pipeline network does not operates at full load, the transmission costs are higher than the ones calculated for the nominal capacity; the rollout plan discussed in Section 5.4.1 and the sensitivity analysis to gas demand of Section 5.4.3 give a sense of this effect. It is important to assess the pace at which the demand will increase and the time period needed to reach full pipeline capacity, and the impact of those parameters on the transmission costs and the economic viability of the pipeline network, however it is beyond the scope of this paper. A strong collaboration between the different players and a careful planning may allow one to optimize the timing, and thus minimize the levelized transmission costs and ensure the success of the project.

6.3. Financing

In our baseline scenario for eight countries the total capital cost of the transmission infrastructure is approximately $57 Billion, which is a very large investment. Even if the total investment will be spread out over 20–30 years, the concerned countries will have significant difficulties to raise the needed capital themselves – at least in the first phase. Multilateral development banks, like the World Bank and the African Development Bank, will have a key role to play. Revenues generated from LNG exports might be an additional source of financing for the domestic infrastructure. Also, transportation agreements for a significant volume of gas would help improve financing conditions and limit investment risk.

6.4. Institutional challenges

In this study we focused on techno-economic aspect, however there are also many institutional challenges associated with the development and operation of large multi-country fixed pipeline infrastructure. Equally important is the parallel development of the gas market. It is beyond the scope of this study to analyze those institutional challenges. Here, we just mention of few of them. When it comes to financing of the infrastructure and associated projects, a good investment climate (i.e., right regulatory framework, enforcement of contracts, no corruption, ...) is needed to attract investors and secure capital. Asiedu [64] highlighted the importance of improving institutions in sub-Saharan countries for facilitating Foreign Direct Investments (FDI). substantial efforts in institutional reforms in infrastructure have been undertaken in Africa in the last decade and those efforts must be continued, especially for improving the efficiency of utilities [65]. In the context of the electricity and telecommunications sectors in developing countries, Stern [66] underlined the importance of having effective and autonomous regulatory institutions for the success of utility liberalisation and privatisation. One can assume that this may also apply to the natural gas sector. There may be also institutional challenges for the adoption by the population of natural gas as new energy source. Murphy [67] discussed such issues in the context of the energy transition in rural East Africa.

6.5. Renewable energy and natural gas

Gas is a flexible fuel allowing more rapid ramping of electricity generation thus allowing greater penetration of renewables when compared to coal fired power plants. Hence the overall mix of generation will be at a lower carbon footprint than a mix that might evolve in the absence of gas for electric power. While electric power is just one energy carrier for which gas is a potential feedstock, rapid demand growth in sub-Saharan Africa has forced utilities to rely on prohibitively expensive liquid fuels to rapidly meet their power generation demands. Moreover as solar PV costs continue down the attractive learning rates (∼20%), and the "discovery" of otherwise unmapped wind resources in East Africa emerge, the potential for leveraging high penetration for solar and wind could be exploited with complementary gas powered generation. Thus natural gas has the potential of playing an important role in delivering of cost-effective affordable electric power.

6.6. LNG for regional supply

While rough estimations prove that costs favor a pipeline-based supply for most urban centers of the considered region, one can raise the question of an LNG-based supply for Addis Ababa, the farthest big city in our proposed network. For LNG, based on liquefaction costs (+associated infrastructure costs) reported by ICF International [16] ($3.3/MMBtu) and Ledesma [3] ($6.5/MMBtu), and assuming a shipping cost of about $0.5/MMBtu and a regasification cost of about $0.5/MMBtu, the total transmission costs to Djibouti may be in the range of $4.3–7.5/MMBtu; then, additional pipeline transmission costs (around $0.7/MMBtu) have to be taken into account from Djibouti, which gives total transmission costs to Addis Ababa of $5.0–8.2/MMBtu for an LNG-based supply. For a pipeline-based supply, we have calculated a transmission cost to Addis Ababa of $3.2/MMBtu in our baseline scenario and in the high-cost scenario it exceeds $12/MMBtu. If the actual pipeline transmission costs are significantly higher than in our baseline scenario, LNG will very likely be a more cost-effective option for Ethiopia.

6.7. Development of the upstream infrastructure

The new gas resources identified in Tanzania and Mozambique are deepwater fields. To exploit such fields, large investments are required for the development of the upstream infrastructure (well, gathering lines, processing plant). This implies that a field developer will look for long-term supply agreements at an early stage of the project to ensure the economic viability of its investment, i.e. there is almost no possibility to change where the produced gas is supplied over the whole project lifetime. The advantage of a scenario that is predominantly based on LNG exports is that the market is already well developed, and thus the liquefaction plant and the production facility can rapidly reach their nominal capacity. In the scenario of regional supply, the demand has to be developed and therefore the infrastructure will reach its nominal capacity after a much longer time. In our analysis, we partially considered this issue for the transmission infrastructure (see rollout plan in Table 4), but not for the upstream infrastructure. To ensure a sufficient supply to the regional network in the longer term, the upstream infrastructure might be developed for a significantly larger capacity than initially needed, which would affect the economics of field development. This implies that in the first phases the production costs might be higher than $3/MMBtu (the production cost that we considered in our calculations which is in the range of the production costs reported by ICF International [16] and Ledesma [3] for scenarios predominantly based on LNG exports).

6.8. Gas supply for remote areas

In remote areas for which it is not cost-effective to extend the pipeline network, Compressed Natural Gas (CNG) could be delivered by truck. This alternative is already proposed by the Matola Gas Company in the Maputo region.

6.9. Industry sector development

Concerning the industry sector, we focused here on nitrogenous fertilizer production. Firstly, because fertilizer plants needs large amount of natural gas and thus represent anchor consumers that could ease the development of gas infrastructure. Secondly, because the demand for fertilizer already exists and would most likely grow rapidly, if a domestic production can offer lower price than the imports. Other industrial developments could include methanol and GTL plants. They are large consumers of natural gas and would represent anchor loads. However, these sectors should be very probably less profitable, as local demand should remain limited and exports would have to compete on the global market. Other industries, such as cement or steel, could take advantage of a low gas price to develop activities in the region.

7. Conclusion

The recent large natural gas finds in Mozambique and Tanzania could be a great asset for the economic development of Eastern Africa. Most of the big projects mentioned so far to exploit those gas resources are connected to LNG exports, in the absence of pre-existing distribution infrastructure and markets. However, the paper makes the case that there is an economic case for developing the infrastructure and the markets both for local economic growth and human development.

The contribution of this paper is twofold. Firstly, it presents an approach to assess the economic viability of building a new complex gas transmission system across a whole region. This approach uses simple models, an open-source software for generating network layouts and data that are relatively easy to obtain. This approach can therefore be easily applied to other regions. The second main contribution of this work is to present an analysis of the potential of using East Africa's gas locally at a large scale (using the mentioned approach) and to discuss the associated potential benefits.

Natural gas is a flexible resource that can be used for various applications. In this study, we focused on four applications particularly relevant for Eastern Africa: cooking, power generation, transportation, and fertilizer production. For these four different applications, we estimated ranges for the maximum price at city gate below which natural gas would represent an affordable alternative. The lowest prices are for cooking ($10–20/MMBtu) and the highest prices are for transportation ($25–52/MMBtu).

Different scenarios of gas transmission networks have been generated based on our estimate of the potential natural gas demand by 2050. First, scenarios with a various number of participating countries have been compared. It appears that the number of participating countries does not significantly affect the average delivered gas cost at city gate (in the range of $5.0–5.7/MMBtu).

This first analysis shows that independently of its size, a transmission network to supply gas from the North of Mozambique to the urban areas of the region seems an economically viable solution. A detailed analysis has been undertaken for a gas transmission network across eight countries (Mozambique, Malawi, Tanzania, Kenya, Uganda, Burundi, Rwanda and Ethiopia), including significant gas exports to South Africa. For the baseline scenario, based on our estimate of the potential demand in 2050, the required investment for the transmission network is estimated at about \$57 Billion and most of the urban centers of the eight considered countries can be supplied for a cost at city gate below \$8/MMBtu (assuming a production cost of \$3/MMBtu at the source). This indicates that natural gas delivered by pipeline could be very attractive for most of the urban population of Eastern Africa. A rollout plan has been suggested for this scenario. A high-cost scenario has been also generated for the same set of eight countries. Assuming that it is not economically viable to connect urban centers if the gas cost at city gate is in excess of \$15/MMBtu, the pipeline network is smaller compared to the baseline scenario; Ethiopia, Burundi and Rwanda are no more connected. For this high-cost scenario, the average gas cost at city gate is \$10.3/MMBtu and the projected gas supply in 2050 is about 2 tcf/year, 52% lower than in the baseline scenario. Sensitivity analyses have been done to highlight the impact of the gas demand, the capital cost, the operating costs and the planned capacity on the delivered cost of gas. The natural gas consumption and needed investment by sector (fertilizer production, cooking/city gas distribution networks, power generation, transportation/CNG refueling stations) have been estimated for our baseline scenario for eight countries. Power generation is the sector with the largest consumption of natural gas (39%). The total needed investment to develop the four sectors reaches approximately \$100 Billion. Finally, a brief analysis of the potential profits that can be expected with LNG exports to Japan and in the case of a regional pipeline network has been carried out. The results show that similar profits than with LNG exports may be generated with the regional pipeline network.

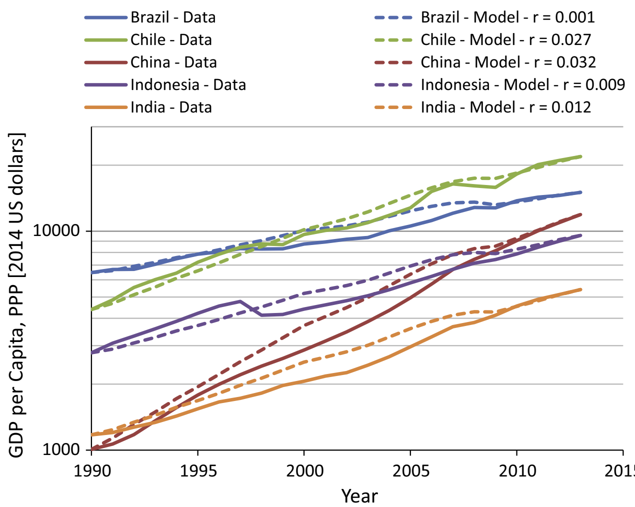

Fig. 25. Comparison between data and model (Eq. (2), Section 4) for the GDP per capita, for various countries. *Data source*: The World Bank [68].

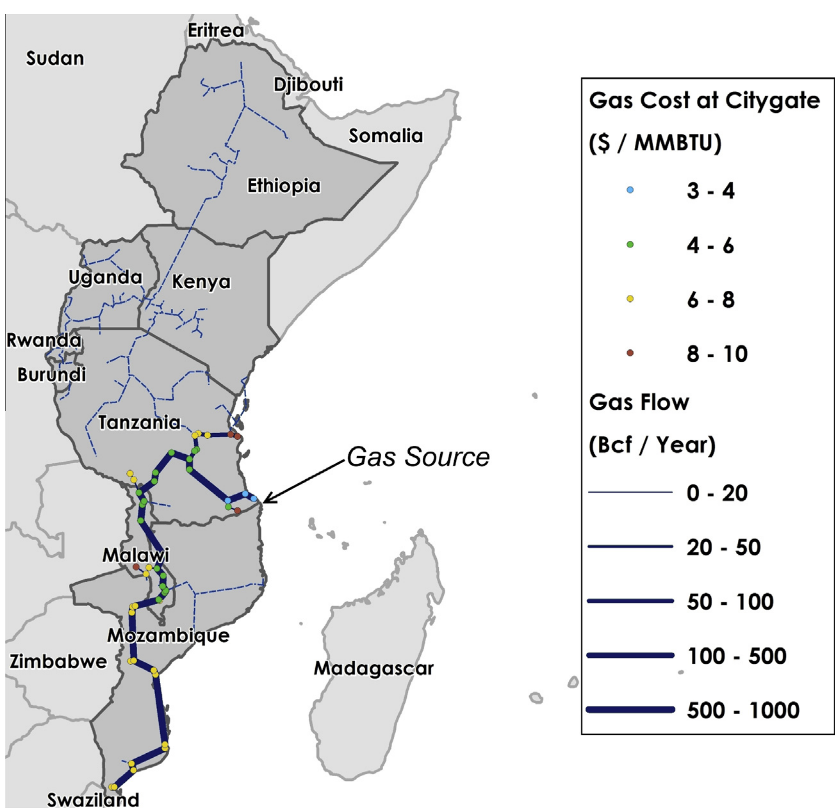

Fig. 26. Optimal pipeline network at Phase I (solid blue lines), in 2030. The calculated gas cost at city gate is based on the estimated gas demand for 2030 and a gas production cost of \$3/MMBtu. The gas source is assumed to be in the region of Palma (Northern Mozambique). It is assumed that 800 Bcf/year is exported from Matola (Southern Mozambique) to South Africa. The dashed blue lines depict the final network in 2050 (Phase III). (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

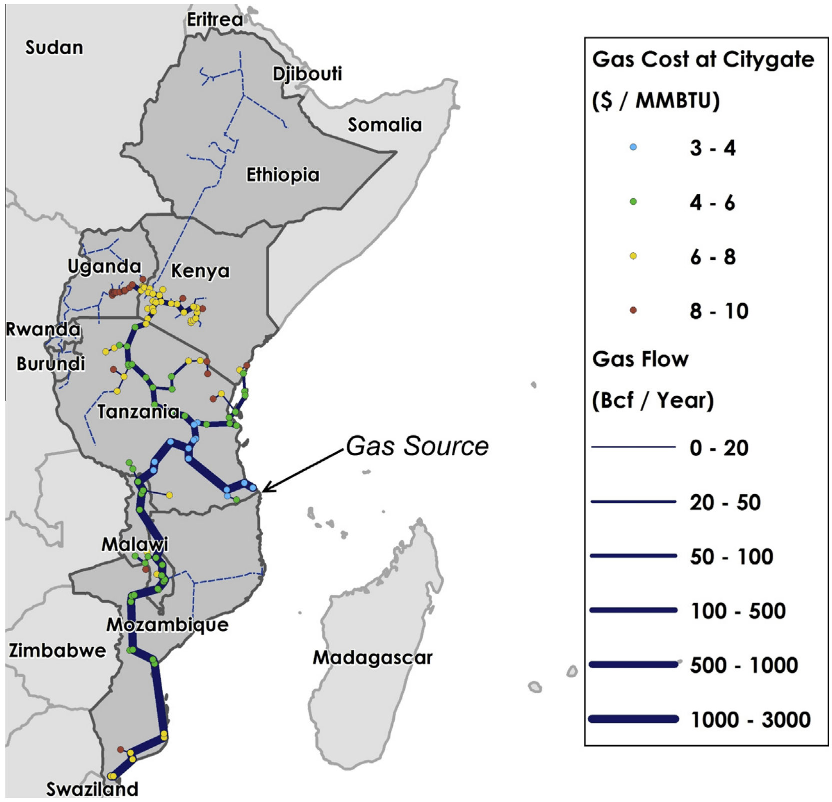

Fig. 27. Optimal pipeline network at Phase II (solid blue lines), in 2040. The calculated gas cost at city gate is based on the estimated gas demand for 2040 and a gas production cost of $3/MMBtu. The gas source is assumed to be in the region of Palma (Northern Mozambique). It is assumed that 1000 Bcf/year is exported from Matola (Southern Mozambique) to South Africa. The dashed blue lines depict the final network in 2050 (Phase III). (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

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Appendix A

Fig. 25 shows a comparison between data from The World Bank [68] and the model that we used (Eq. (2), Section 4) for the GDP per capita, for various countries. r (the "speed of catching-up") has been tuned for each country to match the model with the data for 2013. r varies between 0.001 and 0.032 for the examined countries. In our calculations, we used a value of 0.014 for sub-Saharan Africa.

Appendix B

See Figs. 26 and 27.

Appendix C

C.1. Estimation of electric power consumption in 2050

We estimated the electric power consumption in 2050 in the eight considered countries (Mozambique, Malawi, Tanzania, Kenya, Uganda, Burundi, Rwanda, and Ethiopia) using the projected GDPs per capita obtained with the method described in Section 4 (Eq. (2)) and the population projections from the United Nations [5]. We assumed a linear relation between the GDP per capita and the electricity consumption per capita. The electricity consumption per capita (ELPC) for a country i at year t is calculated as follows:

$$\mathrm{ELPC}_{i,t} = \mathrm{GDP}_{i,t}\mathrm{IEL}_t$$

IEL_t is the electricity intensity at time t and is assumed to be the same for the different countries. We assumed that the electricity intensity is improving at a constant annual rate (α), due to efficiency measures:

$$\mathrm{IEL}_t = (1-\alpha)\mathrm{IEL}_{t-1}$$

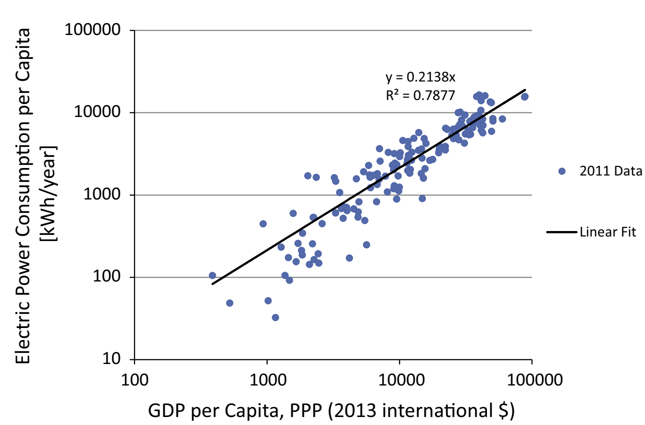

Fig. 28. Electric power consumption per capita versus GDP per capita (PPP) for most countries of the world (data for 2011). *Data source*: The World Bank [68].

Table 8
Projected GDP per capita, electricity consumption per capita, population [5], and annual electricity consumption for the eight considered countries for the time horizon 2050.

Country	2050 GDP per capita (2013 International $)	2050 Electricity consumption per capita (kWh)	2050 Population (Millions)	2050 Annual electricity consumption (TWh)
Burundi	6628	644	13.7	8.8
Ethiopia	9456	919	145.2	133.5
Kenya	12,603	1225	96.9	118.7
Malawi	8749	851	49.7	42.3
Mozambique	8944	870	50.2	43.6
Rwanda	10,436	1015	26.0	26.4
Tanzania	11,688	1136	138.3	157.2
Uganda	10,846	1055	94.3	99.4
Total			614	630

In our calculation, a value of 2% has been assumed for α, which corresponds to the historical trend for the improvement of the world's energy intensity in the *services* sector [69]. To determine the electricity intensity for a year of reference, we used the GDP and electricity consumption data for 2011 reported by The World Bank [68] for most countries of the world (see Fig. 28). Based on those data and using a linear regression, we have obtained an electricity intensity for 2011 (IEL_{2011}) of 0.2138. With the assumed annual rate of improvement (α) of 2%, the projected electricity intensity for 2050 (IEL_{2050}) is about 0.0972. Table 8 gives the data and results for the eight considered countries for the time horizon 2050. The projected total annual electricity consumption in 2050 for the eight countries is 630 TWh.

C.2. Estimation of CNG consumption for transportation in 2050

Our estimation of the CNG consumption per capita for transportation in 2050 in urban areas connected to the natural gas transmission network is based on the work of Harvey [70].[13] Our projection for the average GDP per capita (PPP) in 2050 for the eight considered countries (Mozambique, Malawi, Tanzania, Kenya, Uganda, Burundi, Rwanda, and Ethiopia) is approximately $10,550 (2013 international $), which is close to the projected average GDP per capita for sub-Saharan Africa for 2060 reported by Harvey [70]. Therefore, in our calculations we used the numbers projected by Harvey [70] that correspond to sub-Saharan Africa in 2060. We considered that in 2050 the average per capita travel per year is 5000 km (between the base and green scenarios of Harvey [70], and that CNG is used for Light-Duty Vehicles (LDVs) and public transportation (buses and mini buses). Based on the projections of Harvey [70] for the modal split for passenger travel in sub-Saharan Africa, we assumed that LDVs and public transportation account for 25% and 55% respectively of total passenger-km (pkm) travelled in 2050. We considered average energy consumptions of 2.0 MJ/pkm and 0.7 MJ/pkm for LDVs and public transportation respectively. Given these numbers, the average energy consumption per capita per year for LDVs and public transportation travels in 2050 in the considered countries is about 4.43 GJ. We assumed that in the cities/towns connected to the gas transmission network the penetration of CNG as fuel for LDVs and public transportation is as high as 85%. This gives finally an average consumption per year per capita of 3.6 MMBtu for the population of urban areas supplied with natural gas.

C.3. Estimation of nitrogenous fertilizer consumption in 2050

There exist different nitrogenous fertilizer products. In this work, we considered urea because it is the most widely used product and it is particularly popular in warmer climates [71]. For other products, we assume that the natural gas consumption and the costs would be roughly the same than for urea. For estimating the average needs in urea for the studied region (Mozambique, Malawi, Tanzania, Kenya, Uganda, Burundi, Rwanda, and Ethiopia), we assumed that in 2050 the consumption of fertilizer per capita in those countries will be equal to the world average. According to the scenario presented by Alexandratos and Bruinsma [72], world consumption of fertilizer could reach 263 million tonnes in 2050, for a total population of 9.15 billion. This gives an average of 28.7 kg of nutrient (NPK) per capita per year. Considering a share of nitrogen in total nutrient consumption equal to 57% [72], the average consumption of urea (mass fraction of nitrogen = 46%) per capita per year in 2050 would be equal to 36 kg. It may seem too optimistic to assume that the fertilizer consumption per capita in the eight considered countries in 2050 will be equal to world average. However, one can expect that those countries will export a fraction of their production to neighboring countries that are not connected to natural gas and that have no nitrogenous fertilizer production capacity. In that case, the calculated 36 kg of urea per capita per year should be interpreted as a production average (instead of a consumption average) for the eight considered countries and the average consumption of urea per capita per year for the wider region (the eight countries connected to natural gas + neighboring countries) would be actually lower than this 36 kg.

[13] We used the XLS-file provided as supplementary material with the online version of the paper of Harvey [70].

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