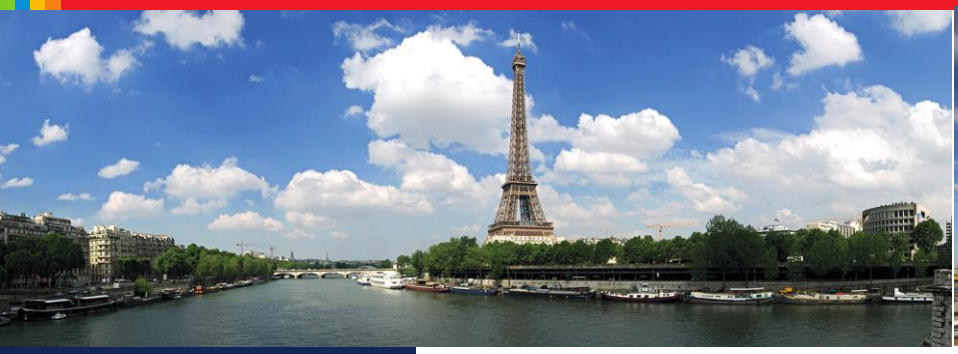
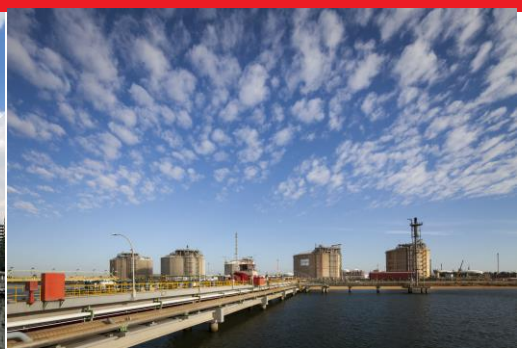
2012-2015 Triennium Work Reports





World Gas Supply, Demand and Trade

International Gas Union

Programme Committee B – Strategy

June 2015

WGCPARIS2015
WORLD GAS CONFERENCE

IGU
INTERNATIONAL GAS UNION
UNION INTERNATIONALE DU GAZ

Table of content

Introduction **3**

Acknowledgements **3**

Aims **3**

Methods **3**

World Gas Supply, Demand and Trade **4**

Regional aspects: 5

North America 5

Latin America 6

Europe 7

CIS 7

Middle East 8

Africa 9

Asia 9

Asian – Pacific region 10

Global natural gas trade patterns 10

Long-Term Outlook for gas in the European Union to 2035 **11**

Natural Gas Demand 11

Power generation 12

Residential and commercial 13

Natural Gas Supply 15

Shale gas production 16

Security of supply and procurement 16

Conclusions 17

Africa's Long Term Perspectives for Natural Gas **17**

Economic Trends 17

Population Growth 18

Primary Energy Demand 19

Energy Consumption Trends in Africa 22

Natural Gas Demand 24

Breakdown of gas consumption by type of activity 25

Natural Gas Supply 28

Natural Gas Resources in Africa 28

Natural Gas Production in Africa 32

Natural Gas Infrastructure Developments 36
LNG Infrastructure 36
Existing pipelines 41
Planned pipelines 42
Global LNG Trade to 2030 45
Introduction 45
LNG consumption 46
Asia Pacific - Asia 46
Middle East 48
Atlantic Basin 48
North American markets - from importers to exporters 49
Caribbean and South American markets 49
Key factors of growth 50
Historical Sources of LNG Supply 50
Future LNG Supply 51
Asia-Pacific 51
Europe, Middle East & Africa and CIS 52
Americas 52
Floating LNG 54
Flexibility 54
The Promise of Natural Gas in North America / Examining Supply and Demand Expectations in the United States and Canada 54
Introduction 54
Results 55
Natural Gas Supply/Demand – United States 55
Customer Growth 56
Distribution Pipeline Infrastructure Expansion: Capacity and Miles 57
Natural Gas Production 58
Domestic Natural Gas Reserves 59
Underground Storage Capacity 59
Natural Gas Supply/Demand – Canada 60
Exploration and Production 60
Canadian Natural Gas Trade 61
References 62

Introduction

Study Group 1 ("World Gas Supply, Demand, and Trade") has a long history of producing long-term forecasts of regional and global developments in the natural gas market. The core of the study group's work is the collection of demand expectations and production forecasts from regional experts that regularly contribute to the study group. Making use of regional expertise is one of the major assets that this study group can boast.

In the current triennium, the focus was on consolidating a global supply and demand balance – together with corresponding trade flows – from the regional input data, and on positioning this result against the background of renowned forecasts from around the world. We find that there is a common view that natural gas has a considerable growth potential in most regions of the world – and that it is well positioned in competition with all other fossil fuels.

Featured articles on trends of the global LNG trade, on the challenges for European gas demand and on other markets constitute the second part of the report. A considerable growth potential – well beyond the growth rates of natural gas as a whole – is foreseen for LNG production and LNG trade.

Acknowledgements

The work of the Study Group 1 in this triennium could rely again on the valuable contributions of all group members, in particular:

Fethi Arabi,
Carlos Brescia,
Anne-Sophie Corbeau,
Thomas Dirksmeyer,
Saeed Ghavampour,
Justin Goonesinghe,
Hiroshi Hashimoto,
Nassim Hallal,
Ranjith Kumar,
Suman Mishra,
Piotr Seklecki

and all the other participants in the working sessions throughout the triennium.

Aims

Giving an overview on current expectations on the growth of the natural gas industry, the evolving trade patterns and the challenges ahead, were the major aims of this report.

Methods

The Study Group followed a well-proven strategy in developing its results: a bottom-up approach constituted the first step in establishing regional supply and demand trends based on local or regional expert knowledge. In a second step, these results were complemented and challenged by global and supraregional modelling results, as performed inter alia by the

International Energy Agency, the US Energy Information Administration and the Institute of Energy Economics of Japan.

The regions covered in this report follow, if not otherwise stated, the definition usually used within the IGU.

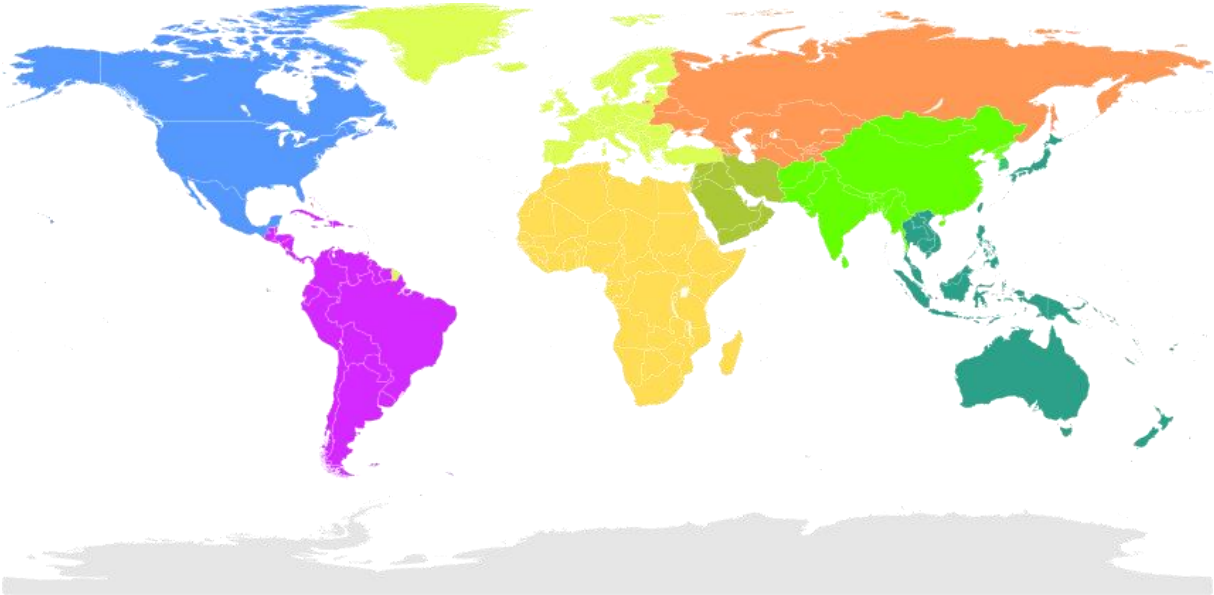


Figure 1: Definition of Regions according to IGU

World Gas Supply, Demand and Trade

There is a general consensus that global gas demand will continue to increase over the next two decades. However, growth has started to shift from the established gas industries in Europe, North America and the CIS to growing markets in Asia, in particular to China, India and other countries of that region. Considerable growth is also expected in the Middle East, which has seen a continuous growth in recent year, adding almost 200 bcm in demand within the last ten years.

Global demand, which is currently at 3300 bcm per year, is expected to grow with a compound annual growth rate (CAGR) of 1.1 % per year, which means that by 2035 global demand will have reached 4800 bcm.

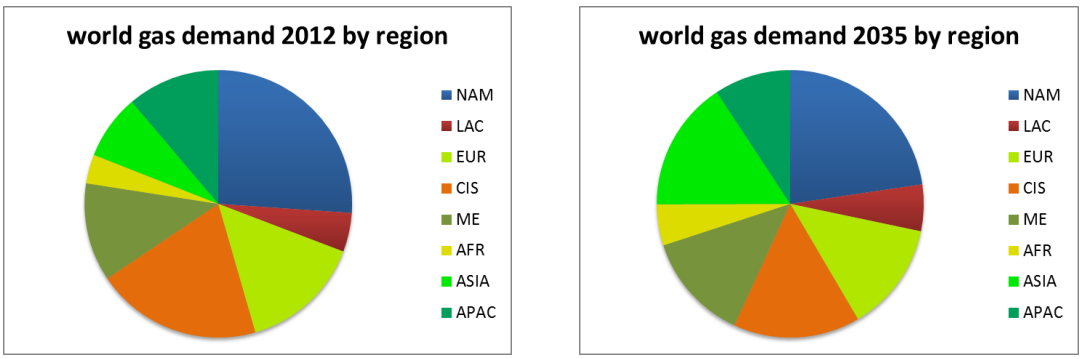
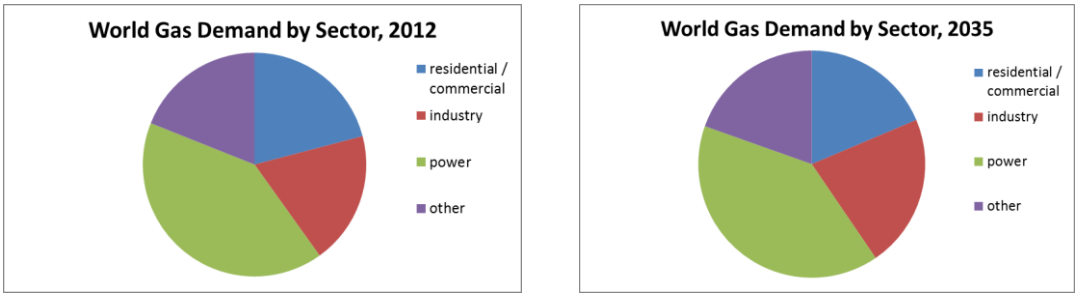


Figure 2: World gas demand by region 2012 vs. 2015 [bcm]



2012: 3,300 BCM **2035: 4,800 BCM**

Figure 3: World gas demand by sector 2012 vs. 2015 [bcm]

Currently, natural gas demand is focused on the three major sectors "residential and commercial use", "industry demand", and "gas for power generation". While there is a huge growth potential for gas in the transportation sector, it does not appear probable, that this sector will contribute a major share in the total demand picture within the forecasting period. Other sectors, summed up under the heading "other" include various other uses, e.g. district heating, chemical feedstock, feedstock for GTL (gas to liquid) processes. On a global scale, gas for power generation will remain the largest sector in total gas demand with a compound annual growth rate of 1.6% and a share in total consumption of 40%.

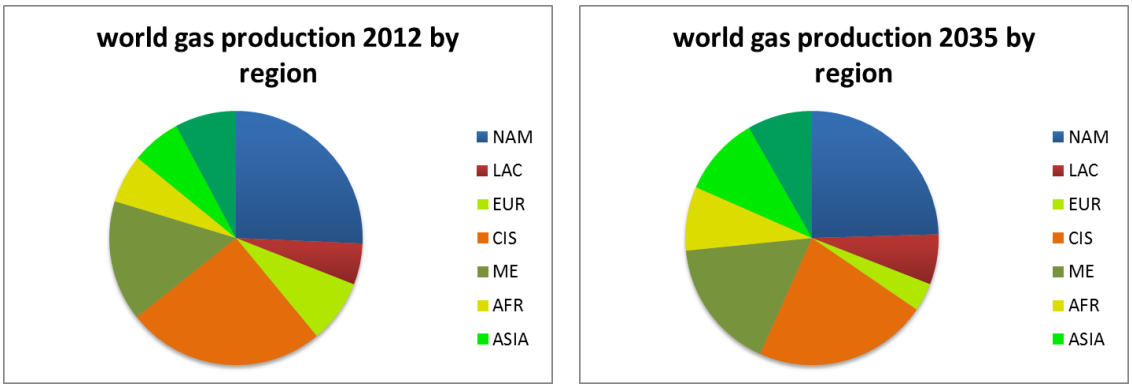


Figure 4: World gas production by sector 2012 vs. 2015 [bcm]

The two largest producing regions, North America and the CIS, constitute more than half the global gas production, and both regions still have a high growth potential. The relative share of these two regions, however, will slightly decline. In North America, which is currently still a minor net importer of gas, development of future production will to a high extent depend on unconventional gas, and shale gas in particular. North American gas production will largely be consumed within that region, whereas the CIS region is already the biggest net exporter of gas today. CIS developments will include the development of East Siberian fields in Russia, but also of large resources in Central Asia.

The largest growth is expected in the Middle East and the Asian region; forecasts for China in particular foresee a growth by more than a factor of three, reaching a level of well above 300 bcm by 2035.

Regional aspects:

North America

North America is by far the largest regional market in the world and will remain so over the next 25 years. The development of unconventional gas resources, in particular shale gas is expected to continue, thus building up a considerable export potential in spite of a huge - and

further growing – domestic market. North American demand will be the only region to surpass the level of 1000 bcm per year by 2035.

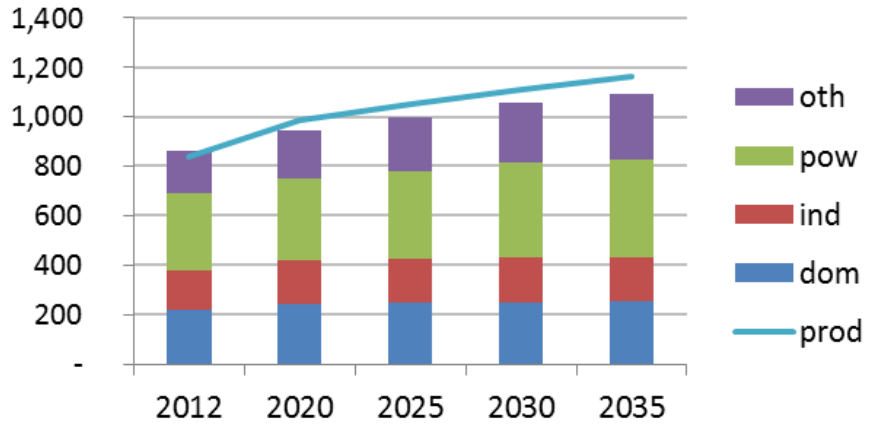


Figure 5: Gas supply and demand projection for North America [bcm]

The IGU committee report from 2012 had already considered an increase in natural gas production to 1000 bcm by 2030, but current forecasts see even 1100 bcm as a realistic target.

As a result, a large number of export projects – mainly conversions of existing LNG receiving terminals into liquefaction plants – are awaiting approval by regional authorities.

Latin America

Latin America and Caribbean (LAC), are still regions consisting of mainly disconnected national markets. Growth both in production and demand for gas expected.

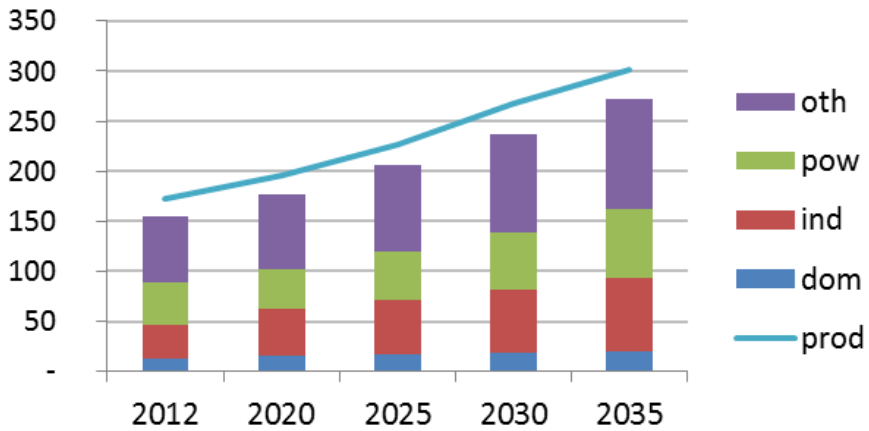


Figure 6: Gas supply and demand projection for Latin America [bcm]

The region's top two producers are Trinidad and Tobago and Argentina, which together account for roughly 44% of total region production. Some countries have been increasing their production over the last decade. For example, Peru's production increased by 2,165% from 2004 to 2013. Meanwhile , Argentina's production fell 22 % in the same period. Despite recent production gains in LAC, the region is always at risk of a decline in dry natural gas production because of maturing fields and a lack of continued investment. Natural gas production in LAC almost doubles by 2035. Most of the growth occurs after 2020, thanks mainly to shale gas supply in Argentina and associated gas from offshore fields in Brazil.

Argentina holds the second-largest shale gas resources in the world and EIA estimates Argentina's technically recoverable shale gas resources at 802 Tcf, the largest shale gas

resource in the LAC. A number of major international energy companies are actively exploring the potential of Argentina's shale resources.

The region's top two consumers are Argentina and Brazil, which together account for roughly 51% of total region consumption. Over the past decade, consumption of dry natural gas increased by 42% in LAC. Of the major consumers, Venezuela increased consumption by 7,5% over the period and Brazil increased by over 100%. Notably, Peru saw consumption increase by more than 663% from 2004 to 2013. Power generation sector will lose its position as the leading natural gas consumer to industrial in 2020. The industry sector will have the highest growth in absolute terms during the period, followed by power sector.

Europe

The European gas market is a mature market with a high share of consumption in the domestic heating sector. Domestic consumption has reached a high market penetration, so that advances in energy efficiency are not expected to be overcompensated by an increased number of building heated with gas. Furthermore, there is a strong political will to reshape the energy landscape in order to achieve the desired ecological targets.

The supply side is characterised by a continuing decline of domestic production with little hope that new production technologies will eventually reverse this process. Consequently, the share of Dutch and British gas production will decline, whereas Norwegian production is not expected to remain rather stable. A topical paper later on will focus especially on the development of the gas market in the European Union (EU) whereas the figure below also includes several non-EU countries, in particular Turkey and Norway.

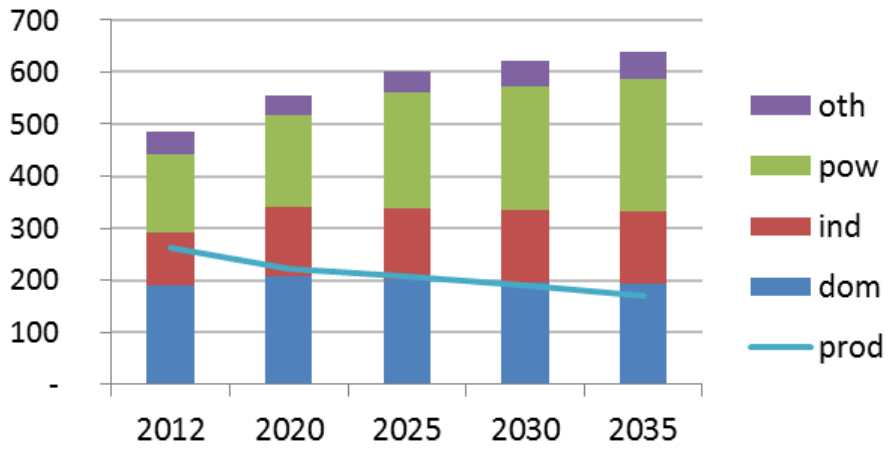


Figure 7: Gas supply and demand projection for Europe [bcm]

CIS

CIS will remain among the largest consumers of natural gas, but more important will remain the largest net exporting region in the world. Demand growth will concentrate on the power sector, while growth in the other sectors will be limited by ongoing efficiency gains.

Traditional export routes from the CIS to Europe will be complemented by new export regions in Asia, in particular to China. The huge export project from Russia to China concluded in 2014 will have a major impact on the CIS gas balance as well as the gas market development in China.

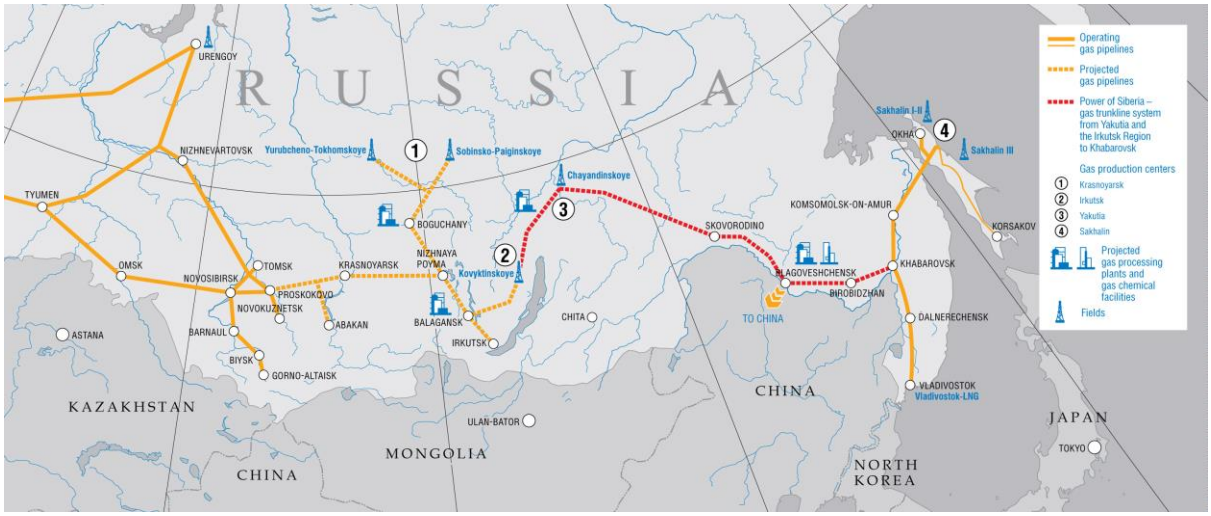


Figure 8: Export projects (source: Gazprom)

As in the past, the gas balance of the CIS states will be dominated by Russian production and demand. However, the Central Asian countries Kazakhstan, Uzbekistan and in particular Turkmenistan will maintain or even increase their role as major exporters.

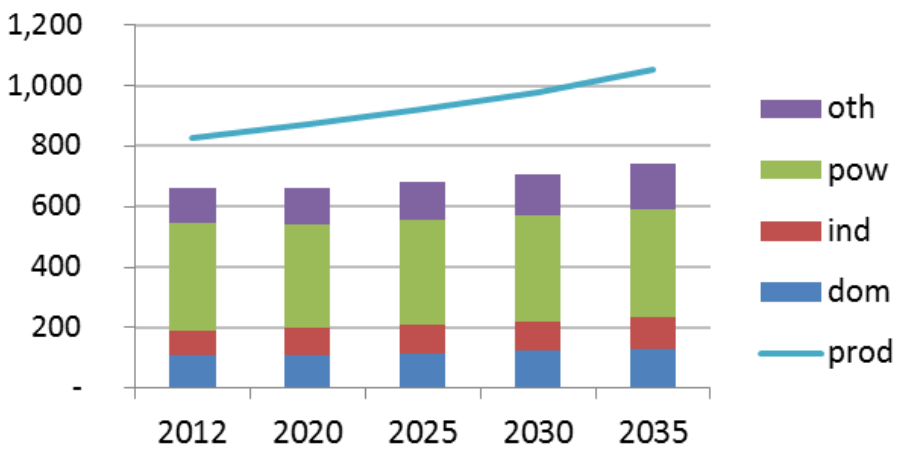


Figure 9: Gas supply and demand projection for CIS region [bcm]

Middle East

Gas and Oil for obvious reasons the dominating fuels in the region. A trend towards an increased level of gas use could be observed.

Therefore, despite constant growth in production in the Middle East, the potential for gas exports is not expected to increase much. Strong demand growth within the region will probably absorb most of the production growth.

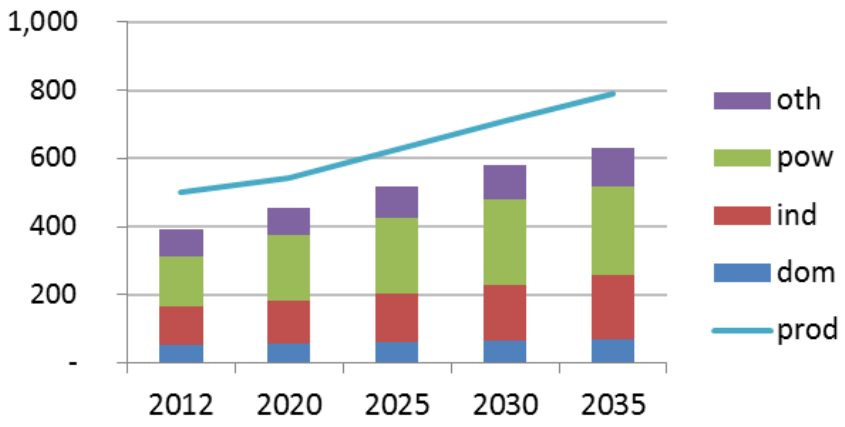


Figure 10: Gas supply and demand projection for Middle East [bcm]

Africa

Africa has drawn particular interest in recent times. The IEA dedicated a special section of its "World Energy Outlook 2014" to the African energy market. With regional disparities between regions, domestic demand for gas is strong in the power sector, particularly in North Africa, and will continue to grow. New gas development projects – although starting slower than initially expected – will complement the traditional producing countries like Algeria, which is expected to remain a major gas supplier along with Nigeria. Additional unconventional gas supply is expected mainly from Algeria and South Africa. African gas exports will have an increasing role in balancing the world supply and demand for gas.

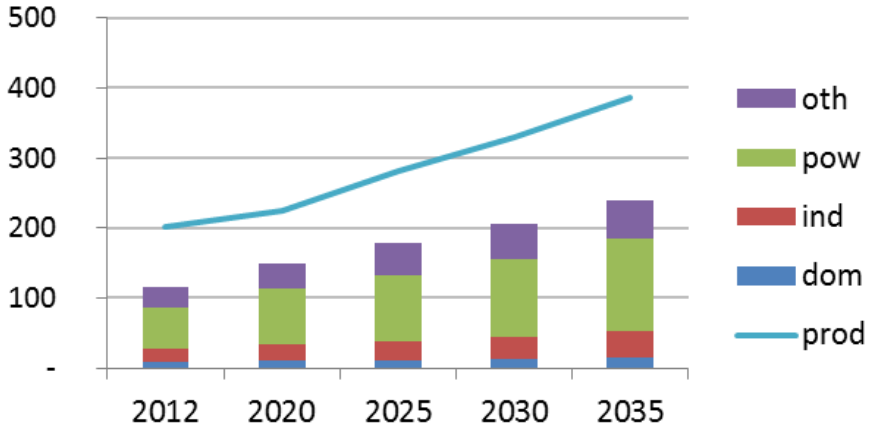


Figure 11: Gas supply and demand projection for Africa [bcm]

Asia

Very impressive demand growth could be observed in China all over the last decade. This growth pattern is expected to continue, and it will have a major impact on global gas trade. The other countries in the region – India, Pakistan, Bangladesh and Myanmar – also show a stable growth pattern.

The forecasted permanent growth of regional production from just above 200 bcm to more than 480 bcm would require a continuous development and expansion of gas industry. As a large share of the reserve base in this region consists of unconventional reserves, the development of this large production capacity will be more challenging than in other regions with more conventional reserves.

If demand growth materialises according to expectations, the region will therefore develop from being a minor, small-scale importer to being the second largest importing region (after Europe) with total import of around 280 bcm.

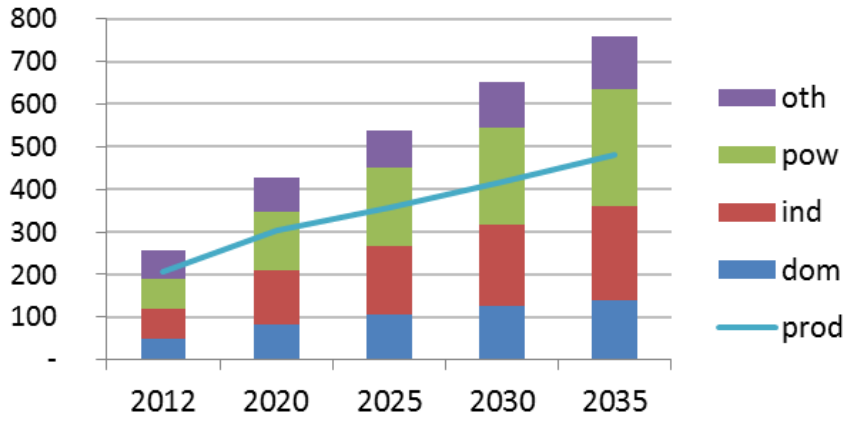


Figure 12: Gas supply and demand projection for Asia [bcm]

Asian – Pacific region

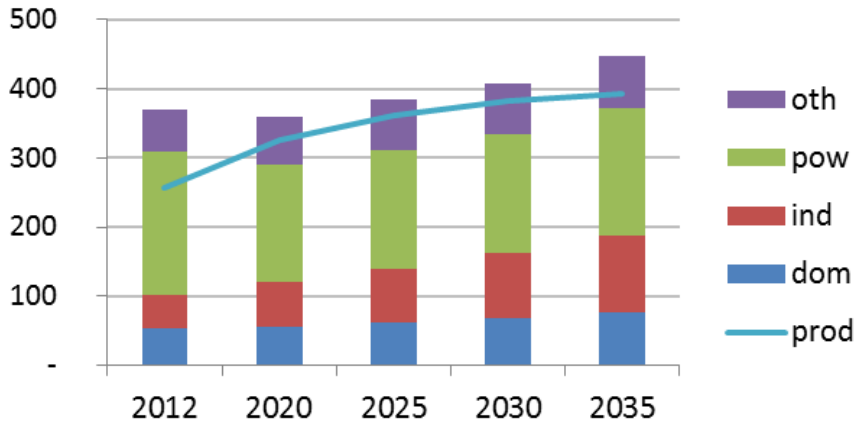


Figure 13: Figure 14: Gas supply and demand projection for Asian Pacific region [bcm]

The Asian Pacific region – ranging from Japan and Korea over the countries of Southeast Asia down to New Zealand and Australia – form a very heterogeneous zone. Traditionally in this region, the major natural gas trading pattern has been Malaysia and Indonesia supplying LNG to Japan and Korea. Several changes of that pattern are expected to materialize in the near future.

Indonesia and Malaysia may reduce their role as major exporters of LNG, as they increase their own gas and LNG use and may see slower pace of gas resource development than expected. On the other hand, a number of Australian LNG projects are under construction, which will make Australia the largest LNG exporter in the world.

Demand growth in Japan and Korea is expected to be relatively stable but may be significant depending on government policies and competitive situation against other energy sources.

Global natural gas trade patterns

Today, roughly 25 % of global production is traded across international borders, so still a very large share of production is consumed within the country of origin. About 490 bcm were imported by pipelines, whereas about 360 bcm were internationally traded as LNG. What is

more, most of this quantity remained within the respective IGU region, with just 400 bcm (or only about 12% of global demand) actually being consumed in a region different from its production region.

Cross border pipeline transport is notoriously strong between CIS countries and Europe; however, also the pipes between Canada and the United States and several cross-border pipelines all over the world contribute to international pipeline transits.

LNG trade of course is almost invariably associated with international trade. While world LNG trade could traditionally be split into an Atlantic market and a Pacific market, with the Middle East potentially supplying both, more global patterns have started to evolve.

The Panama Canal is currently being expanded with construction expected to be finalised by end 2015. After the expansion, the Canal will be accessible to at least 90% of the LNG fleet, thus establishing a new and important link between Atlantic and Pacific LNG markets.

By 2035, we expect global trade to more than double. Inter-regional trade will grow faster than consumption, reaching over 800 bcm (or 17%).

Long-Term Outlook for gas in the European Union to 2035

Natural Gas Demand

Gas consumption represented 23% of Europe's primary energy consumption in 2012, the second most important source of energy after oil at 32%.

After years of almost uninterrupted growth, the European gas industry has been facing severe sales losses since 2008 and the beginning of the economic crisis. First estimates indicate European gas demand is now down to the historical level of 520 bcm or - 9% in 2013 in comparison with 2010. The situation is not expected to improve in the next five to ten years and it will take several years before gas demand reaches the highs recorded of the previous years.

In 2009, the European Union (EU) approved the climate and energy package setting the binding legislation which aims to ensure the EU meets the following ambitious climate and energy targets for 2020:

- a 20% reduction in greenhouse gas emissions from 1990 levels;
- 20% renewables in final energy consumption;
- a 20% improvement in energy efficiency.

Further to this short term objective, the European Council endorsed in February 2011 the EU objective of reducing greenhouse gas emissions by 80 to 95% by 2050 compared to 1990 in order to contribute to keep climate change below 2ºC. For being on track, the Commission has proposed in February 2014 an intermediary objective of 40% emissions reduction in 2030 and an objective of 27% renewables in final energy consumption.

On 23 October, the EU's Heads of State and Government meeting in Brussels took the decisions on the way forward for EU energy and climate policies. They decided on:

- A binding EU-wide greenhouse gas emissions reduction target of at least 40%, broken down into national targets
- A binding EU-wide target for the market share of renewable energy sources of at least 27% without predetermined national targets

- An indicative EU-wide target for energy efficiency of at least 27%, to be reviewed in 2020 for an increase to 30%
- An electricity interconnection target of 15%

The European Council will keep all the elements of the framework under review and will continue to give strategic orientations as appropriate, notably with respect to consensus on the Emissions Trading System, non-ETS sectors, interconnections and energy efficiency. The Commission will elaborate proposals for measures to meet the targets.

So far, the 2020 framework and the Commission's Energy Roadmap 2050 have widely neglected the advantages of gas and the role it could play in all the sectors to participate in achieving the environmental targets. As a result, coal-fired electricity generation has increased together with electricity production from renewable energy sources. This, in turn, has resulted in a rise in CO_2 emissions in some countries. Gas-fired power plants have become uneconomic and are either being closed down or mothballed, although they are particularly needed to back up supply from variable renewables. Governments are addressing the resulting risk to security of electricity supply by intervening in the closure of such power plants or by running or introducing capacity remuneration mechanisms.The deep economic crisis and the action taken in the meantime to reach EU sustainability targets, resulted in expectations concerning the long-term development of gas demand are now some 10% lower than three years ago. These expectations also include more and more uncertainties on whether and when gas demand will be able to recover. Nevertheless, our scenario forecast that natural gas demand in Europe can still be expected to grow from 501 bcm in 2012 to 638 bcm in 2035 and reach 29% of European primary energy consumption. This scenario reflects the fact that the qualities of gas will still lead European customers in all sectors to want to keep using it. The cleanliness, controllability, low carbon dioxide (CO_2) content and flexibility in use of gas – coupled with its adaptability to high-efficiency equipment and innovative technologies – will continue to create demand in both difficult and favourable market and policy conditions.

In our forecast, European gas demand is expected to recover slowly in the medium term, returning to the level of 2010 at 520 bcm only towards the end of the current decade, in the face relative high gas prices, strong growth in renewables-based power and low carbon prices favouring coal in power generation. Thereafter, gas demand grows more strongly, mainly on the back of increasing demand from gas-fired power stations, as policies to reduce CO_2 emissions boost demand for gas relative to other fossil fuels.

Uncertainty in the volume of gas sales to power generation is the main factor behind the uncertainties in the overall level of gas demand in each forecast case. If current trends continue, there is a risk of re-carbonisation in Europe.

Power generation

The role of natural gas for power generation has increased significantly since the 1990s. In 2012, gas-fired power stations produced about 20% of the electricity generated in Europe (6% in 1990).

Since 2010 gas use in power generation has been sliding as a result of unfavourable market fundamentals. The low coal price and a weak carbon price continued to favour coal generation. In addition, the growing share of electricity produced from renewables also reduced the demand for gas in power generation. This has challenged the economics of Combined Cycle Gas Turbines (CCGTs) used for base load. Such factors are still expected to influence demand.

Gas offers considerable potential for reducing CO_2 emissions in the power sector and for achieving Europe's environmental objectives. But there is much uncertainty around whether

this potential will be realised in Europe over the medium and long term. Recent experience makes the short-term prospects very poor. A weak price signal in the EU carbon market, combined with growing imports of competitively priced coal, and high subsidies and feed-in-tariffs for selected preferred low-carbon technologies, have driven gas out of the merit order for power station dispatch. Also the effects of the economic crisis and poor growth continued to result in weak final power demand and gas use in power generation has been sliding since 2010. If these trends continue, gas power plants will be further pushed out of the merit order. Coal-for-gas substitution could more than outweigh any gains from the growth of green technologies, preventing Europe from reaching its ambitious environmental targets.

Various factors must be borne in mind when assessing the future use of gas in power generation. The eventual make-up of the energy mix in power generation will result from a complex interplay of global and European market forces, and of European and national energy policies and market designs. The development of gas in this sector depends on the growth of electricity consumption, the political decisions regarding the support for the penetration of renewables, the future of nuclear, the support given to flexible backup power generation and the evolution of the European CO_2Emissions Trading System. The price relativity of gas to coal and the evolution of the price of CO_2 will determine the load factor at which gas-fired power generation may or will be operated. In the long run, the role of gas will very much depend on the commissioning of new and the decommissioning of old power plants.

For our analysis, we have assumed that the current national nuclear policy will continue to be pursued in the future, including the decommissioning of nuclear power stations in Germany and Belgium after 2025. The decommissioning of old plants will not be compensated by the new nuclear power plants to come online and gas is expected to cover for a declining relative share of nuclear power.

The outlook expects gas and renewables will grow together with gas playing its role as support for flexible renewable sources, with the share of renewables overtaking that of gas in 2015 and rising steeply thereafter while gas grows only slightly.

In thermal power generation, we assume that coal will be displaced throughout the whole period. The emission standards required by the Large Combustion Plant Directive (LCPD) has forced many older fossil power plants to close down. The Industrials Emissions Directive will also force many fossil power plants to close within the next few years. Oil is almost completely phased out.

This outlook expects the environmental benefits of natural gas to be exploited in this segment with a view to achieving ambitious climate protection targets. European gas consumption in power generation therefore rises from 151 bcm in 2012 to 253 bcm in 2035.

Residential and commercial

Whereas gas demand for power generation is very flexible and reactive to market conditions and the competitiveness between fuels, demand from the residential and commercial sector is rather stable and mostly relies on policy decisions and therefore evolves in a steady pattern. Even if developments in this sector are rather slow, they still have noticeable effects on the total natural gas demand in Europe.

A major contribution to the energy efficiency of the European economy will be the development in the residential and commercial sector over the forecast period. This is linked primarily to the roll-out of high-efficiency gas heating systems. Since 1990 gas consumption in the residential and commercial sector has steadily increased in line with the expansion of infrastructure and the associated rise in the number of gas users. With a market share of

approximately 34%, gas is currently the primary heating source for homes throughout Europe, and has a prominent role in heating schools, hospitals, offices and other commercial sector premises. The Outlook suggests, however, that demand in this sector may now be on a track of secular decline for two main reasons: high market penetration has already been reached in many major gas consuming countries, and new gas heating equipment is more efficient than the existing stock that it steadily and gradually replaces.

In future, the population of Europe will grow only moderately. As high market penetration has already been reached in some major gas consuming countries, and in the course of time, other countries will also gradually reach saturation in the residential and commercial market slowing down this market segment considerably. Further factors likely to limit gas demand include the improved energy efficiency of buildings. Indeed, a major contribution to the energy efficiency of the European economy will be the development in the residential and commercial sector over the forecast period. This is linked primarily to the implementation of better thermal insulation standards or the use of new heating systems with higher energy efficiencies including the roll-out of high-efficiency gas heating systems.

All these factors are likely to slow down volume growth quite substantially. Gas demand in this segment is therefore expected to have reached its peak in 2010 at 210 bcm and demand is falling down to 190 bcm in 2035.

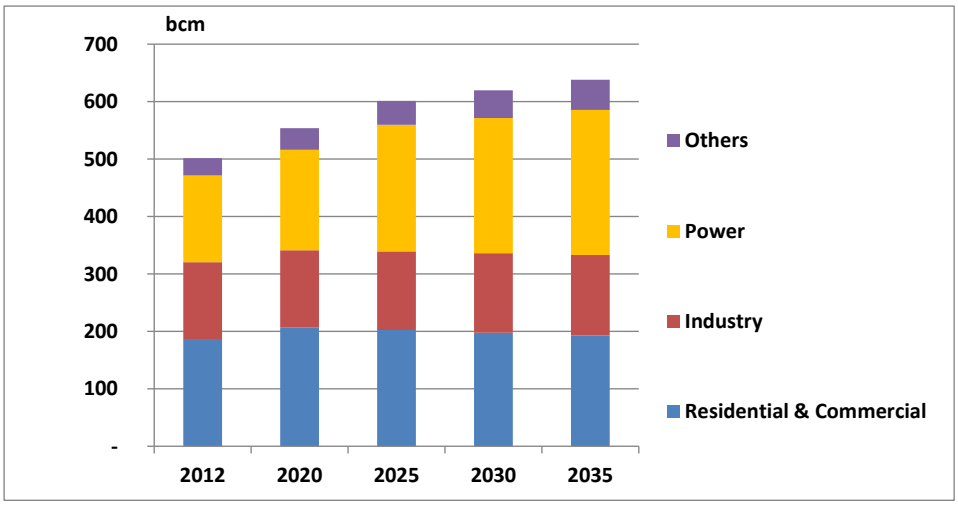


Figure 15: European gas demand development projection [bcm

Gas continues to provide a premium quality fuel and feedstock to industry.

Gas currently accounts for 30% of Europe's industrial final energy consumption and is thus a major source of energy in this market, too.

The overall level of gas demand is likely to remain closely coupled to the rate of economic activity in the industrial sector, conventionally measured in economic terms by industrial "value-added". Forecasts for industrial gas demand are driven by the overall economic expectations, and on the condition that gas can be priced competitively against higher carbon fuels in order to retain its attractiveness.

This sector has traditionally been successful in energy conservation. Given the strong international competition facing European industry, the sector had to adapt by renewing production plants and reduce its production costs. This trend is likely to continue in the future. As a result, the increase in energy consumption due to production developments will largely be cancelled out by efficiency-improving investments in plant modernisation and replacement.

With recovery in industrial activity and substitution of more polluting fuels, gas demand in the industry sector is expected to increase only slightly in the long term from 134 bcm in 2012 to about 140 bcm by 2035.

Transport

If today natural gas vehicles in Europe amount to around one million vehicles and 2 bcm of natural gas consumption, the right political environment and coordinated support of all stakeholders can make it rise significantly and reach about 18 bcm in 2035.

Further work towards improvement of the energy efficiency of road vehicles through enhanced standards will reduce emissions from transport. A gradual transformation of the entire transport system towards a better integration between modes, greater exploitation of the non-road alternatives, improved management of traffic flows through intelligent transport systems, and extensive innovation and deployment of new propulsion and navigation technologies and alternative fuels will also enhance energy efficiency.

While the EU is looking for the long-term substitution of oil as energy source in all modes of transport to break the over-dependence of European transport on oil, natural gas is clearly identified as today's best option for fuel substitution, especially for urban fleets and trucks.

Widening opportunities for gas offer new scope for growth in demand in the transport sector. The potential now extends from fleet and passenger vehicle use of compressed natural gas (CNG) to rapidly expanding possibilities for liquefied natural gas (LNG) in trucks and maritime transport.

Moreover, natural gas have extremely low emissions of NOx and other pollutants and emit no particulates, improving air quality and significantly reducing noise and CO_2 emissions. For trucks, liquefied natural gas is already a proven technology that can easily achieve emissions reductions in the freight sector at large scale from today on. Natural gas is a flexible fuel since it can be used in all means of transport (cars, trucks, ships, planes, trains...) for both short and long distances.

Moreover, the development of natural gas vehicles also paves the way for the introduction of renewables in the transport sector through the blending of natural gas and biomethane and the achievement of the EU objective of 10% share of renewable energy in the transport sector. Biomethane the most cost efficient and environment efficient of the biofuels. There is no limitation to the blending of natural gas and biomethane thanks to the same molecular composition. The penetration of biomethane enables an immediate decrease in the net emission factor of natural gas fuelled vehicles without any technology constraints, using the existing European gas grid.

Natural Gas Supply

European gas production is forecasted to decline even more than previously foreseen due to changes in Dutch gas policy.

In the Netherlands, the largest European gas producer behind Norway, a limit was set for the production of the Groningen field following earthquakes associated to gas production. While Earthquakes in the Groningen field area are registered since 1991, they recently increased in frequency and magnitude above 3 on the Richter scale, seriously damaging houses. The Minister of Economics in January 2013 requested a revised exploration plan before 1 December 2013. After consideration of many studies, the Minister decided on 14 January 2014 to reduce the gas production around Loppersum by 80% to 3 bcm per year for 3 years exploration plan (2014 – 2016) with an overall production cap of 42.5 bcm in 2014 and 2015

and 40 bcm in 2016. A revised exploration plan by 1 July 2016 will be examined based on additional measurement and monitoring data for a decision on the production from 2017.

In this context, no upside factor seems able to counterbalance the expected decline of European gas production, which will amount to 52 bcm or -23% over 2012-2035.

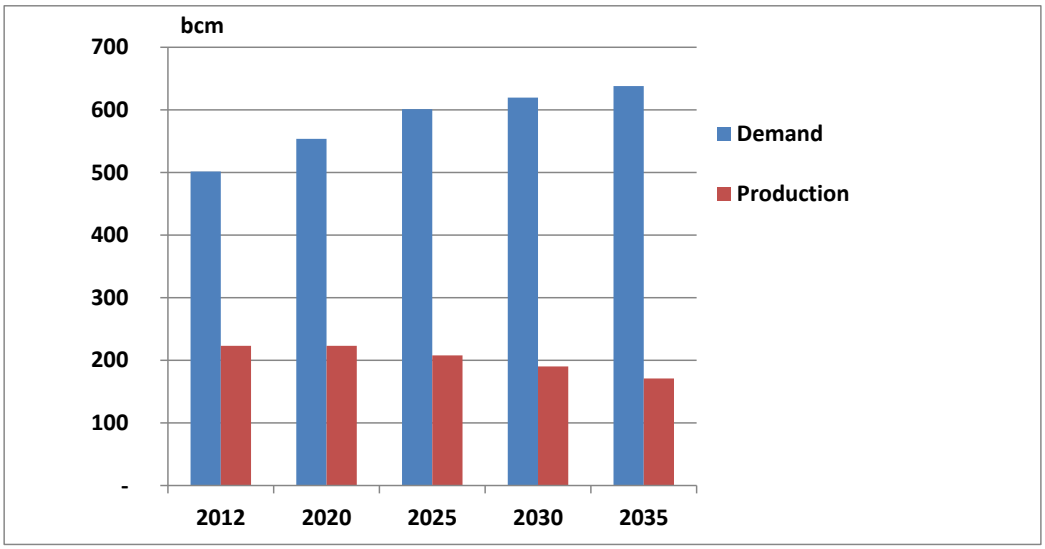


Figure 16: Comparison of Supply and Demand development for Europe [bcm]

Shale gas production

The exploration of shale gas in Europe could improve the prospects of indigenous production. Although the current context does not give very much room for significant volumes to be expected, developments of new techniques and more support to the development of unconventional gas could improve expectations of European shale gas production.

While National bodies regulate the drilling in Europe (Health and Safety Executives or Environment Agencies, who prepare performance reports, local planning permits, mining laws), many European countries have decided to ban the use of hydraulic fracturing or have set up a moratoria.

Potential regulation of hydraulic fracturing has been explored by the European Commission in order to ensure that risks that may arise from individual projects and cumulative developments are managed adequately in Member States that wish to explore or exploit such resources. In this context, the Commission adopted on 22 January 2014 a Recommendation, setting up minimum principles when applying or adapting national legislations applicable to hydrocarbons exploration or production using high volume hydraulic fracturing. Legislation may follow depending on further developments.

The countries which have allowed exploration and extraction and even issued permits did not succeed yet in finding any substantial economically recoverable resources.

Security of supply and procurement

Energy security is identified by some policy makers as one of today's biggest challenges. The availability of stable and affordable energy supplies is crucial for the economic development of all European countries. Ensuring energy security and diversifying sources and routes of supply and a robust internal energy market should be identified as a common objective.

The relative good geographical position enables Europe to diversify gas supply. But the procurement for the Europe cannot be considered in isolation from global developments. The

biggest uncertainties relate to the Europe's market attractiveness, especially for LNG supply in the context of a worldwide market.

Even if overall the future of gas supply to the European Union is rather positive and there are no big concerns about the availability of future sources, the European gas industry recognises the importance of fostering long-term relationships with major suppliers, transit countries and key EU partners. Individual companies remain responsible for conducting commercial relations with producing and transit countries while institutional dialogue is essential to building a framework for increased co-operation on the diverse issues to achieve necessary political assurances from the EU as much as from the countries concerned. A long-term approach is essential to position gas such that it can fulfil its role as the ideal fuel in a future sustainable energy supply.

Conclusions

Gas has a key role to play in achieving a secure and competitive low-carbon energy system, objective of the EU energy and climate policy, being in electricity generation, heating, industrial processes and transport. In power generation, gas emits some 50% less carbon dioxide (CO_2) than coal and provides the most flexibly available power plants to back up electricity from variable renewable sources, mainly solar and wind. Modern gas heating appliances are among the best performing in terms of efficiency and emissions. In the transport sector, cars and trucks running on compressed natural gas (CNG) and liquefied natural gas (LNG) deliver significant carbon emissions reductions and can also reduce particulate matter and nitrogen oxide (NOx) emissions considerably. Furthermore, extending the use of LNG to shipping is being widely considered as a means for the maritime sector to achieve the mandated reductions in sulphur emissions.

Africa's Long Term Perspectives for Natural Gas

Economic Trends

African Economy is dominated at more than 60% by five countries, three of which are from North Africa, namely Egypt, Algeria and Morocco. The continent home to 15% of world's population generates only 5% of world's GDP. Nigeria and Egypt, which share equally 36.5% of Africa's economy, remain the largest economies of the region.

Africa's economy has doubled in size during the last decade, with more than 60% of the increase shared by Nigeria, Egypt, South Africa, Algeria and Angola. Ethiopia is the fastest growing economy of the region, followed by Angola and Nigeria, with two digit average annual growth rates. But this trend has been shared by many African countries, which placed Africa among the fastest growing economies in the world, even if the size remains very low compared to world's average.

Oil & gas producing countries economies are dominated by the industry sector, where more than 50% is generated by the industry sector, even though very low employer. Agriculture remains a large sector in many economies in sub Saharan Africa, both as a value added creator and employer accounting for around 20% of regional GDP (compared with a 6% share globally) and of 65% of employment. Mining is an important industry in several sub-Saharan economies, both as an employer and as a source of export revenue.

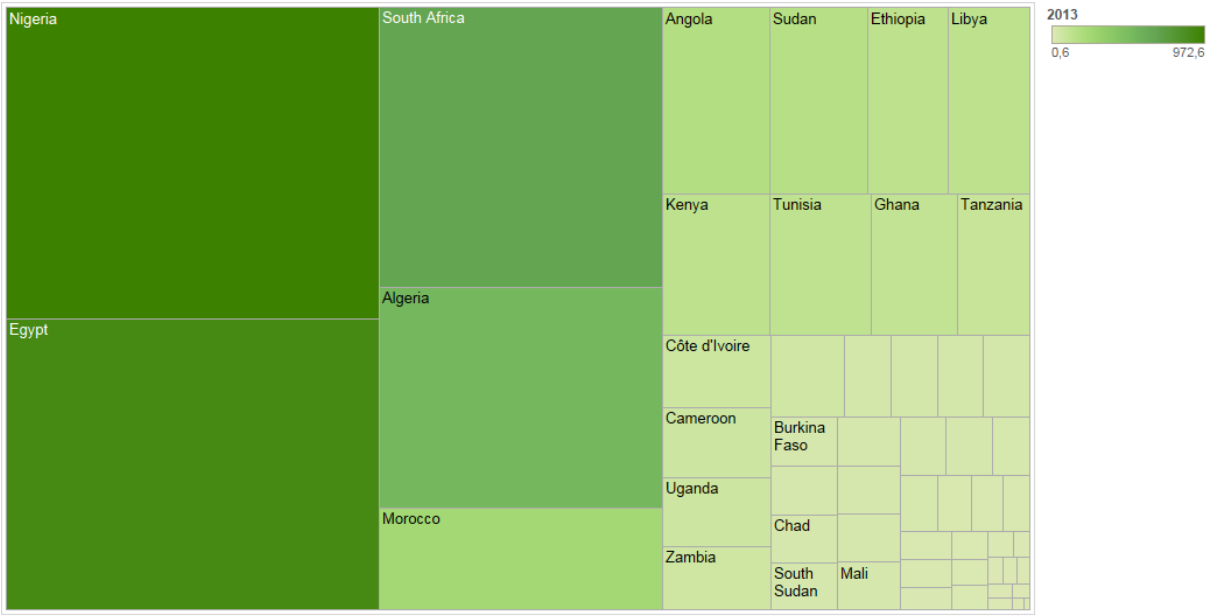


figure 17: GDP in PPP terms, by Country, 2013, $5.1 trillion, Source: IMF, WEO October 2014

The African economy recorded relatively high growth rates in recent years, higher than world average, despite world economic recession and political instability in many countries, and showed strong growth since 2012. Economic growth should continue in 2014 and 2015 with average growth rates of 4.8% and 5.3% resp.

According to IMF, Sub Saharan Africa should experience strong growth rates, more than 5% to 2019 on average. North African countries should also show solid growth with around 4% for Algeria and Egypt, around 4.5% for Tunisia and 5% for Morocco. Libya is expected to recover from 2011 recession to recover its real GDP level of 2010 by 2019.

figure 18: African Economic Growth, *Source: IMF, WEO October 2014, AfDB, 2014*

Population Growth

Africa demographics show a rapid growth, where total population reached 1 billion in 2013 from 848 million in 2003. In 2013, Nigeria was the regions most populated country with 169

million, followed by Ethiopia and Egypt with 88 and 83 million resp. West Africa concentrates 30% of Africa's population, Followed by East and Southern Africa with 22% and 20% of total population. North Africa is home to 15% of the continents population.

Africa population is expected to reach 1.2 billion by 2019 according to IMF and UNDP. Africa is facing many challenges with population growth, like access to employment but the growth should also bring new labor force. By 2035, Africa's population should reach 1.8 billion in the UNDP medium fertility scenario, representing 20% of world's population vs 15% currently.

With a median age of 20 years now (against 30 in Asia and 40 in Europe), and declining fertility rates, the demographic dependency ratio (ratio of dependents -people younger than 15 or older than 64 - to the working-age population - those ages 15-64) will improve. This is an important demographic factor knowing that this was crucial in the case of Asia, a generation ago.

Primary Energy Demand

Primary energy consumption in Africa reached 739 Mtoe in 2012, representing 5.5% of world energy consumption, for a continent home to 15% of world's population. On per capita basis, an African citizen consumes 3 times less energy that the world's average, and even less in sub Saharan African countries. Apart from South Africa and Libya, African countries average energy consumption is far below world average, with the biggest consuming countries being South Africa, Nigeria, Egypt, Algeria and Ethiopia, accounting for more than 60% of the global continental consumption.

On a regional level, these countries dominate their regional energy demand, as South Africa concentrates 2/3 of consumtion of Southern Africa and Nigeria 80% of West Africa, North Africa being dominated to 70% by Egypt and Algeria.

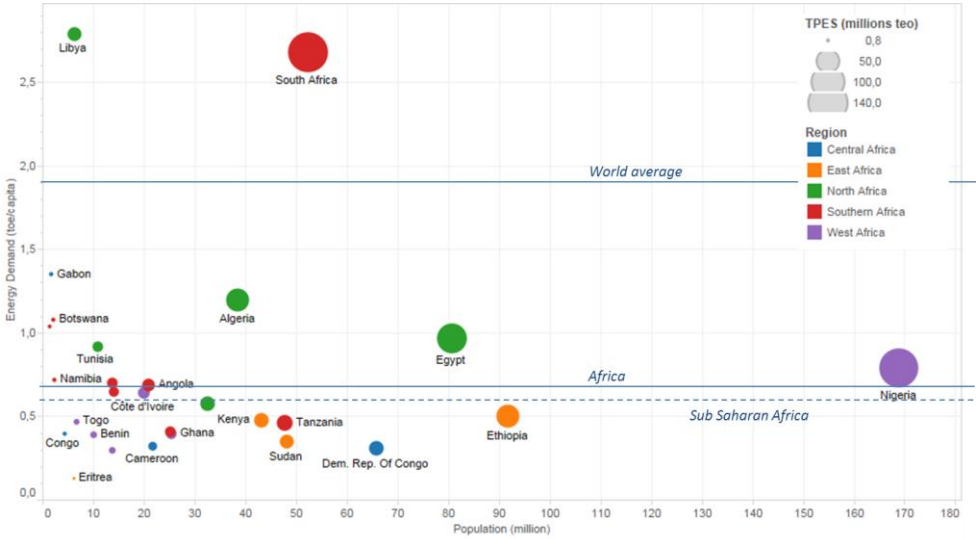


figure 19: per capita energy demand by country in Africa, 2012, Source : EIA, Key World Energy Statistics, 2014

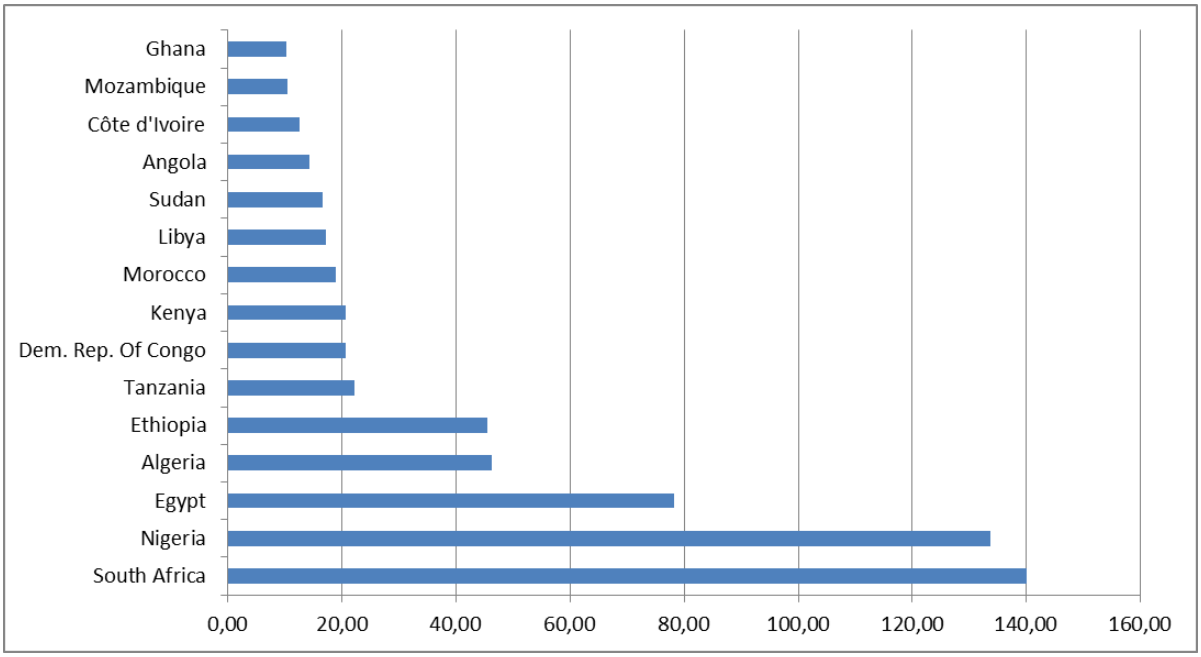


figure 20: Energy consumption in selected african countries (TPES, 2012 in Mtoe), Source : IEA, 2014 Key World Energy Statistics

Primary demand grew by 50% between 2000 and 2012, equivalent to an average annual growth of 3.3% over the same period, driven mainly by three regions which share evenly 80% of the additional 240 mtoe demand. A notable evolution is a greater part of the demand for West Africa and north Africa, with 27% and 23% resp. In 2012 whereas Southern Africa reduced its share of african energy demand.

On by fuel basis, the african energy mix remains dominated by bioenergy, mainly solid biomass used for cooking, accounting for half of the demand, while natural gas and oil improved their share of the energy mix gaining 5% and 3% resp. Coal lost 4% of its share in the energy mix over the same period. Natural Gas has been the fastest growing energy with 6.5% of average annual growth, followed by Oil and Hydro with 4.4% and 4.3% respectively.

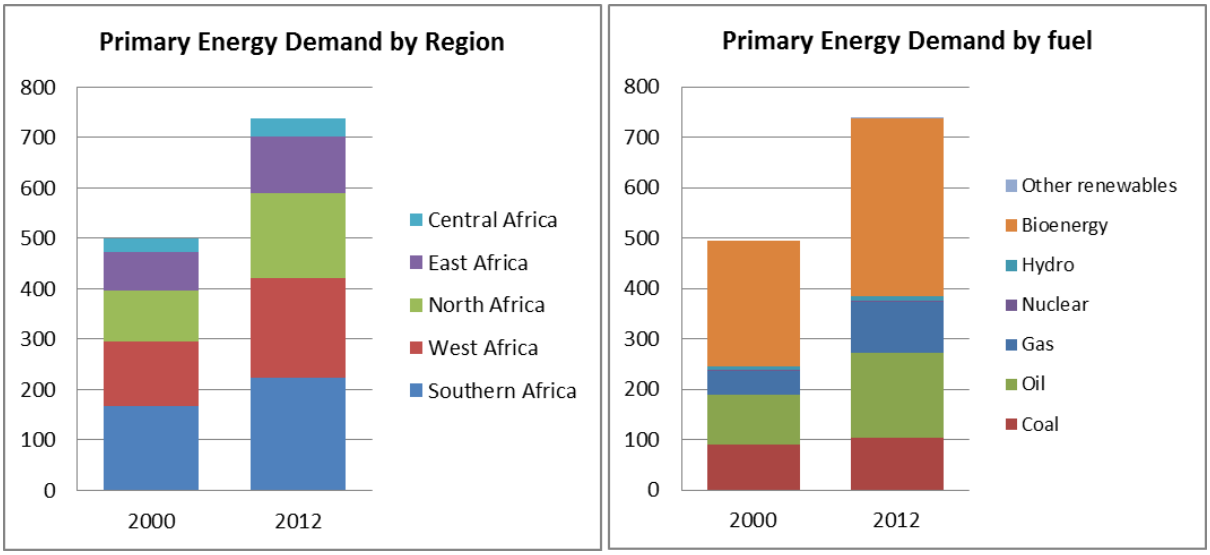


figure 21: Energy consumption in Africa, Source: IEA, Africa Energy Outlook, 2014

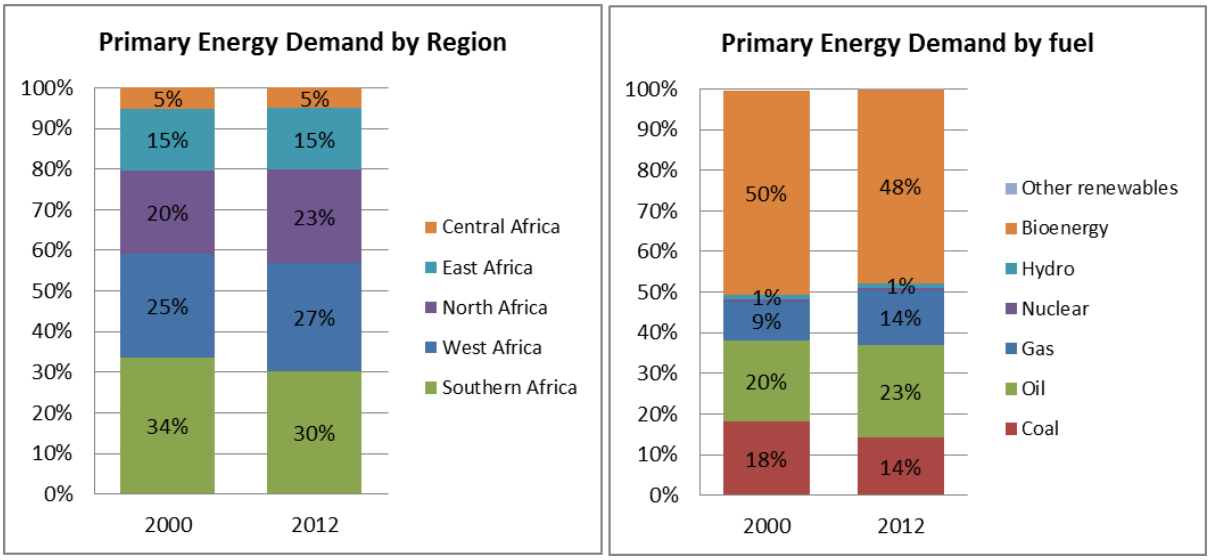


figure 22: Energy consumption by region and by fuel, Source: IEA, Africa Energy Outlook, 2014

On a regional basis, energy profile is very different across regions. Apart from South Africa, dominated by coal for its consumption, bioenergy dominates the energy mix in Sub Saharan Africa, accounting for more than 60% of total sub region energy use, with 75%, 78% and 85% for West, Central and East Africa resp. Bioenergy demand, mainly driven by the use of biomass for cooking, increased by 100 mtoe over 2000-2012 period, far ahead of all other forms of energy. North African countries rely evenly on oil and natural gas for their energy use, with however more gas than oil for Egypt and Algeria due to its availability. These differences highlight the lack of access to modern energy for most Sub Saharan African countries.

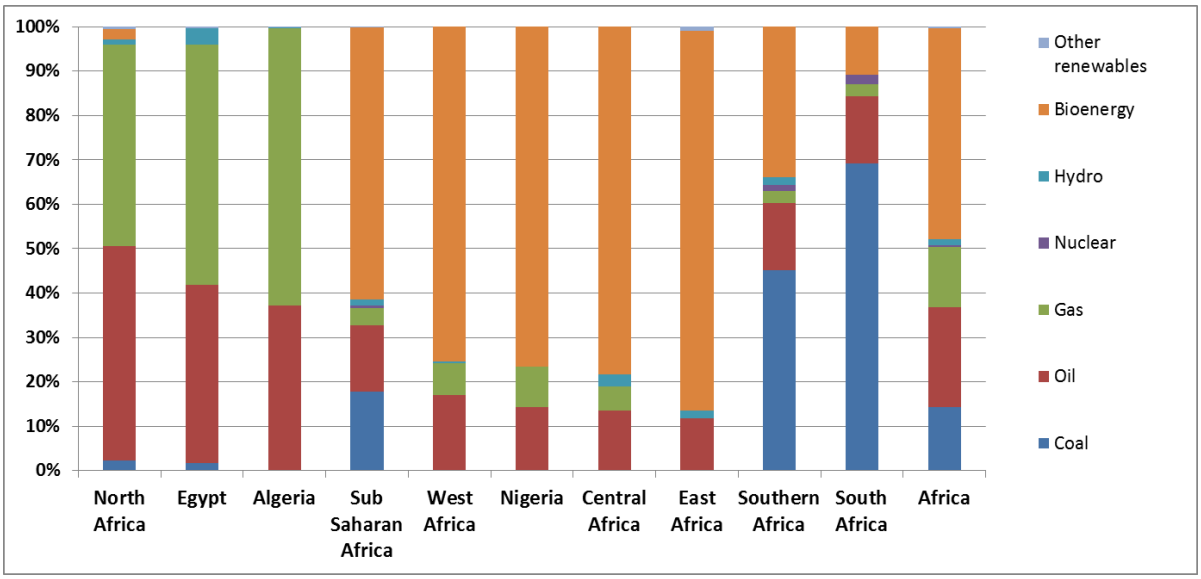


figure 23: Primary Energy mix by sub region in Africa, 2012, Source: IEA Africa Energy Outlook 2014, BP Statistical, 2014

Coal dominates the energy mix in Southern Africa, where 78% is used to generate electricity and 18% in industry. Oil is used mainly in transport sector, with half of the volumes consumed, 23% in industry and 14% in power generation, mainly in North Africa (Egypt) and sub Saharan Africa countries. Natural gas is used in North and West Africa, mainly in Power Generation. Bioenergy is by far the dominating energy in residential sector in sub Saharan Africa.

Renewable energy (excluding traditional biomass) is insignificant in Africa (1.6% including hydropower), despite the huge existing potential.

Currently, 25 GW of hydropower capacity is installed in Africa (Mozambique, DR Congo, Uganda and Kenya), and the same is under construction, but the technical hydropower potential is estimated at 283 GW, so less than 10% of this potential has been tapped. Remaining potential is in Central and East Africa (Cameroon, Congo, DR Congo, Ethiopia and Mozambique), but there are also significant opportunities in Southern Africa (Angola, Madagascar, Mozambique and South Africa) and West Africa (Guinea, Nigeria and Senegal).

For geothermal power, the potential is very important, especially in East Africa Rift Valley Region (which includes 12 countries), estimated at between 10 GW and 15 GW. Kenya is on the lead with 250 MW installed and 280 MW under development, with a target of 5 GW by 2030.

For wind energy, and according to the African Development Bank, 15 countries were identified as having potential resources for the development of wind capacity, mainly Somalia, Sudan, Libya, Mauritania, Egypt, Madagascar, Kenya and Chad which have large onshore wind energy potential. In 2010, installed capacity was around 760 MW, 96% of which located in North Africa (Egypt (430 MW), Morocco (253 MW) and Tunisia (54 MW)).

For solar energy, the potential is estimated at 100 million toe / year, which could largely meet the continent's energy needs and even enable exports of surplus. The deserts of Sahara in the North of Africa and Kalahari in the South are the most suitable regions for the Development of solar projects in Africa.

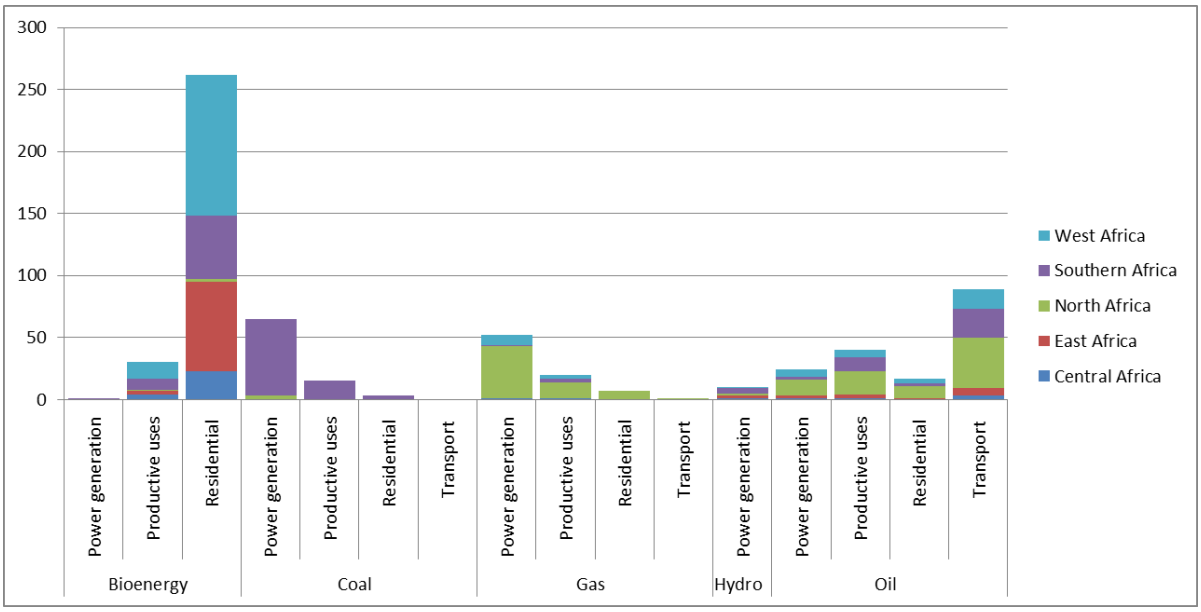


figure 24: 2012 energy use by sector in Africa, Source: IEA Africa Energy Outlook 2014

Energy Consumption Trends in Africa

According to IEA, The total energy consumption is projected to increase at an annual average rate of about 2.1% between 2012 and 2035 in the new policies scenario. The increase of 464 Mtoe between 2012 and 2035 will come mainly from bioenergy with 137 mtoe (30% of the increase) followed by Natural gas with 107 Mtoe (23% of the increase), which places natural gas as the leading energy in terms of speed of growth with an average annual growth of 3.2% over the period.

Coal with 1.6% of annual growth could show the slowest growth after bioenergy (1.2%), followed by oil with 1.8%. The energy mix in 2035 should change in favour of gas, hydro and other renewables, that will increase their share of the mix by 3%, 2% and 5% respectively.

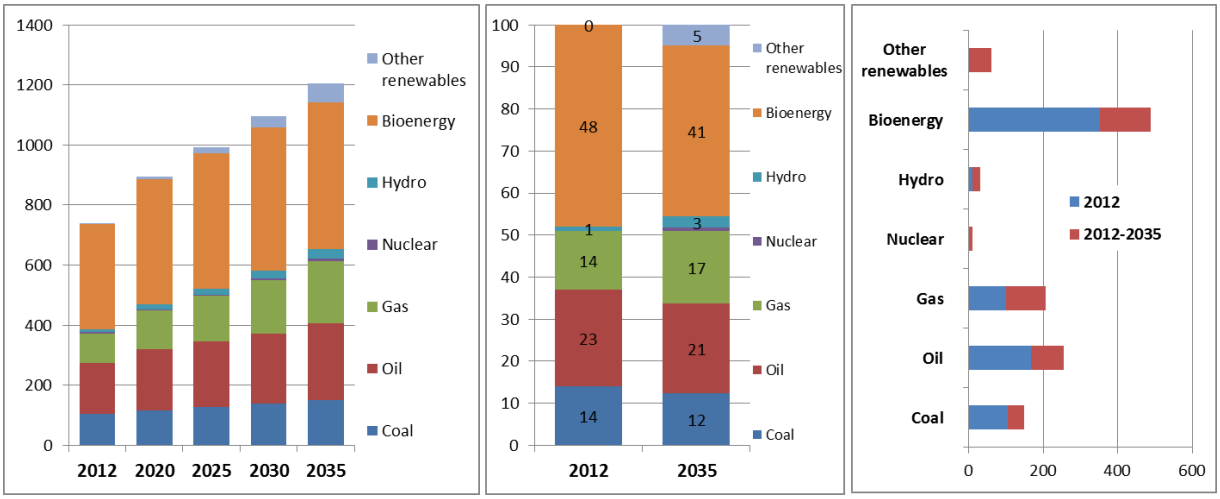


figure 25: projected Primary Demand by Fuel, 2012-2035, Mtoe, Source: IEA, Africa Energy Outlook 2014, New Policies Scenario

The increase in energy consumption in Power generation should come evenly from Natural Gas followed by renewable sources. Coal will increase also its use in Power generation, while oil will reduce its use, mainly in North Africa, where gas would account for the major part of increase in Power Generation.

East Africa will notable increase its use of renewable energy, mainly in Power Generation, from wind and geothermal energy where potential is very important.

Regarding **renewables**, many countries have announced a development policy in order to exploit the enormous existing potential, particularly solar and hydraulic energy. This energy should experience a progression, mainly in North Africa and in the Republic of South Africa, but at the continental scale, the share of renewables would remain relatively low. Algeria aims to achieve a market share of renewables of 40% by 2030 (22,000 MW), Given the huge solar potential in the country, the renewable development program will focus essentially on the Solar Energy (The objective is to produce 37% of total power generation by 2030). Egypt approved a development plan for renewables allowing it to reach a capacity of 7500 MW by 2020. South Africa targets a 15% goal of generated electricity in 2020.

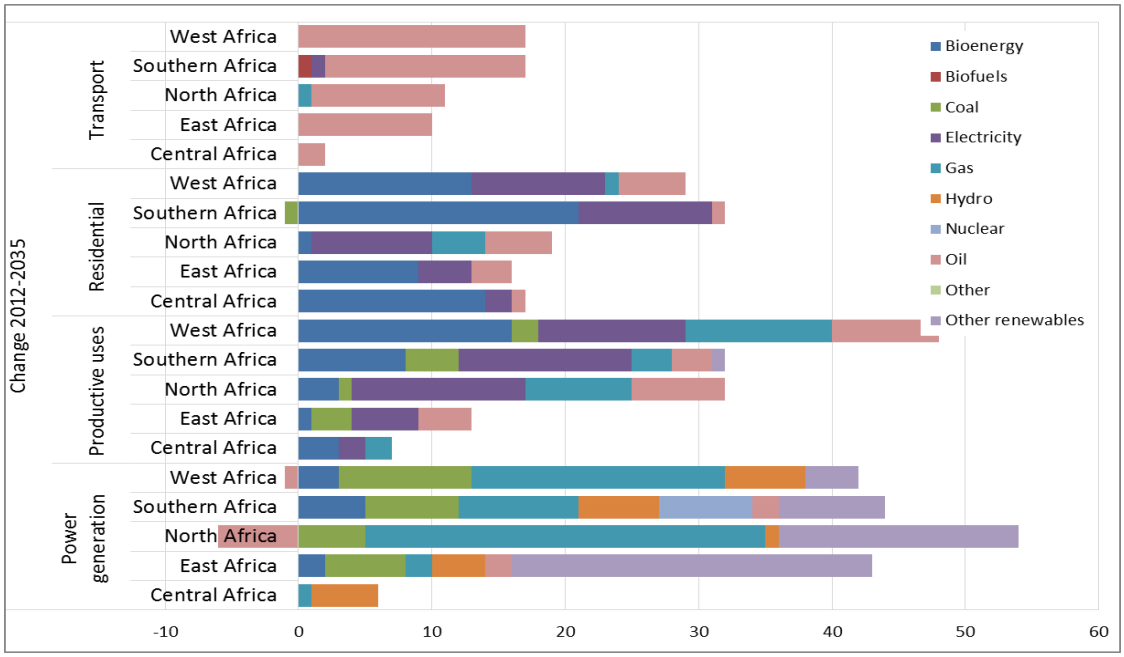


figure 26: regional change in energy demand by sector, Source : AIE, Africa Energy Outlook, 2014

Natural Gas Demand

Natural gas consumption is highly concentrated in a small number of countries, where nearly 92% of this consumption is located in six countries (Egypt, Algeria, Nigeria, Libya, Tunisia and South Africa). The largest consumers are the countries with resources. South Africa and Tunisia are also major importers, while many African countries consume locally their gas production, like Congo and Ivory Coast.

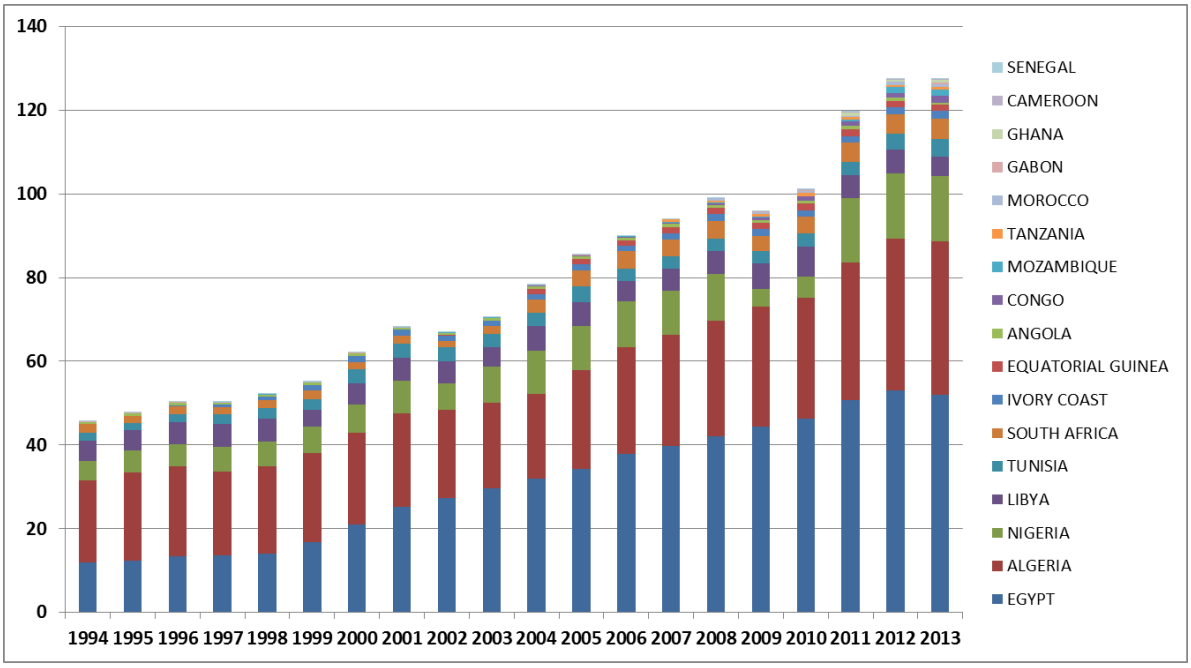


figure 27: Natural Gas Consumption, 1994-2013, bcm, Source: CEDIGAZ 2014

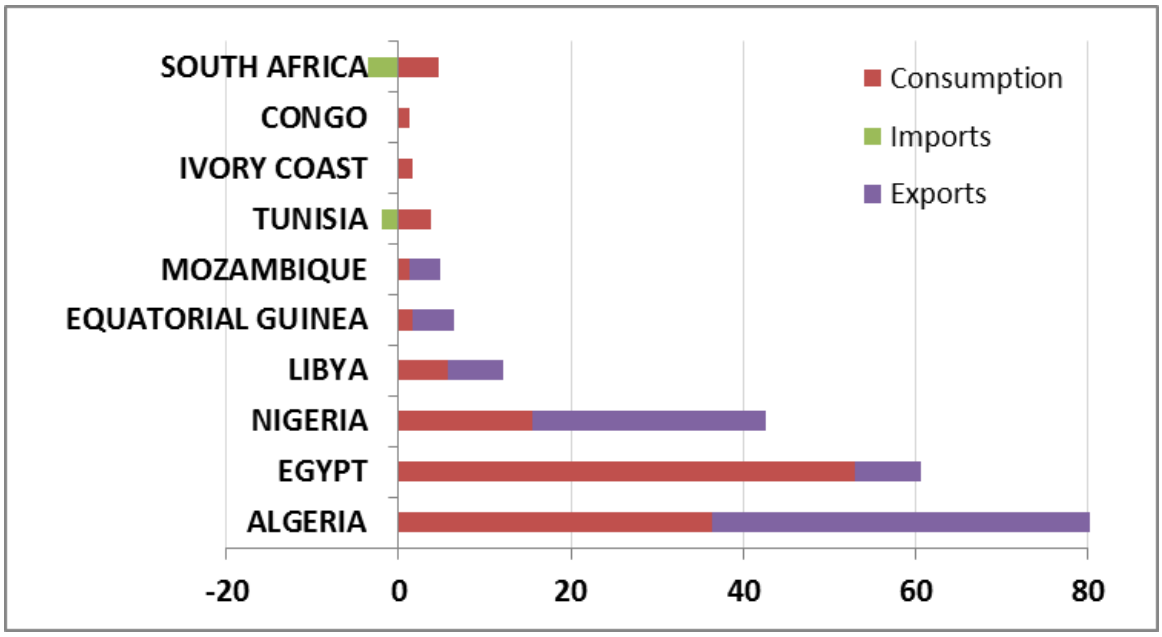


figure 28: 2012 Natural Gas Production Split, by Country, bcm, Source: IEA

The consumption of natural gas in Africa has grown significantly in recent years, spurred by the growing demand from power generation and industrial sectors. It should be noted that some African countries have adopted measures to promote gas consumption such as Nigeria and even Egypt (which gave priority to the domestic market for its natural gas supply).

Natural Gas demand should be the fastest growing energy in Africa in the coming decades, with an additional 120 bcm in 2035 compared to 2012 level. The additional demand should come from North Africa, with an additional 47 bcm, followed by West Africa with 34 bcm and a remaining 13 bcm in southern Africa. East and Central Africa would add very limited volumes to their demand by the same period. Sectorial breakdown of natural gas consumption shows that power generation and industry remain the major consuming sectors.

Access to natural gas remains limited to North African countries, due to its availability, and would begin to increase its use in residential sector by the end of the horizon in West Africa, with development of new gas pipelines and infrastructures, driven by natural gas production in this region.

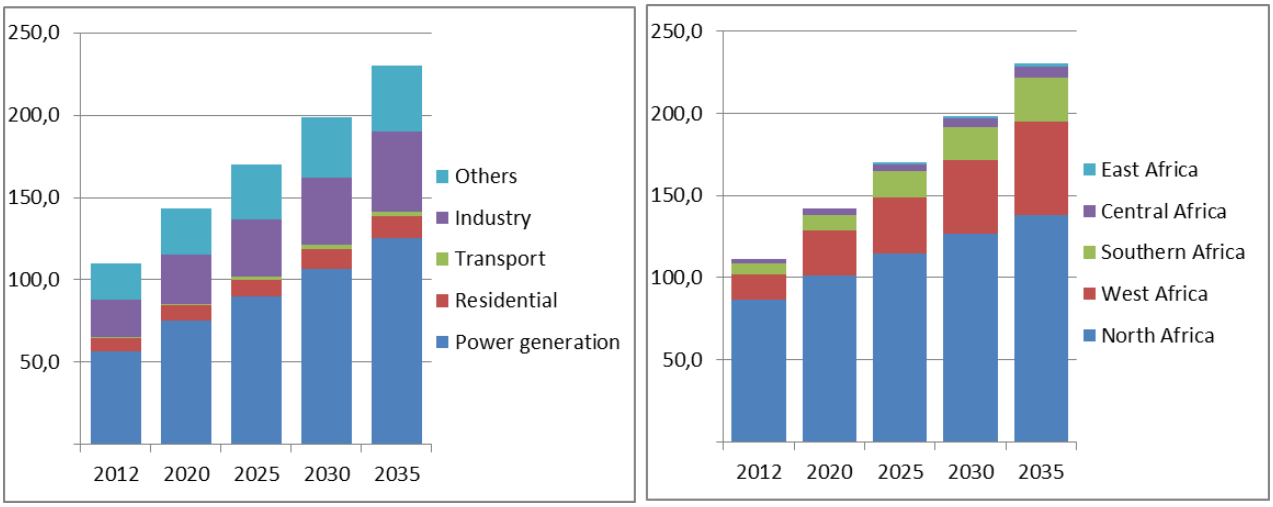


figure 29: Gas Demand, 2012-2035, bcm, Source: IEA, WEO 2014

Breakdown of gas consumption by type of activity

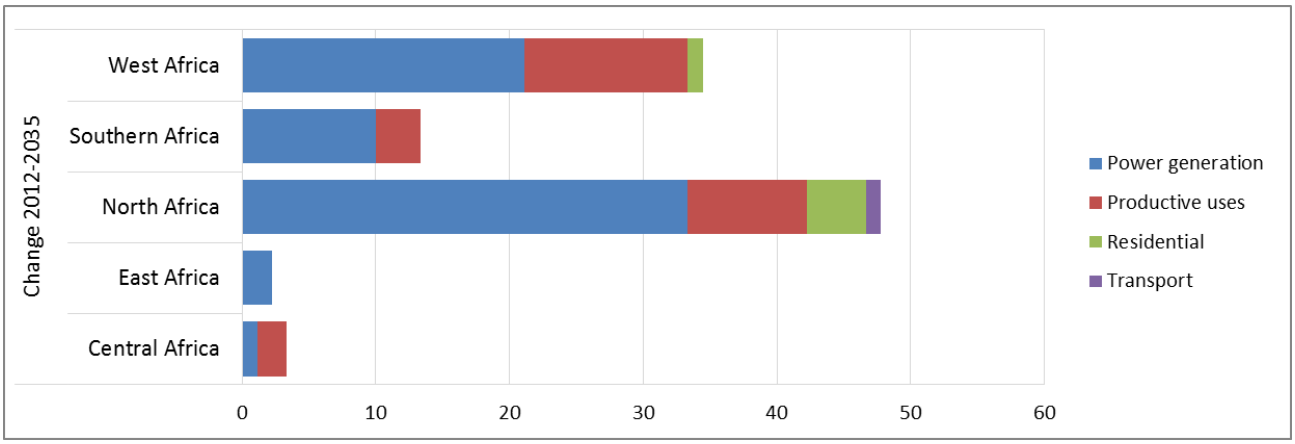


figure 30: regional change in natural gas demand by sector, bcm, 2012-2035, Source: AIE, Africa Energy Outlook, 2014

Residential and Commercial Sectors

Access to commercial gas for households and commercial sector has traditionally been the exception of the North African countries, mainly due to its availability, and the economic advantages that allowed the development of necessary infrastructures to its promotion. It is also used in Nigeria with new development of gas infrastructure in Nigeria and neighbouring countries for local consumption. Natural gas demand in residential sector will add 5 bcm between 2012 and 2035.

Productive uses

Productive uses of natural gas represents 25% of gas demand in 2035, mainly related to its use in industry, services, agriculture and non-energy uses. The growth of gas in this sector is mainly driven by the energy intensive industries, including mining, cement, iron and steel, and fertilizers. The increase will come from North and West Africa, related to its use in fertilizers industries and mining and steel.

Transport

The use of gas for transportation is limited to North Africa, mainly in Egypt, where 189 thousands vehicles were in circulation by the end 2013 and 172 fueling stations. Gas use in transportation in Egypt could increase due to the advantages granted for natural gas use in transportation sector and technology owned by 6 operating companies.

Power Generation

Power Generation capacity in Africa amounts to 163 GW in 2012. North and Southern Africa concentrates 76% of Power Generation capacity in Africa, with 66 GW and 58 GW respectively, followed by West Africa that holds only 26 GW of electric capacity (16% of Africa total). The electric energy mix is very different across regions. North Africa relies to 71% on natural gas for its electricity, with oil in the second position, mainly in Egypt. On the other hand, Southern Africa has the particularity of relying heavily on coal for its power generation, with 40 GW of coal powered generation on 58 GW total, representing 69% of total capacity. West Africa relies evenly on Natural Gas and Oil to generate electricity (42% each). Central and East Africa have very limited access to electricity with 5 GW and 8 GW of power generation capacity, primarily from hydroelectricity, while half of the capacity comes from oil for east Africa. Overall, while gas powered capacity represents the third of continent total, it represents only 13% of power generation capacity in Sub Saharan Africa, still dominated by Coal.

Electricity generation in Africa is expected to grow from 741 TWh in 2012 to 1835 TWh in 2035, a strong growth rate of 4% on annual average, driven mainly by the growth from electricity generated by natural gas (39% of additional electricity) followed by hydro (24%), while coal and renewables add 13% each of additional power generation by 2035. Hydro will show the fastest increase with 5.4% of average annual growth rate, followed by Natural Gas with 4.3%.

Power Generation capacity will increase by 305 GW, roughly tripling by 2035. Major contributors to this increase come from gas fired capacity, mainly from North Africa (18%) followed by West Africa (9%) and Southern Africa (6%). 7% of the increase will come from coal fired capacity in Southern Africa, while 20% will come from hydroelectricity (11% evenly from West and Southern, and remaining shared mainly by East and Central Africa).

African countries should add an additional 115 GW of gas powered electric capacity from 60 GW currently. North Africa will remain major user of gas for power, but the remaining regions will significantly increase their capacity where 26% of added capacity will come from Southern, Central and East Africa, where current gas fired capacity doesn't exceed 2 GW, to reach 33 GW by 2035, 19 GW of which in Southern Africa alone.

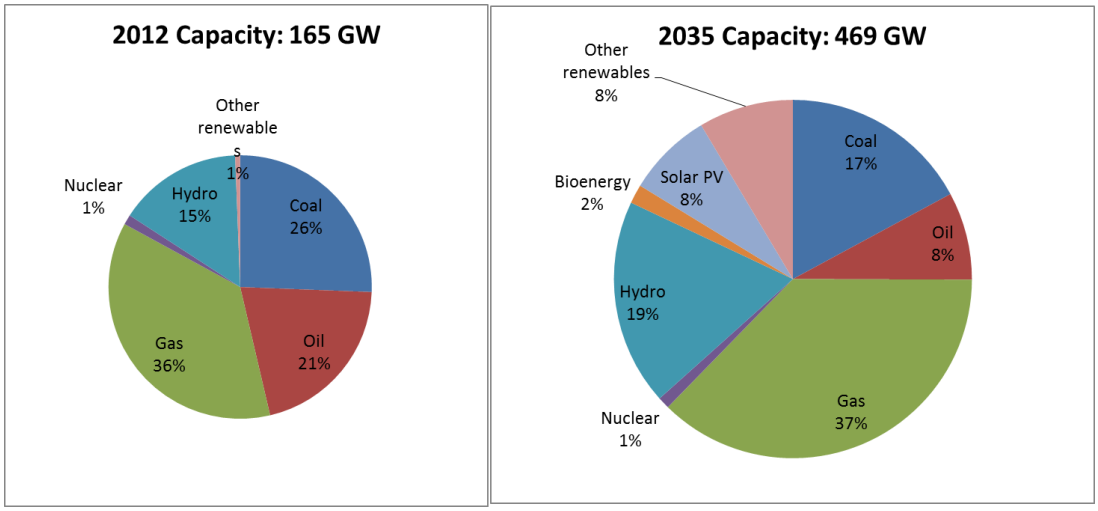


figure 31: Power Generation evolution, Source: IEA, Africa Energy outlook 2014

The power generation sector concentrates the largest part of gas consumption in Africa with 51% of primary gas consumption representing 56 bcm of gas used to generate electricity. This share will increase by 2035 to 55% of share in power sector, where gas consumption in power generation will increase to 125 bcm. Power generation sector is the big winner of the gas consumption by 2035.

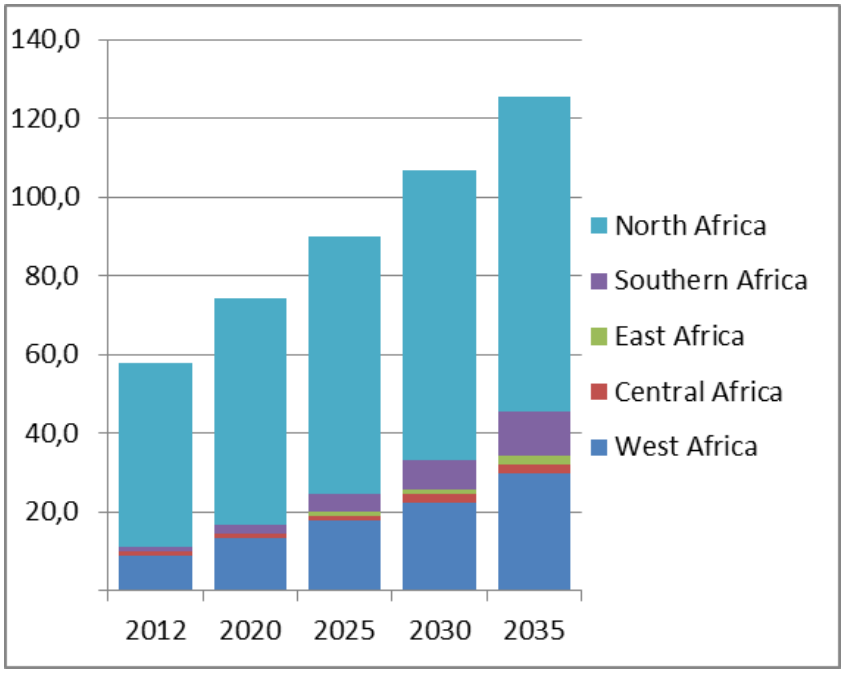


figure 32: Africa – Power Sector Gas Demand, bcm

Access to electricity remains the privilege of North Africa where more than 99% of the population has access to electricity, followed by South Africa with less than 25% of the population without access to electricity. According to IEA, more than 620 million of African people don't have access to electricity, which is 60% of the continent population, and this number is increasing as population growth is more rapid that electric penetration. Since 2000, 145 additional population gained access to electricity, mainly from Nigeria, Ethiopia, South Africa, Ghana, Cameroon and Mozambique, improving electricity access in Sub Saharan from 23% in 2000 to 32% in 2013.

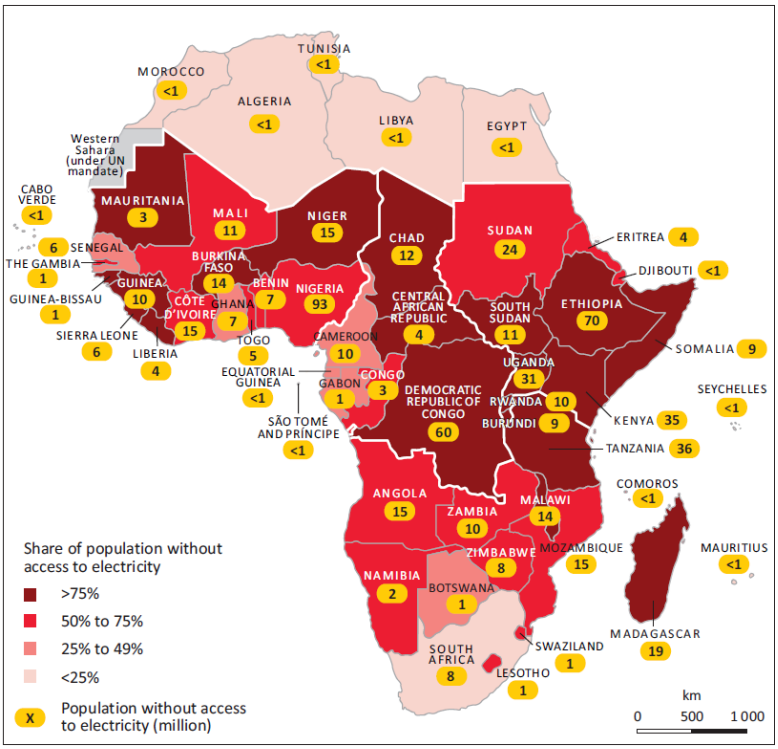


figure 33: number and share of people without access to electricity, 2012, Source : IEA, Africa Energy Outlook 2014

Natural Gas Supply

Natural Gas Resources in Africa

Remaining recoverable gas resources are estimated to more than 100 tcm, half of which unconventional. The remaining conventional potential lies in existing producing regions of North Africa and West Africa, and the new promising regions in Southern Africa. The bulk of unconventional resources lies in North Africa and Southern Africa. The table below shows that 93% of the conventional ultimately recoverable gas resources have not been produced yet, which shows that a huge potential in Africa remains untapped.

Table 1: African natural gas resources and reserves

	Proven reserves end-2013	Ultimately recoverable resources	Cumulative production end-2013*	Remaining recoverable resources	Share (%)	Remaining % of ultimately recoverable resources
Africa	17	56	4,1	52	100%	93%
North Africa	8	24	3,3	21	40%	86%
West Africa	5	10	0,6	10	19%	94%
Central Africa	0,4	2,4	0,1	2,3	4%	97%
East Africa	0,2	2,8	<0,1	2,8	5%	100%
Southern Africa	3,2	17	0,1	17	33%	99%
Unconventional**	0,1	49	<0,1	49		100%

Source: IEA, WEO 2014

Proven conventional gas reserves in Africa stood at 17.2 tcm as of 1st January 2014, an increase of 18% from 14 tcm as of the 1st January 2010, according to OGJ estimates. The bulk of the increase came from Mozambique (with large discoveries in the offshore Rovuma basin), with proved reserves standing up to 2.8 tcm multiplied by 22 times from 2010 level, followed by Egypt with an increase of 32% from 2010. This makes the African continent gas discoveries contributing with as much as 27% of the increase in all the gas discovered in the world over the last 4 years.

Proven gas reserves represent 8.6% of the world's total, according to OGJ estimates. The five largest African holders of gas reserves hold more than 94% of total continent, namely Nigeria (5.1 tcm), Algeria (4.5 tcm), Mozambique (2.8 tcm), Egypt (2.2 tcm) and Libya (1.5 tcm).

Table 2: Table: Proved gas reserves

Country Proven Gas Reserves, bcm	Jan.1, 2014	Jan.1, 2010	Share (%)	Change	Share of change (%)
Nigeria	5 118	5 246	30%	-129	-1%
Algeria	4 504	4 502	26%	2	0%
Mozambique	2 832	127	17%	2 704	23%
Egypt	2 186	1 657	13%	530	5%
Libya	1 549	1 539	9%	10	0%
Other Southern Africa	344	341	2%	3	0%
Other Central Africa	292	292	2%	0	0%
Other East Africa	186	172	1%	14	0%
Other West Africa	80	80	0%	0	0%
Other North Africa	67	67	0%	0	0%
Total Africa	**17 157**	**14 024**	**100%**	**3 134**	**27%**
Total World	**198 892**	**187 154**		**11 738**	**100%**

Source : OGJ, 2014

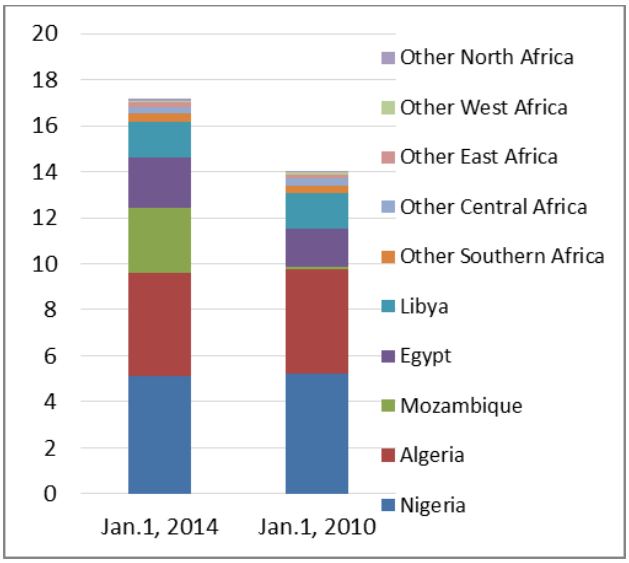


figure 34: Proven gas reserves, *Source: OGJ*

Table 3: Shale Gas Resources

Country, Region	Gaz In place, Tcm	Technically Recoverable, Tcm	Recovery Rate (%)
Algeria	96,8	20,0	21
Egypt	15,2	2,8	18
Lybia	26,7	3,5	13
Morocco	1,6	0,3	21
South Africa	44,1	11,0	25
Tunisia	3,2	0,7	20
Western Sahara	1,1	0,2	21
North Africa	144,6	27,5	19
Southern Africa	44,1	11,0	25
Africa	188,7	38,5	20
N. America (Exc. USA)	131,6	31,7	24
Australia	57,9	12,4	21
Europe	180,9	40,5	22
Asia	138,6	25,0	18
USA	183,9	39,7	22

Source: EIA/ARI, 2013

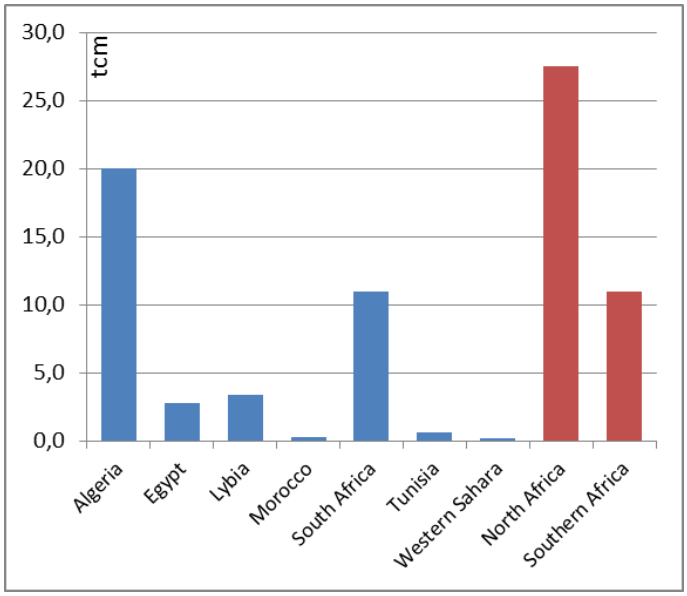


figure 35: Technically Recoverable Shale Gas Resources, Source: EIA/ARI, 2013

According to the IEA/ARI study published in june 2013, African countries hold a considerable amount of shale gas resources that could reach 38 tcm in terms of technically recoverable resources, 71% of which are concentrated in North Africa. The African continent represents

21% of the total world shale gaz TRR and could play a major role in terms of gas supply if the concept is proven and technically and economically viable.

Many countries are engaged in assessing their unconventional resources and conducting pilot projects to better evaluate the potential.

Algeria has gas and oil shale resources spread over 7 basins: Ghadame (Berkine) and Illizi in the east of the country, Timimoun Ahnet Mouydir and the Centre, Reggane and Tindouf in the southwest of the country. Several geological studies and shale reservoirs were conducted with international companies. In place gas reserves are estimated at 3,419 Tcf, with 707 Tcf of technically recoverable gas (third globally according to the IEA). The Algerian State has set up new tax measures in early 2013 to encourage exploration and development of unconventional hydrocarbons, and January 21, 2014, the National Agency for valuation of Algerian hydrocarbons (Alnaft) conducted a tendering of 31 oil areas, nearly half are unconventional hydrocarbons. In 2014, the Government gave its approval for the exploration and exploitation of shale gas. Sonatrach announced production from major shale gas deposits beginning from 2022, with a production capacity of 30 billion m^3/year as the first phase, and an initial production of 20 billion m^3. She announced in early December 2014, the completion of drilling and compression of the first pilot in the Ahnet basin and drilling program of 11 pilot wells over a period of 7-13 years to test the productivity of priority the basins of Ghadames , Illizi, Timimoun Ahnet and Mouydir.

South Africa is a net importer of natural gas, mainly from Mozambique and Namibia. As such, South Africa has given priority to the national oil and gas exploration. The exploration of shale is initiated by a Permit for Technical Cooperation (PTC), which can lead to an exploration permit (EP) and subsequently to a production contract. South Africa has one important Sedimentary shale gas Basin, the Karoo Basin, occupying 2/3 of the country's surface. Shale gas resources in South Africa are estimated at 1,559 Tcf of gas in place, with 370 Tcf technically recoverable. Several companies, including Shell, Falcon, Challenger, Sasol JV / Chesapeake / Statoil, Sunset Energy Ltd. of Australia, the JV Oil & Gas / Chevron, Anglo Coal of South Africa and Anglo-American, had signed permits for technical cooperation for the exploration of shale gas in the Karoo Basin. A moratorium was introduced for exploration drilling in 2011, but was lifted in September 2012 to allow exploration, not including fracturing operations. South Africa issued on 15 October 2013, regulations on hydraulic fracturing, and presented in October 2013, a bill to authorize exploration and exploitation fracturing. The exploration could begin soon and according to a report of Econometrix, published in 2012, the production of shale gas from the Karoo Basin is expected to begin in 2020 and should contribute to the country's GDP by a volume of $100 to $432 billion over a period of 25 years with jobs ranging between 160,000 and 854,000.

Egypt has four pools with a potential gas and oil shale - Abu Gharadig, Alamein Natrun and Shoushan-Matruh. They are located in the Middle Jurassic Khatatba formation, sometimes referred to as Kabrit or Safa. Khatatba shale formation contains about 535 Tcf of gas in place, with 100 Tcf technically recoverable. The exploration activities are carried out by the US company Apache in the Western Desert. In 2010, Apache announced the existence of a shale formation in the East Bahariya field that may contain between 700 million and 2.2 billion barrels of oil shale in place, planning the drilling of 2 evaluation wells in 2013.

Lybia's Shale gas reserves of the three basins of Ghadames, Sirte and Murzuq are estimated at 942 Tcf of gas reserves in place, with 122 Tcf technically recoverable. In addition, these shale formations also contain 613 billion barrels of oil and condensate in place, with 26.1 billion barrels technically recoverable. The government has begun discussions with partners (Shell, Exxon Mobil and Total) for shale gas, but in 2012, the Libyan national oil company NOC

announced that gas and oil shale resource assessments will be carried in-house before calling to international companies for exploration and development of these resources.

Tunisia has two significant formations in Tannezuft and Frasnian, located in the Ghadames basin, with an estimated shale gas potential to 114 Tcf of gas in place, with 23 Tcf technically recoverable. The first well was drilled with fracturing in 2010 by the Chinook Energy Inc. Canadian Winstar Resources acquired a series of shale concessions in the Silurian and Tannezuft Ghadames, with the participation of ETAP and proceeded to a drilling test well (Sabria 12) in 2013. Tunisia could also contain shale potential in the Pelagian basin to the east extending to offshore. Shell Oil, which has gained an important position in the Pelagian Basin, announced an exploration program of $150 million for conventional reservoirs and potential gas and shale oil. Environmental problems on fracking are subject to tense debates in Tunisia.

Morocco. The two cross-country basins Tindouf and Tadla contain a total of 95 Tcf of shale gas reserves in place, with 20 Tcf technically recoverable. The Moroccan state oil company, ONHYM, began assessing the potential of country's shale gas since mid-2010. The drilling of an appraisal well is planned in partnership with San Leon Energy (Ireland) and Longreach Oil and Gas (Canada) on the exploration permit Zag in the Tindouf Basin. No exploration activity was reported on the Tadla Basin.

Natural Gas Production in Africa

African gas production historical data over the past 10 years show a dramatic increase of marketed gas production reaching 206 bcm in 2013 compared to 77 bcm in 1994. This production grew by a two digit average annual growth rate at a 10.3% over this period compared to 4.6% for the rest of the world over the same period. It increased by 1.67 times over the period 1994-2013. 85% of the total volumes are located in Algeria (39%), Egypt (28%) and Nigeria (19%).

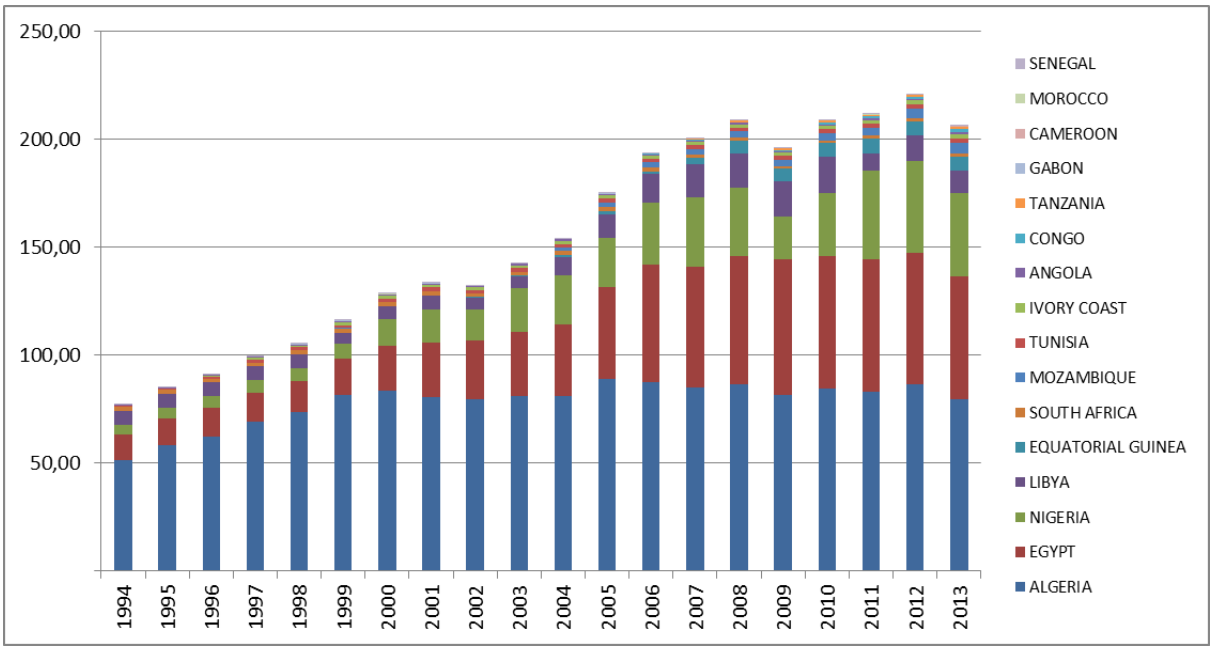


figure 36: Natural Gas Production, Source : CEDIGAZ 2014

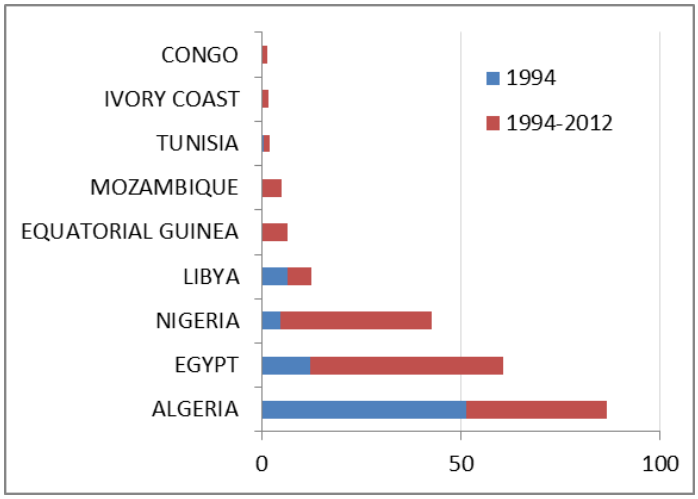


figure 37: Natural Gas Production increase over 1994 to 2012, Source: CEDIGAZ 2014

Egypt has experienced the largest increase of marketed production over the last decade, with +44 bcm/y in 2013 compared to 1994 level, which corresponds to an average annual growth of 16.9%, but was rapidly overtook by the spectacular increase in domestic gas consumption of 15.8% on annual average, that absorbed much of the available gas for export.

The second largest increase came from Nigeria which added 33.9 bcm/y to its production, from a low level of 4.5 bcm/y in 1994, and only one third of this volume has been absorbed by domestic consumption, leaving two thirds for exports.

Algeria accounts for almost 40% of African gas production, and increased its marketed production by 35.5 bcm over between 1994 and 2012, from an already high level of 51.2 bcm in 1994, while its domestic consumption increased by only 17 bcm, creating an additional 18.5 bcm for export.

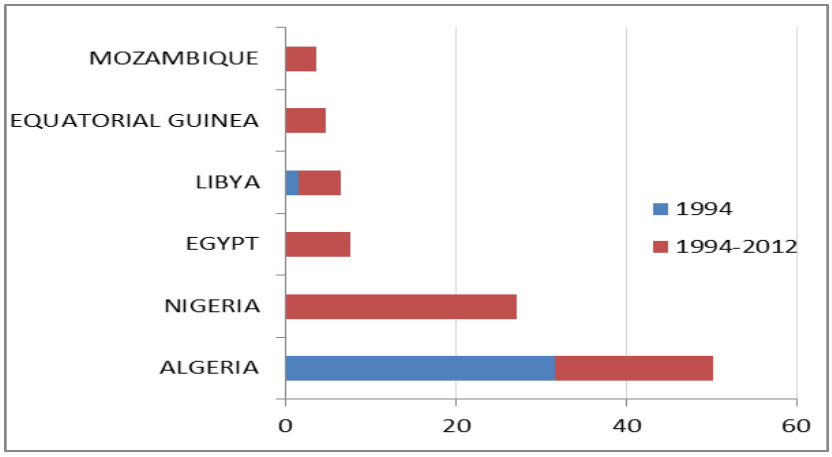


figure 38: Natural gas exports

A remarkable evolution noteworthy is the advent of two new gas producers in the region that added a significant production to the additional volume of Africa, namely Equatorial Guinea and Mozambique that added 6.6 bcm and 5.3 bcm respectively, and accounted for 9% collectively of the global regional increase.

The remaining production is mainly used for domestic use by Tanzania, Senegal, South Africa, Gabon, Ivory coast, Tunisia, Congo and Cameroon.

Collectively, African countries exported 85.6 bcm of natural gas in 2013, 50% by Algeria and 27% from Nigeria that accounted for the major additional export volumes since 1994 with 43% of the additional export volumes. Algeria added 22% to the increase from 1994, the remaining is shared almost evenly by Equatorial Guinea through LNG, Egypt to western Mediterranean through pipeline and other countries though LNG, Libya to Italy through pipeline and LNG and Spain through LNG, and Mozambique to South Africa through pipeline.

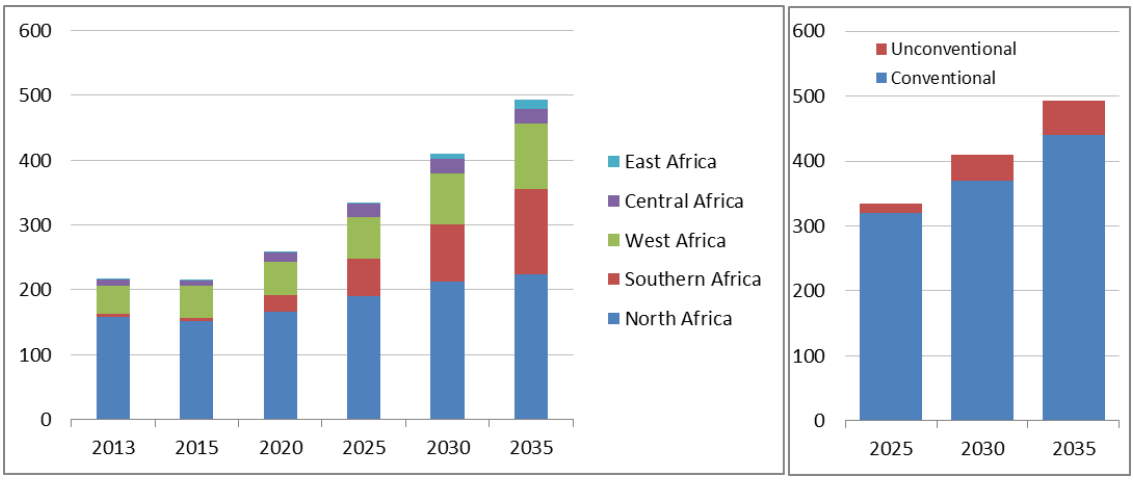


figure 39: Natural Gas Production Perspectives to 2035, Source: Rystad Energy 2014, WEO 2014, various announcements

Natural gas production should increase significantly during the coming years in the African continent from 197 bcm in 2013 to almost 494 bcm in 2035, driven mainly by the growth from North Africa, Sourthern Africa and West African countries representing respectively 48%, 26% and 19% of the 2035 output. Unconventional gas production will amount 53 bcm in 2035 in this scenario, representing 10% of the total gas output.

A growing number of countries will begin production in the next decade, like Angola, Tanzania, Tunisia and Namibia, and South Africa. Mozambique will experience the largest increase amongst Sub Saharan Africa countries.

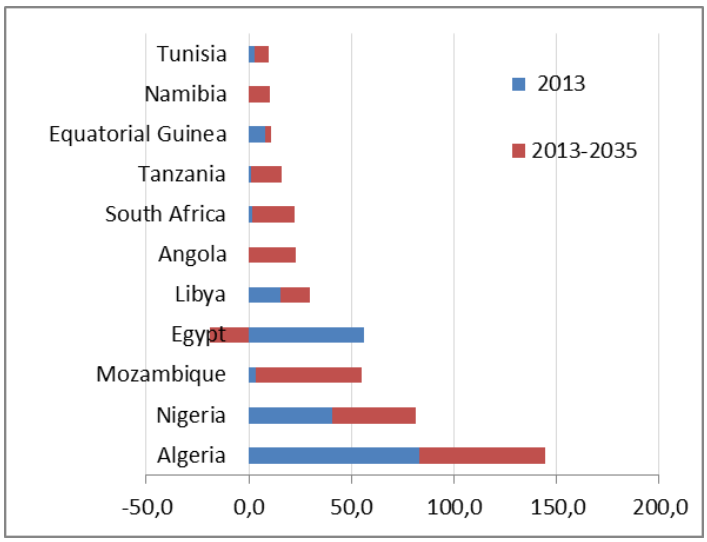


figure 40: Natural Gas production increase in selected countries, Source : Rystad Energy 2014, IEA 2014, internal estimates

Algeria. The potential of growth of gas production in Algeria is significant. According to official announcements, Algeria intends to increase in gas production capacity by 40% within the next 5 years, with the commissioning of several projects in the South West Pole including Tinhert

(+24 MMscmd), Hassi Bahamou and Hassi Mouina (+21 MMscmd), Touat (+12 MMscmd), Timimoun (+5 MMcsmd), Reggane Nord (+12 MMscmd), and also Rhourde Nouss/Quartzit of Hamra in the South East Pole. Additional output should come from shale gas production that would come on stream in 2022, as announced by Sonatrach CEO, with a planned capacity of 25 bcm in 2025 to reach 30 bcm before 2030. Earlier in 2014, Sonatrach CEO had mentioned the project of a third boosting on the Hassi R'Mel field that would allow the recovery of additional volumes estimated at 400 bcm and would postpone the decline of the field by a decade. Additionally, Sonatrach in investing heavily on exploration, with an average annual expense of 2 b$ over the last 5 years, which proved successful as 250 mtoe/y have been added annually to its reserve base. Algeria mining domain remains under explored, and Sonatrach has announced that it will pursue an extensive exploration program of 125 well/y and 26 000 km2/y over the next 5 years, with a particular focus on the assessment and development of unconventional resources and the exploration of Algerian northern and offshore areas.

Nigeria remains the largest gas producer in Africa, after Algeria with a projected gas output of 81 bcm in 2035 according to IEA estimates. Around 60% of Nigeria's gas reserves are associated gas (rich in butane and propane). In 2013, 21.5 bcm of gas was reinjected in oil fields, while 12 bcm were flared, down by 8% from 2012 levels. Presently, the priority of the government is to raise gas production in a significant manner in the next three years by cutting gas flaring and raise domestic gas prices to attract foreign private investment. Nigeria plans to boost gas in Power sector and industrial development, while supporting exports. According to IEA WEO 2014, Nigeria will face challenges to raise its non-associated gas output, and will require a new framework to incentivise the large scale capital investments.

Mozambique will have the largest increase in gas production amongst sub Saharan African countries, reaching 55 bcm of gas production in 2035, according to IEA/WOE 2014 African Century Case scenario. The main upstream gas projects in Mozambique come from the Area 1, with discoveries of 2010-2012 period, led by Anadarko (26.5% share) Mitrsui (20%) and ONGC (16%) and Area 4 fields, discovered between 2011 and 2013 and led by Eni (50%) and CNPC (20%). According to Rystad Energy, discoveries from Areas 1 and 4 could reach up to 100 bcm of gas production in 2035. Current production of the Penda and Temane fields should be maintained in the same level until 2030. Estimates from Rystad Energy put Mozambique production to 116 bcm in 2035.

Table 4: Main new upstream gas projects in Mozambique and Tanzania

Block / main fields	Partners	Status
Mozambique		
Area 1: Golfinho, Tubarao, Prosperidade	***Anadarko*** (26.5%), Mitsui (20%), ONGC (16%), ENH (15%), Bharat (10%), PTT (8.5%), Oil India (4%)	Area 1 is closest to the Mozambique coastline. Discoveries in 2010-2012; part of the Mamba field (Area 4) straddles the border with Area 1
Area 4: Coral, Mamba	***Eni*** (50%), CNPC (20%), Galp Energia (10%), KOGAS (10%), ENH (10%)	Discoveries in 2011-2013, part of the Prosperidade field (Area 1) straddles the border with Area 4
Tanzania		
Blocks 1,3,4: Chaza, Jodari, Mzia, Papa, Chewa	***BG*** (60%), Ophir (20%) Pavilion (20%)	Nine discoveries in total in 2010-2014, although considerably smaller than those in Mozambique
Block 2: Lavani, Tangawizi, Piri,	***Statoil*** (65%), ExxonMobil (35%)	Six discoveries in 2012-2014

Notes: Existing production in Mozambique comes from the Sasol-operated Pande and Temane fields (connected by pipeline with South Africa) and in Tanzania mainly from the Songo Songo field. These were discovered in the 1960-1970s, but only started operation in the 2000s. No final investment decision has yet been taken on any of the projects in the table above.

Source : IEA/WEO 2014, Africa Energy Outlook.

Tanzania should continue to raise its production from its producing and under development fields to reach 3 bcm of output by 2020. But on the long run, it should raise significantly its gas production to approximately 16 bcm in 2035, mainly from the fields of Blocks 1,3,4, discovered between 2010 and 2014, led by BG (60% share), the fields of Block 2, discovered in 2012-2014 period, and led by Statoil (65% share). The potential of growth is however more important with the possibility to double this level by 2035.

South Africa could become a large shale gas producer with a potential production of 15 bcm by 2035, mainly from the Prince Albert shale play in the Karoo basin. Additional production could come from conventional resources with an additional 8 bcm.

Tunisia produced 1.9 bcm of marketed gas in 2013 mainly from the Miskar and Hasdrubal fields with BG, and could increase its conventional gas output to 4 bcm in 2035. However, Tunisia has two significant shale formations of Tannezuft and Frasnien in the Ghadames basin. Winstar Resources and Chinook Energy have already complete test wells with fracturing in 2013 and 2010 resp. Tannezuft coul add a significant shale gas production and could reach 5 bcm of production by 2035, but many obstacles have to be overcome, like fiscal regime, technical feasibility, and favorable economic and market conditions. Estimated potential unconventional output by Rystad Energy could reach 18 bcm by 2035 if all conditions are met.

Natural Gas Infrastructure Developments

LNG Infrastructure

According to the Petroleum Economist database, Africa possesses LNG export capacity of 103 BCM a year (75 million tons), and could reach over 248 BCM a year (180 million tons) by 2020 if all projects are realized.

The increases in LNG capacities are mostly in Nigeria with plans to more than triple their existing capacities from 29 BCM (21 million tons) to 103 BCM (75 million tons) if they materialized. Increases are also planned in Equatorial Guinea and Egypt although the latter is speculative and will depend on new discoveries.

Otherwise the other increases are in in new exporters such as Cameroon, but mostly Mozambique and Tanzania. Indeed, the major focus in the years to come in Africa will be in East Africa where major discoveries have led to LNG projects with capacities up to 69 BCM a year (50 million tons).

There are still no regasification capacities in Africa at the time of writing, although different projects are on the table in Ghana, Morocco and FLNG in Egypt.

Existing LNG Infrastructure

Six countries in Africa currently possess LNG export infrastructure, the latest one is Angola in 2013 and the first one was Algeria in 1964 followed by Libya in 1971. In 2013, LNG export from Africa amounted to 46 BCM, a decrease of 13.44% compared to 2012 due to various issues in 2013. The main markets have evolved from North America to Asia Pacific and Europe has experienced a decrease in its gas demand. African exports represent around 14% of the total LNG exports in 2013 according to BP data.

Table 5: Existing African Liquefaction Capacity

Country	Location	Trains	Capacity (mt/y)	Partners	Start date	Notes
Algeria	Arzew GL4z (Camel)	3	0.9	Sonatrach	1964	Has been at a stand still since 2010
	Arzew GL1z	6	8.1	Sonatrach	1978	
	Arzew GL2z	6	8.2	Sonatrach	1981	
	Arzew GL3z	1	4,7	Sonatrach	2014	
	Skikda GL1k Phase I & II	3	5.2	Sonatrach	1972	Trains added or current train(s) expanded 1978 and 1981
	Skikda Mega train project	1	4.6	Sonatrach	2013	
Libya	Marsa el Brega	1	2.3	Sirte Oil Co.	1970	Currently closed. Unclear if facility will restart
Egypt	Damietta	1	5.00	SEGAS (Union Fenosa, ENI, EGAS, EGPC)	2005	Currently idle due to a lack of feed gas
	Idku	2	7.2	Egyptian LNG, (EGPC, EGAS, BG, GDF SUEZ, Petronas)	2005	
Equatorial Guinea	Bioko Island	1	3.70	EG LNG (Marathon, Sonagas, Mitsui, Marubeni)	2007	
Nigeria	Bonny Island	3	9.60	Nigeria LNG, (NNPC, Shell, TOTAL, ENI)	1999-2002	
		2	8.10	Nigeria LNG (NNPC, Shell, Total, ENI)	2006	
		1	4.00	Nigeria LNG (NNPC, Shell, Total, ENI)	2008	
Angola	Soyo	1	5.2	Sonangol, ENI, Chevron, BP, Total	2013	

Table 6: Planned and in construction African Liquefaction Capacity (FEED and Pre-FEED)

Country	Location	Trains	Capacity (mt/y)	Partners	Start date	Notes
Equatorial Guinea	Bioko Island	1	4.4	EG LNG (Marathon, Sonagas, Mitsui, Marubeni)	2016	Mitsui to sell stake to one of the partners
	Bloc R Offshore	FLNG	3	Excelerate Energy, Ophir Enrgy	2019	
Nigeria	Bonny Island	1	8.4	Nigeria LNG (NNPC, Shell, Total, AGIP)	2016	
	Brass Island	2	10	Brass LNG (AGIP, NNPC, Total)	2020	
Mozambique	Area 1 (Palma)	2	10.0	Anadarko, Mitsui & Co, ENH, Bharat Petroleum, Videocon, Cove Energy	2019	

Country	Location	Trains	Capacity (mt/y)	Partners	Start date	Notes
	Area 4 (Palma)	2	10.0	Eni, ENH, Galp Energia, KOGAS	2019	
Tanzania	Lindi	2	10	BG Group, Ophir Enrgy,Statoil	2020	
Cameroon	Kribi	1	3.5	GDF Suez, SNH	2018	

Planned LNG Infrastructure

The main planned infrastructure in Africa comes from the discovery of enormous gas fields off the coast of Mozambique and Tanzania, but also from existent LNG exporters such as Nigeria and Equatorial Guinea who are planning to increase their liquefaction capacity.

Production made available to the market is five-times greater than it was in 2000, mainly from Nigeria, which now has six LNG trains, but also from Equatorial Guinea and Angola, which joined the ranks of global LNG exporters in 2007 and 2013 respectively.

In terms of regasification capacity, the likes of Morocco and Ghana are the latest to decide on such infrastructures, along other countries like Kenya and South Africa. Egypt is also considering FSRU to be able to import LNG.

Mozambique

In Mozambique, the two main players are Anadarko and ENI.

The plan is for Anadarko to build two trains of 2.5mtpa each by 2020. It has signed agreements with Asian buyers for about 70% if the gas. The problem is that Anadarko, with around a quarter of the equity in Area 1, will have to finance around 5 billion dollars of the project, which could see the company diluting its stake with Exxon a favorite to enter the partnership.

Another issue is that Anadarko has no liquefaction development experience.

As for ENI, it is planning to commission its first LNG train in 2020. It has not yet secured sales agreements but has more reserves than Anadarko. It is looking to sell 20% of its 70% interest in area 4 but will remain the operator.

ENI has also launched FEED activities in May 2014 for an FLNG vessel for the Coral South Development project. The FEED process is due for completion by April 2015 and this project could be an alternative for Mozambique if the onshore facility does not materialize.

Tanzania

In Tanzania, a state of turmoil is affecting the petroleum sector with rampant allegations of corruption that even led to the sacking of senior officials in December 2014. This unstable situation adds to the uncertainty surrounding the attempt to build an LNG liquefaction plant to exploit its newly found resources. International companies and investors are awaiting legislation in order to be able to invest, that would have been provided by the Natural Gas Bill, but it is now unlikely that it will pass in 2015; as elections are awaited by the end of the year.

Without passage of this law, the operators of the Tanzanian offshore blocks 1-4 Statoil and BG Group are uncertain of how much gas will be allowed to be exported, Tanzania's demand potentially growing and absorbing the gas.

According to state owned Tanzania Petroleum Development Corporation, the offshore reserves reach 50 Tcf, but it includes P50 and P10 estimates as well as P90. Statoil estimates block 2 reserves at 21 Tcf and BG at 15 Tcf.

The government has declared many times their intention to prioritize the domestic development before exports, which would limit the operator's profits.

As reserves of 12-15 Tcf are generally required for a two train LNG facility during a 20 year lifespan, it is unclear whether Tanzania will have enough gas to export after meeting its local demand.

Libya

According to the Cedigaz 2014 year in review, the aged Marsa el Brega LNG facility sustained heavy damage during the 2011 conflict and is offline at the time of writing. The instable situation in the country makes any planning risky and difficult.

Equatorial Guinea

Activity has accelerated in Equatorial Guinea recently for the development of the Block R FLNG project.

An awaited agreement on the fiscal terms to provide financial transparency has been finalised in November 2014 between the government, Ophir energy (80%, operator) and GePetrol (20% equity partner, national oil company of Equatorial Guinea).

In the same month, it was also announced that Excelerate would head a consortium to provide the floating liquefaction and storage facilities at Ophir's operated FLNG project in Block R.

The unit will be located in Block R of Equatorial Guinea's offshore acreage about 140 kilometers off the Coast of Bioko Island, in water depths of approximately 1600 meters and benign ocean conditions. It is expected to produce up to 3.0 million tons per annum of LNG over a period of 20 years from 2019.

The Fortuna field is expected to form the first phase of the planned FLNG development and has estimated mean recoverable resources of 1.3 Tcf. Block R has reserves of 3.4 Tcf and is meant to be developed in 4 phases.

The next milestones for the Block R FLNG development are the award of the upstream and midstream FEED contracts planned for early 2015. A FID is expected in 2016 and first gas in 2019.

Nigeria

According to the AEO 2014, Nigeria is, and remains, the largest gas producer in sub-Saharan Africa over the period, with a production of 85 bcm in 2040.

Four new LNG projects are under consideration (Brass LNG, OK LNG and trains 7 and 8 at Nigeria LNG), however, the government faces a challenge to mobilize the necessary upstream investment and, even if the netback prices are less attractive, the government is assumed to prioritize domestic supply over export.

There is talk of a moratorium on new LNG export projects and the expansion of the shell led NLNG's capacity.

Cameroon

An FLNG project 20 km off the southern coast of Cameroon near the city of Kribi has been agreed by Golar LNG, a company based in London, the SNH (Société Nationale des Hydrocarbures) and Perenco Cameroon. GDF Suez is also involved as the partner of SNH.

The gas would come from the nearby offshore Kribi Fields operated by Perenco, a French hydrocarbons group, at a rate of 500 bcf. The ship is a LNG ship belonging to Golar; a company

specialized in LNG transportation, being transformed in an FLNG unit in Singapore at the Keppel shipyard.

Golar will provide the liquefaction facilities and services under a tolling agreement to SNH and Perenco who are the owners of the upstream Joint Venture.

The JV is expected to produce 1.2 million tons of LNG for about 8 years. Apart from this FLNG project, SNH have a longstanding plan for an onshore liquefaction plant at Lolabé, further south of Kribi, along with its close partner GDF Suez.

According to Golar, production is expected in 2017, after all licenses and commercial agreements have been finalized in 2015. If there are no delays, this project would become the first FLNG project in Africa to start production.

Egypt

There were plans for extensions of Egypt's LNG capacity at Damietta and ELNG but the lack of feed gas has put them on hold. The Damietta terminal is currently idle due to a lack of feed gas.

Planned Regasification Terminals

There are still no regasification terminals on the whole of Africa but a few projects are considered including FSRUs.

Morocco:

Morocco has launched a national plan to boost imports of liquefied natural gas (LNG), including the construction of a terminal at the industrial hub of Jorf Lasfar, worth up to $4.6 billion. The idea to build a LNG terminal was announced a few years ago but the government has given no reasons for the delay. Jorf Lasfar is an industrial hub on the Atlantic coast near El Jadida city where the state-run phosphate companies OCP and Abu Dhabi's TAQA have facilities.

The plan will allow Morocco to import up to 7 billion cubic meters (bcm) of gas by 2025 and includes a jetty, terminal and pipelines, with estimated investments of $600 million, $800 million and $600 million respectively. A long awaited gas law is also expected to come before parliament by June 2015. Talks on contracts for 3-5 bcm/year are expected to begin with suppliers including GDF Suez and Shell.

South Africa:

PetroSA has decided not to establish a Floating Liquefied Natural Gas (FLNG) import terminal in Mossel Bay, following extensive feasibility research conducted by Worley Parsons. South Africa's national oil company has determined that the identified location had technical and commercial challenges for the operation. PetroSA has been investigating the possibility of bringing in LNG to supplement dwindling gas reserves since 2008 but the study found that meteorological and oceanographic (metocean) conditions in Mossel Bay are severe, and would inevitably increase the logistical and overall gas supply costs of the project. The proposed FLNG facility for Mossel Bay comprised a breakwater and berth structure allowing a permanently moored Floating, Storage and Re-gasification Unit (FSRU) to discharge vaporised LNG into a subsea and overland pipeline leading to the Mossel Bay Gas-to-Liquids (GTL) Refinery. Due to the failure of locating a LNG import terminal in Mossel Bay, the company has decided to explore the suitability of locating it at other sites, and it is currently evaluating various location options.

Kenya:

Bids for construction and operation of a gas plant in Kenya failed to meet the criteria set by the government. In the last stage of the tender process, only two firms submitted bids and none of

them met the timelines. Both teams proposed to build the plant over two years, contrary to the Request for Proposal tender which stipulated a timeline of 18 months. The Minister said the evaluation committee had recommended to the Treasury's Public Private Partnership (PPP) unit to sanction a repeat of the process and not to open the non-responsive financial bids. Among the bidders were China Petroleum, Tata Power in consortium with Gulf Energy, Globeleq, Mitsui & Co, Toyota Tyusho, Marubeni Corporation, Samsung C&T, GMR Energy, Quantum power and GDF Suez.

The successful bidder for the Dongo Kundu plant in Mombasa will be required to build a floating storage and re-gasification unit with sufficient capacity and infrastructure to supply natural gas to power plants using heavy fuel oil.

Ghana:

Despite the opening of the West Africa Gas Pipeline, the lack of reliable supply has forced Ghana to ration its power, and to explore options for liquefied natural gas (LNG) imports. HR Wallingford has supported Quantum Power in assessing the operational viability of the proposed LNG storage, regasification and delivery facilities at Tema, Ghana. Quantum Power has recently signed a collaboration agreement with Golar LNG to complete the facility and deliver gas by early 2016.

As part of the proposed Ghanaian LNG project at Tema, HR Wallingford carried out advanced feasibility studies, which included metocean, ship mooring and operational assessments.

Quantum Power aim to deliver first gas by early 2016.The Tema LNG Project, located in the Eastern part of Ghana, will have the initial ability to receive, store, re-gasify and deliver over 1.75 million tons of LNG per year, utilising a state-of-the art, purpose-built, dedicated FSRU moored off-shore, with associated sub-sea and onshore pipeline networks to deliver the natural gas to power generators in Tema.

Egypt:

In May 2014 the Egyptian government signed a letter of intent with the Norwegian shipping company Höegh LNG for the use of a floating storage regasification unit (FSRU), to be located on the port of Ain Sokhna for a period of five years. FRSUs regasify liquefied natural gas, a key step for expanding Egypt's capacity to process imports.

It had also lined up LNG shipments from Algeria's Sonatrach, Russia's Gazprom, and France's EDF.

By mid-July, however, the deal with Höegh had stalled prompting Egypt to reopen talks with the US-based FSRU operator Excelerate Energy.

Benin:

The FSRU will have a capacity of 430 mmcf/day and the regasified LNG will be distributed to Benin, Togo and Ghana via the 678 km West African Gas Pipeline. Financing is required to proceed and the project has been delayed by a variety of issues, including Ghana being reluctant to commit to deal due to potential of obtaining adequate volume of gas offshore Ghana.

Existing pipelines

In 2013, the African countries exported 40 bcm of natural gas by pipeline, representing 5.5% of global gas trade by pipeline. Algeria, Libya, Mozambique represent 96% of the gas sold through gas pipeline and respectively account for 72%, 14% and 9% of the gas sold by pipeline in 2013. 31.5 bcm have been exported to Europe. The remaining 7.1 bcm (18%) have been traded

between African countries, with the existing pipelines from Algeria to Tunisia and Morocco, and from Mozambique to South Africa, with a small amount from Nigeria to Ghana.

There are seven main pipelines operating in Africa, with 90% of the installed capacity in North Africa, and 66% in Algeria.

Three transcontinental gas pipelines connect Algeria directly to Europe via Italy and Spain: The Enrico Mattei gas pipeline (GEM) towards Italy via Tunisia with a capacity of 32.5 Bcm/y, The Pedro Duran Farel gas pipeline (GPDF) towards the Iberian Peninsula via Morocco, with 11.6 bcm/y, and the the Medgaz gas pipeline linking directly Algeria to Spain, operational since April 2011, with a capacity of 8 bcm/y. Another gas pipeline of 9 bcm/y connects Libya to Italy.

Algeria remained the only gas exporter by pipeline until 2004, when pipeline exports from Libya, Egypt and Mozambique started. In 2013, these three African countries, along with Nigeria, exported 11.2 bcm with 4.3 of which remained in Africa. Egypt gas exports fell dramatically from a peak level of 5.5 bcm in 2009 to only 1.8 bcm in 2013.

Table 7: Existing African pipelines

Country	Name	Destination	Completion	Capacity (BCM)	Length
Algeria	GPDF	Spain, Portugal	1996	11.6	1,620
	Medgaz	Spain	2011	8	757
	GEM	Italy	1983	33	2,485
Libya	Green Stream	Italy	2004	9	520
Egypt	Arab Gas Pipeline	Jordan, Syria, Lebanon, Israel,	2003	10	1,000
Mozambique	Southern Africa Regional	South Africa	2004	3	865
Nigeria	West African Gas Pipeline	Ghanan, Benin, Togo	2006	5	678

Planned pipelines

With the growing availability of gas resources in Africa, many pipeline projects are planned or announced.

a) Trans Sahara Pipeline

The Trans-Saharan Gas Pipeline is a planned from Nigeria to Algeria through Niger. On January 2002, NNPC and Sonatrach signed a Memorandum of Understanding for the preparation of the project. The Feasibility study was completed in September 2006. In 2009, NNPC and Sonatrach agreed to proceed with the draft Memorandum of Understanding between the three governments and the joint venture agreement. The intergovernmental agreement on the pipeline was signed by the energy ministers of Nigeria, Niger and Algeria on July, 3rd 2009 in Abuja, Nigeria.

The 4,200 kilometre pipeline will start from the Warri region, in Nigeria, and run North through Niger to Hassi R 'Mel in Algeria, where it will be connected to the existing Algerian infrastructure. The annual capacity is estimated between 20 and 30 bcm/y.

The TSGP project is considered as an innovative and challenging project both because of its technical challenges and also the strategic and structuring role it can play in the Region.

Indeed, TSGP project has two partnerships dimensions: first, a trans African dimension that allows and encourages a South-South cooperation and improves living standards in crossed areas that are characterized by extreme poverty, and second, a trans Mediterranean dimension that strengthens the economic relationships between Africa and Europe.

Table 8: Trans-Saharan technical details

Details	
Capacity	20 – 30 bcm
Diameter	48-56”
Shareholders	
Length	4,200
Start location	Warri (Nigeria)
End location	Hassi R‘mel

b) Galsi gas pipeline

The Galsi project connects Algeria to northern Italy via Sardinia, with a transport capacity of 8 Bcm/year. Galsi starts from the field of Hassi R’Mel and will run through 640 km to the Algeria coasts through the undersea pipeline. For the 285 km sea crossing from Algeria to Italy, a 26 inch diameter pipe is laid down along the floor of the Mediterranean, reaching Sardinia at Porto Botte. At Porto Botte, the gas continue through the 48 inch pipeline crossing Sardinia from South to North over nearly 272 km to reach Olbia. At Olbia, the gas in injected into the 32 inch undersea piping throughout 280 km and terminates at Piombino, where it joins the national gas distribution network.

The Galsi pipeline is included among the Projects of European Interest. The European Union allocated 120 million euros to finance its construction in the European Energy Plan for Recovery (EEPR).

Table 9: Galsi technical details

Details	
Capacity	8bcm
Diameter	26-48“
Shareholders	Sonatrach (41.6%, Edison (20.8%) ENEL (15.6%), Sfirs (11.6%), Hera Trading (10.4%)
Length	640 (Hassi R’mel-El Kala), 837 (El Kala – Piombino)
Start location	Hassi R’mel
End location	Piombino via Sardina

c) New gas pipeline between Mozambique and South Africa

Mozambique exports gas to South Africa via a pipeline linking the Temane and Pande fields to the South African city Secunda with a capacity of 5 bcm / year, with plans to increase it to 10 bcm / y. it is expected that some of the new production is directed offshore to South Africa,

knowing that the latter's gas consumption should increase to 5 bcm in 2013 to 10 bcm in 2020 and 50 bcm in 2030.

In december 2014, a joint development agreement has been signed between SacOil, PIC and IGEPE for a feasibility study of a new transcontinental terrestrial gas pipeline to be built between South Africa and Mozambique. The 2,600 km and $6bn gas pipeline will transfer natural gas from Mozambique's Rovuma fields into South Africa, with off-takes to other neighboring Southern African Development Community (SADC) countries and a right granted to them to participate in the investment.

d) New connection to Ivory Coast from the West African Gas Pipeline

WAGP gas pipeline, along 678 km, runs from Itoki in Nigeria to the Ghanaian town of Takoradi – near the offshore oil and gas site Jubilee - with branches to Cotonou (Benin), Lome (Togo) and Tema (Ghana). The Ivorian authorities aspire to extend it to the coastal town of Hamilton Island in the South East of the country.

figure 41: West African Gas Pipeline, Source : West African Gas Pipeline Co. Ltd.

WAGP could be connected to a pipeline project awarded to the Italian group Saipem, which will link Assini in Abidjan (about 100 km). This pipeline of € 50 million is expected to transport gas of Ivorian blocks CI 01 and CI 202 respectively operated by Vanco and CNR to Abidjan to supply electricity plants. The junction with the WAGP would carry Nigerian gas to Abidjan.

Global LNG Trade to 2030

Introduction

LNG has grown from almost nothing in 1970 to the current 10%, meaning that the growth rate for LNG has been much higher than that of natural gas as a whole, which in turn has been much higher than total primary energy. In the past the size of the global LNG market has doubled every ten years from 50 million tonnes in 1990, 100 in 2000, and 220 in 2010. Today, deliveries of LNG represent one of the most significant sources of global energy trade, making up more than 30% of gas traded internationally[1]. With more than 400 LNG carriers on the oceans[2], LNG has transformed the natural gas business from a regional to a truly global industry.

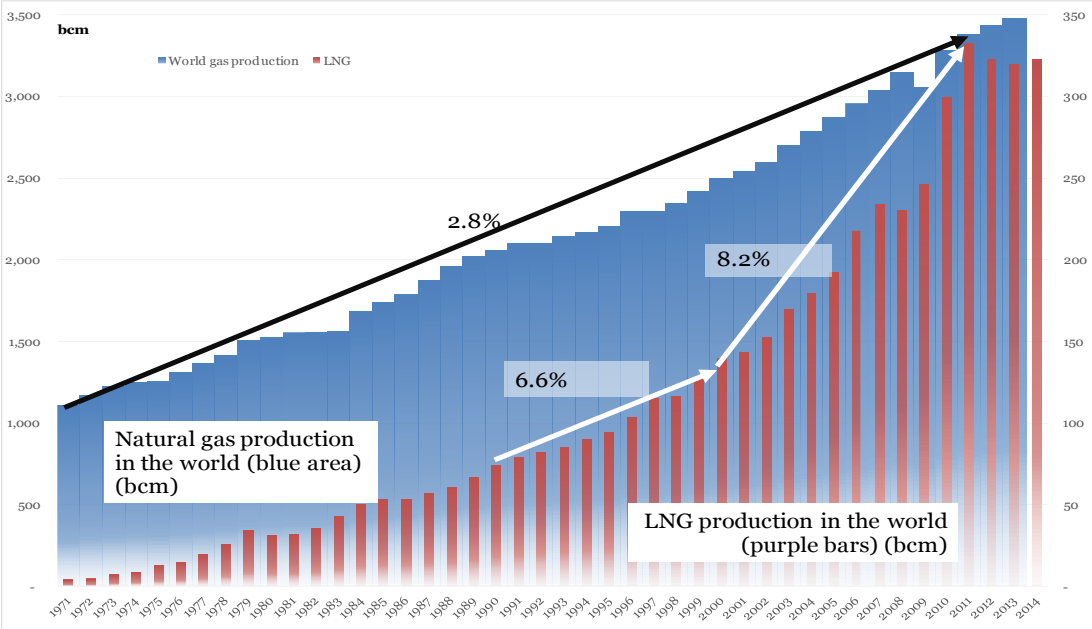


Figure 42: World natural gas and LNG production[3]

2014 marked the 50th anniversary of the first commercial cargo of LNG. Departing Arzew, Algeria, the Methane Princess delivered 27,400m³ of liquefied gas to Canvey Island in the United Kingdom[4]. Global LNG demand and supply side investment have historically been somewhat dependent on each other. Given the scale and complexity, this has often involved long lead times between supply projects being conceived and first LNG. The result is LNG supplies which reach the market in waves, as high demand periods signal investment in new liquefaction capacity, which only finds its way onto the market some years later.

[1] BP Statistical review 2014, page 28
[2] IGU 2014 World LNG Report
[3] Compiled by the author based on data from Natural Gas Information 2014, International Energy Agency, August 2014.
[4] WoodMackenzie: LNG @ 50

Figure 43Q-Max LNG Vessel "Al-Dafna" Image Courtesy of RasGas Company Limited

Since the completion of large scale Qatari facilities in 2011, LNG demand has been constrained by a lack of new supply. However the trade is forecast to return to growth in the coming years, as a number of large supply projects in Australasia begin operations. New supplies from a wide variety of other regions are expected to follow, resulting in an expected doubling of the global LNG trade by 2030.

This paper looks at brief history and factors that are expected to shape the future of the LNG industry.

LNG consumption

Asia Pacific - Asia

The East of Suez LNG markets today represent three-quarters of the global LNG demand. As the regions are expected to continue leading global growth of energy consumption and are not necessarily connected by pipelines (compared with other consuming regions in the West), LNG is expected to continue playing an important role to meet expected increasing demand of natural gas in the regions.

Brief history of region's LNG trades

Northeast Asia ("traditional") markets - Japan, Korea, and Chinese Taipei

LNG trades in the Asia Pacific region started in 1969, when Japan introduced LNG from Alaska. The regional market was dominated by Japan until Korea started importing LNG in 1986, followed by Chinese Taipei in 1990.

The original motivations to introduce LNG into those markets were: firstly to meet increasing energy needs to support rapid economic growth in those days; to diversify away from oil in the power generation and industry sectors given the inherent lack of domestic energy sources in the region; and to clean up air in urban areas, as well as to introduce cleaner, more affordable and stable sources of city gas supply, replacing gas manufactured from oil and coal.

The three traditional LNG markets, particularly Japan, dominated not only the East of Suez, but also the global LNG markets until new importing markets emerge in the 21st century, with the three representing (71%) of the global total imports of LNG as of the turn of the century, supported by exports from regional suppliers like Indonesia, Malaysia, Brunei and Australia, supplemented by suppliers in Alaska and the Middle East. As of 2013, the three markets still represented 60% of the total global LNG demand.

While individual electric power and city gas companies directly import LNG through receiving terminals that have been set up by themselves, LNG is mostly imported by single wholesale companies arranged by the respective governments in Korea and Chinese Taipei. This was partly because it was necessary to create economy of scale to enable LNG imports and in turn LNG production project development. In many cases in Japan, however, companies formed consortia or partnerships to establish LNG value chains, rather than creating a national buying agent.

New markets - India and China

Two of the today's fastest growing economies in the world, India and China, are relatively new in the LNG market, with India and China having started imports in 2004 and 2006 respectively. Primary LNG buyers in the countries have been either national companies or entities set up by the governments of national companies. Although they are new to the LNG market, China and India are already the third and fourth largest LNG importers in the world as of 2013, respectively.

Emerging markets - Southeast Asia

Southeast Asia, traditionally considered to be an LNG exporting region, is now also starting its own consumption of LNG. Malaysia and Indonesia, the second and fourth largest producer of LNG in the world as of 2013, respectively, have also started operation of their own LNG receiving terminals, as have Thailand and Singapore. Southeast Asia as a whole, including the four countries along with Vietnam, the Philippines and Brunei Darussalam, has been a larger consumer of natural gas since the turn of the century. While the region has been bestowed with natural gas resources, lower local natural gas prices have encouraged faster growth of demand than other markets.

Key factors in sub-regions

Northeast Asia ("traditional") markets - Japan, Korea, and Chinese Taipei

As the traditional three markets do not have much domestic production of natural gas or other forms of natural energy resources, they are expected to continue relying on LNG as a core energy supply source. Absolute demand levels will be dependent on competitiveness of LNG against other energy sources, new technologies to utilise natural gas, accompanying infrastructure development, developments of nuclear power operations, renewable energy sources, and energy conservation measures. As LNG prices in the region have been by far the most expensive among gas prices in various regions in the world, future pricing and flexibility of LNG trades will be a crucial factor to shape the region's LNG market.

India and China

Although LNG demand in the two markets has developed rapidly in recent years, future development will be also affected by not only those factors similar to those in the above traditional markets but also by domestic gas resource development and possible pipeline gas supply from neighbouring countries, as pipeline connections could be easier than the above

traditional markets. Pricing reforms will be also important factors affecting LNG demand in the countries.

Southeast Asia ("producing and consuming" region)

Although the region is still expected to produce more gas and LNG in the future, it is also expected to use more gas and LNG into the future. Balanced policy measures that can stimulate both domestic market development and gas and LNG production will be the key for the region.

Interaction with other regions/ Globalization of the market

Up until the turn of the century, the global LNG markets were relatively clearly divided into the East and West of Suez. Only the Middle East LNG producers, Qatar and Abu Dhabi used to supply both the East and West at that time. Only small numbers of occasional cargoes were traded between the regions.

After the proliferation of LNG production projects since the turn of the century, frequent cross-basin voyages, cargo diversions between regions, and even reloadings are now common, mostly from the West to East, due to unforeseen demand decline in the West and higher than expected demand surges in the East. The global exchanges of LNG volumes have fortunately helped balance the markets in recent years.

Expected new supply sources to Asia Pacific

Given the expected healthy increases in LNG demand in the Asia Pacific region, in addition to existing supply sources that are expected to continue fuel the market, new external supply sources are expected to supply the market in the years to come, including North America, additional projects in Eastern Russia, and East Africa. Even some projects in West Africa and Russian Arctic North may be underpinned by future gas demand in the Asia Pacific region.

Middle East

The Middle East region has a rapidly growing population. This is leading to increasing LNG demand for power generation, especially during the peak summer months. This demand falls outside of the traditional Northern Hemisphere winter, making it particularly attractive for LNG sellers trying to balance their production levels.

Importing LNG allows Middle Eastern economies the opportunity to grow whilst continuing to export their lucrative oil production. Therefore LNG demand is expected to increase quickly from today's levels. However given the region's relatively low population, LNG demand is expected to remain small when compared with the global market, reaching around 20Mtpa by 2030.

Kuwait and the United Arab Emirates represent the main importers of LNG today and it is expected that these two countries will remain the key importers throughout the period, with incremental volumes imported by Jordan and Bahrain.

Atlantic Basin

Brief history of region's LNG trades

The early days of the region's LNG trades were represented by a couple of traditional gas markets, with LNG supplementing pipeline gas supply. During ten years from 1997, interest in the Atlantic Basin has returned and supported much higher growth in LNG trade supported by increasing number of importers and exporters. In recent years new importing countries have joined from Latin America and Eastern Europe.

West Europe ("oldest") markets - United Kingdom, France, Italy, and Spain

The United Kingdom was the first country to import LNG in the world in October 1964. After importing LNG between 1964 and 1982 and relying on growing gas production from the North Sea for following years, the country in 2005 restarted LNG imports with a newly built terminal at the Isle of Grain. Two more regasification terminals (Dragon and South Hook) are currently operational at Milford Haven, Wales.

France is also among the oldest LNG importers. Its first terminal in Le Havre started operation in 1964 but was decommissioned in 1989. The country has three terminals at this time: Two Fos terminals on the Mediterranean coast and Montoir-de-Bretagne on the Atlantic Ocean. Another terminal is under construction in Dunkirk to be operational in 2015.

Italy started importing LNG in as early as 1969. But LNG accounts for a small portion of the country's natural gas imports, with the bulk imported by pipeline. The Rovigo terminal became Europe's first offshore LNG terminal when it began operation in 2009.

Spain is one of the world's largest importers of LNG and was one of the fastest growing LNG markets in 2000s with import volumes increasing almost three times between 2000 and 2007. Spain's first terminal in Barcelona was opened in 1969. While Algeria was the main LNG supplier in the past, the import sources have been diversified.

West Europe ("younger") markets - Belgium and the Netherlands

Belgium has one regasification terminal in Zeebrugge since 1987. With the connection to major import pipelines and the downstream pipeline network on Continental Europe, as well as the Interconnector with the United Kingdom, its role as a hub terminal has become more important in recent years.

The Netherlands opened its Gate terminal in 2011 and it has a similar ambition to function as an important gas hub in the region, although its utilisation rate has not been so high so far.

After importing some regasified volumes through Spain since 2000, Portugal opened its Sines terminal in 2003, supplying its own market and storing some volume for third parties.

East Mediterranean markets - Turkey and Greece

Turkey has been an LNG importer since 1995 with two terminals in Marmara Ereglisi and Izmir. Greece started importing LNG in 2000.

Baltic markets - Lithuania and Poland

Poland is building an LNG terminal at Świnoujście to open in 2015 while Lithuania opened a floating receiving terminal at Klaipėda in late 2014.

North American markets - from importers to exporters

The United States first imported LNG from Algeria in 1970. After years of relatively small imports throughout the 1980s and 1990s, the prospects of LNG imports were huge until 2007 when the country was the fourth largest importer. However around 2008, when the first land-based LNG terminals built in the United States for more than 25 years, domestic gas production began to surge.

Although Mexico and Canada started LNG imports in 2006 and 2009, respectively, huge potential of regional pipeline gas supply, North America is not expected to increase LNG import volumes significantly in the future.

Caribbean and South American markets

Puerto Rico has been importing LNG since 2000, followed by Dominican Republic in 2003.

Argentina and Brazil inaugurated their first LNG regasification terminals in 2008. They have recently increased presence in the international LNG market helped by extensive use of floating regasification units. Chile joined them as an importer although its terminals are located onshore.

Key factors of growth

Factors of growth of LNG are varied; they include:

- Expectations of new external supply from various sources, including North America, the Middle East and Africa
- The transition of the United Kingdom from net exporter to net importer
- Interest in gas-fired power generation and competitive situation against other energy sources, including coal and renewable
- Interest in supply diversification

During the course of the industry's growth, the traditional integrated business model has been supplemented by new more flexible arrangements.

The new arrangements have less stringent delivery commitments, both with regard to volume and delivery point and the LNG sellers often market the gas itself (or via an agent) on the market of importing countries or on the respective hubs.

This could further enhance LNG's role as a flexible supply source in the region.

Historical Sources of LNG Supply

1964 – 1990: The LNG Export Pioneers

Algeria was the first country to commercially export LNG, beginning 1964, with the majority of the volume being supplied on the world's first purpose built LNG carriers to the United Kingdom and France. Algerian exports were followed by exports from the United States (Alaska), Libya, Brunei, Indonesia and the United Arab Emirates (UAE), as countries with large gas reserves began to find customers in countries where gas was not so readily available around the world. The growth in LNG supply was rapid. By the end of the 1980's there were eight LNG exporting countries, supplying around 50 million tonnes per annum[5] (Mtpa) of LNG[6].

1990 – 1999: A Steadily Growing Trade

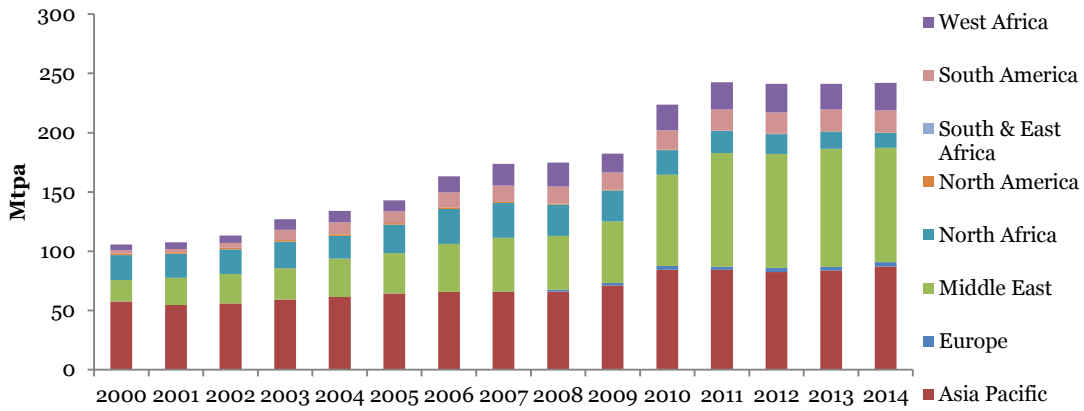
Throughout the 1990's, LNG exports continued to grow as the number of suppliers diversified to include Qatar, Trinidad, Nigeria and Oman. Despite this diversification, the traditional LNG giants of Algeria and Indonesia plus Malaysia continued to dominate the market. Together these three countries contributed around half of the 100Mtpa[5] of LNG exports that were occurring at the turn of the 21st century.

2000 – today: Rapid Growth of LNG Supplies

Between 2000 and 2014, global LNG exports more than doubled to around 240Mtpa. Much of this increase was driven by new Qatari liquefaction capacity. Qatar developed the largest LNG trains, the largest ships and invested in receiving capacity around the world. These investments meant that Qatar's export capacity alone reached around 77Mtpa in 2011. By the end of 2013, the Middle East, driven by Qatar, had overtaken Asia Pacific as the largest

[5] 1Mtpa of LNG is equal to around 1.32Bcm/y
[6] IGU 2014 World LNG Report

producing region, supplying more than 40% of global LNG, compared with 30% from Asia[7]. By the end of 2014 there were 19 countries exporting LNG and 29 importing countries[8].



Source: Wood Mackenzie

Figure 44: Recent Growth in LNG Supply

Future LNG Supply

The global LNG trade looks set for a further period of rapid growth from now to 2020. Precisely where the growth will come from, and how it evolves within the longer term outlook to 2030 is somewhat more uncertain. Given the general requirement to secure demand before financing, regions, countries and individual supply projects find themselves competing with one another to secure the robust, yet ultimately limited, new sources of LNG demand.

Asia-Pacific

Figure 45: Queensland Curtis Coal Seam Gas to LNG Plant (Australia)
Image Courtesy of BG Group

[7] IGU World LNG Report 2014
[8] WoodMackenzie Global LNG Tool

Although new Qatari LNG capacity was the catalyst for Middle East overtaking Asia-Pacific as the largest LNG exporting region, this trend looks set to reverse again in the near future. Large LNG export volumes are expected to come online in Asia-Pacific, the majority from projects in Australia. More than 60Mtpa of new Australian LNG capacity is set to come online between 2014 and 2019. These projects will include LNG supply based on new technologies such as large scale Coal Seam Gas to LNG plants and floating liquefaction. Most of these new projects are funded by major international oil companies rather than by national governments which has often been the case in the past.

Post 2020, Eastern Russia and Australia look likely to remain the most favourable sources of incremental Asia-Pacific LNG supply. However these projects remain uncertain when viewed in the context of potential lower cost supply development opportunities elsewhere. Competition throughout the LNG value chain is increasing and this trend is not expected to slow down anytime soon.

Europe, Middle East & Africa and CIS

Unlike the Asia-Pacific region where there is some confidence in future LNG supply growth, new supplies from Europe, Middle East & Africa are altogether more uncertain.

Looking first at the Middle East, Qatar holds large gas reserves which are ideally placed for incremental LNG supply. However a development moratorium remains in place, restricting new production from its super giant North Field. Stable Qatari LNG production implies that Middle East volumes will remain relatively flat in the long term, with the potential for some Israeli supply offsetting declining production from Oman and the UAE in the 2020's[9].

Given its large gas demand and integrated pipeline network, Europe has historically been a relatively small producer of LNG. This is not expected to change before 2030. New LNG supplies from Europe look most likely to come from the Russian Arctic, however such resources are remote and may be challenging to produce. Cyprus may also contribute to LNG supply, but volumes are likely to be relatively small. Even if such new supply sources start up successfully, Europe is likely to remain a large net importer of LNG, with only modest LNG supply volumes of around 20Mtpa before 2030[9].

Africa was home to some of the earliest LNG producers, Algeria and Libya. Still LNG suppliers from the region have been relatively flat at around 40Mtpa since the mid 2000's. LNG supplies are expected to be supplemented in the near future by new volumes from Angola. However, a major step change in African LNG supply could come around 2020 if project sponsors are able to turn large new discoveries of gas off the Eastern coast into feasible LNG projects in both Mozambique and Tanzania. If potential supply from these two countries is added to existing and new Nigerian supplies, African LNG production could amount to more than 100Mtpa in 2030[9]. To make this a reality, many things would need to fall into place including large scale infrastructure projects, new petroleum laws and agreements between partners as to how best to develop the remote resources.

Americas

North America is the region which will see the biggest transformation in terms of LNG supply potential over the next two decades. Today, the only North American LNG supply is an Alaskan facility exporting small volumes mainly to Japan. In fact, prior to 2010, the United States was expected to become a major importer of LNG. However advanced exploration techniques have

[9] WoodMackenzie Global LNG Tool

resulted in vast quantities of unconventional gas production. This unconventional gas revolution now looks set to turn the United States into a major global LNG exporter.

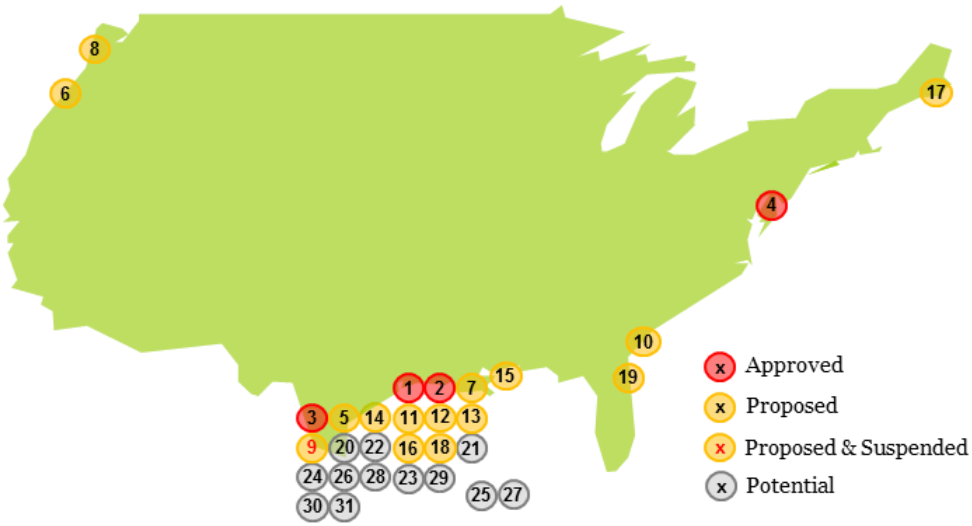


Figure 46: Status of US Export Projects according to US Federal Energy Regulatory Commission

Project Status with FERC	No. of Projects	Volume (Mtpa)
Approved	4	55
Proposed	15	137
Potential	12	127

In the United States alone there are currently more than 30 projects seeking to export over 300Mtpa of domestic gas as LNG. Whilst the market is not expecting all of this LNG capacity to be built, current signals indicate that the United States will produce large volumes of LNG before 2020, significantly impacting global gas markets.

Canada, like the United States, has traditionally been an importer of LNG. Nonetheless, the country is also now positioning itself to export its large unconventional gas resources. There are at least 17 projects seeking to export LNG from Canada on both the Pacific and Atlantic coasts. However Canadian LNG projects are largely greenfield, requiring greater investment and resulting in longer lead times than many of their competing United States equivalents.

Finally, outside of North America, both Trinidad & Tobago and Peru have historically provided LNG volumes. Both are however expected to decline significantly. Without substantial investment or new gas reserve discoveries, South America is not expected to be a major contributor to global LNG supply by 2030[10].

Key Uncertainties in the Development of Future LNG Supplies

Whilst the future global LNG trade can look forward to significant new supplies, a number of factors are emerging which will be key to deciding where and when new supply projects come

[10] WoodMackenzie Global LNG Tool

online. How the final outcome affects established global gas markets in the long term remains extremely uncertain, with a numbers of key factors to watch.

LNG Supply Growth in the United States

How much US LNG capacity will be built, how much LNG the new facilities will produce, and by when, remains the key uncertainty in the global LNG market. Despite the great potential, projects and regions are competing with one another for long term customer commitments. Firm offtake contracts with LNG buyers will remain a key factor in a project's ability to make a Final Investment Decision on capacity. The relative prices of gas and oil and the differential between United States and global gas prices will be important in determining how much LNG the facilities will produce. Given the global nature of the LNG market, exports from the United States have the ability to push out new supply projects from other regions due to their cost competitiveness derived from their potentially lower capital, labour and feedstock costs compared with competing projects elsewhere.

Floating LNG

Floating LNG (FLNG) represents a new and innovative concept in LNG supply whereby the LNG liquefaction and export equipment is mounted on a floating vessel. There are no FLNG projects operating today, however, three projects are currently under construction which will be deployed to gas fields in Australia and Malaysia. Elsewhere, many other FLNG projects have been proposed around the world, particularly in North America, Africa and Australia.

FLNG concepts range in scope and design. Plans include small near-shore barges, conversions of existing LNG tankers and large new build vessels built to operate far out on the open seas. Advantages include the ability to access remote gas sources, control development costs, long term mobility and potentially reduced geopolitical risk. However the effect of open sea conditions on LNG production infrastructure and maintenance has yet to be tested and remains a significant source of risk.

Flexibility

Traditionally, LNG contracts have specified where LNG will be delivered. However, the potential for large scale exports from the United States may bring an unprecedented element of destination flexibility to the LNG supply chain. In the United States model, liquefaction terminal operators are simply leasing out the infrastructure to liquefy gas bought in the United States market. LNG plants may operate as tolling facilities, providing buyers with liquefied gas without such destination restrictions.

Such an LNG production model would provide buyers with a new found ability to select the destination for their LNG based on their own commercial and contractual priorities. This is expected to bring new levels of interconnectivity to global gas markets with potentially far reaching consequences on global LNG and gas market dynamics.

The Promise of Natural Gas in North America / Examining Supply and Demand Expectations in the United States and Canada

Introduction

North America boasts two of the five largest natural gas producing countries in the world – the United States at number one and Canada, the fifth largest natural gas producer among

hydrocarbon producing countries around the world. Both have been profoundly influenced by the recent development of natural gas resources in unconventional reservoirs, most particularly natural gas from shale formations. As large producers of natural gas, both the United States and Canada are also significant consumers of gas energy with a North American pipeline grid that allows the countries to efficiently connect supply basins to demand centres around the continent and to transport natural gas as pipeline imports and exports across borders. Growth in natural gas production, reserves and estimated resources in both the United States and Canada have built market expectations of near- and medium-term relative price stability and supply elasticity just as demand for natural gas grows not only in the United States and Canada but worldwide.

Demand for natural gas in North America comes from nearly every part of the continent's economy. More electricity is being generated with natural gas-fired technologies; burner tip and feedstock applications are supporting growth in industrial sector consumption; residential and commercial natural gas applications are growing customers, however, efficient equipment is moderating overall gas volumes required; and, natural gas is increasingly viewed as a viable fuel in transportation. Even the first exports of natural gas in the form of liquefied natural gas (LNG) are about a year away from taking hold with North America positioned to serve Asian, South American, Caribbean and European customers.

Results

North America has experienced and demonstrated many positive effects from growing natural gas production and consumption during the past decade in a competitive energy market. The economic activity created, the environmental benefits of a lower-carbon fossil fuel and expectations for a relatively stable North American marketplace for decades to come are underpinned by strong supply fundamentals and demand pull from virtually all consuming sectors.

Natural Gas Supply/Demand – United States

Expectations regarding natural gas demand in the United States for the next 15 years include features of a natural gas market shaped by an elastic natural supply position and growth in demand subject to environmental regulations, government policy choices and economic decisions made by individuals and business consumers. Simply stated many analysts believe that any plausible natural gas demand scenario (like that represented in Table 1 from the United States Department of Energy, Energy Information Administration, *Annual Energy Outlook* published in 2014 and supplemented with data from Bentek Energy and the American Gas Association) will be met primarily with domestic natural gas production and pipeline imports from Canada reliably and within the bounds of a relatively stable wellhead pricing environment. These ideas of relative market stability and growth are common themes seen in the numbers.

Table 10: U.S. Natural Gas Demand 2012 and Forecasts through 2030

	2012	EIA AEO Reference 2015	EIA AEO Reference 2020	EIA AEO Reference 2025	EIA AEO Reference 2030
Quadrillion BTU					
Res/Com	7.52	7.78	7.79	7.89	7.78
Power Gen	9.46	8.22	9.00	9.69	10.28

	2012	EIA AEO Reference 2015	EIA AEO Reference 2020	EIA AEO Reference 2025	EIA AEO Reference 2030
Industrial	7.29	7.87	8.26	8.59	8.71
LNG Exports	0	0	1.93	2.57	1.43
Exports to Mexico	0.58	0.83	1.13	1.50	1.50
NGVs	0.04	0.06	0.08	0.14	0.28
Total US Sector Demand	24.89	24.76	28.19	30.38	29.98
Henry Hub Price (2012 $/MMBtu)	$2.75	$3.74	$4.38	$5.23	$6.03

Sources: US Department of energy, Energy Information Administration, *Annual Energy Outlook 2014; B*entek energy; American Gas Association.

The vision expressed in Table 1 is supported by a set of facts regarding key metrics within the natural gas market in the United States and more broadly in North America. Every forecast of U.S. natural gas supply and demand can be dissected, argued and supported with a range of metrics and statistics. However, it is worth noting the following key measures of a robust, dynamic natural gas marketplace in the U.S. today with similar expectations in to the future.

Customer Growth

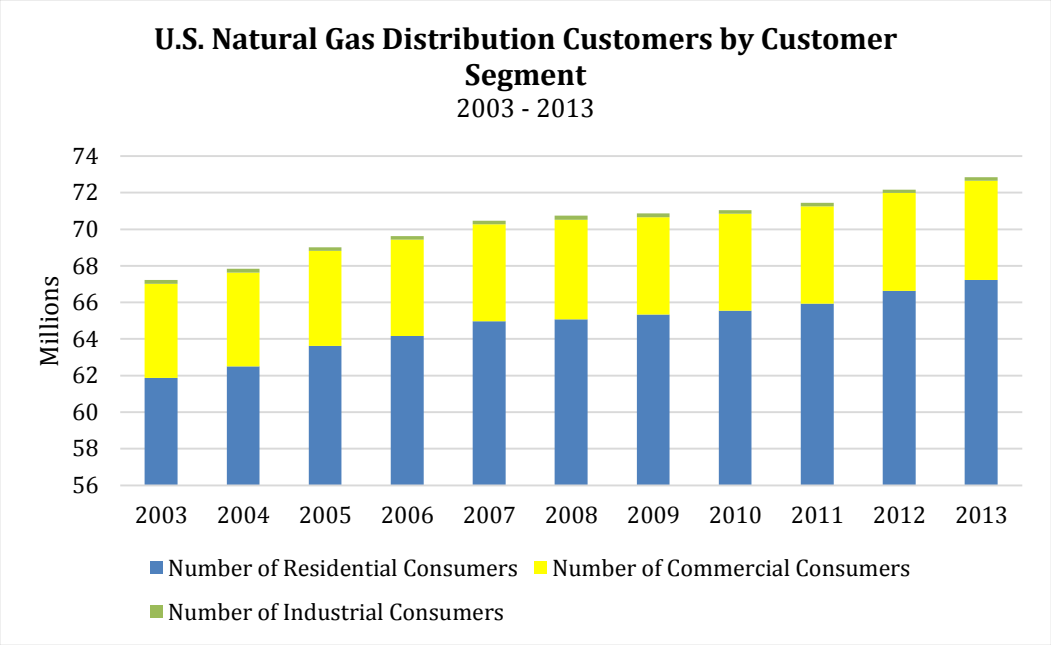


Figure 47: Natural Gas Distribution Customers (Source: EIA 176, *Annual Report of Gas Operations).*

For the period of 2003 - 2013, total natural gas customers in the United States grew by more than five million. Most of this growth occurred in the residential sector, although a small increase took place in the commercial sector as well.

While the number of customers in the industrial sector shrank from 205,000 in 2003 to about 192,000 in 2013, industrial natural gas consumption actually increased by 4.3 percent.

Distribution Pipeline Infrastructure Expansion: Capacity and Miles

The natural gas distribution system also expanded during the 2003 - 2013 period. Distribution mains increased by about 170,000 miles from nearly 1.1 million to more than 1.27 million miles during this ten-year period. Likewise, overall capacity to deliver natural gas increased, also.

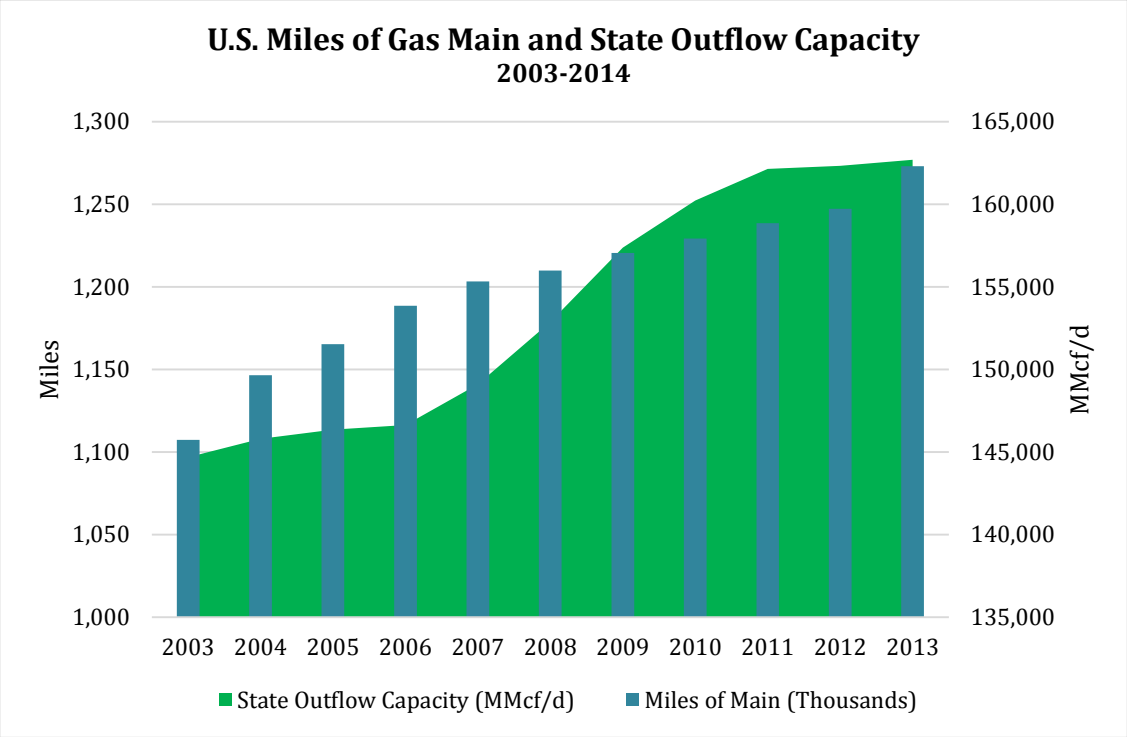


Figure 48: Main and State Outflow Capacity (Source: DOT 7100, PHMSA, Annual Report Data from Gas Gathering, Gas Transmission, Hazardous Liquids and LNG Operations).

This infrastructure growth is reflected in recent increases in construction costs. For all parts of the natural gas value chain, construction expenditures were consistently higher during the three-year period of 2011-2013 compared with 2003.

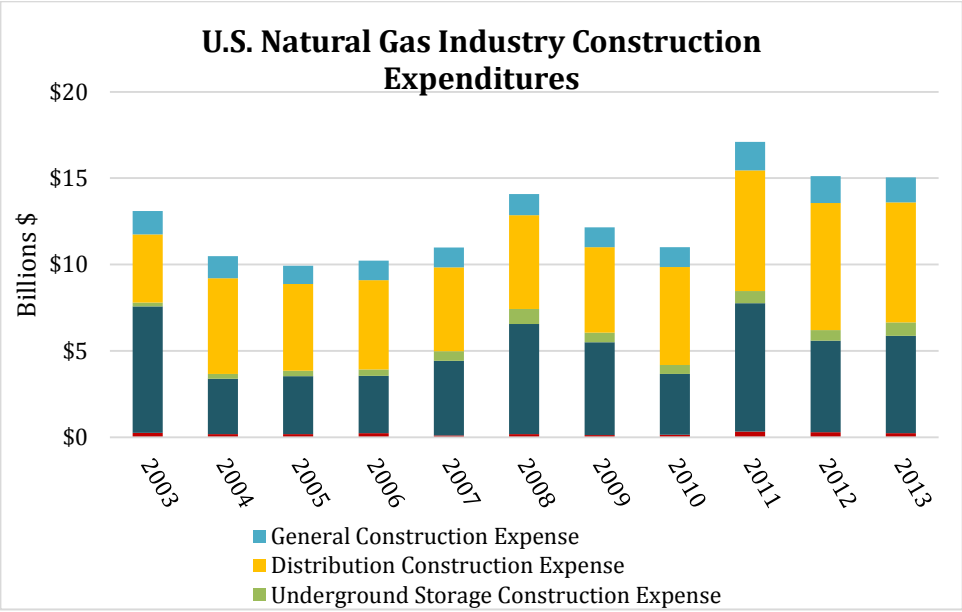


Figure 49: U.S. natural Gas Industry Construction Expenditures (Source: American Gas Association, *Gas Facts*).

Natural Gas Production

Dry natural gas production grew from less than 20 trillion cubic feet (Tcf) annually to nearly 25 Tcf during the 2003 - 2013 period. Domestic production is expected to continue to grow as additional unconventional and conventional resources are developed and as demand requirements continue to pull on a growing gas market.

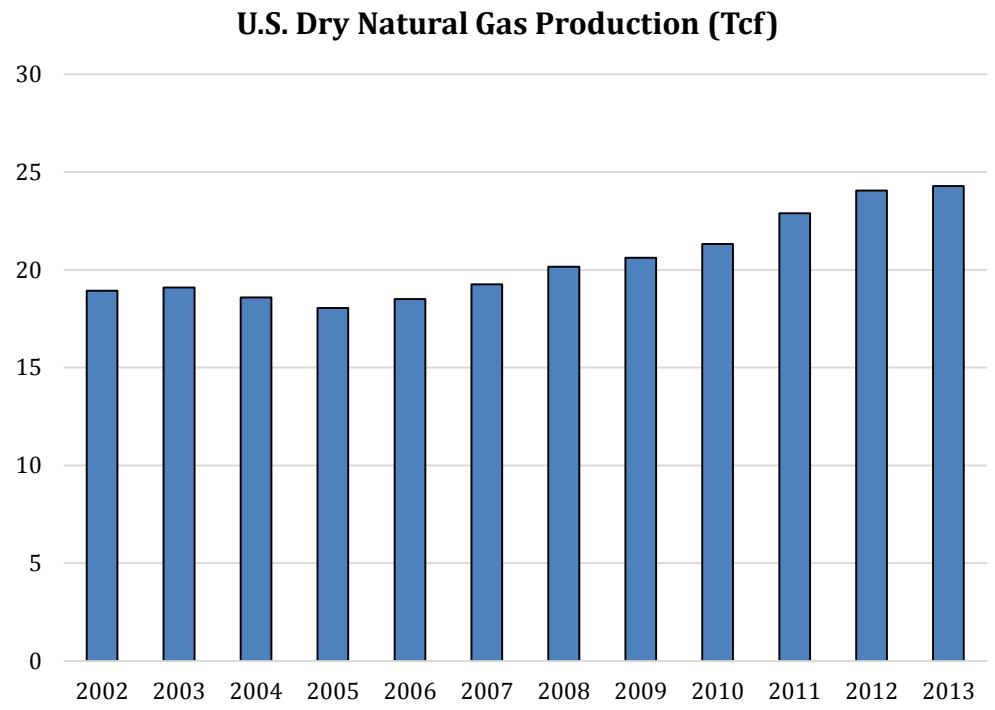


Figure 50: U.S. Dry Natural Gas Production (Source: US Department of Energy, Energy Information Administration 2002-2013).

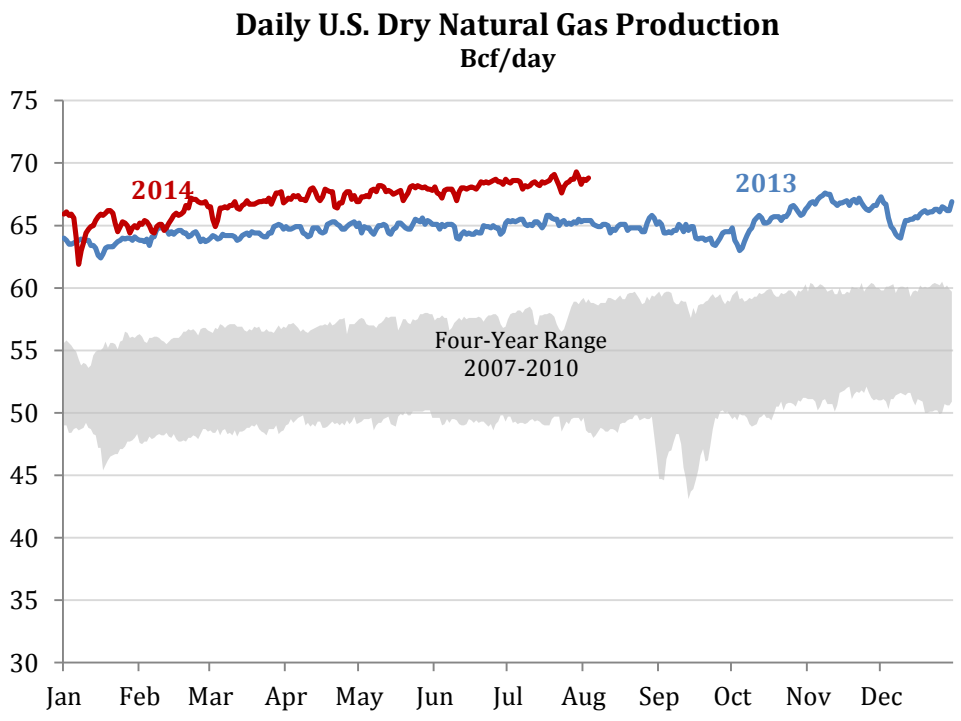


Figure 51: Daily U.S. Dry Natural Gas Production (Source: Bentek Energy).

Domestic Natural Gas Reserves

As with production, natural gas reserves have grown steadily during the past decade. Underpinning domestic production capability, dry natural gas reserves have grown from less than 200 Tcf in 2003 to over 335 Tcf in 2013.

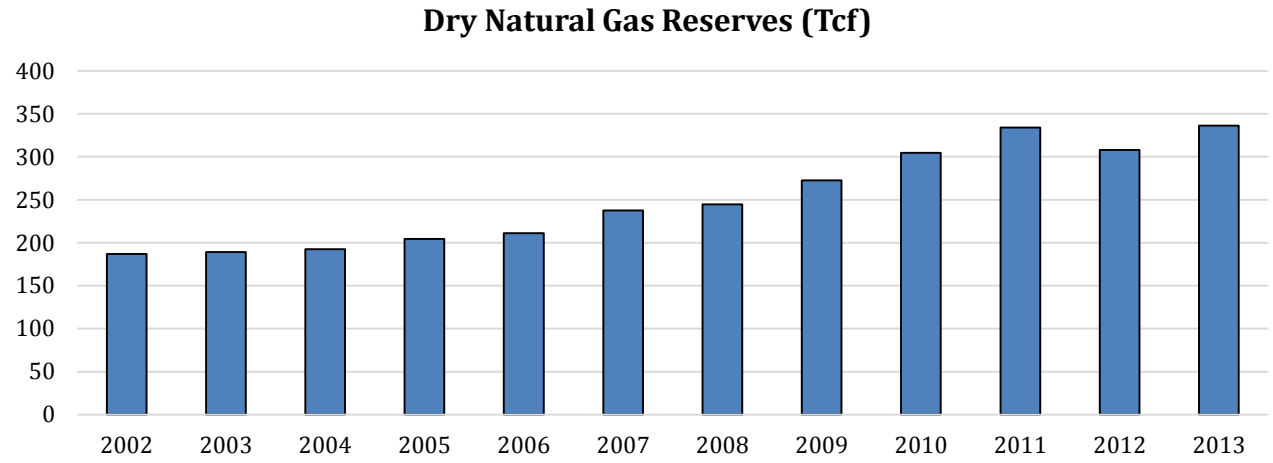


Figure 52: Dry natural Gas Reserves (Sources: Energy Information Administration and American Gas Association).

Underground Storage Capacity

Working gas in storage provides about 15 to 20 percent of total winter heating season gas supply (November 1 through March 31) in the United States and is therefore an important piece of the national supply asset base. During the 2013-2014 winter heating season 3.0 Tcf was delivered from underground storage to customers – the first time in history that net working gas withdrawals reached 3.0 Tcf.

The United States has the largest underground storage system in the world with base and working gas capacity currently exceeding 9.0 Tcf. The share of storage working gas within the total supply asset pie has grown in the past decade. According to the Energy Information Administration, design working gas capacity in America's underground storage system grew by about 1,000 billion cubic feet (Bcf) in the past 10 years.

During the extraordinarily cold 2013-14 winter heating season in the United States, storage played a critical role as a supply source providing additional deliverability during peak load periods.

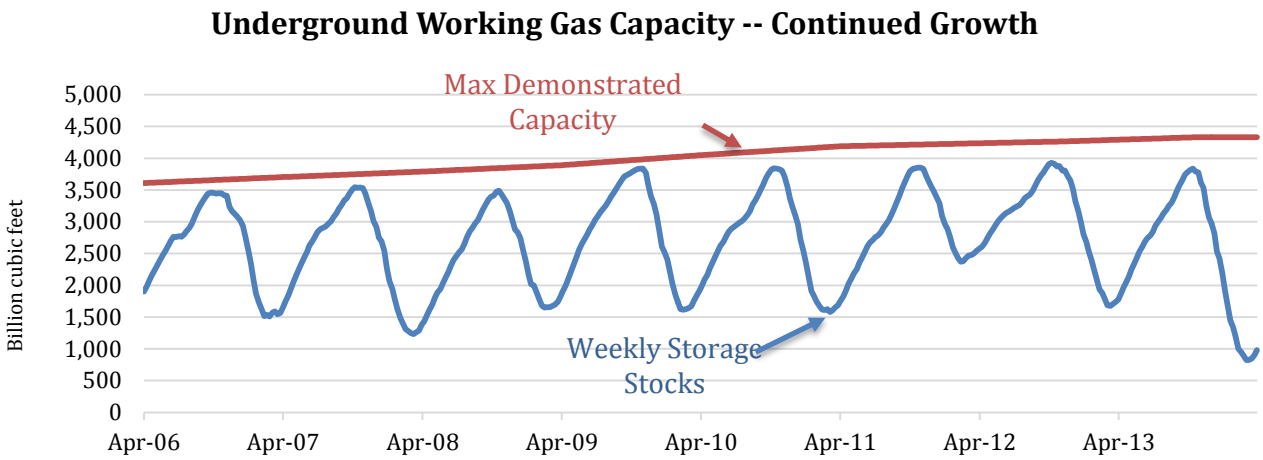


Figure 53: Underground Working gas Capacity (Source: Energy Information Administration, US Department of Energy).

Natural Gas Supply/Demand – Canada

Despite holding a relatively small share of the world's proved natural gas reserves, Canada ranks fifth in dry natural gas production. In addition, it is the fourth-largest exporter of natural gas (primarily pipeline gas to the United States at about 5 billion cubic feet per day), behind Russia, Qatar, and Norway. Canada plans to become a LNG export country also. However, Canada is a significant consumer of natural gas in homes, businesses, industrial applications and power generation and consumption levels, particularly in the industrial and power generation sectors, are likely to grow.

Table 11: Canada Natural Gas Demand 2012 and Forecasts through 2030

[Quadrillion BTU]	2012	NEB Reference 2015	NEB Reference 2020	NEB Reference 2025	NEB Reference 2030
Res/Com	1.25	1.29	1.35	1.40	1.44
Power Gen	.232	.214	.336	.405	.509
Industrial	1.94	2.04	2.30	2.49	2.65
NGVs	.0001	.0005	.0019	.0041	.0067
Total Canada Sector Demand	**3.42**	**3.54**	**3.99**	**4.30**	**4.61**

Source: National Energy Board, Canada's Energy Future 2013: Energy Supply and Demand Projections to 2035, November 2013.

The U.S. Energy Information Administration estimates that Canada's proved natural gas reserves were 67 trillion cubic feet (Tcf) at end of year 2012 compared to more than 300 in the United States. Much of Canada's natural gas reserves are *traditional* resources in the western sedimentary basin. Other areas with significant concentrations of natural gas reserves are in eastern Canada's offshore fields, principally around Newfoundland and Nova Scotia. The estimate of technically recoverable natural gas resources also defined by the Energy Information Administration (US Department of Energy) is 573 Tcf and the resources geographically are widely distributed. Canada's National Energy Board estimated 861 Tcf of remaining marketable natural gas resources as of December 31, 2012 to underpin future growth in domestic consumption and exports to the United States. In fact, estimates of Canadian natural gas resources have been reported at 1,000 Tcf and higher, depending on the assessment source.

As with recent developments in the United States, sources of unconventional natural gas reside in the western sedimentary basin in the form of coal bed methane (CBM), shale gas, and tight gas, although they have not been developed as extensively, as in the U.S.

Exploration and Production

Canada produced about 6.3 Tcf of gross natural gas in 2012, of which 5.1 Tcf was dry natural gas, 675 Bcf was reinjected, and 65 Bcf was vented or flared. Today, Canada's natural gas production is less – about 14 Bcf per day and 5 Bcf of that total is exported to the United States. Most of Canada's natural gas production comes from production in the western sedimentary basin. Alberta produced more than two-thirds of Canada's gross natural gas in 2013, according to National Energy Board data, with most of the remaining amount coming from British Columbia.

Offshore natural gas production has been focused primarily off the coast of Eastern Canada, on the Scotian Shelf near the province of Nova Scotia. The most mature example of offshore natural gas production in Canada is the Sable Offshore Energy Project (SOEP), however, recently production in SOEP has declined. In 2012, SOEP produced 200 million cubic feet per day (MMcf/d) of raw natural gas from a peak of 500 MMcf/d. Another major natural gas project off Nova Scotia, the Deep Panuke Project began production in 2013. It is designed to produce 300 MMcf/d.

Canadian Natural Gas Trade

Most of Canada's natural gas exports are directed to the United States via pipeline although an additional small volume is moved via truck. The United States imported 2.8 Tcf of natural gas from Canada in 2013 down from near-peak levels of 3.8 Tcf in 2007. Canada accounts for 97% of U.S. natural gas imports, most of which come from western provinces. Interestingly, although the United States is a net importer of natural gas from Canada, it exported more than 900 Bcf of natural gas to Canada in 2013, a dramatic increase from less than 100 Bcf in 2000. Canada's natural gas pipeline system is extensive and highly interconnected with the U.S. pipeline system.

Changes to North American natural gas supply fundamentals have reduced Canada's need for imported liquefied natural gas (LNG). Canaport is Canada's only operating regasification terminal, which began importing LNG in June 2009. The Canaport terminal has a processing capacity of 1.2 Bcf/d. According to the IGU World LNG Report 2014, Trinidad and Tobago and Qatar are the primary sources of imported Canadian LNGAccording to the BP Statistical Review of World Energy 2014, Trinidad and Tobago and Qatar are the primary sources of imported Canadian LNG.

Further proof of the changing outlook for North American natural gas is provided by the number of applications for LNG export licenses in the United States and Canada. In Canada, there have been 20 companies that have applied, and 11 have been approved by the National Energy Board. Most of the export terminals approved for development are on Canada's west coast in the province of British Colombia. Many factors, including infrastructure development to support export terminals, internal social debates, First Nation rights and world market developments will dictate how aggressively Canada positions itself as an LNG exporting country.

References

LNG at 50, WoodMackenzie, 2014

Asia/World Energy Outlook 2014, IEE Japan, Tokyo 2014

Annual Energy Outlook 2014, energy Information Administration, US Department of Energy 2014

Global and Russian Energy Outlook to 2040, The Energy Research Institute of the Russian Academy Of Sciences, the Analytical Center for the Government of the Russian Federation:, Moscow 2014

BP Statistical review of world energy 2014, BP, 2014

IGU 2014 World LNG Report, International Gas Union, Paris 2014

IEA World energy outlook 2014, International Energy Agency, London 2014

IEA Key World Energy Statistics 2014, International Energy Agency, 2014

Africa Energy outlook, International Energy Agency, 2014

Long-term Outlook for Gas to 2035, Eurogas, Brussels 2013

Eurogas Statistical Report 2014, Eurogas, Brussels 2014

Annual Energy Outlook 2014, Energy Information Administration, US Department of Energy, May 7, 2014.

Canada's Energy Future 2013: Energy Supply and Demand Projections to 2035, National Energy Board, November 2013.

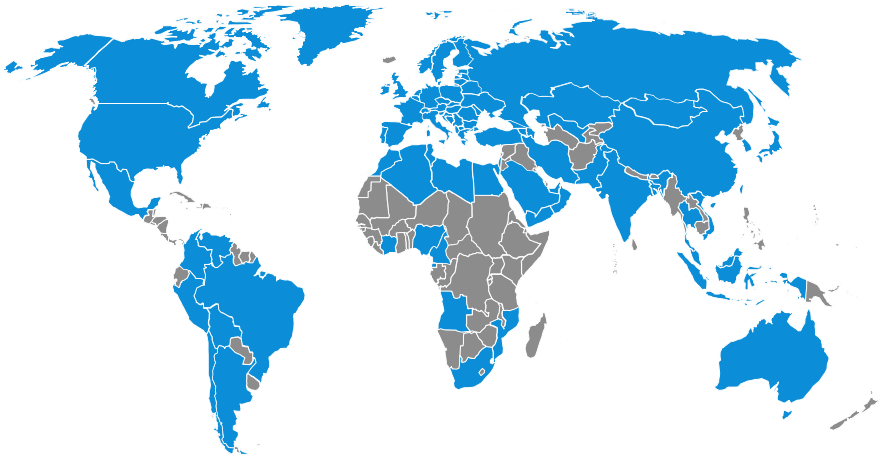
Canada Energy Overview, Energy Information Administration, US Department of Energy, September 30, 2014.

Fueling the Future: Bringing It Home, IHS CERA, American Gas Foundation, January 2014.

Promise Delivered: Planning Preparation and Performance during the 2013-14 Winter Heating Season, American Gas Association, September 2014.

Rethinking Natural Gas: A Future for Natural Gas in the U. S. Economy, American Gas Association, October 2012

NOTES



The International Gas Union (IGU) was founded in 1931 and is a worldwide non-profit organisation promoting the political, technical and economic progress of the gas industry with the mission to advocate for gas as an integral part of a sustainable global energy system. The IGU has more than 142 members worldwide and represents more than 97% of the world's gas market. The members are national associations and corporations of the gas industry. The working organisation of IGU covers the complete value chain of the gas industry from upstream to downstream. For more information please visit **www.igu.org**

Address: Office of the Secretary General
c/o Statoil ASA, P.O. Box 1330, Fornebu, Norway

Telephone: +47 51 99 00 00
Email: secrigu@statoil.com
Website: www.igu.org

WGCPARIS2015
WORLD GAS CONFERENCE

IGU
INTERNATIONAL GAS UNION
UNION INTERNATIONALE DU GAZ