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UNDERSTANDING NATURAL GAS AND LNG OPTIONS

Understanding Natural Gas and LNG Options

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Foreword

November, 2016

A diverse group of global experts created this handbook in the hope that it can facilitate a shared understanding between government officials and companies about the technical, commercial, and economic factors that will spur investment in Africa's gas and power sectors. This handbook is intended to inform decision-making of options to develop natural gas. It does not promote any specific business model, but rather promotes better understanding of the stakeholders' shared aims in developing natural gas and Liquefied Natural Gas (LNG) projects.

Whether a country is a potential exporter or importer of natural gas, this handbook will provide a framework to evaluate natural gas and LNG projects critical to monetizing many of the large natural gas fields recently discovered while matching resources with demand from regional and global markets.

Power Africa was created in 2013 with the goal of adding more than 30,000 megawatts (MW) of electricity generation and 60 million new home and business connections. Power Africa partners with U.S. government agencies to bring together the world's top companies, political leaders, and financial institutions to help address Africa's acute energy shortages. The U.S. Department of Energy is a key partner to help build human capacity in the region to realize and accelerate natural gas development.

This book is the third volume of Power Africa's "Understanding" series of handbooks that illustrate best practices for developing power projects in sub-Saharan Africa. The two previous handbooks are:

- Understanding Power Purchase Agreements: *http://cldp.doc.gov/programs/cldp-in-action/details/1378*
- Understanding Power Project Finance: *http://cldp.doc.gov/programs/cldp-in-action/details/1603*

The authors of this book, all of whom contributed their time on a pro-bono basis, included experts from African governments, a multilateral development bank, international industry, financial institutions, consultancies, academia, and law firms. The outcome is a product that reflects collective teamwork rather than the personal views of individual authors or the institutions they represent.

We hope this handbook, and any following dialogs that it engenders, will improve information flow and build human capacity that accelerates natural gas development, cleaner power generation, energy security, economic growth, and environmental stewardship.

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This handbook was produced using the "Book Sprint" (http://www.booksprints.net) collaborative writing method. The outcome is a product that reflects collective teamwork rather than the personal views of individual authors or the institutions they represent.

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Prior to the Book Sprint process, the Department of Energy met with a broad range of oil and gas experts in sessions in Washington, DC, Houston, New York City, and London in an attempt to better frame the contents of this book. We would like to thank USEA, Rice University's Baker Institute, Columbia University's Center on Global Energy Policy, and Imperial College, London, respectively for hosting these meetings. A list of experts, some of whom were able to join us as authors of the handbook, and others who were unable to join, but whose insights were valuable to the success of our effort, will be available on the LNG handbook website.

The Department of Energy authors would like to thank the Department of Energy Africa Task Force, particularly Assistant Secretary for Fossil Energy Christopher Smith for his active involvement and leadership, and the co-chairs, Deputy Assistant Secretary for Eurasia, Africa, and the Middle East Andrea Lockwood, and Associate Deputy Secretary John MacWilliams, for their support and leadership. We would like to thank the following members and former members of the U.S. Department of Energy and U.S. Energy Association teams who have participated in this project. Without their tireless efforts this book would not exist: Steven Davidson, Natenna Dobson, Allison Good, Devin Hampton, Geoff Lyon, Alia Mohammed; Andrew Palmateer, Heather Greenley, and Marjorie Jean-Pierre.

Introduction

LNG exports are poised to be an important catalyst for economic growth in African countries. Natural gas and LNG development can enable economic development and stimulate further investment in national infrastructure.

The recent large offshore natural gas discoveries in Africa have focused the attention of the international oil and gas industry on large LNG export projects that are essential to monetize these resources. Large offshore resources are expensive to develop and projects may not be able to clear investment hurdles if dedicated solely to the domestic gas market. Developing an LNG export project, however, and reserving a portion of the gas production for the domestic market - with the full support of the host government - can make natural gas available for local use in addition to earning revenue through export. This can enable the development of a diverse market for gas including power generation, local and regional industrial and commercial enterprises, transport, feedstock for petrochemical manufacturing, and other domestic uses of gas for the local population. LNG imports could also enable the development of domestic gas markets throughout Africa.

This handbook attempts to cover a broad spectrum of topics involved with developing and financing an LNG project, covering in depth the considerations for an LNG export project and development of a diverse domestic market. The book also addresses LNG import projects for intra-Africa LNG sales as an alternative to country-to-country pipelines. We discuss the decisions that need to be made and the lenses through which to view the factors leading to these decisions. Each country will need to make its own decisions based on its specific national priorities, trade agreements, GDP goals, and assessments of changing political and market dynamics.

In the following chapters, the reader will find overviews of the global gas market, LNG and domestic gas value chains, and domestic and interconnected regional markets for LNG and natural gas. We discuss project structure, government roles, capacity building, LNG export project development, environment, social impact, and safety. We also review pricing, contracts, financing, risk management, local content, LNG import projects, and new and emerging markets and technologies for natural gas and LNG -

touching on successes from other regions such as the EU, Asia and the U.S. that might inform future natural gas and policy decisions in Africa

This reference is not intended to be comprehensive and African governments would wisely employ the services of experienced advisors in legal, contractual, financial, technical and strategic areas. This advice should be directed at rapidly promoting the training of governmental staff, using all means available, including well-established academic institutions which focus on the oil and gas or LNG sectors.

Global Gas Market

Introduction

Global gas demand has increased over the past decade and is expected to grow rapidly into the future with increased interest in cleaner energy to fuel economic growth. Historically, most natural gas is sold locally or by gas pipeline to adjacent markets. Liquefaction of natural gas, as LNG, allows it to be transported from producing regions to distant countries. There are vast known global natural gas resources that are considered 'stranded' as they have not been able to be economically produced and delivered to markets.

LNG History

In 1959, the world's first LNG carrier, the Methane Pioneer, set sail from Lake Charles, Louisiana with a cargo of LNG destined for Canvey Island, UK. This first ever US-UK shipment of LNG demonstrated that large quantities of LNG could be transported safely across the ocean, opening the door for what would become the global LNG industry.

As the LNG markets evolved over the decades, they tended to develop in regional isolation from each other, primarily due to the high cost of natural gas transportation. Historically, two distinct LNG trade regions developed - the Asia-Pacific region, and the Atlantic Basin region which included North America, South America and most of Europe. Until Qatar began to export LNG to both regions in the mid-1990s, the two regions were largely separate, with unique suppliers, pricing arrangements, project structures, and terms. In recent years, the increase in inter-regional trade, as well as the development of a more active spot market, has tended to blur the distinction between the two main regions.

There are three main global gas markets: the Asia-Pacific region, the European region, and the North American/Atlantic Basin region which includes North America, South America, and Latin America. The Asia-

Pacific region has historically been the largest market for LNG. Japan is the world's largest LNG importer, followed by South Korea and Taiwan. China and India have recently emerged as LNG importers and could become significant buyers of LNG over time.

The growth of LNG in Europe has been more gradual than that in the Asia-Pacific, primarily because LNG has had to compete with pipeline gas, both domestically produced and imported from Russia. The traditional European importing countries include the UK, France, Spain, Italy, Belgium, Turkey, Greece and Portugal. More recently, a growing number of European countries have constructed LNG import terminals, including Poland, Lithuania, and Croatia.

In North America, the United States, Canada and Mexico have strong pipeline connections and abundant supplies of natural gas. Historically, this region had been able to supply all of its natural gas requirements from indigenous supplies. During the supply-constrained 1970s, however, the US began importing LNG from Algeria and four LNG import terminals were built between 1971-1980. The 1980s was a period of oversupply and US LNG import terminals were either mothballed or underutilized.

In the late 1990s, the United States was forecasting a shortage of natural gas, which led to the reactivation of the mothballed terminals and the building of additional import terminals, including Cheniere Energy's Sabine Pass. But by 2010, it became apparent that the US would be a major shale gas producer, making LNG imports unnecessary. The cargoes that were to be sold in the US were then available to be sold on global markets. Many of the existing US import terminals were subsequently re-designed as LNG liquefaction and export terminals.

In February 2016, Cheniere Energy's Train 1 came online, thus heralding in a new wave of LNG supply. As of early October 2016, DOE had issued final authorizations to export 15.22 billion cubic feet per day (Bcf/d) of US Lower-48 States domestically sourced natural gas to non-FTA countries.

The following table shows the US large-scale projects have received regulatory approvals and are under construction or operating.

Project	Volume (Bcf/d)	In Operation
Sabine Pass Cameron, LA	4.14	Feb 2016
Dominion Cove Point Calvert County, MD	0.77	2018
Cameron Cameron, LA	3.53	2018
Freeport Quintana Island, TX	1.8	2018
Corpus Christi Corpus Christi, TX	2.1	2019

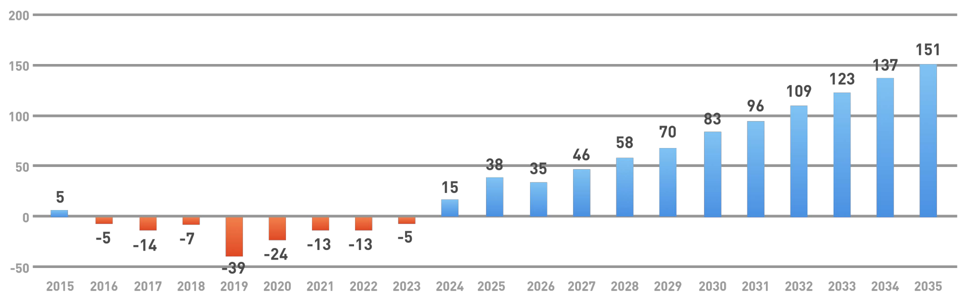
Supply and Demand Balance

In 2015, Global LNG trade accounted for 245.2 million metric tonnes per annum (MTPA). Also in 2015, there were 34 countries importing LNG and 19 countries that export LNG. In terms of the global supply balance for LNG, the key features of the last few years have been: 1) the emergence of the US as a major LNG exporter, potentially adding more than 60 MTPA to global supplies; 2) the completion of a number of major LNG export facilities in Australia, which will soon achieve a nameplate capacity of about 85 MTPA; 3) slower than expected demand increase from Asian markets, and 4) new gas discoveries, particularly large discoveries in frontier regions. The confluence of these four factors, which continue to evolve, has created a short-to-medium term situation of material LNG oversupply. Oversupply is depressing spot and medium term prices for gas that has not already been contracted. In addition, a major portion of the LNG market has long-term contracts indexed to oil prices which have also dropped significantly. All these factors have created a difficult environment to develop greenfield LNG export facilities.

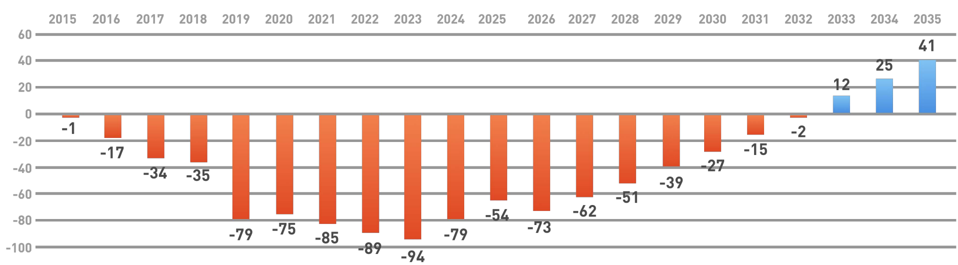
For excess LNG that has not been contracted on a long term or destination-specific basis, prices in most key consuming markets, such as Europe or Asia, have fallen from a high of $10-$15 per million british thermal units (MMBtu) to below $5/MMBtu, and while this remains above the marginal cost of production for some projects, it typically falls well short of the whole-life costing of an LNG project, once amortization of capital and loan repayments are taken into account.

For a gas/LNG project developer/investor or host government, one of the main challenges is to determine when a rebalancing of gas markets might take place, as this would have implications on LNG price projections and the project's economic viability. Opinions vary on when, and in what manner LNG global markets will rebalance. Even if a number of the existing LNG liquefaction terminals, either in production or under construction, take steps to rephase their output or delay completion to realign with market demand, it appears likely that an oversupply will continue at least into the early 2020s. Conversely, if development plans continue, based on the completion dates and FID decisions currently quoted in investor's and press materials, the oversupply could continue through the next decade. While commercial and financial pressures suggest that some kind of shorter term realignment will result, it is not yet apparent how this realignment will happen, and what the implications are for African gas and LNG projects.

The charts below indicate two possible realignment scenarios, based on a prompt (short term) market realignment, or a longer term oversupply. The red bars represent the amount of global LNG oversupply.



Under/Over Supply in MTPA



Under/Over Supply in MTPA

Source: Gaffney, Cline & Associates

Opportunities for Africa Natural Gas

More countries in Sub-Saharan Africa are on the cusp of emerging as major natural gas producers. Mozambique and Tanzania recently have discovered more than 250 trillion cubic feet (TCF) of gas reserves. Nigeria and Angola are also important gas producers. The huge shortfall in power supply in Africa, coupled with the the relatively high cost of electricity based on the high cost of available fuel in many African countries, presents a new opportunity for natural gas and LNG imports to fuel the projected growth of African economies.

In September 2016, the US Power Africa Roadmap report outlined a goal to increase power generation in sub-Saharan Africa by more than 30,000 megawatts (MW) by 2030. This translates to about 5.5 bcfd of additional natural gas consumption or about 42 MTPA of LNG, assuming natural gas is the fuel of choice. This is equivalent to the growth of LNG observed in China and India during a similar timeframe. Similarly, the African Development Bank Group has set an aspirational vision to achieve universal access to electricity by 2025. This vision is encapsulated in the New Deal on Energy for Africa.

The domestic natural gas prices in many African countries are quite competitive. The prices are mostly established by bilateral negotiation between buyers and sellers and are usually indexed on alternative fuels such as crude oil or petroleum products, as in the case in Ghana, Mozambique, and Nigeria. The natural gas prices range from about $1.21/MMBtu in Mozambique for industrial customers to around $8.4/MMBtu for power generation in Ghana, with gas prices in Nigeria falling within the range.

The emerging African natural gas markets will attract pipeline gas and LNG in the near-to-medium term. For example, the LNG Floating Regasification and Storage Unit (FSRU) Golar Tundra arrived in Tema port in Ghana in July 2016 to supply gas to the Ghana National Petroleum Company. The natural gas price levels in Ghana and the high cost of imported alternative fuel are adequate to accommodate LNG imports to complement the other gas supply sources.

Nigeria delayed development of LNG liquefaction projects after NLNG Train 6 to give more attention to delivering natural gas to the domestic market. The Nigerian government is focusing on the domestic natural gas market, especially for power generation and gas-based industries. Cameroon has one LNG export terminal under construction with another planned. Mozambique and Tanzania are already making provision for meeting domestic natural gas demand as the terms of the LNG export project are being negotiated. Equatorial Guinea is also one of the LNG exporting nations from sub-Saharan Africa.

Global Shipping Considerations

Similar to the broader LNG supply-demand balance, the LNG shipping sector is currently encountering some major changes that result both from overbuilding of LNG carrier capacity and from technology changes which have substantially improved the fuel efficiency and operating costs of more modern ships.

LNG carriers trended towards a 125,000 cubic meter standard in the 1980s. Economies of scale and newer technology gave rise to increased ship size of 160,000 to 180,000 cubic meters, with the newest generation of Qatari ships being 216,000 to 266,000 cubic meters. The largest ships can carry around 6 billion cubic feet of gas, equivalent to one day's average consumption for the entire UK, or around 10% of US daily gas production.

A new build LNG carrier might be expected to cost around $200 million to $250 million, which would typically require a charter rate of about $80,000-$100,000 per day to support capital and operating costs. Spot charter rates in the industry are currently only at around a third or a quarter of these levels, so ships without long-term charter arrangements are struggling to find economically viable short-term charters. Also, LNG sellers are passing on many of the cost/revenue pressures created by the gas oversupply. For example, charterers are now typically paying only for the loaded leg of a journey, perhaps augmented by a small fee or bonus for the return ballast (empty) leg of the delivery trip.

The depressed shipping market does have some spin-offs for the gas/LNG development industry. Relatively new LNG carriers (even post 2000) which have a limited prospect of finding viable future long-term charters are becoming available for conversion to other types of floating facility. Conversion to a floating storage and regasification unit (FSRU) would be the easiest and quickest conversion to carry out. More recently and less frequently, ships have become a candidate for conversion to a floating liquefaction (FLNG) facility. FLNG conversion usually requires more structural alteration of the hull, given the significant additional tonnage of equipment on the topside, but the advantages of an existing hull/cryogenic storage facility can represent a significant cost saving.

It is interesting to note that a converted LNG carrier is to be used for the FLNG facility proposed for Cameroon, as well as the planned Fortuna project in Equatorial Guinea. Benefits claimed in both examples include shorter time to market and lower cost.

African countries may want to capitalize on short-to-medium term low-cost LNG to provide an initial gas stream for power projects and promote local market development using converted LNG carriers as floating storage and import terminals. Later, as domestic markets develop and natural gas development projects are implemented, countries could replace or supplement LNG imports with indigenously-produced gas. Available options include a variety of configurations with a combination of LNG storage, regasification, or ship-mounted power generation, and some proposed configurations even include water desalination in a coordinated package.

In light of these shipping market dynamics, engineering solutions for African gas and LNG projects include a much wider spectrum of options than in recent years.

LNG and Domestic Gas Value Chains

Introduction

The LNG value chain starts upstream with exploration and production operations. It then proceeds through the midstream stage of processing and transportation, and then the downstream phases of liquefaction to shipping and distribution to the consumer.

Government and private sector partners need to develop trust and firm long-term commitment so that relationships between partners in each part of the chain can endure. In order to build this trust, compromise and cooperation are critical as is a cooperative rather than adversarial approach to negotiations.

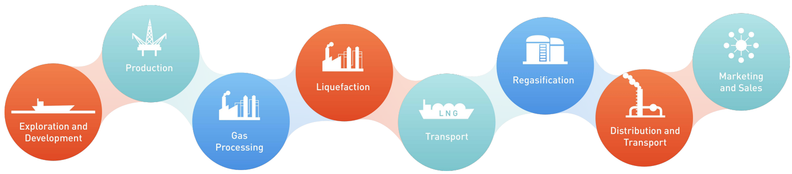
The LNG value chain is only as strong as its weakest link. The development of all portions of the chain must be carefully coordinated to avoid project failures that can result from missed connections. Planning to accommodate both the LNG exports and local supply (domestic gas) within the available natural gas resource base will be important to maintaining host country support for the production, processing, and export portions of the project. If the gas and LNG value chain does not result in the development of domestic supply infrastructure, it will be difficult to sustain the rest of the value chain, ensure that all parties profit, and promote long-term harmony between the producers (international oil companies or IOCs) and the host country.

LNG Value Chain

Ensuring that LNG projects create value for all participants requires that each link in the chain fully performs its contractual obligations within a framework of trust and commitment. Failure of one link adversely affects other key links. Contracts must set forth integrated rights and responsibilities and must set up the long-term relationships which require joint planning, coordination, and flexibility. Successful value chain management should help ensure completion within budget, timeliness of start-up, safe and reliable operations within and across links, and the ability to overcome changes in the market and operating conditions.

LNG is not currently a commodity business and continues to be dominated by long-term contracts. A spot market and shorter-term contracts are emerging due to commercial and geopolitical factors. “Base load” sales of LNG are long term, typically 20-25 years with take-or-pay provisions to limit risk. LNG projects are capital intensive and it is currently harder to make the whole value chain appear profitable in the face of lower prices and projected market over-supply. Fully dedicated shipping is often required. Dedicated shipping is capital intensive and project financing depends on creditworthy partners, firm agreements and a reliable LNG value chain. Market uncertainty caused by increasing supply competition, limited demand growth, and competition from pipeline supplies, are driving shippers and suppliers to attempt to sell cargos allocated to term contracts, or new cargos, on spot markets to cover the capital costs of LNG ships and infrastructure. Pipelines have point-to-point rigidity and geographic inflexibility making it difficult to supply islands or mountainous countries or regions fragmented by geopolitical issues, trade barriers, or security conflicts. LNG may provide a competitive supply option if pipeline supply cannot profitably surmount long distances and challenging construction routes. LNG might also be considered if the buyer has security-of-supply concerns, insecure borders, or deep oceans to be crossed.

The below graphic provides a depiction of the LNG value chain.



Link 1: Exploration Development and Production

The LNG value chain begins with the drilling and production of natural gas from subsurface gas reservoirs, usually offshore. This exploration and production (E&P) activity is historically dominated by national oil company (NOC) partnerships with international oil companies (IOCs) - particularly in countries with stranded reserves far from major markets -due to large capital requirements and the need for experienced operators. Smaller international companies and national oil companies are increasingly involved in exploration and production activities but may lack experience in working with the full value chain. US markets have introduced new upstream dynamics. Large gas reserves were developed by a variety of suppliers that are able to connect to and ship gas through existing infrastructure to large markets. This has somewhat mitigated the high capital costs and risks and helps to ensure a high return on investment, though it would be difficult to replicate this in other countries. Production optimization methodologies can help to manage costs and help to understand the key value drivers and risks across upstream production processes. Thorough and detailed strategic planning is key to success at this stage. Asset plans and strategies identify the long-term requirements for physical assets and match production levels at all phases of the project with planned supply to local and export markets.

This stage provides direction and guidance to enable the creation of investment and maintenance plans – essential to putting in place the resources (including finance) to manage the assets consistent with achieving desired outcomes. Agreements must be in place so that the other links are proceeding apace to accept the gas and begin supplying consumers.

Link 2: Processing and Liquefaction

The gas supply that comes from the production field is called "feed" gas and this feed gas must be sent to a processing facility for treatment prior to liquefaction. While natural gas used by consumers is almost entirely methane, natural gas is associated with a variety of other compounds and gases such as ethane, propane, butane, carbon dioxide, sulfur, mercury, water, and other substances. Sometimes gas is also produced in association with oil and sometimes liquids are produced in association with gas. Most of these compounds must be removed prior to the liquefaction process.

Once the impurities and liquids are removed, the natural gas is ready to be liquefied at the liquefaction plant. At the liquefaction plant, the natural gas is chilled into a liquid at atmospheric pressure by cooling it to -162ºC (-260ºF). In its liquefied form, LNG takes up about 1/600th of the space of the gaseous form, which makes it more efficient to transport.

Liquefaction plants are typically set up as a number of parallel processing units, called trains. Each train is a complete stand-alone processing unit but typically there are multiple trains built side by side. Liquefaction is the most expensive part of the value chain.

Some African nations are considering floating liquefaction solutions due to environmental issues and the remote location of the resource offshore. In floating liquefaction, all processes occur on the vessel at sea. The same principles apply but the marine environment and limited space for equipment require slightly different technology solutions.

From a commercial standpoint, liquefaction is historically dominated by NOC/IOC partnerships and specialized contractors are required for the construction of liquefaction facilities. High capital costs are typically financed across a long development cycle of several decades. The LNG development project team must finalize bankable commercial structures for LNG projects, possibly including both onshore and floating solutions. Careful project management and assurances that the local authorities are supportive of the project are required to bring in the costly design and execution service companies. It is critical that agreements are in place to allow for shipments to credit worthy offtakers so that the government and companies can begin to recover cost and generate revenues. It is, however, equally important to assure that planned supplies to the domestic market are productively allocated and relevant processing and transportation is in place so that the local authorities and citizens will see more direct benefit from the project.

Link 3: Shipping

Once the natural gas is liquefied, it is ready to be transported via specialized LNG ships/carriers to the regasification facility. LNG carriers are double-hulled ships specially designed to contain the LNG cargo at or near -162ºC.

Asian shipyards dominate the market for LNG ship building since this part of the industry also requires specialized expertise and Asian shipyards have he most experience. Ships are typically owned by a shipping company and chartered to seller or buyer. In some fully integrated projects, the ships are built and owned by the project consortium, Qatar being a prime example of this. High capital costs and highly leveraged financing often bring low risk to the ship-owner but also sometimes generate a low return on investment. If the ships are not owned by the company, agreements need to be in place to assure that ships arrive when the terminal begins operations. If local supplies are planned, it is also critical that infrastructure to support trucking and smaller local maritime shipping is also planned and in place; also that local consumers are prepared to accept shipments or provisions are made for allocated gas to be redirected until consumers are prepared to use the gas.

Link 4: Regasification and Storage

At the regasification stage, LNG is returned to its original gaseous form by increasing its temperature. Regasification usually occurs at an onshore import terminal that includes docking facilities for the LNG carrier, one or more cryogenic storage tanks to hold the LNG until regasification capacity is available, and a regasification plant. The LNG development project team must finalize bankable commercial structures for LNG projects possibly including both on-shore and floating solutions. Specialized cryogenic expertise is required but the capital costs are much lower relative to upstream and liquefaction. Terminals can experience challenges to site and permit requirements that must be resolved by agreements with local stakeholders. Agreements must be in place early in the development process to ensure that the regasification capacity is available to accept the LNG when the liquefaction project is completed.

Link 5: Distribution and Transport to Final Market/Sales

Key aspects of this stage include the ability to factor in volume, price, and supply/demand to best position parties to negotiate and satisfy agreements for transportation, distribution, and sales. Buyers and sellers must account for changing (and potential for change in) local and international market conditions. LNG marketing and trading require careful design so that revenues are generated to satisfy all stakeholders and allow for expansion if that is part of the project plan. Countries will need to assure the implementation of infrastructure required to derive maximum domestic benefit from the LNG value chain, including the construction of power and gas infrastructure required for delivery to consumers.

Domestic Gas Value Chain

The domestic gas value chain begins with production and proceeds to processing and treatment. Processing and treatment remove impurities and petroleum liquids that can be sold separately where available in commercial quantities (for petrochemicals, cooking gas, and so on.) The gas can then be compressed into a pipeline for transmission, distribution, and sale to consumers. In many countries, the gas aggregator, in many cases the national gas company, markets the gas to customers and operates the infrastructure.

Many national governments mandate the allocation of gas to the domestic market as this allows the development of local industries, including use as a feedstock and as fuel for power generation. Small markets will take time to develop and for some years the most likely customers for domestic gas are power plants and existing and planned large industries.

Although supplying gas to the domestic market is an aspiration of the government, developing a commercially viable and financeable project plan based on domestic markets requires careful planning and structuring. A thorough economic analysis is required to ensure that the industry consumers are profitable and the entire value chain is financially sustainable.

Hand in hand with the development of gas-fired generation, appropriate wholesale and retail market rules are a critical feature assisting in the formation of a viable gas monetization plan. Unlike an LNG take-or-pay contract, the integrity of the systems to collect bill payments from potentially thousands or millions of end-users in the domestic market can be a key challenge for credit risk management.

Domestic Market

Introduction

African countries have begun to develop local and regional gas markets, largely based in some cases on domestic pipelines, and in a few cases on regional pipelines. Markets and infrastructure remain underdeveloped and require large new investment to satisfy the needs of local populations. With properly designed market structures, local and regional gas demand could underpin more development of natural gas resources. Market participants across Africa are expressing a clear preference for leveraging indigenous natural gas resources as a primary source of fuel, feedstock for industrial chemical manufacture, a method for attracting foreign direct investment, and as a source for additional foreign exchange.

Given the substantial potential gas demand in many parts of Africa, especially for gas-fired power generation, for fueling industry and natural gas vehicles, and LNG for transportation, a well-structured, properly-regulated, local or regional market can be a deciding factor in how quickly gas can be developed to satisfy that demand. Although there are many challenges involved in using local and regional markets to support large gas development projects, with a suitable market structure, technology solutions, and contract models, there is likely to be an increasingly attractive range of options.

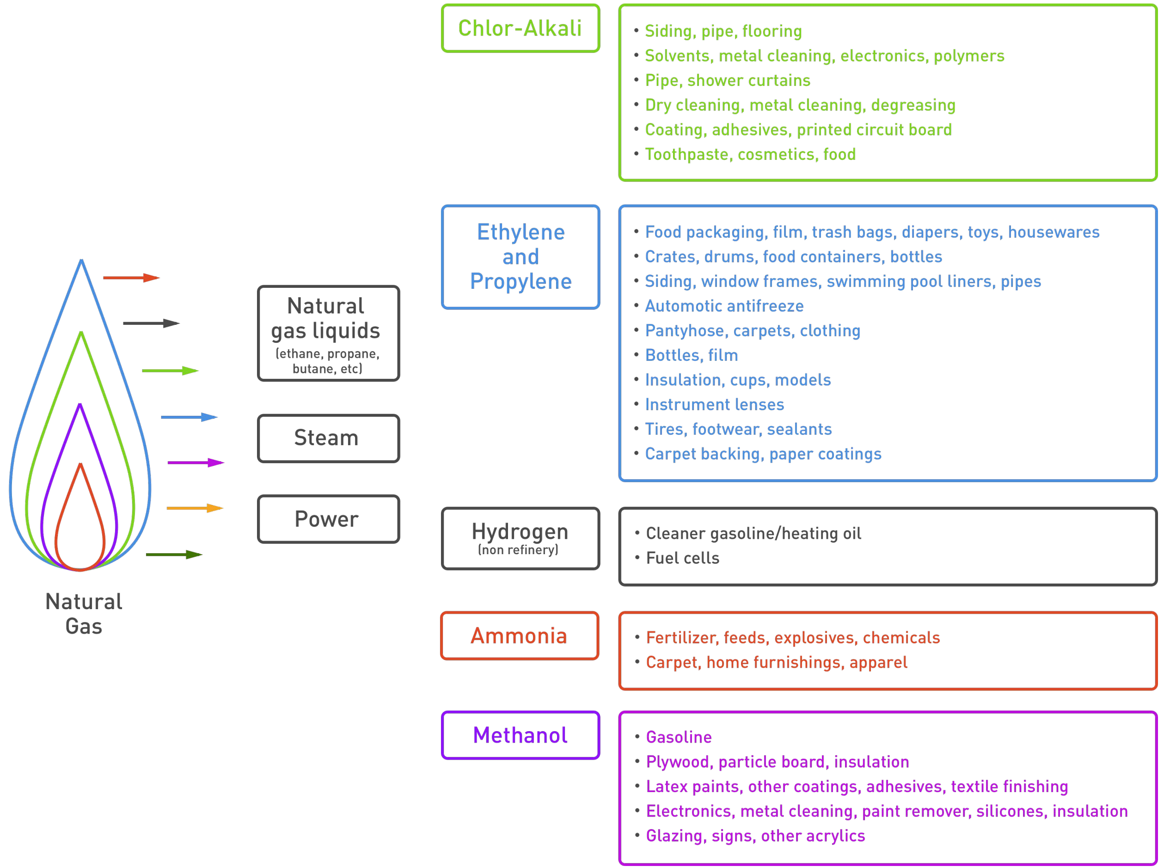
The chapters which follow review elements that can enable domestic market development and create beneficial spin-offs in terms of replacing competing fuels that can be more expensive. Some examples of local or regional infrastructure serving markets are also provided. A well-developed gas utilization master plan with adequate local participation and buy-in is normally a key component of enabling market development.

In today's oversupplied global market for LNG, there are opportunities for supporting import projects, but also challenges for developing large-scale projects domestically.

Domestic Use of Gas

This section provides an overview of the potential domestic uses of natural gas. A major use for domestic natural gas is power generation. Natural gas can also be used as fuel in transportation, industries, commercial buildings or residences. Natural gas can provide fuel substitution for higher cost and more environmentally damaging fuels as well as utilizing a country's domestic gas resources. Additionally, natural gas can be used as a feedstock for various other industrial plants, such as fertilizer plants, methanol plants, petrochemical plants and gas-to-liquids plants.

The below diagram shows some of the domestic uses of natural gas.


Natural Gas
Natural gas liquids (ethane, propane, butane, etc)
Steam
Power
Chlor-Alkali
• Siding, pipe, flooring
• Solvents, metal cleaning, electronics, polymers
• Pipe, shower curtains
• Dry cleaning, metal cleaning, degreasing
• Coating, adhesives, printed circuit board
• Toothpaste, cosmetics, food
Ethylene and Propylene
• Food packaging, film, trash bags, diapers, toys, housewares
• Crates, drums, food containers, bottles
• Siding, window frames, swimming pool liners, pipes
• Automotic antifreeze
• Pantyhose, carpets, clothing
• Bottles, film
• Insulation, cups, models
• Instrument lenses
• Tires, footwear, sealants
• Carpet backing, paper coatings
Hydrogen (non refinery)
• Cleaner gasoline/heating oil
• Fuel cells
Ammonia
• Fertilizer, feeds, explosives, chemicals
• Carpet, home furnishings, apparel
Methanol
• Gasoline
• Plywood, particle board, insulation
• Latex paints, other coatings, adhesives, textile finishing
• Electronics, metal cleaning, paint remover, silicones, insulation
• Glazing, signs, other acrylics

Natural Gas - Fuel Supply and Demand Economics

The price of natural gas must be balanced between the cost of supply and what is affordable for consumers; otherwise, consumers will not switch to gas, assuming other alternatives are in place and/or available. The price level must be sufficient to demonstrate to the consumer adequate value that overcomes the risks and costs of converting to natural gas from the incumbent fuels (diesel, fuel oil, etc.). The fuel-switching economics must be favorable in the long term, which means, first and foremost, the price difference between the delivered cost of natural gas and the incumbent fuel must be strong over the life of investments by consumers and suppliers.

Local gas prices, particularly for imports, are influenced by global market prices and are also impacted by regulatory policy choices which impose costs through taxes and mandated technology choices. Taxes, or the lack thereof, can provide incentives or disincentives for fuel choices, while grants, subsidies, and the developing economies of scale as the adoption of new technology increases, can offset capital costs. Perhaps the greatest challenge to switching to natural gas fuels has been the recent collapse in crude oil prices and the attendant decline in refined product prices (e.g. of distillates and heavy fuel).

As mentioned above, an equipment owner (power plant, ship or vehicle) must be convinced that the benefits of switching to natural gas outweigh both the next best alternative and the risks of change. First and foremost, they must be convinced that natural gas will be reliably available at their chosen fueling location, thus the readiness of fuel supply infrastructure, both in equipment and suppliers, must be sufficient to provide the comfort of reliability. It is imperative to understand the physical infrastructure which will be required to meet demand so as to alleviate this critical concern. Owners must also be convinced that the benefits outweigh the time and effort required to understand natural gas and its impact on operations and maintenance. Some questions that could arise by the owners are: How safe is this fuel? What happens if there is a fire? How will my operations need to change (if possible) to accommodate this fuel? These are all very real questions requiring honest public answers.

Natural Gas Power Generation

In the past, many large gas developments in Africa have focused on global gas export markets to underpin development, and domestic market opportunities have been secondary. Given the emergence of significant high-quality gas resources in many parts of Africa, the current weak demand in the global LNG market and the urgent need for new power generation facilities in many parts of the continent, the domestic gas and power value chain is becoming a much more critical feature of natural gas development.

There are challenges involved in connecting gas resource development with power demand, particularly with respect to the size of domestic gas demand in most African countries compared to the magnitude of natural gas resources required to justify a world-scale LNG project. Nevertheless, the ability of power projects to provide the credit necessary to support financing arrangements, and the infrastructure required to transport gas to where the power generation is needed, means that such development remains one of the most promising opportunities with which to connect African gas resources to domestic markets. The use of gas for power generation is, therefore, an important policy goal, especially as power is an enabling factor to stimulate and promote other industrial development

The purpose of a gas-to-power strategy is to encourage the use of domestically produced natural gas and increase power supply to meet domestic needs for power. Imported gas is also an option, assuming either pipeline gas or LNG is available to the country and domestic tariffs support the cost of imports. When developing a natural gas power market, the following objectives should be considered at a national level:

- **Secure stable, reliable, consistent quality, and cost-effective electric power and fuel supplies to fuel electric generation or industrial operations.** Global energy price volatility and geopolitical risks will likely continue. This requires an understanding of in-country risks, regional/local power grid reliability, present and future public power supply availability, local competition for power and fuel resources, public transportation systems, logistic considerations, and insourcing or outsourcing risks and opportunities to operate in an uncertain investment environment.

- **Achieve sustainable cost and efficiency improvements.** Understand energy-related opportunity costs at a country level. Focus on cost savings, improving domestic manufacturing and trade revenue and achieving predictable operating performance for industries through stable and affordable energy supplies.
- **Collaborate internally and engage externally on energy policies and regulations, energy supplies, challenges, and opportunities.** Communication, transparency, and collaboration amongst all stakeholders are essential to managing various aspects of the natural gas power generation, transmission, and distribution project development.
- **Consider renewable energy, energy-efficiency strategies and carbon offsetting to mitigate carbon footprints.** African nations receive hydroelectric or coal and oil base-load power across the continent. Natural gas and other renewable sources (such as wind and solar power) may be used to supplement/offset base-load power-reducing GHG emissions. Unlike hydroelectric power, which is dramatically impacted by drought and climate change, natural gas provides consistent and reliable power.
- **Adapt energy generation and assist local communities to prevent future physical impacts of climate change.** It is important to assess present and predicted climate change impacts to communities and projects and to apply natural gas power generation and mitigation measures during the design stage or make modifications to existing facilities and structures to reduce emissions and increase energy efficiency. Gas-to-power measures may include power generation for industrial facilities. Gas-fired plants can also be used to run facilities for water storage, desalinization, diversion for mitigation of drought or flooding, irrigation, and controlling or containing environmental releases of hazardous materials, process solutions and/or impacted water.

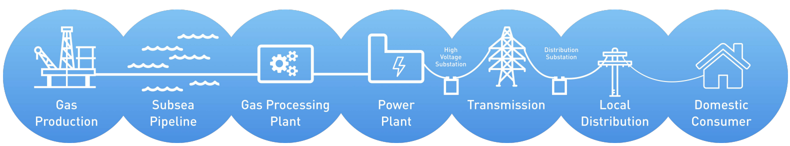
Gas to Power Implementation

Natural gas-fired power generation is based on existing and known technologies with low technology risk, repetitive and standard design, experienced engineering, procurement and construction (EPC) contractors, a global vendor market, a well-established supply chain, and flexible fuel consumption options. The result, even within Africa, is a broad selection and training environment for operators, maintenance technicians, and craft workforce. When combined with natural gas-powered vehicles or industrial, commercial and retail customers, larger scale natural gas power generation could serve as an anchor client for developing large-scale capital infrastructure for pipelines, road/rail and supporting infrastructures.

For more information on power project finance see a previous book in the series **Understanding Power Project Financing** http://cldp.doc.gov/programs/cldp-in-action/details/1603

Elements of a Gas-to-Power Value Chain

The below diagram shows a typical gas-to-power value chain in connection with an LNG export project.



This diagram assumes the gas reserves and production are offshore. The gas is piped to the shore for processing/treatment, and is then supplied to an LNG export facility. Part of the gas, after any required processing/treatment, will be transported to power plants to generate electricity. Some of the constituents of the gas, such as NGL and condensates, may be separately sold to the market. An onshore-value chain schematic would show onshore production and onshore pipeline systems.

Gas-to-Power Value Chain Planning

To ensure the success of a domestic gas-to-power project, proper and careful planning is required. The objective of such planning is to identify the demand centers/end-users and ensure that power can be delivered to the domestic end-users at the lowest cost while meeting reliability, safety ,and environmental requirements.

For countries with an integrated electricity utility company (usually owned by the government) responsible for the generation, transmission and distribution of power, the utility's planners will conduct studies to identify the demand centers and locations for future demand growth. These are usually targeted at the main cities and other major populated areas. The electrification plan will need to address how to develop these markets in an optimized manner, and this involves the following alternatives:

> Build power plants close to the demand centers, and pipelines to deliver gas to the power plants

> Build power plants close to where gas is available, and build transmission lines to connect to the demand centers

The factors to be considered include:

> **Cost:** the difference between cost of the above alternatives is primarily the difference between the cost of pipeline vs. transmission line

> **Losses:** while there are losses associated with transmitting power over long distances, transporting gas over long distances may also require intermediate compression

> **Strategic considerations:** the development of the initial gas-to-power project under consideration will need to fit in the overall electrification plans for the country

> **Expansion potential:** whichever option is selected, the ease of expansion for additional power generation and any associated incremental pipeline/transmission investment will need to be examined

Gas-to-Power Value Chain Implementation

Successful implementation of a gas-to-power supply chain depends on the ability of each party to execute the elements for which it is responsible in a timely manner and in coordination with other parties. Below is an example that shows typical construction and ownership arrangements:

Party	Supply Chain Ownership
Upstream Investor	Raw gas production / Offshore pipeline / Onshore gas treatment plant
Pipeline Investor	Pipeline connecting gas treatment plant to the power plant
IPP	Power plant
Utility Company	Transmission lines, substations and distribution network

A successful gas-to-power project typically has each party having the technical, financial and operational capability to undertake its respective investment. The parties must coordinate their plans, including development, construction, and financing plans, in a way to enable a timely FID (final investment decision) and start up of the entire value chain. In cases where the government-owned utility company is responsible for funding and constructing transmission and distribution networks, it must plan for and budget towards the large investments required, and provide confidence to other investors on the availability of government funds and its ability to complete the transmission and distribution networks. Likewise, other investors in the value chain will also need to demonstrate the ability to complete their respective segment of the value chain in a timely manner.

Power Generation Investment

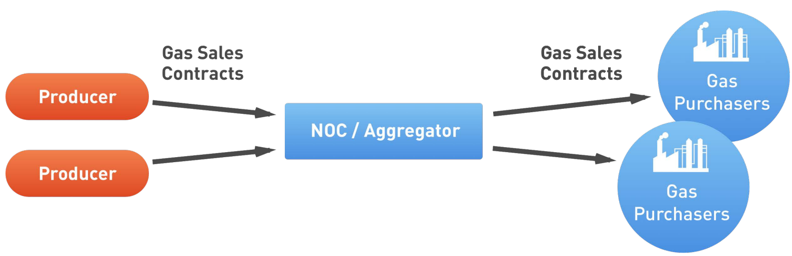
Power plants are capital-intensive, long-term investments. Independent Power Project (IPP) investors require, among other things, steady revenue from a creditworthy power offtaker under a power purchase agreement (PPA), reliable fuel gas supply, and a stable legal, regulatory, and taxation environment. To attract IPP investment, host governments will need to provide the necessary legal and regulatory framework in the gas and electricity sector to underpin the PPA which typically has a duration of 20 or more years. Under a conducive investment environment, the IPP will be able to secure project financing as well as payment securitization provided by multilateral agencies such as the World Bank and African Development Bank.

Market Structure

The ability of local or regional gas and power markets to partially or wholly underpin a major gas resource development depends largely on the way in which the wholesale and retail gas and power markets are structured.

The market segments for natural gas are supply, wholesale, and retail. Each market segment can be structured as exclusive, mixed, or competitive, with prices either regulated or market-based. In the supply segment, the producer sells to an aggregator or directly to an end-user. In the wholesale segment, an entity, such as an aggregator, purchases gas from another entity for resale to other customers. In the retail segment, an end-user purchases gas from an entity for its own use.

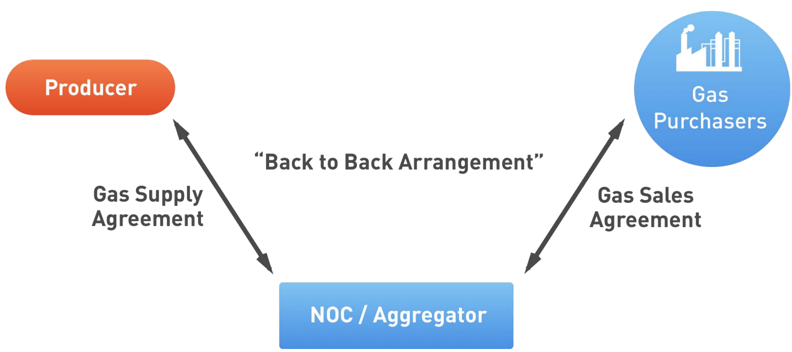
An example of an exclusive structure is shown below where a gas aggregator, e.g. the national oil or gas company, acquires natural gas, provides transportation and compression, if required, and then on-sells the natural gas to wholesale and retail customers.



Of critical importance in any energy market, is a clear and dependable path through which end-users pay for energy received. The flow of energy from the gas developer through to the end-user and the flow of funds in the opposite direction are the key feature of any market and the critical facilitating feature of any project. For domestic and regional markets to provide dependable revenues similar to that which would result from gas or LNG exports to international markets, appropriate planning and execution of market rules, and the nature and level of regulation, are critical factors.

One of the concerns with an aggregator exclusive structure is that the aggregator will stand between the supplier and the customer for contractual and payment purposes. This could lead to a situation where the aggregator is obligated to pay the supplier despite the fact that the gas customer has not paid the aggregator. This concern can be addressed through a mixed structure which includes some sort of payment security from customers or security provided on behalf of the customers.

The diagram below shows an example of a back-to-back structure where the supplier looks to the customers for payment instead of the aggregator:



In a more established market, as shown below, a direct commercial structure where a supplier sells directly to a customer may be used. This structure requires that the supplier or the customer obtains transportation for the gas supply.

In the case of an export sale, the project developers usually rely on a long-term take-or-pay LNG contract, supported by a creditworthy buyer who will sign a binding contract, thereby putting a strong balance sheet behind the purchase obligations. This means that project developers and lenders rarely need to examine what happens to the gas once the take-or-pay buyer has purchased it, so the need to examine market rules downstream of the foundation sale-and-purchase agreement is rarely considered.

For local and regional markets in Africa, establishing a creditworthy buyer presents more complex challenges, due to the lack of gas buyers with a pre-existing credit position who are able to support financing requirements. As a result, lenders and project developers typically have to examine the gas or electricity value chain down to the source of the cash flow, which terminates at the end-user of the gas or power produced. In order to provide a similar level of credit support to a traditional take-or-pay contract, the way in which monies flow through the various market participants is integral to the way the market is structured.

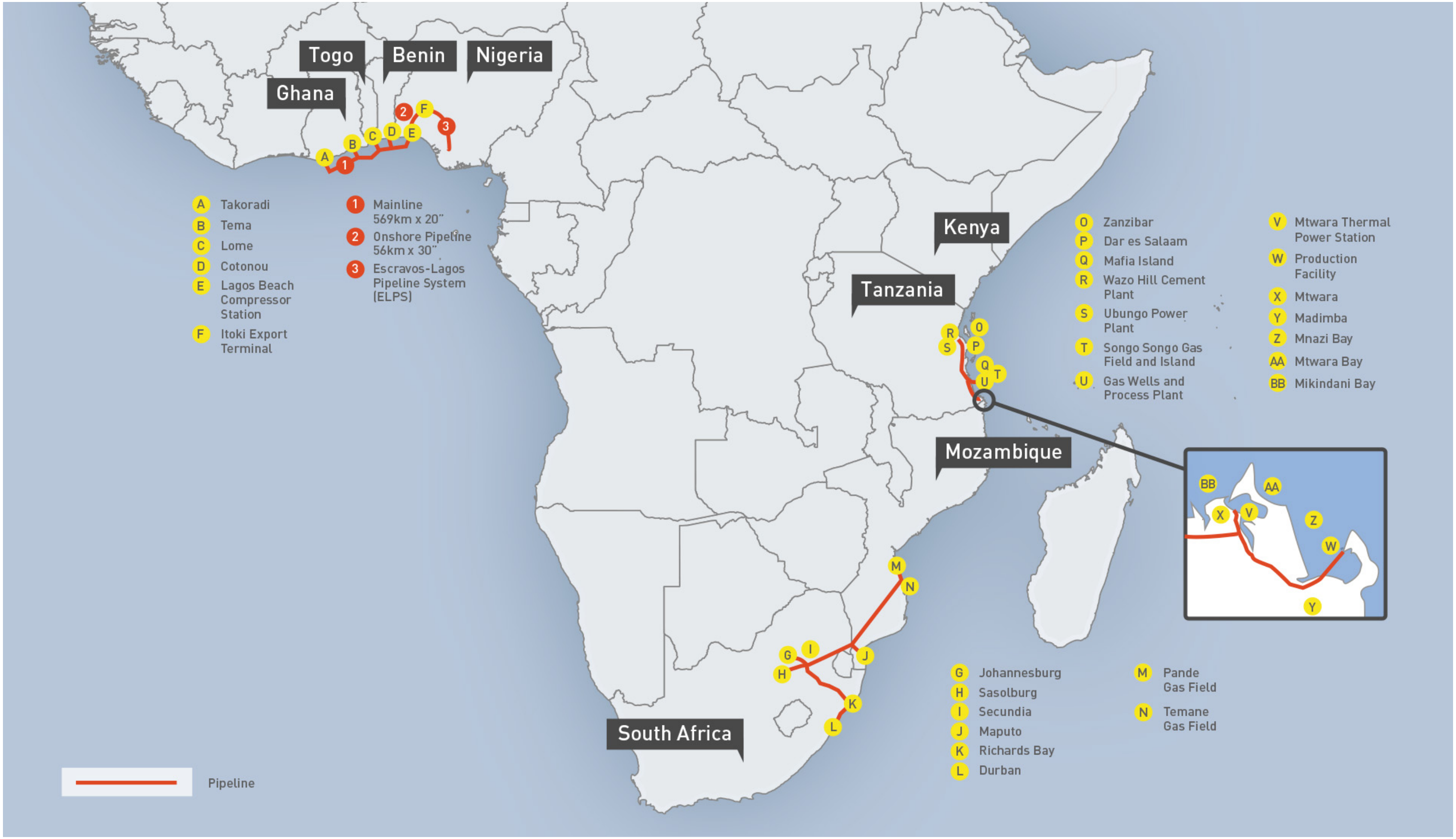
Interconnected Gas Markets within Sub-Saharan Africa

Within sub-Saharan Africa, there are neighboring countries without gas resources next to countries with gas production or large potential gas resources. As a result, some cross-border gas supply has begun to be established and there is much potential for future trade as additional development occurs.

There are just a few examples of regional and trans-border pipeline projects across sub-Saharan Africa. In this section, we will discuss the following:

- West Africa Pipeline System
- Mozambique to South Africa Pipeline
- Tanzania Pipeline Systems
- Mozambique and Tanzania recent gas discoveries

These systems are depicted on the following map.



Togo
Benin
Nigeria
Ghana
A Takoradi
B Tema
C Lome
D Cotonou
E Lagos Beach Compressor Station
F Itoki Export Terminal
1 Mainline 569km x 20"
2 Onshore Pipeline 56km x 30"
3 Escravos-Lagos Pipeline System (ELPS)
Kenya
Tanzania
Mozambique
South Africa
O Zanzibar
P Dar es Salaam
Q Mafia Island
R Wazo Hill Cement Plant
S Ubungo Power Plant
T Songo Songo Gas Field and Island
U Gas Wells and Process Plant
V Mtwara Thermal Power Station
W Production Facility
X Mtwara
Y Madimba
Z Mnazi Bay
AA Mtwara Bay
BB Mikindani Bay
G Johannesburg
H Sasolburg
I Secundia
J Maputo
K Richards Bay
L Durban
M Pande Gas Field
N Temane Gas Field
Pipeline

West Africa Gas Pipeline (WAGP)

West Africa produces much more natural gas than is required for domestic consumption and exports natural gas within the region and overseas. Natural gas is produced mainly in Angola, Equatorial Guinea, Cameroon, Ghana, Ivory Coast and Nigeria, The largest natural gas reserves in the region are in Nigeria.

The West Africa Gas Pipeline was built to transport natural gas from Nigeria to consumers in the Benin Republic, Togo, and Ghana. The WAGP took about 30 years to implement after being proposed by the Economic Community of West African States (ECOWAS) in 1982 with the goal of promoting regional economic growth. A series of intergovernmental agreements and treaties were negotiated and signed by the four countries.

The WAGP System consist of a 691km 20" (508mm) pipeline and associated processing/receiving facilities in Lagos, Itoki, Cotonou, Lome, Tema and Takoradi. The WAGP receives gas from the Escravos-to-Lagos Pipeline System (ELPS) which gathers the gas from Shell and Chevron fields in the Niger Delta. The capacity of ELPS is being expanded from 1.1 billion cubic feet per day (bcfd) to 2.2 bcfd. The expansion work is scheduled to be completed in 2016.

The West Africa Power Company (WAPCo) owns and operates the WAGP system with headquarters in Accra, Ghana. The pipeline is owned by a consortium including the Nigerian National Petroleum Corporation (NNPC), Shell, Chevron, the Volta River Authority (VRA) - a multi-national power company, the Electric Company of Ghana (ECG), Benin's gas company, Société Beninoise de Gaz (BENGAS SA), and Togo's gas company, Société Togolaise de Gaz. The initially contracted capacity of WAGP is 170 million cubic feet per day (mmscfd) with provision to grow up to 474 mmscfd with compression. The natural gas supply comes from NNPC, Shell and Chevron fields in Nigeria. The gas buyers are VRA in Ghana and Communauté Electrique du Bénin (CEB) in the Benin and Togo as fuel for power generation.

Construction began in 2005 and the first gas was received in Ghana in April 2009. Third party access, Open Access, was declared on July 1, 2012. The gas sales from the WAGP have been limited because of disruptions to gas production from Nigeria's oil and gas fields and periodic payment disputes.

Temane - Secunda Pipeline (Mozambique to South Africa)

In the 1960s, the U.S. company Gulf Oil discovered natural gas in the Pande and Temane fields, located onshore in the south of Mozambique. Because the main objective at the time was oil, the gas reserves remained undeveloped until in the 1990s, while Empresa Nacional de Hidrocarbonetos (ENH) did the appraisal of the fields which culminated with the signature of the Petroleum Production Agreement (PPA) in 2000.

This agreement signed by the Government and the National Oil Company (ENH) with a consortium composed of Sasol Petroleum Temane, Lta. (SPT) with 70%, the Companhia Mocambicana de Hidrocarbonetos, SARL (CMH), a subsidiary of ENH, with 25%, and the International Finance Corporation (IFC) as an integral part of this agreement with acquired 5% of CMH as part of their commitment.

With proven reserves of 3.5 trillion cubic feet (TCF), the anchor customer of the project was Sasol's petrochemical manufacturing facilities in South Africa.

To take the gas from Temane in Mozambique to the anchor customer in Secunda, South Africa, a 26" pipeline with 865 km length and capacity of 149 million gigajoules per annum (MGJ/a) was built, with five offtake points within Mozambique.

When the first commercial production of gas started in 2004, the gas market in Mozambique was very small. The gas distribution network consisted of 300 km of pipeline owned by ENH, which, has supplied gas to power generation and commercial and residential consumers since 1992. Mozambique used 0.2 MGJ/a, compared to 120 MGJ/a that was exported to South Africa.

As soon as the pipeline infrastructure was built, the demand for natural gas increased exponentially, and today the whole domestic supply obligation

(DSO) from the project - 27 MGJ/a- is used internally and many industrial projects are demanding additional natural gas.

ENH accomplished the successful construction of the Maputo Gas Distribution Network Project in 2014, bringing natural gas from the fields to Maputo city and Marracuene district. This project was an important milestone in the history of hydrocarbons in Mozambique because, for the first time, piped natural gas was supplied to a city in Mozambique. Previously, all fuels in Mozambique were imported, so the natural gas plays an important role in the replacement of these imported fuels.

Pipeline Infrastructure in Tanzania

As any other southern Africa country, Tanzania has a huge demand for power. Focused primarily on resolving the power shortage, three pipelines were built to connect the natural gas fields to the power plants:

- Songo Songo pipeline - with 232 km of pipeline connecting Songo Songo fields to Dar es Salaam, began operating in July 2004;
- Mnazi Bay Pipeline - with 27 km of pipeline connecting Mnazi Bay to Mtwara, began operating in July 2006;
- Mtwara to Dar es Salaam Pipeline - 551 km of pipeline connecting Mtwara to Dar es Salaam, began operating in November 2015.

These pipelines help to establish the basic infrastructure to develop the domestic market for natural gas, reducing the importation of fuels and stimulating local industries.

New Gas Discoveries in Mozambique and Tanzania

In Mozambique, more than 200 TCF of natural gas has been discovered offshore in the Rovuma Basin, while in Tanzania more than 57 TCF of natural gas has been discovered offshore. These giant gas reserves can be a game-changer for the southern African region.

Because the reserves are so large, it is possible to have a good balance between the export of LNG, which will generate needed foreign exchange, and the expansion of the domestic natural gas market to meet the power needs in the country and region, as well as an opportunity to develop local industry. Many downstream projects were presented to Mozambique pursuant to the Mozambique Gas Master Plan, supporting a potential for 26 TCF consumption of natural gas in Mozambique.

The energy demand in the southern Africa countries has increased exponentially each year. In Mozambique, the demand for electricity is estimated at more than 1,000 megawatts (MW) in 2016 and may triple in the next 15 years, according to the Mozambican power company, Electricidade de Mocambique (EDM).

Besides the gas needed for power, various other downstream industries that utilize gas as feedstock in the production of value-added products are demanding natural gas for the production of fertilizers, gas-to-liquid fuels, and methanol, among other products, which may contribute significantly to the industrialization of those countries and associated job creation if they can be made profitable.

The governments and communities expect that the discoveries of natural gas, either in Mozambique or in Tanzania, can contribute significantly to solving the energy crisis in the region, and facilitating investments in downstream projects.

The experience of Mozambique in the Pande and Temane Project - which allowed interconnection of the Pande and Temane gas fields in Mozambique to Secunda, in South Africa, and enabled development of small gas markets within Mozambique - can be quite useful in the Rovuma projects in Mozambique, and Tanzania.

Elements of a Gas Master Plan

A starting point for many countries, especially countries that wish to develop gas resources and/or domestic markets for natural gas, is the creation of a Gas Master Plan (GMP). While the contents of a GMP will be unique to each country, there are some helpful general guidelines and principles. In general, a GMP is a holistic framework to identify and evaluate options for natural gas use for domestic supply and/or export. The main goal of the GMP is to provide the foundation to guide policy development for the gas sector of the country. The GMP provides a detailed road map for taking strategic, political and institutional decisions, on the basis of which, investments in the area can be designed and implemented in a coordinated manner.

The role of the government in developing the GMP is to provide a stable, transparent regulatory, fiscal, and financial policy regime to foster the development of the gas sector in a manner which benefits the country as a whole.

While the elements of the GMP vary by the country, there are some broad elements to consider. These elements include:

- Objective of the Gas Master Plan
- Gas resource evaluation
- Gas utilization strategy and options consistent with country's energy policy
- Domestic supply and demand analysis (power and non-power sector)
- Identification of other domestic “priority” projects
- Infrastructure development plan/formulation
- Institutional, regulatory and fiscal framework

- Development of recommendations about the volumes and revenues from gas finds and future gas production
- Identification of possible mega or “anchor” projects. For example, a country with a large natural gas find might consider an LNG export project, or other similar industrial-scale plant such as methanol, ammonia production, gas-to-liquids (GTL) projects and dimethyl ether (DME).
- Formulation of a roadmap for implementation of projects
- Gas sector regulatory reforms
- Socioeconomic and environmental issues associated with development
- Gas pricing policy

An “anchor” project is a large project that provides the economies of scale that may justify the investments in capital-intensive gas infrastructure, which is then available to smaller users. Launching a gas industry from scratch has traditionally required one or more large “anchor” customers to undertake to purchase enough gas to justify the significant investments required to build the requisite pipeline infrastructure. Examples of anchor projects include LNG export terminals that may justify offshore gas exploration and production in the first place, power plants, gas-to-liquids plants, methanol or fertilizer plants, which in turn could provide the economic underpinning for pipeline expansions.

With the generally weak global demand for LNG from traditional markets such as Europe or Asia, GMP considerations may have to focus more closely on domestic or regional gas demand to underpin major gas developments, and this may require innovative approaches to gas market development, contractual mechanisms for gas sales, and financing arrangements.

Examples of Domestic Gas Projects

To replace flagging global demand for natural gas, the range of mega or anchor projects might also include a discussion of “priority” gas projects that might be undertaken while plans for any mega projects are being developed. Examples of possible projects include:

- Power projects
- Gas-to-liquids projects
- Fertilizer plans
- Petrochemicals
- Methanol projects
- Gas transmission and distribution pipelines
- Fuel for industry such as iron, steel and cement projects

Domestic Gas Reservations – Domestic Supply Obligation

Assurance of gas supply is critical to delivering the policy objectives of the GMP. This includes recognition that gas-based industries, such as methanol, fertilizer, or power industries, need a certainty of gas supply before large investments are made. At the same time, many governments face the issue of ensuring that gas is available for critical domestic gas utilization projects which will advance the domestic economic growth agenda.

To balance these often competing objectives, many gas-producing nations have some form of gas reservation policy or domestic supply obligation, aimed at ensuring that local industry and local consumers are not disadvantaged by gas exports.

International examples of domestic supply obligations (DSO) include:

- Nigeria requires all oil and gas operators to set aside a pre-determined minimum amount of gas for use in the domestic market. This is a regulatory obligation with the initial obligation level determined based on a view of the base-case demand scenario for gas in the domestic market. The domestic gas obligation provides a base load of gas that must be processed through the gas-gathering and processing facilities. Since the obligation to supply the domestic market is the responsibility of the gas supplier, title to gas-processed remains with the gas suppliers.

- Israel, Indonesia, and Egypt have laws mandating that a percentage of gas extracted must stay within their domestic markets.Israel reserves 60% of its offshore natural gas. Egypt has legislated that 30% of gas production must be directed to domestic consumers. Indonesian reservation is applied on a case-by-case basis to new projects, but reservations of up to 40% have been agreed to in recent years.
- In the United States, the Department of Energy's (DOE) authority to regulate U.S. natural gas exports arises from the Natural Gas Act (NGA) of 1938. By law, applications to export U.S. natural gas to countries with which the United States has Free Trade Agreements (FTAs) are deemed to be consistent with the public interest and the Secretary of Energy must grant authorizations without modification or delay. The NGA directs DOE to evaluate applications to export U.S. natural gas to non-FTA countries. Under the NGA, DOE is required to grant applications for authorizations to export U.S. natural gas to non-FTA countries, unless the Department finds that the proposed exports will not be consistent with the public interest, or where trade is explicitly prohibited by law or policy. Canada also has similar public interest laws regarding the export of its gas.
- Norway, Qatar, Russia, Algeria, and Malaysia ensure domestic advantage from their gas reserves by having state-owned companies taking the role of dominant producer.
- Western Australia is the only state in Australia with a gas reservation policy. Under Western Australia law, 15% of all the gas produced in that state must remain in the state. Western Australia's gas reservation scheme has been able to guarantee domestic supply at attractive prices, while still allowing investment in the LNG industry and a healthy level of exports.

Gas Sector Regulatory Reforms

Depending on the level of development in the country, various regulatory reforms may be needed to promote the development of the gas sector. Legislation and regulations for licensing the construction, operations, and pricing of natural gas transmission and distribution pipelines might be needed. There should be standard, publicly available terms and conditions for licensing developers of infrastructure that define service obligations, operating rules, and tariffs.

The licensing, operations and tariffs of gas transmission and distribution pipelines should be overseen by an independent regulator.

Many governments are considering unbundling value chains for regulatory purposes. Unbundling refers to the separation of segments in the gas value chain to reduce the potential for monopoly, and to increase transparency and the ease of regulating smaller projects. Consumers should see the gas price separately from the cost of transporting and distributing it for transparency. Unbundling can facilitate third-party access to pipelines.

Structuring an LNG Project

Introduction

Natural gas liquefaction projects require considerable capital investment and involve multiple project participants. As a result, the projects typically need to have long, productive lives. Risk needs to be properly allocated and functions for the project participants defined in order to allow debt to be paid off and to generate sufficient returns for investors. Each project would be expected to produce LNG over a period which could span 20-40 years, so it is important to structure the project correctly from its inception to anticipate project risks over time and to avoid misalignments between stakeholders and other risks to the project's success.

As a result of their high costs, LNG projects are typically executed by joint venture entities with more than one sponsor and with multiple project participants. An appropriate structure will enable entities, often with different aims, such as governments or state-owned entities and private sector companies to comfortably participate in the project. Private sector companies could be energy companies, utilities, and, as is increasingly the case, investors from the financial community. A well-structured project will afford participants sufficient protection in their endeavors. A robust and well-thought-out structure can make provisions for changes to ownership and the future addition of facilities. Liquefaction projects are often expanded via the addition of new LNG trains.

The structure of liquefaction projects will have ramifications for the allocation of risk. The structure can determine whether the sponsors are able to successfully sign sales or tolling contracts with buyers or tolling counterparties. It will also have an impact on whether the project is able to attract further equity investors, if needed, and raise debt funding from financiers. If a project's structure is weak or overly complicated, the sponsors may struggle to attract buyers for their product as buyers will be evaluating project risk when deciding whether to enter into a sales contract. The structure can impact the financing to the extent that the sponsors may be charged a higher price for any debt that is raised or it may even prevent the project sponsors from attracting funding. These structures may be applied to liquefaction projects utilizing floating liquefaction technology.

LNG import facilities, both land-based and FSRU, will cost less to implement than liquefaction projects, but similar considerations apply. They will often operate over a long timeframe and involve multiple partners.

Choosing a Project Structure

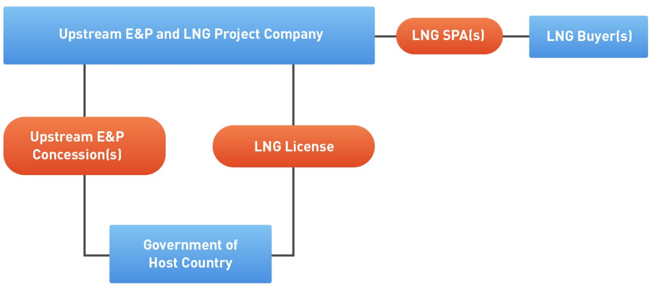
Three basic forms of commercial structures have emerged for LNG export projects - integrated, merchant, and tolling. There are hybrid variations of these three models and the potential exists for further changes in the future. But these three structures are reviewed herein because they are the prevailing structures being used in the LNG industry. There is another option for the host government to fully develop the LNG plant, but this option has had limited application since governments generally do not have the experience or access to the necessary capital.

The selection of a particular commercial structure is a matter of sometimes heated debate and negotiations among the investors in the project and the host government, and the outcome is influenced heavily by the driving factors discussed below. The choice of a commercial structure has a significant impact on the success of the project both in the short-term and over the life of the project. With the wrong structure in place, local investors may not be able to participate in an LNG project and the expansion of the LNG project may be prevented or impeded. Since, ultimately, the government must approve the development under most PSAs/PSCs or licenses, the investor is wise to give consideration to government preferences and engage closely and collaboratively with the government when making key decisions on project structure.

Integrated Commercial Structure

Under the integrated commercial structure, the producer of natural gas is the owner of the LNG export facilities as well as the upstream. The exploration and production project is fully integrated with the LNG liquefaction and export project. The project revenues for both projects are derived from the sale of LNG under one or more LNG sale and purchase agreements (SPAs) entered into by the individual upstream participants or the integrated project company, if one exists. Because the owner of the upstream exploration and production project is the same entity as the owner of the LNG liquefaction and export project, there is typically no other user of the LNG liquefaction and export project. The credit of the LNG buyer or buyers provides the financial underpinning for both the upstream exploration and production project and the LNG liquefaction and export project.

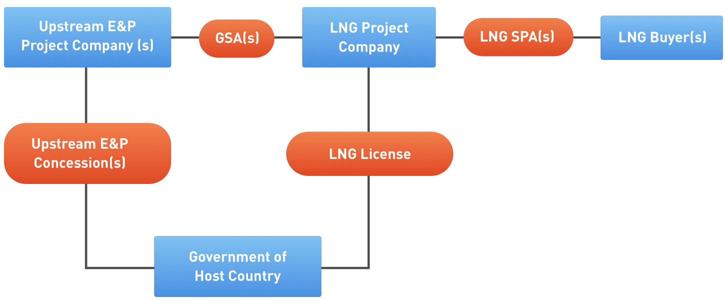
Examples of integrated project structures include Qatar's Qatargas and RasGas projects, Russia's Sakhalin Island, Norway's Snohvit, Australia's Northwest Shelf and Darwin LNG, and Indonesia's Tangguh. The integrated commercial structure for LNG liquefaction and export projects in the below diagram.



Merchant Structure

Under the merchant commercial structure, the producer of natural gas is a different entity than the owner of the LNG export facilities, and the LNG liquefaction project company purchases natural gas from the upstream exploration and production project company under a long-term natural gas sale and purchase agreement. The upstream exploration and production project revenues are derived from the sale of natural gas to the LNG liquefaction project company. The LNG liquefaction project profits, in turn, are derived from the amount by which the revenues from LNG sales exceed the sum of the cost of liquefaction (including debt service) and natural gas procurement costs. Because the owner of the upstream exploration and production project is a different entity than the owner of the LNG liquefaction and export project, there may be more than one supplier of natural gas to the LNG liquefaction project company. The credit of both the LNG buyer or buyers and the natural gas producer or producers provides the financial underpinning for the LNG liquefaction and export project.

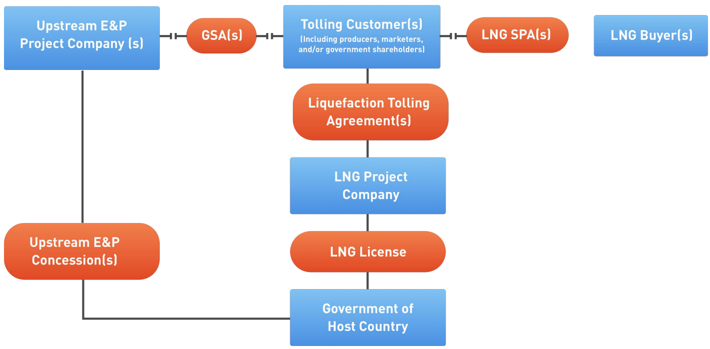
Merchant structure examples include Trinidad trains 1, 2, and 3, Angola, Nigeria, Equatorial Guinea, and Malaysia. The merchant commercial structure for LNG liquefaction and export projects is illustrated in the diagram below.



Tolling Structure

Under the tolling commercial structure - the owner of natural gas, whether a producer, aggregator or buyer of natural gas - is a different entity than the owner of the LNG export facilities. The LNG liquefaction project company provides liquefaction services (without taking title to the natural gas or LNG) under one or more long term liquefaction tolling agreements. The LNG liquefaction project revenues are derived from tariff payments paid by the terminal's customers. The payments typically take the form of a two-part tariff. Fixed monthly payments cover the project company's fixed operation and maintenance costs, debt servicing, and return on equity. Cargo payments are designed to cover the project company's variable costs, such as power. Because the functions of the LNG liquefaction project company do not include a commodity merchant function, the LNG liquefaction project company does not bear commodity merchant risks such as the supply, demand, and cost of natural gas and LNG. The credit of the tolling customer or customers provides the financial underpinning for the LNG liquefaction and export project.

Tolling structure examples include Trinidad's train 4, Egypt's Damietta, Indonesia's Bontang, and the US' Freeport LNG, Cameron LNG, and Cove Point facilities. The tolling commercial structure as applied to LNG liquefaction and export projects may be illustrated as follows:



Hybrid Structures

Hybrid structures combining some of the attributes of integrated, merchant, and tolling models may be used to tailor LNG liquefaction and export projects to the characteristics and needs of particular host governments and project participants. For example, hybrid merchant-tolling structures have been used in the US by Cheniere's Sabine Pass and Corpus Christi projects. Here, the project companies provide a marketing service to acquire natural gas and actually take title to the natural gas and sell the LNG to the customer, but also receive fixed monthly reservation charges regardless of whether their customers take LNG.

The below table lists some advantages and disadvantages of the different commercial structures.

Commercial Structure	**Advantages**	**Disadvantages**
Integrated	• Commercial parties are perfectly aligned between the upstream and LNG liquefaction project • No need to determine a transfer price	• Does not allow for different upstream projects with different ownership to come together in one LNG project • Does not allow for other entities, including the host government, to also have ownership in the plant • Complex to expand for non-concession production
Merchant	• Known and commonly used structure familiar with buyers and lenders • Flexibility to allow non-concession investors in the LNG plant	• Requires additional project agreements with government • Potentially different fiscal and tax regime • Requires negotiation of gas transfer price
Tolling	• Known and commonly used structure familiar with buyers and lenders • No price or market risk for the LNG project investor	• Requires additional project agreements with government • Potentially different fiscal and tax regime
Government Owned	• Owner (government) has full control	• Government may lack experience in developing, marketing and operating LNG

Driving Factors on Choice of Structure

There are a number of key driving factors that influence the choice of an LNG project structure for the host government, the investors, the LNG buyer(s), the project lenders and the other project stakeholders. Some of these key driving factors include:

- **Legal Regime and Taxes:** The host country legal regime and local taxes often have a major impact on project structure. An LNG project may not be considered as a part of the upstream legal regime in the host country and therefore will need to comply with another legal regime, e.g. general corporate regime, special mid-stream regime or downstream regime. Additionally, the tax rate for the upstream regime may be different (higher or lower) than the legal regime for the LNG project. Both of these factors are considered in selecting a structure.
- **Governance:** The typical upstream venture is an unincorporated joint venture with the external oversight provided by the host country regulator and internal 'governance' provided through an operating committee to the operator, who is generally one of the upstream parties. Day-to-day governance and oversight tend to be less rigid and controlled when compared to an incorporated venture. The government, local stakeholders, lenders and the LNG buyers may desire to have a more direct say in internal project governance and decision making. This needs to be reflected in the structure selected. A poorly governed structure can lead to conflicts among the parties and impact the efficiency and reliability of the LNG Project.
- **Efficient Use of Project Facilities:** The LNG project structure should encourage efficient use of all project facilities, by the project owners and by third parties. The structure should encourage sharing of common facilities, open access to third parties for spare capacity and

reduction of unnecessary facilities and their related costs, thereby making the project more profitable for all stakeholders.

- **Flexibility in Ownership:** There may be a desire by the government, other local stakeholders, LNG buyers or lenders (e.g. the International Finance Corporation) to have a direct ownership interest in all or specified portions of the LNG project. Alternately, some of the upstream investors may not be interested in owning the liquefaction portion of the LNG project. The choice of a particular structure can enable different levels of ownership in the different components of the LNG project.
- **Flexibility for Expansion:** A chosen structure may discourage or enable maximum use of common facilities and future expansion trains. For example, an integrated project structure is more difficult to expand if new production comes from third-party gas resources than would be the case with a merchant project or a tolling project. If at some point the upstream does not have enough gas, it may be more difficult to integrate another player with a different gas production model or a different IOC into an integrated project.
- **Desire for Limited Recourse Financing:** If the LNG project is going to try to attract limited recourse project financing, a special purpose corporate entity must generally be set up as the finance partner. It is harder to get this sort of project financing with an unincorporated joint venture structure. Consequently, an LNG project looking for financing will typically have a separate corporate structure for the full LNG project or at least for the financing aspect of the LNG project.
- **Operational Efficiencies:** The integrated structure offers operational efficiencies because only one operator is involved in construction activities. The operational inefficiencies of having two operators can be overcome through transparency and coordination between the operators. Separate projects can lead to project-on-project risk ie. where one project is ready before the other.
- **Marketing Arrangements:** The marketer of the produced LNG can be different from the producer, depending on the LNG project structure. The issue is whether there is individual marketing by an investor of its share of LNG production or whether LNG is marketed by a separate corporate entity.

- **Regulations:** The choice of project structure will affect the required regulations.
- **Gas Transfer Price:** The gas transfer price is the price of gas being sold by the upstream gas producer to the LNG plant in a merchant structure. This is often a contentious issue, since the major sponsors of the LNG project need to negotiate benefit sharing with the upstream gas producer. In many cases, each segment of the gas value chain may fall under a different fiscal regime. The overall profit of the sponsor may then be maximized by selectively determining where the economic value is to be harvested. When the gas is moved from the upstream (production) to the downstream (e.g. LNG) sector, an “arm's length” price may be difficult to negotiate. For example, the natural gas production phase of the project may be subject to an upstream fiscal regime which in many countries includes a high tax rate (Petroleum Profit Tax or equivalent). The transportation segment, such as a gas pipeline or conversion of the natural gas to other products such as methanol, usually does not fall under the high tax regime.

Import Project Structures

LNG import projects typically follow the same major project structures utilized with LNG export projects, namely integrated, merchant and tolling. In this context, it should be noted that the LNG import terminal itself, whether land-based or floating, can be owned by the LNG import project or leased, often through a tolling mechanism.

> **Integrated Structure:** the integrated import structure entails the upstream and liquefaction owners extending their reach into the gas market by including a regas terminal. This allows the upstream owners who produce the gas to sell their regasified LNG as gas in a distant market. Examples include the U.K.'s South Hook LNG receiving terminal, Italy's Adriatic receiving terminal and a number of Japanese and Korean receiving terminals.

> **Tolling Structure:** in the tolling structure the import terminal provides services, including offloading, storage, and regasification, and charges a fee for such services. Examples include the U.S. and Canadian import terminals, and Belgium's Zeebrugge import terminal.

> **Merchant Structure:** here the owner of the import project buys LNG and sells natural gas, earning a profit on the difference between the price of the LNG and the costs of the import terminal. This structure is exemplified by the various Japanese terminals serving the Japanese utilities.

These structures are discussed in more detail in the chapter on LNG Import Projects.

Government Role

Introduction

In general, the government's role is to set policies that define development objectives for the gas sector, establish institutions that set priorities, establish legal and fiscal frameworks governing gas and LNG development, and monitor governmental entities and private sector partners to ensure the rules and priorities are followed by all parties during development and operation of infrastructure projects. In some countries, projects are developed and operated by state oil companies, but, typically, LNG projects, whether they are developed by national or foreign investors, require access to specialized knowledge. In some cases, governments also directly participate in developing strategic projects.

Rules, regulations, and procedures should be established, sometimes through the implementation or amendment of legislation or other agreements that have the broad approval of government authorities and its diverse constituencies/stakeholders. Rules, regulations, and procedures should be clear and consistent so that all stakeholders know what to expect from each other. Since it is expensive and difficult to store gas in strategic quantities, plans should also be in place to utilize gas received under domestic supply allocations to promote the development of power and other industrial projects, important for industrialization and job creation.

Gas Policy and Regulatory Framework

Gas development would typically require 1) a national gas policy 2) a gas act or law that provides the overall legal basis for the gas industry 3) a gas master plan that develops an overall plan for gas utilization in the country.

National Gas Policy as a Key Enabler for Gas Development

One of the key challenges in the gas sector is the enactment of effective policies that define policy objectives for the sector and address and help prevent shortfalls in access and supply for both domestic and export markets. The government should provide an enabling environment to promote connecting infrastructure both to meet domestic demand and facilitate export.

Important outcomes that must be generated by a good gas policy include:

- **Gas deliverability:** the government must ensure that key gas infrastructure across the value chain is properly planned and built in concert with planned power and industrial consumers. This can be achieved via non-discriminatory regulations to enable investment by domestic as well as foreign investors in gas infrastructure.
- **Affordability of gas:** ensure equitable gas pricing both in the local market and the international (LNG export) markets if necessary to support government priorities. The government should also evaluate the need to establish floor prices to grow the domestic market by incentivizing gas suppliers.

- **Commercialization of supply:** creating a policy that
    - addresses the commercial requirements of gas supply for both local and export markets;
    - enables willing buyers to contract with willing sellers;
    - allows and protects commercial structures which enable alignment along the value chain;
    - facilitates secure offtake with long term back-to-back bilateral contracts that pass obligations and liabilities through to sub-contractors and partners and/or use of integrated business models throughout the value chain with creditworthy parties.
- **Availability of gas:** balancing available gas resources in line with demand in domestic, regional and international markets and in line with key strategies in the gas master plan.
- **Access to market**: supporting the right, but not the obligation, to directly access or invest in all parts of the market.
- **Regulations:** need to be clearly defined and agreed among all parties with regard to issues such as third party access, pipeline ownership, and tariff structures.

The above criteria will set the tone for necessary regulatory and policy frameworks for domestic and export gas supply through the gas master plan as well as the national gas policy. An effective policy and regulatory framework should start with clear objectives as captured in the gas master plan. The plan needs to provide directions for development of the legal and regulatory frameworks via the national gas policy such that the sector can align with gas master plan objectives. The plan needs to allocate gas utilizations across various gas sectors, such as domestic or export, so it can serve as a basis for investment decisions.

Features of an Effective Policy and Regulatory Framework

- **Facilitate effective project development/operation for all stakeholders:** Both project development and operations for stakeholders are enabled through well-defined government policies and regulations. The government should seek to facilitate participation by local stakeholders such as communities, local government, and other entities.

- **Provide transparency, clarity of roles/responsibilities and ease of doing business:** Business investment and foreign direct investment (FDI) inflows for gas/LNG development are supported by government legislation backing the provision of transparency, clarity of roles and clear responsibilities. The ease of doing business will continue to be a factor for private investment decisions in countries with very large gas resources. It is expected that the government should provide a conducive environment for gas project investment.
- **Minimum complexity:** A good policy framework requires minimum complexity in term of definition, application and usage. Minimum complexity is achieved when there are clearly defined gas policies that do not contradict or duplicate provisions in other gas documents such as the gas master plan.
- **Monetary policy (exchange rate/repatriation of profits, etc.):** Government must provide the necessary assurance that movement of profit from invested capital for gas projects or LNG projects are not subjected to restrictions. Repatriation of profits must be allowed if countries want to attract FDI or investors for their gas resource development.
- **Facilitate local gas utilization projects:** Promotion of critical local gas utilization projects is vested within the gas master plan and is needed to ensure fast acceleration of the domestic gas market. It is, therefore, imperative for government to facilitate local gas utilization programs and policies.
- **Facilitate development of local infrastructure, either by government, public/private partnership, or private investors:** Regulations should allow multiple options for developing gas infrastructure, either by government, public/private partnership (e.g. build-operate-transfer) or private investors.
- **Economic and social development outcomes for local communities:** an important consideration for project sustainability,

- **Stakeholder consultation:** an important role of government is to engage and consult stakeholders in order to take into account their expectations and build a national consensus.

Elements of a Gas Master Plan

The Gas Master Plan falls under the National Energy Policy that aims, among other objectives, to ensure energy security for the country. The elements of a Gas Master Plan may include:

- Objective of the Gas Master Plan
- Gas resource evaluation
- Gas utilization strategy and options consistent with country's energy policy
- Domestic supply and demand analysis (power and non-power sector)
- Identification of other domestic “priority” projects
- Infrastructure development plan/formulation
- Institutional, regulatory and fiscal framework
- Development recommendations about the volumes and revenues from gas finds and future gas production
- Identification of possible mega or “anchor” projects. For example, a country with a large natural gas find might consider an LNG export project, or other similar industrial scale plant such as methanol, ammonia production, gas-to-liquids (GTL) projects and dimethyl ether (DME).
- Formulation of a roadmap for implementation of projects
- Gas sector regulatory reforms
- Socioeconomic and environmental issues associated with development
- Gas pricing policy

Domestic Gas Obligation and Local Aspiration

A tool to ensure appropriate allocations of gas resources for domestic and export use can be the establishment of a domestic gas obligation. Reasonable and equitable domestic supply obligations to promote gas utilization should be carefully specified in the Gas Master Plan and aligned to the country's national development plan. This should be based on a proper analysis of the national and regional demand for gas together with a plan to develop the transmission infrastructure. The domestic supply obligation (DSO) is a major provision available to countries with gas resources to stimulate the development of the domestic gas market. The policy can allow domestic supply for the needs of gas as industry feedstock as well as fuel for power generation to support the economy. The percentage of DSO varies from country to country and should have the flexibility to allow for any unplanned delay in infrastructure development. For gas producers to satisfy DSO objectives:

> Mechanisms should be developed to allow for gas producers to meet or otherwise allocate (not meet) their domestic obligations when the infrastructure is not available in their operating area.

> Obligations should be reviewed on a regular basis.

Pros and cons of DSO

Pros

> A DSO provides opportunities for domestic gas market development.

> A DSO helps to stimulate the economy through provision of energy supply. Energy supply is directly proportional to GDP growth.

> A DSO helps to meet domestic demand of gas-based industries.

Cons

> Depending on the mechanisms adopted, a DSO may constrain the development of a sustainable gas market if the DSO institutionalizes high subsidies or the development of infrastructure that would not otherwise be economic.

> Local obligation supplies often come at the expense of export market revenues.

Legislation and Fiscal Regime

The host Government first needs to define long-term policy objectives for the exploitation of natural gas resources. These could include sustaining government revenues, increasing access to the generation of power, establishing industrial developments, and so on. For investors considering potential investments in the gas/LNG sector of a developing country, a critical element in the investment decision is the country’s hydrocarbon legislation. That legislation creates the legal environment within which investors may explore, develop and produce the country’s hydrocarbon resources.

In some countries, legislation is more general and broad and leaves details of the fiscal, taxation, and other pertinent terms to be addressed in the agreements between the host government and the investors via instruments such as production-sharing contracts or other agreements. In other countries, legislation is more detailed, in which case the agreements may be less comprehensive and still adequately cover the required fiscal and regulatory framework. In cases where the country's legislation is in early development stage or does not adequately cover the gas/LNG sector, a specific project law is often put in place or the law must be amended in addition to the above-mentioned agreements in order to ensure stability and enforceability of the fiscal and regulatory terms agreed among the government and the investors (e.g. PNG, Qatar, Australia). For LNG projects, such project-specific law authorizes the export of gas as LNG, and facilitates and incentivizes investment in the LNG plant and related export facilities. Regardless of the approach (via a combination of legislation and agreements), the objective is to create a stable and viable investment climate to underpin substantive and continued investments, usually spanning decades, in the country’s hydrocarbon sector.

A number of non-profit organizations have developed guidelines that can be accessed online for policy and regulatory framework formulation. Some of these organizations also provide technical assistance.

An example,"Principles for Developing Country Hydrocarbon Investment Policies", published by the International Tax and Investment Center (found at http://www.iticnet.org/news-item/itic-releases-principles-for-developing-country-hydrocarbon-investment-policies, http://www.iticnet.org/), is reproduced below. Another good resource is Chatham House and its guidelines for Good Governance in Emerging Oil and Gas Producers (found at https://www.chathamhouse.org/publication/guidelines-good-governance-emerging-oil-and-gas-producers-2016) and other efforts of the Chatham House sponsored New Petroleum Producers Discussion Group (found at https://www.chathamhouse.org/about/structure/eer-department/new-petroleum-producers-discussion-group-project .)

Principles for Developing Country Hydrocarbon Investment Policies

The overall fiscal and regulatory structure should begin with an alignment on valuing and recovering resources in a manner consistent with the country's framework for economic development.

> **Create the greatest overall value from the country's resources by generating:**

- Value through the maximum life-cycle economic recovery of resources consistent with the most efficient, safe and environmentally sound development and decommissioning/restoration.
- Growth in local economies as part of value creation via development of local infrastructure, industries, jobs, and training.
- Revenues for the country (including all governmental stakeholders) to reinvest.

- **Be equitable both to government and investors:**
  - Ensure the government, as ultimate steward of the resources, receives for the country an equitable share of the benefit from those resources.
  - Provide that investors receive a share reflecting all of their contributions and commensurate with the overall risks they bear.
- **Align government and investing companies through project life:**
  - The regime should be responsive such that equitable sharing of value is realized through all stages of a project life-cycle and across ranges of outcomes and market conditions.
  - Recognize that projects and relationships are long-term and thus seek ways to promote partnership and mutual trust.
- **Promote a stable and sustainable business environment:**
  - Country and investors should be able to plan ahead and rely on terms agreed upon.
  - Investors should be willing to manage and accept business risks (e.g., exploration, technical, project execution, operation, market, price, and costs) and the country should seek to provide maximum possible certainty on rights and economic terms (e.g., rule of law, contract terms, legal framework, land access or ownership, and fiscal terms).
  - Country and investors should operate in good faith to solve potential disputes quickly and efficiently and adopt mutually-agreed dispute resolution procedures, such as mediation and/or arbitration practices, which lead to principles-based, timely resolved and satisfied outcomes.
- **Be administratively simple:**
  - Provide a clear, practical, enforceable, and non-discriminatory framework for the administration of laws, regulations, and agreements.
  - Adopt programs promoting cooperation and trust between tax administrators and taxpayers.

- **Be competitive:**
  - Should be competitive with other countries, given the relative attractiveness and risks of resource development.
  - Should attract the widest range of potential investors to ensure a country maximizes competition for its resources.

Specific proposals and policies, including the structure and administration of taxation, percentage comprising other government take, and legal requirements, should be tested in terms of whether they further the general objectives above.

Finally, it is worth noting that the overall legal framework of the host country, including bilateral investment treaties, regional and other multilateral treaties and free trade agreements, are all part of the framework within which an agreement between a host country, its broader constituencies, and an investor resides. The legal standing of a contract in relation to a country's laws is an important consideration. Contract and revenues stability are paramount in establishing a viable investment in gas/LNG, which is generally the case for large-scale, long-term investments.

Key Elements of A Fiscal Regime

The objective of the fiscal regime is to provide a framework for an equitable sharing of revenues between the investors and the host government. The key elements of a fiscal regime governing the exploration, development, and production of a country's hydrocarbons are covered either in legislation or agreements between the host government and the investors. Such elements may include the following but are not limited to:

- Signature bonuses
- Production bonuses
- Royalties
- Corporate income taxes
- Sharing of production
- Special petroleum taxes incentive
- Custom and import duties

- Value added tax
- Pioneer status
- Tax holiday

While there are different types of fiscal agreements, such as Production Sharing Contracts and Concession Agreements, the basic objective is the same, which is to provide certainty on how costs are recovered and profits are divided between the host government and the investors.

Institutional Framework

An effective gas industry governance and institutional framework is required to ensure good governance and will be a crucial step to promote investor confidence in the development of gas resources, whether for LNG or for the domestic market. The government needs, through legislation, to define clear institutional arrangements to effectively manage the sector. Particular consideration should be given to clarity of roles among the various institutions. In some countries, there is a need for innovative institutional arrangements or reform. One potential beneficial institution is a one-stop shop for visas, permits, licenses, and approvals. An alternative to a one-stop shop is reform that streamlines these processes. Particular attention should be given to streamlining the number of institutions responsible for managing funding/finance, permits and authorizations, local content, community development, sustainability, contracts, fiscal regimes, and regulation. This requires the government to also clarify roles without merely creating new institutions to compensate for the ineffectiveness of old structures.

Requirements for visas, permits, licensing and approval must be transparent for all investors.

Stakeholder Participation

Aligning the interests of stakeholders is a key to the success of any major project. Stakeholders in a project include the host country represented by the Government, as well as potentially by the participation of the National Oil Company, private investors, project contractors, and the local community. The greater the number of stakeholders in the project, the greater the effort that will need to be devoted to ensuring alignment of interests and expectations, and this may lead to complexities, delays and cost overruns. It is, therefore, desirable to manage the number of core project stakeholders to ensure that the project can be developed in a timely manner. Clear policy guidance from the government is also required so all stakeholders understand the basic expectations they should have of the project partners and of local and national government authorities.

The local community generally participates by taking advantage of the opportunity to provide goods and services and by benefiting from training and employment opportunities in the construction and operational phases. The government should ensure that social responsibility agreements and policies are implemented. Local community participation can also take the form of community input generally provided in the regulatory permitting process. On some occasions, if the government and community desire, the community can participate as an investor. In addition to initial input, generally, there are other opportunities made available for ongoing community input at various points, such as at scheduled community forums.

The government also plays a role, in conjunction with the project company, in managing local expectations by providing information on the timing and status of project implementation, from the planning stages on through to final implementation. The government plays an important role through the creation of a national consensus in favor of the project and its implementation.

Government Participation

Strategic government participation in the project is crucial. Government support in many countries is critical to gaining access to land and proper approvals. Government participation in a gas project, especially an LNG export project, may be of significant assistance in all phases of the project, improving project credibility by visibly showing government support, and perhaps also improving alignment along the value chain.

Many governments require government participation in LNG export projects. Government equity participation is generally through the national oil company owning a share in the LNG company that has been established for the project. Some countries also may invest directly in projects without creating a national oil company. Examples include Qatar Petroleum Company (QPC) ownership participation in Qatargas and Ras Laffan Liquefaction (Ras Gas) companies in Qatar and Sonangol in Angola LNG. In these cases, the government entity provides its share of the investment and participates in the financing and profits from operations after the project is completed. Often the government share can be financed by partners but that may also influence the distribution of profits since this carried share must be repaid over time by the government. If the government is unable to pay its share, this can cause misalignment with project partners later in the project. Governments may also receive revenues from the projects through percentages of sales, taxes and/or fees as outlined in the agreements.

For domestic gas and power projects, government investment may also be required to provide an initial platform for subsequent growth. Infrastructure investments such as gas transmission pipelines and gas distribution systems typically require initial government investment, particularly in countries with minimal existing infrastructure. Generally, power generation and electric distribution systems are initiated by government entities. However, some power generation projects, such as IPPs, are done with private participation. When the sector and regulations are more developed, private companies can build and operate whole integrated systems, at which point the government participation may be reduced to regulation and the collection of taxes and fees.

As projects for which government has provided the initial investment mature to the point of becoming economically self-sustaining, there is then the opportunity for the government to divest the project through privatization. However, projects that are subsidized by the government will often require legislative reforms and removal of subsidies before they can be successfully privatized. This is due to the difficulty in attracting private parties to an asset that may not be self-sustaining economically or which might have previously suffered from under-investment.

Roles of Regulator

The government ideally should empower an independent regulator to oversee, supervise, monitor and advise the government on project approval and implementation. The regulator should play a key role in monitoring industry players to ensure that government objectives and established rules and regulations are followed. The regulator may also help to formulate incentives for sector development in coordination with the legislature and other parts of government and would monitor their implementation. A further role may also include the provision of data sources and information as a way of facilitating development within the sector.

The independent regulator should have a role monitoring the sector across the whole value chain. If there are separate regulators for upstream, downstream, midstream, and/or electric power, they should coordinate closely and roles and responsibilities of each should be clear. The regulator often has a role in setting tariffs across the value chain. Tariff formulas must be reviewed frequently by expert staff with sufficient public consultation to account for changes in the market and to allow for the maximum alignment of stakeholders. The regulator may also have a role in setting and monitoring the collection of taxes and fees but the nature and extent of these taxes and fees must be clear and consistent and not arbitrarily or randomly imposed.

Capacity Building

Introduction

Countries with new natural gas resource discoveries, or those looking to start or increase the use of natural gas, may not have the requisite technical and commercial capacity required to develop their resources or capture and preserve the benefits of resource development.

Furthermore, these countries may have existing laws that govern development but may not have the capacity that will be needed to successfully develop a large natural gas resource or form a viable domestic natural gas industry. Capacity building is intended to bridge that gap and to build the capabilities and knowledge of government officials to negotiate with confidence and on an equal footing with project developers. Capacity building also helps local people make informed decisions concerning the country's resources and how to develop them to benefit their citizens and improve the economic situation in the country - not only for the short term but for generations to come. Another goal of capacity building is to create a ready pool of educated, trained and informed personnel to feed into the labor force for future projects.

Training

For local content participation to be effective and sustainable, there needs to be a deliberate policy that requires building the capacity at various levels within the country, such as national and local government officials, and the private sector including small-to-medium enterprises (SMEs). Training for national and local government officials should be targeted primarily at a better understanding of the project to facilitate regulatory and environmental permitting processes. Private sector training should include strategies for project development including effective contract negotiations as well as overall project management to provide the needed trades, professional services, and goods.

Specific skills need to be identified as early as possible in the planning of a project to allow training to be organized and provided to meet project schedules. The capacity building effort should galvanize support from other stakeholders such as government, academia, and subject matter experts. It is important that the qualification of the intended service providers and the quality of the goods supplied are consistent with the requirements of the project with appropriate evaluation and monitoring protocols in place.

The training could be delivered through a combination of formal instruction, (both locally and abroad), and supervised on-the-job-training (OJT). It can be provided or facilitated through various means and may require a partnership of academia, government, foreign donors and subject-matter experts. The training should be considered along the entire value chain with emphasis on the appropriate delivery for the needed goods and services. For LNG export and import projects, training should be considered in the initial assessment of the project's economics and viability, through to the engineering, procurement, construction and project commissioning phases. It is important that trained personnel are gradually absorbed in the appropriate phases of the project to provide them the opportunity to bridge theory and practice. However, any on-the-job-training should have minimum disruption of the project workflow.

Transparency and Openness

Achieving successful development of domestic gas infrastructure and LNG plants is a complex process that requires communication, transparency, and ongoing dialog between host governments, local governments and stakeholders, and industry. Conflicts are naturally going to arise at various times during development and operations due to unstated or unfulfilled expectations or failures to meet projected schedules or goals. It is important to create open formal and informal lines of communication to jointly address problems at an early stage as they arise. This builds trust between parties that will enable them to work through more difficult problems later. These dialogs can prevent roadblocks which could lead to costly delays in development and other potential legal remedies.

It is important to recognize that the host government and project developers are not adversaries, rather they are partners dually responsible for natural gas development. Neither can accomplish the end result without the other's help. Capacity building creates common understanding which is the foundation of any partnership.

Technology Transfer

Technology transfer is a deliberate policy by a host country to ensure that there is a process in place for the sharing of skills, knowledge, expertise and technologies in the oil and gas sector between expatriate and foreign oil companies, government officials and the local workforce. This is mostly for areas of expertise that are new to the country's workforce. Technology transfer is closely related to knowledge transfer, but not in totality. Technology transfer is a vehicle for bridging the gap in knowledge and expertise from LNG investor expatriate staff to the local workforce. Often,technology transfer can take the form of on-the-job training or learning through doing.

In a specialized industry like LNG, the host country workforce often does not have the requisite knowledge, know-how or technical skills to participate in the project. In order to achieve human technology transfer, the host country often signs a technology transfer agreement with the LNG investor. The agreement provides that technology transfer will occur within a specified time frame for local workforce knowledge and expertise development. A government agency (or agencies) are assigned responsibility for ensuring compliance by the LNG investor with the technology transfer agreement commitments. Technology transfer is measurable and time-bound as specified in the agreement. Technology transfer is developed through conscious and sustained efforts by both LNG investors and government.

The transfer of technology can be measured by answering the following questions:

- To what extent are increasing technological capabilities of the host country workforce reflected in terms of expertise in the LNG/gas plant technology?
- To what extent has technological learning and technical expertise influenced the performance and know–how of the local workforce?

Reasons for Technology Transfer in LNG industry

- The drive to bring awareness and develop necessary capabilities to the local workforce by the host government.
- The need to put a deliberate strategy in place for succession planning from expatriates to the local workforce of the host country.
- The need for human capacity development for the host country through an LNG project development.

LNG Development

Introduction

An important policy objective of developing gas resources in Africa is to promote domestic access to energy resources while growing the electricity and industrial sectors. In many cases, because the investment associated with developing the resources is very significant, LNG export appears as the reasonable option for securing the necessary financial resources underpinned by long-term LNG offtake contracts. Typically a portion of the gas will be allocated to the domestic market, the rest to the liquefaction plant.

The following chapters describe the developmental steps of a typical LNG export project, which covers estimation of gas reserves, project screening evaluation, pre-FEED (pre-front end engineering Design), FEED, tender, and selection of the engineering procurement and construction (EPC) contractor, the EPC phase and finally, facility startup.

Resource Reserve Estimate

Before embarking on a project, it is essential to formulate a comprehensive reserve estimate for the resource. After the exploration and development (E&P) company (or consortium) obtains the lease, they will likely complete 3D seismic surveys, which allows a geological and geophysical understanding of the oil and gas resource potential. The E&P company will proceed with one or more exploration wells. If the results of the exploration well(s), evaluated in well logs, are promising, then flow tests may be performed. Additional appraisal wells may then be drilled to delineate the extent and quality of the reservoir before a discovery may be announced.

The resource can be appraised at any point in time, based on the information available at that time. As more information becomes available through additional wells or production tests, the resource will be evaluated using engineering methods. Resources can then be classified as reserves after more certainty exists that they can be technically recovered. Production probabilities of proven, probable and possible reserves are estimated. Reserve estimates continue to be refined throughout the development of the field(s). After the initial reserve estimate is completed, the field flow rates will be estimated based on best engineering practices. Then, economic analysis is typically performed to determine the economic recoverability of the reserves.

As the field development moves progressively from the initial phases into the final phases, the reserves are increasingly defined with more certainty as well as the upstream investment requirements to produce them and achieve the desired deliverability for the LNG plant and any domestic gas requirements. At least 20 years of plateau production from dedicated proven reserves is highly desirable to proceed with an LNG project and begin LNG marketing and financing efforts.

Before the sales and purchase agreements are finalized, reserves must be certified by an independent petroleum engineering reserve certification firm. The lenders will also require the certification of the reserves dedicated to the project before providing financing.

LNG Project Development Phases

Progressing an LNG project from inception to final investment decision (FID) requires three main work streams that run in parallel: commercial, technical, and financial. The commercial work stream consists of securing the necessary project agreements and LNG offtake contracts. The financial team will rely on the technical and commercial feasibility of the project to structure and secure the necessary capital investments to finance the project. The technical work stream ensures that the technical aspects of the project are sufficiently defined and a contractor is selected to undertake engineering, procurement and construction (EPC) works. Details of the technical work stream are described in this section; commercial and financial work streams are addressed separately in this handbook.

An LNG export project typically comprises the following developmental phases:

- Screening and Evaluation.
- Pre-Front End Engineering Design ("Pre-FEED")
- Front End Engineering Design (FEED)
- Engineering, Procurement and Construction (EPC) bidding, evaluation, and selection of contractor
- EPC Phase - performing final engineering designs and drawings, procurement of materials and equipment, and construction of the project

As project development progresses from the screening evaluation phase through EPC, the project developer will be spending increasingly larger amounts to complete the work deliverables under each phase. Each phase prior to the EPC (which occurs after FID) acts as a decision point where the project developer may exit the project if the analysis does not support proceeding to the next phase.

In each phase below, the project developer will work to provide increasing definition in the description and cost of the facilities, and the execution schedule with a goal of achieving a high definition of costs (+/- 10-15%) by the time of awarding the EPC contract. Project economics, calculated for each phase based on the latest cost estimates, schedule, and the LNG pricing outlook, would be a key factor in determining whether the project is economically viable to move on to the next phase.

- **Discovery** of a gas field has resulted in a preliminary reserve estimate that may be sufficient to support an LNG project.
- **Screening and evaluation** - based on the initial estimation of the size and deliverability from identified gas reserves, an initial description is developed of a potential LNG project, including the size of the LNG trains and their initial and ultimate number. Several potential LNG plant sites are evaluated, based on their suitability for berthing for year-round shipping via LNG carriers (water depth, weather conditions, etc.). Possible pipeline routes to the potential plant sites are assessed as well as pipeline sizing. Initial cost estimates are made based on benchmark cost data. LNG market opportunities are assessed and LNG price forecasts are secured. Screening economics over a range of scenarios are developed to help in optimization and assessment of the attractiveness of the potential project and whether the potential project has sufficient merits to warrant proceeding, e.g. if the reserves could support a 15-20 year plateau gas sale at a minimum 3-5 MTPA which is the minimum economic size of a single LNG train. Economies of scale can improve the financial decisions with a larger size train and multiple trains if the market exists. The reserve requirements for a 5 MTPA plateau sale of 20 years is approximately 8 TCF.
  The duration of this screening work can vary from 6 months to more than a year depending on what information is already available from existing reserve studies and previous drilling and reservoir assessments. Staffing is increased and a rough cost of this phase could be around 500,000 to 1 million US dollars.
- **Pre-Front End Engineering Design ("Pre-FEED")** - initial or preliminary designs for the intended project. This results in a better estimation of project and costs and can take an estimated six months. Costs can be on the order of 2 to 5 million US dollars typically.

> **Front End Engineering Design** - information necessary to prepare bidding documents for selection of an EPC constructor. This phase can take 1 to 1.5 years. This can typically cost in the range from 40 to 80 million US dollars.

> **Engineering, Procurement and Construction (EPC) Bidding, Evaluation and Selection of Contractor** (See separate section) - 6-8 months duration. It is often necessary to pay several million dollars to each of the unsuccessful bidders for their work (See separate discussion).

> **EPC Phase -** after a final investment decision, the EPC contractor will produce final engineering designs and drawings, arrange the procurement of materials and equipment, and oversee construction of the LNG plant and export facilities. Costs should be more accurate at this phase and completion of the project could cost US $1,500 - 2,500 per tonne of capacity or perhaps more depending on local and market conditions.

FEED

After the in-house screening and evaluation and contractor led pre-FEED which covers optimization of various plant equipment and configuration options, the basic scheme is selected for the FEED in order to provide better scope definition to the EPC contract bidders. The FEED process takes approximately 12-18 months to complete with a resulting FEED package.

Two of the key outputs from the FEED are cost estimate and schedule projection. Estimated FEED cost for an LNG plant can range from US $40-80 million depending on size and complexity.

Company personnel required for the FEED are in the order of 20-30 full-time persons.

The better the definition of the project at the FEED stage, the better the definition for project cost and schedule. LNG project cost estimates after the pre-FEED stage generally have a contingency (uncertainty in the estimate) in the order of 30-40%. After the FEED, the contingency level is reduced to about 15-25%. The EPC contract will generally have a contingency of about 10-15% as you gather more information and do progressively more design work.

EPC Contractor Bidding and Selection

Failure to implement a proper bidding process is likely to result in significant problems with project completion. Performance guarantees are required (legal agreements that require agreed specifications be completed). EPC contract bidding for a greenfield project is almost always done on a competitive basis. The number of contractors experienced and qualified to carry out an LNG project is limited, on the order of 6-7. The number of qualified bidders is often further reduced by the practice of forming consortiums for bidding on the EPC work, which can reduce the number of separate bidding companies or groups to only 3 or 4. Usually, one company acts as the lead for the consortium. Competitive bidding is highly important for obtaining a competitively-priced proposal.

One method employed to increase the competitive intensity is to utilize a competitive FEED approach, whereby two well-qualified bidding consortiums are selected to conduct separate FEEDs, with a commitment from each to submit lump sum bids as the price of admission to such a limited competitive bidding slate. Prior experience indicates that this bidding strategy can potentially save 10-20% on the price of the EPC bid.

An additional approach occasionally employed that may be used by companies without significant LNG experience to reduce requirements for internal company expertise is the so-called Open-Book FEED / EPC approach. Under this approach, a chosen EPC contractor provides a price at the end of FEED with an option for the company to continue forward under a given pricing approach utilizing open disclosure of adjustments based on actual equipment bid costs. This method has not been as commonly used.

The following discussion is based on selection processes based on competitive bids from multiple bidders or bidding consortiums (i.e., two or more) whether under a competitive FEED approach, or a process where multiple EPC contractors are provided with a single FEED for their bidding.

The FEED package is provided to the EPC contractor-bidders as the basis for their bid submittal. As part of their bid submittal, they are requested to provide a Design Endorsement Certificate (or equivalent) stating that they are in accord with the FEED and endorse the FEED design. This is essential in order to prevent future Change Order legal claims that might result from a defective LNG FEED package, which can be very costly. If a bidder cannot endorse the FEED, then they must propose any required changes necessary to achieve the specified LNG capacity, obtain the LNG company's concurrence, and then base a bid and guarantees on an approved revised FEED package. In addition, included in a company's bid instructions, an opportunity is provided to each LNG EPC bidder to provide in the bid submittal a higher LNG capacity performance by up to a specified limit (e.g. 5%).

The bidders are typically provided a period of around 4-6 months to prepare and submit their bids after receipt of the company's FEED package. The EPC bidders submit their bids in 2 packages.

The first EPC bid submittal is the unpriced proposal or technical proposal, that describes in detail all important technical and project execution aspects of the bid, including major equipment specifications and performance sheets (e.g., for refrigerant gas turbines, refrigerant compressors, main cryogenic heat exchanger or cold boxes, fired heaters, waste heat recovery units, LNG storage tanks, LNG jetty and berth including LNG vapor recovery facilities at the berth). The unpriced proposal bid also includes a complete detailed project execution plan, including a detailed EPC Schedule. The execution plan will address (1) the early site work; (2) the plan for the temporary facilities (construction camp, roads, construction material offloading facility (MOF), site preparation); (3) the plan for site mobilization of construction personnel and the arrival of concrete batch plants), and the delivery schedule of the major equipment to the site and its installation. The company evaluation of the unpriced proposal requires about 2 months. As part of the unpriced proposal, each bidder is required to provide a schedule guarantee and performance guarantees for LNG capacity and fuel consumption.

Proper evaluation of contractor capability is highly important for assuring the successful completion of an LNG project. This capability is generally assessed by evaluating the engineering, procurement, and construction capabilities from each contractor's technical submittal, including key personnel they propose for their project team, as well as assessments in the three areas of quality, project control, and project management. Safety performance is also critical, and their performance on past LNG projects is critical. Safety is a component of each of the six area mentioned earlier and goes into the evaluation score for each of the areas.

Adjustments are made for any non-conformities or differences in guaranteed plant performance (LNG capacity, fuel consumption, assessed downtime) and are priced as adjustments to the proposal. Each bid submittal is judged as to whether it is acceptable or non-acceptable, and the results of the evaluations are reviewed with management for approval of the non-conformity price adjustments and final approval of the bid slates. Approved EPC bidders are then requested to submit the priced proposals. These submittals include a lump sum price and an EPC completion schedule guarantee. Plant performance guarantees and the schedule completion guarantee are each backed by a schedule of liquidated damages (escalating penalties) in the event of non-performance. Plant LNG capacity is measured by a plant performance test conducted within a specified time after startup (typically on the order of 6 months). The Priced Proposals are evaluated and the price adjustments from the unpriced proposal evaluations are applied. The overall evaluation is then assessed, and a recommendation prepared for EPC contract award. This process may require going back to the EPC contractors for some final clarifications, but generally, this priced evaluation can be accomplished within 1 to 2 months.

The EPC award to the successful EPC contractor is not made until the other necessary conditions for the final investment decision (FID) have been achieved and the FID decision taken. These other conditions include (1) government approvals, including passage of any enabling legislation, (2) execution of sales and purchasing agreements (or alternately, binding heads of agreements), (3) financing agreements. The lack of any of these other necessary agreements can hold up the final investment decision and the subsequent EPC award.

Final Investment Decision (FID)

The final investment decision (FID) is the decision to make a final commitment to the project, including the financial commitment to award the EPC contract and the satisfaction of conditions precedent in the LNG SPA. This decision by the project partners requires (1) the prior completion of all necessary government agreements, including complete fiscal terms and passage into law of all required enabling legislation and land allocation and access; (2) financing commitments provided to the project by the lenders, including export credit agencies, multilateral development banks, commercial banks, and other lenders.

EPC Stage

The EPC contractor is required to provide a project execution plan (PEP) which shall include the detailed engineering specifications, the procurement plan; the construction plan; health, safety, and environment (HSE) plan; as well as quality assurance, project management, and project control aspects.

Engineering

The EPC contractor uses the FEED work as the starting point to carry out detailed engineering and design needed for construction, utilizing appropriate design specifications, material specifications, and construction specifications. In addition, detailed engineering requires the application of a safety-in-design process, a safety-in-review process (HAZID), and a hazardous operations plan (HAZOP).

EPC contractors generally have fairly complete databases detailing cost and deliveries for major equipment that they have compiled prior to submitting their bids. During periods of high industry activity, there can be shortages even of common equipment, such as normal valves (Australian Gorgon experience) and price spikes for such materials as copper or specialized alloy cryogenic materials, such as the nickel-chrome alloy used in the LNG storage tanks.

Considerations should be given to ordering materials and equipment in advance, where warranted to maintain or improve schedules. Some major equipment, such as the refrigerant turbines, can generally be ordered with a schedule of cancellation costs. The costs are generally low during the first 6 to 9 months since they only represent engineering costs and therefore have only limited exposure for the company if cancellation is required during that time frame. Engineering work and procurement work should be done in the same office to ensure proper coordination.

Construction

This part of the EPC phase typically takes 4 to 6 years. It is performed at the plant site, except for those plants that are modularized, (i.e., have their main equipment placed inside modules that are fabricated in offsite fabrication yards such as those in Korea or China).

During the first 16 months, EPC contractor focus is on Engineering and Procurement in the contractor's home office. Meanwhile, initial mobilization on the plant site is focusing on site clearance and road construction.

After 16 to 20 months, the majority of project activities shift from home office to the site. Approximately 5,000 to 8,000 workers may be required. Initial activities include:

- Building the large construction camps.
- Arrival of concrete batch plants on site.
- Construction of foundations.
- Construction of pipe racks (supports).

With the availability of the construction camps, the mobilization of large numbers of workers can occur. Equipment delivery on site occurs between the 30th to 45th months. Then installation of equipment and running piping on pipe racks can begin.

Commissioning of plant equipment can begin between the 12th and 18th months before start-up. The first major equipment to be commissioned and started up is the power generation system.

After the plant is mechanically complete, and after equipment commissioning is completed, the plant is ready for the introduction of the natural gas feedstock. Start-up can range from two to as long as six months or more if there are problems. Typically it takes about six months for the plant to ramp up to its full capacity.

After the plant is operating at full capacity and operations are stable, the plant performance and acceptance tests are conducted by the company jointly with the contractor. Any deficiencies found that are covered under the guarantee provided by the contractor, must be corrected by the contractor before the company accepts the plant as complete and final payment is released.

LNG Technology

The production of LNG from natural gas is based on three main processes: gas treating, dehydration, and liquefaction. Treating results in the removal of impurities from the raw gas and these comprise entrained particulate matter, mercury, and acid gases such as H_2S and CO_2. The chilling or liquefaction process is the conversion of the treated and dehydrated gas into liquid by refrigeration of the gas down to a temperature of about -162°C (-240°F). There are two main commercially available processes for liquefaction, the Cascade process and the Air Products (APCI) C3MR process which employs a combination of propane and mixed component refrigeration (C3MR process). Most of the LNG trains in operation employ the APCI technology rather than the Cascade process (about 80/20), due to the number of trains built pre-1995 employing only the APCI process. Since then, the ratio of APCI trains to Cascade process trains has changed to about 65:35, based on capacity. There is not a large advantage to either major technology.

The most common liquefaction process currently used for land-based LNG plants is the APCI -C3MR. The feed natural gas stream is essentially pre-cooled with a propane refrigerant and the liquefaction is completed with a mixed refrigerant of Nitrogen (N_2), Methane (C_2), and Propane (C_3). The C3MR technology is well-known and has high efficiency, ease of operation and reliability, with the use of readily available refrigerant streams. However, the use of propane as a key refrigerant requires some risk mitigation due to flammability concerns, especially at low points, and this is reflected in the plant design by locating the refrigerant storage tankage at some distance from the main process.

The Cascade process typically employs three pure refrigerants, such as methane, ethylene, and propane. The feed stream is first is cooled to about -35°C in the propane cycle, then it is cooled to about -90°C in the ethylene cycle, then finally it is liquefied to -155°C in the methane cycle.

LNG Technology has generally followed an evolutionary path rather than one of radical, rapid changes. Over the last 30 years, the size of LNG plants has grown from 2 MTPA to as much as 7.8 MTPA (size of the large Qatar trains), with attendant economies of scale - though required specialized equipment and materials and large required gas reserves for the 7.8 MTPA size make facilities of this size difficult to replicate. The current standard size is about 5 MTPA. The size increase has resulted from the availability of large size gas turbines for refrigerant service.

The evolutionary approach has served the industry well. The well-established LNG technology has given LNG EPC bidders the confidence to bid on a lump sum turnkey basis, increasing the execution certainty of the companies developing LNG plant projects.

Innovative technology continues to appear on this evolutionary track; the recent use of aero-derivative turbines in LNG plants is an example. Use of aero-derivative turbines reduces plant fuel consumption by about 10% and improves plant up-time by about 2% through avoidance of the long downtime maintenance cycles associated with the frame industrial turbines. The first use of aero-derivative turbines was in the Conoco LNG plant at Darwin, Australia. The second use was in the ExxonMobil LNG plant in Papua New Guinea which started up in 2015.

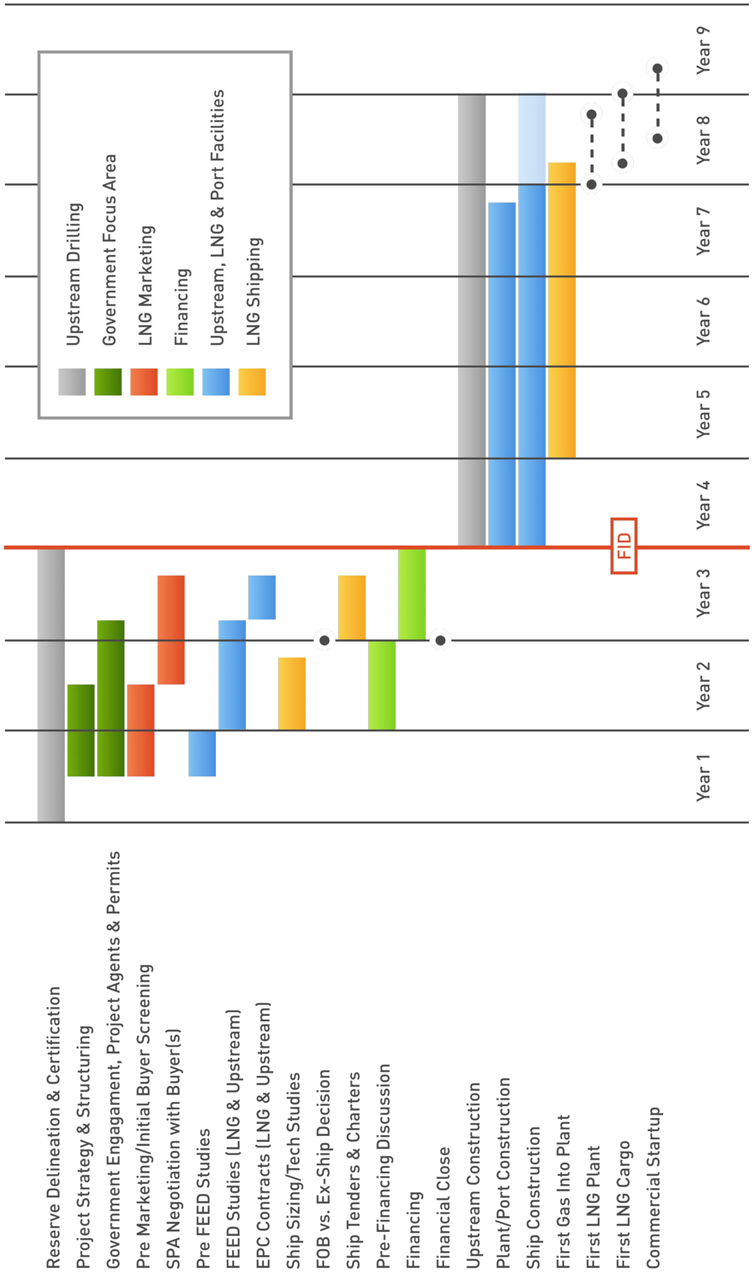
A company's project manager charged with executing an LNG Plant project on budget and on schedule generally prefers that there be only limited use of new technology and that it has first been utilized at other sites; i.e., only limited or no use of "Serial No. 1 technology".

Modularized LNG plants have been utilized in selective locations in recent years at locations such as Gorgon LNG and Pluto LNG with mixed results. They require earlier and more complete engineering during the EPC phase for the use of the fabrication yard in the module fabrication. Any delays in the engineering and procurement work can be very disruptive to the module fabrication work, so some additional execution risk is introduced. Large modules can also be difficult to offload and transport.

Schedule Estimate

With the gas resources already defined, the estimated time for execution of an LNG export project could range from 6 - 10 years, assuming no interruptions. As expected, many unforeseen developments can occur during project implementation which can impact the schedule, so contingencies are normally factored into the indicated schedule range. Schedule discipline should be maintained throughout the project. Schedule recovery options should be identified to mitigate delays. Change management must also be employed to minimize changes since any changes will impact the schedule and almost always add cost. It is important to optimize the engineering, procurement and construction schedules to minimize the number of critical path items for the project. Delays in the overall project schedule result in liquidated damages for the contractor (giving the contractor incentive to complete the project on time). It is a requirement for the EPC contractor to develop a level 4 project schedule (Primavera) as a guide throughout the project.

The following chart depicts an example of a project schedule:



Source: Galway Energy Advisors

Key Success Factors

Some important factors contributing to the success of the LNG project include:

> Government support, timely issuance of permits and authorizations, timely access to the plant construction site.

> A complete set of geotechnical data from an adequate number of bore holes on the plant site to determine soil conditions and allow proper foundation planning or soil remediation if required. Seismic information to evaluate potential earthquake problems is also necessary.

> A well-qualified and experienced LNG EPC contractor. Key EPC personnel assigned to the project must be capable and experienced in the LNG area.

> EPC contract should be lump sum turnkey to increase project certainty:

- Ensures contractor has 'skin in the game' and is aligned with the company in being highly motivated to keep costs under control and project on schedule.
- Needs to be turnkey to provide contractor the latitude he needs to perform in order for him to take on the obligation of a lump sum contract.

> Company and EPC contractor relationship needs to be collaborative.

> EPC contractor needs to evaluate and formally endorse the company's FEED design (Design Endorsement Certificate). If he finds an issue with the FEED, he is to propose and agree with the company on a proposed remedy to the FEED, and then provide the formal endorsement. This is important so as to avoid future costly change orders due to later design changes;

> Minimize change orders in the EPC no matter how attractive they may appear;

> Maintain focus on safety in all aspects of the LNG project. Maintain a strong, proactive, involved safety program in collaboration with the contractor.

- In the EPC contract, secure strong guarantees on:
  - LNG plant production capacity.
  - Fuel consumption.
  - LNG product quality meeting all specifications.
  - Plant completion schedule.
  - All other products or emissions must meet specifications.
  - Completion guarantees.
- LNG partners need to be fully aligned throughout the project development phase.
- Take measures, where available, to increase project execution certainty.
- Embrace new technology but on a measured basis. Avoid "Serial No. 1" unproven applications which almost always result in delays and increased costs.
- Implement an effective training program to facilitate utilization of local labor in the construction and operation of the LNG plant.
- Persistence and patience are critical - LNG plants are challenging and complex and take some time to implement.
- Keep the project as simple as possible.
- Recognize other associated investment opportunities that may be available with the LNG project, such as natural gas liquids extraction, helium recovery if it exists in the feed gas (the LNG process increase the concentration of helium 10-fold, and can make its recovery economic, as was the case in Qatar), potential for domestic gas deliveries for power generation, and so on.

Environment, Social Impact and Safety

Introduction

Natural gas and LNG development projects can have a significant environmental and social impact in the communities where they are located, both positive and negative. These impacts can be managed through appropriate laws, regulations, and compliance balanced with corporate social responsibility, which becomes part of the social compact called the "social license to operate." In recent years, LNG project developers in partnership with central and local governments have included a wider constituency of stakeholders at an earlier stage of planning and as a result, this social compact has become a critical success factor of any major LNG project.

Environmental Impacts of LNG Facilities

The construction of LNG facilities, whether liquefaction or regasification/import terminals, gives rise to numerous potential environmental impacts. The potential impacts and associated necessary regulations vary depending on the project and the country. These general guidelines should be tailored to the hazards and risks established for each project on the basis of the results of an environmental impact assessment in which site-specific variables are taken into account. In general, the following types of impacts should be considered:

Threats to aquatic and shoreline environments: Construction and maintenance dredging, disposal of dredged soil, construction of piers, wharves, breakwaters and other structures, and erosion, may lead to short and long-term impacts on aquatic and shoreline habitats. Additionally, the discharge of ballast water and sediment from ships during LNG terminal loading operations may result in the introduction of invasive aquatic species.

Marine Environmental Impacts: The coastal/nearshore area, is composed of several marine coastal habitats, such as the sandy and rocky shores, mangroves, estuaries and deltas and seagrass meadows. An enormous diversity of associated fauna and flora congregates in these habitats, providing important goods and services for the local human population. The following are some of the potential environmental impacts on marine habitats of operations:

- Colonization of subsea structures – subsea structures can be recognized as drivers for aggregation of ocean life and they will provide surfaces for colonization by encrusting fauna and flora. Depending on the source of colonists, the impact could be positive (increasing of biodiversity consistent with the geographical area) or negative (invasive alien species threaten local species).

- Impact on subsea and on benthic (ocean bottom dwelling) fauna during installation
- Impact on the marine habitat due to the discharge of cooling water
- Impact on the biodiversity from ballast water
- Impact on the water quality and marine fauna from liquid effluents
- Disturbance of marine environment, flora, and fauna from the offshore operations

Hazardous Materials Management: Storage, transfer, and transport of LNG may result in leaks or accidental release from tanks, pipes, hoses, and pumps at land installations and on LNG transport vessels. The storage and transfer of LNG also poses a risk of fire and, if under pressure, explosion due to the flammable characteristics of its boil-off gas.

Some recommended measures to manage these types of hazards include:

- LNG storage tanks and components (e.g. pipes, valves, and pumps) should meet international standards for structural design integrity and operational performance to avoid catastrophic failures and to prevent fires and explosions during normal operations and during exposure to natural hazards. Applicable international standards may include provisions for overfill protection, secondary containment, metering and flow control, fire protection (including flame arresting devices), and grounding (to prevent electrostatic charge).
- Storage tanks and components (e.g. roofs and seals) should undergo periodic inspection for corrosion and structural integrity and be subject to regular maintenance and replacement of equipment (e.g. pipes, seals, connectors, and valves). A cathodic protection system should be installed to prevent or minimize corrosion, as necessary.
- Loading / unloading activities (e.g. transfer of cargo between LNG carriers and terminals) should be conducted by properly trained personnel according to pre-established formal procedures to prevent accidental releases and fire / explosion hazards. Procedures should include all aspects of the delivery or loading operation from arrival to departure, secure connection of grounding systems, verification of

proper hose connection and disconnection, adherence to no smoking and no naked light policies for personnel and visitors.

Air emissions: Air emissions from LNG facilities include combustion sources for power and heat generation in addition to the use of compressors, pumps, and reciprocating engines. Emissions resulting from flaring and venting may result from activities at both LNG liquefaction and regasification terminals. Principal gases from these sources include nitrogen oxides (NOx), carbon monoxide (CO), carbon dioxide (CO2), and in the case of sour gases, sulfur dioxide (SO2).

Waste management: Waste materials should be segregated into non-hazardous and hazardous wastes and a waste management plan should be developed that contains a waste tracking mechanism from the originating location to the final waste reception location.

Noise: The main noise emission sources in LNG facilities include pumps, compressors, generators and drivers, compressor suction/discharge, recycle piping, air dryers, heaters, air coolers at liquefaction facilities, vaporizers used during regasification and general loading/unloading operations of LNG carriers/vessels.

LNG transport: Common environmental issues related to vessels and shipping are relevant for LNG import and export facilities. For example, emissions from tugs and LNG vessels, especially where the jetty is within close proximity to the coast may also represent an important source affecting air quality.

Environmental Impact Statements

Project developers must comply with all environmental laws and regulations of the host country. This will often require the preparation of a detailed Environmental Impact Statement (EIS).

The principal purposes for preparing an EIS are to:

- identify and assess potential impacts on the human environment that would result from implementation of the proposed action;

> identify and assess reasonable alternatives to the proposed action that would avoid or minimize adverse effects on the human environment;
> facilitate public involvement in identifying significant environmental impacts; and
> identify and recommend specific mitigation measures to avoid or minimize environmental impacts.

The topics typically addressed in an EIS include: geology; soils; water use and quality; wetlands; vegetation; wildlife; fisheries and essential fish habitat (EFH); threatened, endangered, and special status species; land use, recreation, and visual resources; socioeconomics; transportation; cultural resources; air quality; noise; reliability and safety; cumulative impacts; and alternatives.

The EIS describes the affected environment as it currently exists and the potential environmental consequences of the project and compares the project's potential impacts to those of alternatives. The EIS also presents the conclusions and recommended mitigation measures of the regulatory agency in charge of preparing the EIS and conducting the environmental and regulatory review of the project.

Climate Change

Natural gas and LNG are generally viewed as cleaner-burning fuels that might contribute to a lower carbon future. Climate change negotiations have noted that natural gas can be used as a bridge to a renewable energy future in countries currently using higher-carbon fuels, including coal, oil, and diesel for cooking, power generation, or heating and cooling. As African economies develop, the need for energy will continue to grow not only for base natural gas but for natural gas derivative products, such as fertilizers, for agriculture.

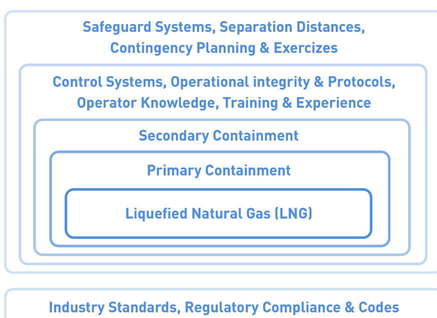
However, there is controversy in the methane and carbon emissions life cycle and contradictions that result from LNG project development, liquefaction, transportation, storage, regasification, distribution, and end-use of LNG. Methane and carbon dioxide emissions are powerful greenhouse gases. Throughout the value chain, natural gas and LNG development should seek to minimize and reduce emissions. In an LNG facility, small gas flares are needed for operational safety but flaring should be minimized. Methane emissions must be measured and mitigated against throughout the value chain, including processing equipment, pipelines, storage tanks, valves, compressors, and other fugitive sources.

Rising sea levels require general consideration while designing ports and berths and a special consideration for weather modification both on-shore and offshore.

Safety

Safety is critical in any industrial project, but LNG export or import projects can introduce specific safety considerations, mainly owing to the sheer size of the energy storage facilities involved. The LNG sector has been operating now for over 50 years, with a good safety record, mainly as a result of diligence and planning to ensure that very high standards are maintained in project planning, design, procurement, construction, and operating phases of the project. While liquefied gas is inherently a safe substance which does not burn directly, the vapor that it generates, effectively natural gas, is flammable, and care must be taken in handling vapor to avoid a release. In many countries, LNG is classified as a hazardous material (depite the industry's excellent safety record and the stability of LNG until it starts vaporizing), and rigorous standards often apply to its storage and transportation. Various international or trade bodies also publish safety standards, some of which are used internationally.

How LNG containment is considered by the industry is summarized in this illustration from the industry trade body Groupe International d'Importeurs de Gaz Natural (GIIGNL):



Source: GIIGNL

The whole design basis for an LNG facility is built around minimizing the chances of a containment failure. However, in the unlikely event that this may occur, an uncontrolled release of LNG could lead to jet or pool fires if an ignition source is present, or a methane vapor cloud which is potentially flammable (flash fire) under unconfined or confined conditions if an ignition source is present. LNG spilled directly onto a warm surface (such as water) could result in a sudden phase change known as a Rapid Phase Transition (RPT), which can also cause damage to nearby structures.

The following features are typically among the recommended measures to prevent and respond to LNG spills:

> Conduct a spill risk assessment for the facilities and related transport / shipping activities;

> Develop a formal spill prevention and control plan that addresses significant scenarios and magnitude of releases. The plan should be supported by the necessary resources and training. Spill response equipment should be conveniently available to address all types of spills, including small spills;

> Spill control response plans should be developed in coordination with the relevant local regulatory agencies;

> Facilities should be equipped with a system for the early detection of gas releases, designed to identify the existence of a gas release and to help pinpoint its source so that operator-initiated ESDs can be rapidly activated, thereby minimizing the inventory of gas releases.

> An Emergency Shutdown and Detection (ESD/D) system should be available to initiate automatic transfer shutdown actions in case of a significant LNG leak;

> Clear and well-rehearsed procedures governing the loading and unloading of vessels, should have a focus on ensuring appropriate coordination between the Master or the vessel and any shore-based operations.

> Ensuring that onshore LNG storage tanks comply with the double containment principle involves a completely redundant layer of LNG containment, only used in the unlikely event of primary containment failure.

- Facilities should provide grading, drainage, or impoundment for vaporization process, or transfer areas able to contain the largest total quantity of LNG or other flammable liquid that could be released from a single transfer line in 10 minutes;
- Material selection for piping and equipment that can be exposed to cryogenic temperatures should follow international design standards;
- In the case of a gas release, safe dispersion of the released gas should be allowed, maximizing ventilation of areas and minimizing the possibility that gas can accumulate in closed or partially closed spaces. Spilled LNG should be left to evaporate and the evaporation rate should be reduced, if possible, e.g. covering with expanding foam.
- The facility drainage system should be designed such that accidental releases of hazardous substances are collected to reduce the fire and explosion risk and environmental discharge.
- Hydrocarbon leak detection must be situated throughout the facility. Another design feature which has been shown to be of critical importance is the suitable separation of offices/accommodation from the potentially hazardous plant.

Finally, the emergence of new LNG technology categories, such as FSRUs or FLNG facilities, may require additional features broadly comparable with the guidelines above, adapted to a marine environment.

The HSE requirements for the FLNG projects should cover drilling and completion, construction, installation, commission, start-up, production, maintenance, and decommissioning operations. The design philosophy should be based mostly on the concept of personnel-safety first, due to the fact that there is a limitation of space within the platform.

The project development is supported by a HSE design based on a formal risk-based assessment process, through the following relevant studies:

- Hazard identification by analysis (HAZID, HAZOP) is performed to find out the relevant HSE concerns associated with the project.
- Specific HSE studies to validate the layout and define all necessary measures and protections to put in place (i.e. Fire and Explosion Risk Analysis, Emission and Gas Dispersion Studies, such as heat radiation, etc.).

- Quantitative Risk Analysis.
- Verification of the measures to prevent, control or mitigate the consequences of these hazards.
- Identification of changes or additions to the design in order to improve the prevention, control or mitigation of the consequences of the identified hazards.
- Demonstration that personnel risks are, at worst, ALARP (as low as reasonably practicable).

Security Considerations

The concentration of very high-value plant and equipment with a large, potentially hazardous energy store creates unique security concerns for national governments. The host government will be concerned about the strategic nature of the assets and the related petroleum revenues, investors/lenders will focus on the security of their invested capital in the asset, whereas natural gas customers may have security of supply concerns, particularly where a particular facility supplies a significant portion of a third country's energy supply.

Because of these factors, safety and security of LNG facilities are rarely discussed in a public forum but nevertheless attract considerable attention internationally. The security agencies of many countries where LNG import or export facilities exist, or who receive strategic LNG supplies from elsewhere, all have very well-developed arrangements, procedures and emergency plans in hand, and this expertise is best accessed through government-to-government dialogue.

Marine security for LNG tankers entering or leaving a facility can be provided by the national government through their Coast Guard or Navy. Adequate equipment and personnel are needed to ensure safety. Typically, all crew must be cleared by national government officials, not only by the companies who employ them.

In some regions, piracy may be a concern for ocean-going LNG carriers, and various special measures may be required to address this threat.

Social and Economic Impact

The social and economic impact of major gas developments has taken greater significance within the last decade as the global gas industry has reached a scale and impact such that local communities are requiring more transparency and using media to hold operators accountable. Social and Economic Impact Assessments are important to provide a baseline of the local community prior to the project development and to facilitate monitoring the potential changes on the local communities during the project. These studies ensure responsible operations as well as environmental safety.

Some of the communities where gas projects are being considered are economically disadvantaged and the impact of the project will be designed to improve the economic conditions of both the host communities and the state. Under the sustainability condition, the community may remain in their current location and way of life, but project development may result in relocation or possible disruption of community standards which will be addressed by a social development plan.

The ultimate goal of the social impact assessment is:

- provide a social development plan which will amongst other things provide mitigation measures to deal with any potential adverse community economic impacts.
- reduce company risk of operational disruption by collecting baseline data and undertaking continuous monitoring.

Main social impacts

The social development plan orchestrates the positive economic impact and aims to eliminate the potential negative social and economic impacts that may result from the development of gas projects. Some of these impacts are:

- Job creation: increased income generation opportunities from direct and indirect job creation at local, regional and national levels.
- Reduced income-generation opportunities related to fishing. The ocean is for these communities an important natural resource for community living, used for main purposes such as fishing and transportation of goods from one to other economic areas.
- Resettlement of local communities including potential physical displacement along pipeline corridors.
- Loss of subsistence crops within the right of way.
- Impact on traditional governance mechanisms and structures.
- Loss of local 'Sense of Place' and decreased social and cultural cohesion.
- Potential increase in anti-social behaviors.
- An increase in vector-borne and communicable diseases.
- Increased injuries and mortality from traffic accidents.
- Reduced access, pressure and overburdening of physical and social infrastructure.
- Improvements related to community development initiatives.
- Impact on landscape and visual environment during construction.
- Construction exposure of workforce to insufficient health and safety standards.

Social and Economic Development Plan - "Social License To Operate"

There are numerous regulatory and licensing processes required to fully permit the project, however obtaining and maintaining a "social license-to-operate" for the project requires focused and targeted effort, engaging with the host communities and the state to create a robust social and economic development plan to cover the anticipated life of the project. This has challenged the extractive industry for a long time and has negatively impacted many projects. An example of how this can play out if inadequate benefits filter down to local communities is the chronic troubles in the Niger Delta in Nigeria where frequent pipeline attacks cripple large portions of Nigeria's oil and gas infrastructure. The cost associated with the social and economic development plan to mitigate against social risk and disruptions may be between 1% - 5% of total capital expenditure. Project developers, as part of their social responsibility or "Social License To Operate" may take on additional tasks that are not specifically required to ensure project completion but which are important to the community in which they operate. The robust development plan may link the economic interest of the plant and the communities thereby creating an alignment of interest for mutual benefits. This is a pragmatic economic and ethical framework in which the project company has an obligation to act for the benefit of society at large for the broad commitment to the host community and to the well-being of the investment,

The social and economic development plan may be influenced by four main factors: legislation, licensing process, land acquisitions and stakeholders:

- **Rigorous, complex, and dynamic legislation:** regulation tends to change, increase, and to be improved in most countries, not only driving companies towards increased compliance but also creating the need for anticipating changes.

- **Complex licensing process/Strict licenses:** the licensing process can be large and fragmented, which increases the number of decision-making entities involved and the frequency of interactions required.
- **Need of land acquisitions and management:** licensing often includes expropriations and, consequently, complex land management and acquisition processes which create internal challenges in terms of coordination of actions.
- **Multiples and diverse stakeholders:** a large number of institutions (public or private), authorities, communities, and so on, are affected by licensing processes, and their interests are not always aligned to those of the operating company.

The Social License to Operate remains highly important for these countries to maintain internal stability, reduction in armed conflict, and, most importantly, cooperation regionally such as within the Economic Community of West African States (ECOWAS) or East African power markets.

Pricing

Introduction

As opposed to crude oil, LNG does not feature a harmonized global price. In contracts, the price of LNG is segmented into regional markets, the main ones being:

- the Asian market (Japan, Korea, and China) with the Japan Customs-cleared Crude price index
- the European market with the National Balancing Point price index
- the North American market with the Henry Hub price index.

LNG pricing has historically been tied to crude oil, as the replacement fuel to natural gas. Pricing into Japan and much of Asia was based on a percentage of the price of Japan Customs-cleared Crude (JCC), which is the average price of custom-cleared crude oil imports into Japan as reported in customs statistics; nicknamed the Japanese Crude Cocktail. As an example, a pricing formula may be "LNG price = JCC x 0.135" where JCC is further defined as the previous three monthly averages of JCC priced in yen and converted into US dollars. In Europe, Brent has been favored in oil-linked LNG pricing formulas.

LNG pricing in parts of Europe and in North America have relatively recently been tied to readily available natural gas indices. In Europe, a main index is NBP or National Balancing Point, a virtual trading location for the sale and purchase and exchange of UK natural gas. In North America, a main index is Henry Hub, a distribution hub in South Louisiana which lends its name to the pricing point for traded natural gas futures contracts.

LNG Reference Market Price

As noted in the previous section, LNG pricing is following the global trend that has been underway for many decades, whereby instead of being priced relative to oil, it is starting to be priced based on a variety of established and emerging global reference prices. This is generally referred to as "gas-on-gas" pricing as it is a measure of the relative supply and demand in natural gas markets, quite independently of whether the oil market is in balance or not. From an economist's point of view, this would be the established way to set the appropriate market clearing price for a globally traded commodity.

The US market

The historical rationale for gas reference pricing emerged from the development of a liquids wholesale market in the US, with exchange-traded futures contracts to support a pricing mechanism that was not vulnerable to undue influence from a single buyer or seller, and was derived from a transparent, market-based mechanism. Historically, natural gas prices were fixed by the government, but in 1992, the Federal Energy Regulatory Commission (FERC) issued its Order 636. Prices were decontrolled and interstate natural gas pipeline companies were required to split-off any non-regulated merchant (sales) functions from their regulated transportation functions. This unbundling of gas contract pricing and transportation contract pricing meant that exchange-traded gas contracts, based on Henry Hub and other secondary hubs, were established, and the industry moved to market-based indices for pricing purposes.

The European market

In Europe, this same trend was first established in the UK, following gas market deregulation in the mid-1990s, and the emergence of National

Balancing Point (NBP) pricing, which, though similar to Henry Hub, is not a physical place. In Continental Europe, the so-called Title Transfer Facility (TTF) has now become an equally dependable mechanism for long-term pricing, though Southern Europe is still transitioning to a mechanism of gas-on-gas pricing, as new hubs start to emerge.

The Asia-Pacific market

The first signs that a new pricing basis was emerging for the Asia-Pacific region occurred in the early 2010s with the signing of Henry Hub-based LNG tolling contracts. At the time, buying gas in the US and paying a tolling fee to put it through one of the emerging LNG liquefaction facilities, represented a lower landed price in Japan and other SE Asian countries, compared to traditionally oil-priced gas.

A number of attempts are being made to establish a pricing index for the Asia-Pacific market, including the so-called JKM index (Japan-Korea-Marker) and also the Singapore Gas Exchange (SGX) spot price index known as SLiNG, which is intended to represent an exchange-traded futures market for LNG based on gas being traded at or around the Singapore LNG facilities. At the time of writing, no index exists that is considered sufficiently dependable for use on long-term contract pricing.

Current developments

The LNG sector has been relatively slow to move away from oil-based pricing. There are many reasons for this, but the main brake on pricing change for LNG has been the lack of availability of a reliable, transparent pricing reference for gas, similar to Henry Hub or NBP, in the Asia-Pacific region, which accounts for about two-thirds of LNG consumption.

The other feature of LNG, compared to pipeline gas, is that it is bought and sold in single ship-borne cargoes, instead of being commingled within a pipeline system, and this too has tended to slow down the development of gas on gas mechanisms.

In Europe, over the last decade, the majority of traded gas has now migrated from oil-based to gas on gas based pricing, and some commentators believe that gas-on-gas based pricing will gradually replace oil-based index pricing, particularly as new LNG projects bring additional LNG into the global markets.

An increasing number of African countries are considering moving to LNG imports, or establishing relatively smaller scale projects. Because these are under development and/or negotiations, no pricing has been established as yet.

Price Indexation

Natural gas may be sold indexed to the price of certain alternative fuels such as crude oil, coal and fuel oil. The natural gas feedstock prices into the LNG plants are sometimes indexed on the full revenue stream of the LNG plant including LPG and propane plus (other gas liquids), as in the case of the 2009 amendment of the NLNG contract in Nigeria. Such a pricing mechanism is markedly different from the one found in traded gas markets, where price is determined solely by gas demand and supply at market areas or “hubs”.

In the United Kingdom, around 60% of the gas is sold at the National Balancing Point (NBP) price and the rest at an oil index price based on old long-term contracts. The oil-indexed and hub-priced contracts co-exist.

On the European continent, the case is different. Oil-indexed contracts dominate, with hardly any hub-priced long-term contracts. The continental markets are mainly supplied on a long-term take-or-pay basis. However, a number of short-to-medium contracts do exist which are either fully or partially hub-priced.

Crude Oil Prices

Different crude oil prices are used for the oil index in LNG long-term contracts such as:

Japanese Custom Cleared crude (JCC)

JCC is the average price of crude oil imported into Japan and published by the Japanese Ministry of Finance each month. It is often referred to as the Japanese Crude Cocktail. The JCC has been adopted as the oil price index in LNG long-term contracts with Japan, Korea and Taiwan. LNG pricing for China and India is also linked to crude oil prices but at a discount to Korea and Japan. The discount reflects the fact that China and India, although short of natural gas supplies have other sources of natural gas that LNG complements. As a result, China and India have some additional market leverage in negotiating contracting terms.

Average price of Indonesian crude oil (ICP)

PERTAMINA uses the average price of Indonesian crude oil (ICP) for the supply of LNG from the Bontang and Arun plants.

Dated Brent Crude

Dated Brent is a benchmark assessment of the price of physical, light North Sea crude oil. The term "Dated Brent" refers to physical cargoes of crude oil in the North Sea that have been assigned specific delivery dates, according to Platts. Kuwait, Pakistan, and many European LNG prices are indexed on Brent.

Coal indexation

In markets where gas is used to fuel power generation, some LNG buyers have pushed for LNG indexing against substitute fuels such as coal. Coal indexation has been used for many years in a Norwegian gas sales contract to the Netherlands and is also an indexation parameter in the Nigeria NLNG contract to Italy. This parameter may become more common if clean coal technologies are used to satisfy incremental baseload electricity demand, or if electricity generators come under increased pressure to reduce carbon emissions under the Kyoto protocol.

Oil Indexed Price Formula

Approximately 70% of world LNG trade is priced using a competing fuels index, generally based on crude oil or fuel oil, and referred to as “oil price indexation” or “oil-linked pricing." The original rationale for oil-linked pricing was that the price of gas should be set at the level of the price of the best alternative to gas. Historically, the best alternative was heavy fuel oil, crude oil or gas oil. This was especially the case in the Asia-Pacific region, which historically has represented the largest buyers of LNG, including Japan, Korea and Taiwan.

In the Asia-Pacific region, LNG contracts are typically based on the historical linkage to the Japanese Customs-cleared Price for Crude Oil (JCC, or the “Japanese Crude Cocktail). This is due to the fact that at the time that LNG trade began, Japanese power generation was heavily dependent on oil so early LNG contracts were linked to JCC in order to negate the risk of price competition with oil. The formula used in most of the Asia LNG contracts that were developed in the late 1970s and early 1980s can be expressed by:

$$P_{LNG} = \alpha \text{ x } P_{crude} + \beta$$

Where:

P_{LNG} = price of LNG in US$/mmBtu (US$/GJ x 1.055)

α = crude linkage slope

P_{crude} = price of crude oil in US$/barrel

β = constant in US $mmBtu (US$GJ x 1.055)

Historically, there was little negotiation between parties over the slope of the LNG contracts, with most disagreements centered on the value of the constant β. Following the oil price declines of the 1980s, most new LNG contracts incorporated a floor and ceiling price that determined the range over which the contract formula could be applied. Since suppliers had to make substantial investments in LNG liquefaction trains, a pricing model developed that provided a floor price. For suppliers, this floor limits the fall in the LNG price to a certain level, even if the oil price were to continue falling. Conversely, buyers are protected by a price cap, which restricts LNG price rises when oil prices rise above a certain point.

More recently, the historic price linkages to oil have been called into question as more LNG supply comes on the market from new LNG exporters, such as the United States, which developed a pricing mechanism linked to US Henry Hub. At the same time, the traditional LNG buyers, such as Japan, have balked at new contracts linked to oil, claiming they no longer make sense. As the LNG market continues to evolve, there are likely to be more and more creative solutions to pricing LNG.

Spot and Short-Term Markets

In recent years, the LNG markets have seen the emergence of a growing spot and short-term LNG market, which generally includes spot contracts and contracts of less than four years. Short-term and spot trade allows divertible or uncommitted LNG to go to the highest value market in response to changing market conditions. The short-term and spot market began to emerge in the late 1990s-early 2000s. The LNG spot and short-term market grew from virtually zero before 1990, to 1% in 1992, to 8% in 2002. In 2006, nine countries were active spot LNG exporters and 13 countries were spot LNG importers.

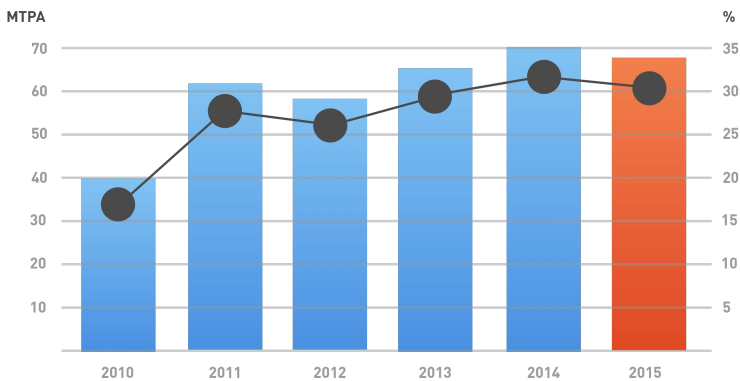
Due to divergent prices between the markets in recent years, the short-term LNG market has grown rapidly. By 2010, the short-term and spot trade had jumped to account for 18.9% of the world LNG trade. In 2011, the spot and short-term again recorded strong growth, reaching 61.2 MTPA (994 cargoes) and more than 25% of the total LNG trade. Asia attracted almost 70% of the global spot and short-term volumes primarily due to Japan’s increased LNG need following the March 2011 Fukushima disaster, which took Japan's nuclear reactors offline. This lost power was replaced with LNG. Spot and short-term LNG imports into Korea almost doubled (10.7 MTPA) and almost tripled for China and India with both countries importing a combined 6.5 MTPA of LNG.

By the end of 2011, twenty-one countries were active spot LNG exporters and 25 countries were spot LNG importers. The growing number of countries looking to participate in the spot market is indicative of the increased desire for flexibility to cope with market changes, unforeseen events such as Fukushima, as well as the increased number of countries now participating in the LNG markets.

In 2015, global LNG trade accounted for 245.2 MTPA, a 2.5% increase vs. 2014. There are now 34 countries importing LNG and 19 countries that export LNG. Approximately 28% of global LNG volumes (68.4 MTPA) were traded on a spot or short-term basis.

The following chart shows the growing importance of spot and short-term sales in global LNG trade:

Spot and Short Term* Vs Total LNG Trade



**short-term trade denotes trades under contracts of a duration of 4 years or less.*

*Source: International Group of Liquefied Natural Gas Importers (GIIGNL), **The LNG Industry 2015**, www.giignl.org.*

Netback Pricing

The concept of "netback" pricing is particularly important for producing countries because netbacks allow the countries to understand the varying value of LNG in different destination markets. Netbacks are calculated taking the net revenues from downstream sales of LNG/natural gas in the destination market, less all costs associated with bringing the commodity to market, including pipeline transportation at the destination, regasification, marine transport and, possibly liquefaction, and production, depending on the starting point of the netback.

Netbacks allow the producer and producing country to assess the relative attractiveness of different destination markets for exported LNG.

There is no single formula for determining the netback price as it depends on specifics of the deal and is determined on a case-by-case basis, depending on the start and delivery point of the LNG sales contract and the particular destination market involved. The starting point for calculating a netback price can be at the well, at the inlet to a liquefaction plant, or at the exit of the liquefaction plant. The delivery point of the LNG sales contract can be at the liquefaction facility (a free on board (FOB) sale, or a costs, insurance and freight (CIF sale)), or at the destination market (a delivered at terminal (DAT) sale, or a delivered at place (DAP) sale). The terms DAT and DAP have replaced the term delivered-ex-ship (DES), although some parties continue to use the DES reference term.

To determine costs in netback pricing, the following terms are relevant:

Free On Board (FOB) Pricing: contemplates that the buyer takes title and risk of the LNG at the liquefaction facility and the buyer pays for LNG transportation from the liquefaction facility to the destination market.

Delivered at Terminal (DAT), Delivered at Place (DAP) and Delivered Ex Ship (DES) Pricing: contemplate that the seller retains title and risk of the

LNG until the receiving terminal in the destination market and the seller pays for LNG transportation from the liquefaction facility to the destination market.

Costs, Insurance and Freight (CIF) Pricing: is a hybrid which contemplates that the buyer takes title and risk of the LNG at the liquefaction facility but the seller pays for transportation from the liquefaction facility to the destination market. The significance of the delivery point is that costs are shifted between the seller and buyer.

The calculation of marine transportation and regasification costs are specific to the ship and receiving terminal to be used.

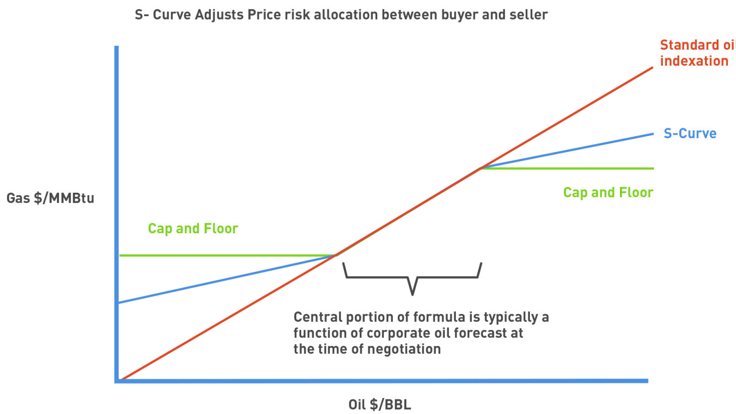
The destination market pricing is specific to the destination market. For example, US netbacks come from an average of the closing price taken from the New York Mercantile Exchange (NYMEX) on the 3 trading days before and including the date reported for delivery at Henry Hub. A local adjustment may be required for pipeline transportation costs depending on the location of the LNG receiving terminal. The calculation of United Kingdom netbacks comes from an average of the closing price on the Intercontinental Exchange (ICE) futures contract for delivery at National Balancing Point (NBP). Japanese netbacks are derived from the official average ex-ship prices for the most recent month. A *World Gas Intelligence* European Border Price table is used to estimate the most recent ex-ship prices for Spanish market netbacks.

Price Review or Price Re-openers

As previously discussed, unlike crude oil, LNG is not yet priced on an international market basis and most LNG is priced on a long-term basis of 20 years or more. The contractual and confidential nature of LNG pricing, coupled with a lack of transparency of individual cargo prices, means that a wide range of prices might exist even within the same country or region. For example, an LNG contract entered into many years ago may still be in effect under far different pricing structures than those that existed at the time it was first agreed.

Historically, some Asian buyers have been able to introduce price caps or “S-curves” into their pricing mechanisms, which protect them against very high oil prices and in return, protect sellers against very low oil prices.

An S-curve is so-called because the relationship between the oil price and the gas price is altered to give the seller relief in a low oil price market (a higher price than would apply from strictly applying the oil index - 14% JCC as an example), and to give the buyer relief in a high oil price market (a lower price than the oil index would generate). Thus in a plot of gas price against oil price, the start and end of the line has a flatter slope than the middle and the resulting line has an S-shape which gives rise to the name. Sometimes, the S-curve approach can be used to derive a price floor at low oil prices, and a price ceiling at high oil prices. The graphic below illustrates a generalized S-curve.



In addition, a price review or price "re-opener" clause is found in many long-term contracts. An example of the language typically used is as follows:

"If . . . economic circumstances in the [buyer's market] . . . have substantially changed as compared to that expected when entering into the contract for reasons beyond the parties' control . . . and the contract price . . . does not reflect the value of natural gas in the [buyer's market] . . . [then the parties may meet to discuss the pricing structure]"

Price review clauses have been a feature of continental European long-term pipeline gas sale contracts for a long time. Lawyers from other regions and legal traditions are often uncomfortable with such clauses because when they are invoked, the parties usually find that their interests are more divergent than expected.

Nonetheless, price review or reopener clauses still remain a key clause of most long-term LNG SPAs and many, if not all, LNG suppliers and buyers enter into negotiations without fully grasping how difficult it is to negotiate such clauses, especially if they are to be enforceable if invoked. As such, the following are key elements that must be addressed with negotiating a price reopener clause:

- The trigger event or conditions entitling a party to invoke the clause must be defined. Usually, this is a change of circumstances beyond the control of the parties.
- The elements of the price mechanism which are subject to review must be defined and usually include:
    - The base price
    - Indexation
    - Floor price
    - Ceiling price
    - Inflection points of the S-curve formula

If a requesting party has satisfied the trigger event or criterion, then there is the challenge of determining which benchmark should be applied to determine the revised price mechanism and often the buyer's and seller's view of the relevant market differ significantly. Moreover, since the LNG market is still mostly long-term negotiated contracts that are not public and transparent, the parties may not always be able to access the information and data needed in relation to the broader market for the price-reopener negotiations.

If the parties cannot agree on a revised price mechanism, then the parties should consider referral of the matter to a third-party or arbitration. However, many LNG contracts contain "meet and discuss" price review clauses that do not allow for such referral, leaving the parties without recourse unless some specific recourse is specified. For example, the parties could provide that if the parties are unable to agree on the revised price mechanism, then the seller has the right, upon written notice, to terminate the long-term LNG SPA.

Recent Pricing Issues

Given the volatility and significant variations in regional gas pricing over the last few years, both LNG sellers and LNG buyers are becoming increasingly focused on how to develop gas pricing mechanisms which give sellers a revenue which reflects the global value of their product, in a manner that will support project development. These pricing mechanisms also provide buyers with a market clearing price, which will enable them to supply gas to their customers at a competitive rate.

With the increasing power of buyers in the currently over-supplied market, new pricing mechanisms are emerging which give the buyer a choice or mix of pricing indices. This new flexibility is sometimes coupled with short-term volume and destination flexibility, with the ability to turn back cargoes that are priced at what the buyer may consider an uncompetitive level.

These increasingly complex price-and-volume provisions are leading sellers to more complex hedging and risk management strategies. New pricing provisions are also supporting the LNG aggregator business model, where an intermediary, either an IOC or an LNG trading entity, takes on the role of accommodating both buyer and seller pricing concerns and manages a portfolio of gas sources and destinations in order to appropriately manage risk.

LNG pricing formulas are evolving at the moment from pure oil-linked pricing to pure gas-linked pricing, although the full evolutionary process is still underway. As a result, there are various mixed pricing formulas in use at the moment, including pricing techniques that modulate fluctuations in oil pricing, such as an "S" curve which bends the percentage of a crude price at extreme highs and lows.

Another consideration in pricing is the emergence of 'pricing review' clauses in LNG SPAs, where the LNG price can be examined and changed at periodic intervals if specified market conditions are triggered. While the intent of these clauses is to preserve a link between a long-term contract and the actual market pricing, such clauses can be very contentious and lead to disputes between sellers and buyers.

LNG and Gas Contracts

Introduction

Upstream Contractual Structures

Preliminary Agreements

Domestic Gas Sales Agreement

LNG Sale and Purchase Agreement

Miscellaneous Agreements

Introduction

Gas projects require different types of contracts at different stages of the project development, from upstream to midstream through to downstream. While a significant amount of these contracts are negotiated between private parties, some of the most important ones involve host governments. The ability of governments of resource-rich countries to effectively steward the exploitation of natural resource wealth is predicated upon a number of factors. One of these is the ability to represent the interests of current and future generations in negotiations with private investors and regional partners involved in cross-border natural resources projects.

In that context, an understanding of the different types of contracts, their place in the value chain, and the development of the project, are important. Particular attention should be paid to the technicality and complexity of these contracts. The objective is that governments can prepare effectively for these negotiations, build necessary knowledge to make informed decisions and create dedicated negotiations teams. In addition, contract implementation is equally important and host governments should also build capacity and dedicate resources.

This section aims at providing an overview of the different types and categories of contracts in order to enable governments to prepare accordingly.

PSC v. Licenses

The way in which the upstream contractual arrangements are configured is a complex matter, the basics of which are summarized as follows.

The four contractual structures that have been adopted comprise:

- Production sharing contracts
- Licenses/ Concessions
- Joint ventures
- Service contracts

Typically a PSC would involve lower risk for the investor in that costs are sometimes recovered in a more timely and efficient manner. However, the mechanisms can be complex and entail longer-term risks and cost recovery in economics. In upstream environments that are more stable and sustainable, concessions may offer a better long-term balance.

In the context of LNG projects, the upstream contractual arrangements are not a primary determining factor and have been developed around the world using both primary types of arrangements. Examples of LNG projects under licenses can be found in Qatar, Australia, and the U.S. LNG projects under a PSC/PSA can be found in Indonesia, Malaysia, and Angola. Nigerian LNG projects are based on upstream joint venture arrangements.

Regardless of the upstream structure selected, other legislation (laws), regulations and/or contracts will likely be required for liquefaction and new large-scale natural gas development since many pre-existing host government contracts do not address the specifics of natural gas development. Some of these other contracts are discussed below in the section on Miscellaneous Agreements.

Preliminary Agreements

The negotiation process for the LNG sale and purchase agreement (SPA) can often be quite lengthy and detailed. Given the multi-year timeframe, it is often necessary to demonstrate progress in the negotiating process. Some sort of preliminary document between the parties is therefore often desired to build confidence in the project and, perhaps, document acceptance of specific terms for the government or the investors' management.

Preliminary documents can include:

- Term Sheet
- Letter of Intent (LOI)
- Memorandum of Understanding (MOU)
- Heads of Agreement (HOA)

These documents are listed in their progression of detail and completeness, with an HOA typically representing one step below a full definitive agreement, such as an SPA.

The key issue in all preliminary documents is whether the parties involved are legally bound by the provisions of the preliminary document or whether the parties are still free to negotiate other or different terms, and this may often be a complex matter on which legal counsel would advise. For example, local law may treat some or all of a preliminary document as legally binding even where the preliminary document states otherwise.

Even if a preliminary document is clearly not legally binding, it can lead to disputes if one party later deviates from the provisions of the preliminary document.

Consequently, care should be exercised in entering into any preliminary documents and their use should be limited to only situations where deemed commercially essential.

Domestic Gas Sales Agreement

The domestic Gas Sales Agreement (GSA) follows the typical pipeline gas sales agreement format, with the following key points:

Commitment

The issue is whether the domestic buyer will have a firm "take or pay" commitment under which they are required to pay for supply even if they are unable to accept delivery, or a softer reasonable endeavors commitment. If it is only a reasonable endeavors obligation, the question arises whether the domestic buyer forfeits the right to the committed volumes if delivery is not taken on schedule. By contrast, the LNG plant developer will want to secure gas supply for the liquefaction plant. This includes a take or pay commitment and reserves certification.

The commitments of the seller and the buyer should be balanced.

Price

Pricing of natural gas going to the liquefaction plant may depend on the structure of the LNG chain, whether it is integrated, merchant or tolling. The price may be indexed or may be fixed, with or without escalation. If the structure of the LNG export project is integrated, there is generally not a transfer price between the upstream and LNG plant for the gas feeding the LNG plant.

Similarly, the domestic gas price can be fixed and/or regulated, or negotiated between buyers and sellers.

Payment

Domestic gas contracts can be priced in the local currency and this can give rise to foreign exchange risk for the investors involved. Payment currency risk analysis should be an ongoing process. Gas sales for exported LNG are typically priced in dollars, however, the trend in domestic gas sales worldwide has been that payment is typically made in the local currency.

Other elements of a standard GSA include Definitions and Interpretation, Term, Delivery Obligation, Delivery Point and Pressure, Gas Quality, Facilities and Measurement, General Indemnity, Dispute Resolution, Force Majeure, Suspension and Termination, General Provision, Warranty, and Indemnities.

LNG Sale and Purchase Agreement

The LNG Sale and Purchase Agreement (SPA) is the keystone of the LNG project bridging the liquefaction plant to the receiving regasification terminal.

There is no worldwide accepted model contract for a SPA, with most major LNG sellers and LNG buyers having their own preferred form(s) of contract. Some international groups, including The International Group of LNG Importers (GIIGNL) (www.giignl.org) and the Association of International Petroleum Negotiators (AIPN) (www.AIPN.org), have prepared Model Form short-term contracts, e.g. AIPN has a Model Form LNG Master Sales Agreement.

Most LNG SPAs have become lengthy and very detailed documents. However, the main points of an LNG SPA can be summarized below:

Commitment

The commitment made in a SPA, in its broadest sense, is epitomized by the following statement:

"...the Seller commits to sell and the Buyer commits to purchase ..."

The elements of the commitment are term, transportation, volume, level of commitment and ability to divert LNG cargoes.

Term

Historically, LNG SPAs have been long-term contracts with terms of 20-25 years. These long-term contracts were needed by both the seller and the buyer to justify the significant investments required by the liquefaction project and by the receiving terminal and the natural gas end-users. The majority of the throughput of the liquefaction plant needs to be tied into these long-term contracts to enable the developer (see the chapter Financing an LNG Export Project) to secure project finance. As the LNG industry has grown and LNG supplies have become more readily available, there are now some shorter term contracts (5-10 years) for a minority percentage of throughput, but long-term SPAs are needed to underpin financing, described in detail in that section of this book. Additionally, a growing spot market for LNG has developed as a result of several unforeseen factors:

- the development of many global LNG export projects to meet expected US demand (at the end of the 1990s and the beginning of the 2000s) where the cargoes were subsequently available to other global markets;
- the availability of re-exported LNG cargoes from the US and other countries due to reduced demand
- the development of tremendous quantities of shale gas in North America and the resulting reversal of a large import destination to an emerging exporter;
- the Fukushima nuclear accident following the 2011 tsunami and earthquake, the consequent increased demand for LNG in Japan and the uncertainty of the timing of the re-start of their nuclear power plants;
- the collapse in oil prices in 2014/2015.

Transportation and Discharge

LNG sales can be done on a FOB (free on board) basis, with the buyer taking title and risk at the liquefaction facility and being responsible for transportation of the LNG; CIF (cost, insurance and freight) basis, with the seller being responsible for delivering the LNG to the tanker at the liquefaction plant. The buyer assumes title and risk, but the seller is responsible for the costs of transportation to the destination or DAT (delivered at terminal) or DAP (delivered at place), with the seller retaining title and risk until the LNG is delivered and the seller being responsible for transportation. The terms DAT and DAP replace the delivered ex-ship (DES) terminology that may still be encountered in some forums.

Volume

The SPA will specify the volume of LNG that the seller is obligated to deliver, and the volume the buyer is obligated to take, each contract year (generally a calendar year), and provide a process for scheduling and delivering this volume in full cargo lots aboard, agreed upon shipping. The SPA will provide for certain permitted reductions to the committed volume. For example, this would include volumes not delivered due to force majeure, volumes not delivered due to the seller's failure to make them available, and volumes which are rejected because of being off specification.

Level of Commitment

It is important to understand the level of commitment being taken on by both the seller and the buyer. If the commitment is "firm," a failure by the seller to deliver or by the buyer to take the LNG would result in exposure to damages. If the commitment is "reasonable endeavors," damages would probably not result.

LNG SPAs are almost always founded on a "take or pay" commitment, where the buyer agrees to pay for the committed volume of LNG, even if it is not taken, subject to the right of the buyer to take an equivalent make-up volume at a later time. Take or pay has been the cornerstone of an LNG SPA since the beginning of the industry and likely will continue into the future. However, some LNG SPAs now use a mitigation mechanism, whereby the seller sells cargos not taken and charges the buyer for any reduction in price, plus the costs of sale.

Similarly, the seller seeks to limit its exposure in a shortfall situation - where the seller does not deliver the full commitment - to something less than full damages. Often the seller will be responsible for a shortfall amount calculated as a negotiated percentage (15%-50%) of the value of LNG not delivered, with this amount paid either in cash or as a discount on the next volumes of LNG delivered.

These features, although detailed in nature, can typically involve financial commitments of hundreds of millions of dollars, and are therefore to be negotiated carefully, with the benefit of expert advisors.

Cargo Diversions

Recent LNG SPAs contain the right to divert a cargo to a different market. Where the seller or the buyer diverts a cargo, it is generally done to obtain a higher price. Two key points to address in situations of cargo diversions are the allocation of non-avoidable costs between the parties (e.g. receiving terminal costs, pipeline tariffs, damages for missed natural gas sales) and whether and how the parties should share in the profit obtained through the diversion sale. This later point may entail anti-competition exposure in some countries.

Price

At the time of writing this handbook, LNG pricing formulas are evolving from largely oil-linked pricing to largely gas-linked pricing, although the full evolutionary process is still underway. As a result, there are various mixed pricing formulas in use, including pricing techniques that modulate fluctuations in oil pricing, such as an "S" curve which bends the percentage of a crude price at extreme highs and lows.

One important trend in pricing is the emergence of 'pricing review' clauses in LNG SPAs, where the LNG price can be examined and changed at periodic intervals if specified market conditions are triggered. While the intent of these clauses is to preserve a link between a long term contract and the actual market pricing, such clauses can be very contentious and lead to disputes between sellers and buyers.

Technical

Technical provisions to be included in an LNG SPA include provisions on minimum and maximum specifications for LNG (including heating value and non-methane components), measurement and quality testing of LNG, LNG vessel specifications and requirements, receiving terminal specifications and requirements and provisions for nomination and scheduling of cargos.

Miscellaneous

Aside from the above key components, an LNG SPA would typically include:

- Provisions for invoicing and payment
- The mechanism for delivering gas feedstock into the liquefaction facility
- Currency of payment
- Security for payment, including prepayment, standby letters of credit and parent company or corporate guarantees
- Governing law of the LNG SPA, which typically will be England or New York
- Dispute resolution through international arbitration
- Conditions precedent
- Definitions and interpretation
- LNG quality
- Testing and measurement
- Transfer of title and risk
- Taxes and charges, liabilities
- Force majeure
- Confidentiality

Miscellaneous Agreements

There are a number of other key agreements that might be necessary for an LNG project, depending on the structure selected. The following is a representative list:

Project Enabling Agreement

Unless specifically authorized by legislation (law) or enabling regulations, a liquefaction project will require some sort of project enabling agreement between the host government and the project sponsors. This project enabling agreement will describe in detail:

- the scope of the liquefaction project to be undertaken;
- the legal regime and the tax regime to which the liquefaction project will be subject, including any tax incentives or exemptions benefiting the liquefaction project;
- the ownership of the liquefaction project, including any reserved local ownership component;
- the governance and management of the liquefaction project;
- fiscal requirements applicable to the liquefaction project;
- local content requirements and procurement procedures applicable to the liquefaction project;
- government assistance including in connection with acquiring land and other licenses and permissions;
- any special local terms and provisions.

Shareholders Agreement(s)

If an incorporated special purpose vehicle (SPV) is to be used, it will be necessary to document the agreement of the shareholders regarding governance and management in a Shareholders Agreement. The Shareholders Agreement complements and expands on the Articles of Incorporation or other constitutional documents of the SPV.

Liquefaction Agreement

If a tolling structure is selected, it will be necessary for the liquefaction tolling entity to have a contract outlining the services to be performed, the tolling fee structure for such services and other provisions regarding risks, etc. with the natural gas customer. This agreement may go by many names, including Liquefaction Agreement and Tolling Agreement.

Gas Feedstock Agreement

If a merchant structure is selected, the merchant liquefaction entity will need to purchase the natural gas to be liquefied in the liquefaction facility. The most contentious issues in the Gas Feedstock Agreement are: (1) the transfer price for natural gas, with the gas seller typically wanting a net-back price and the liquefaction entity wanting a fixed price, and (2) the liability of the natural gas supplier for any shortfall in deliveries, with the gas supplier wanting to limit liability and the liquefaction entity wanting a pass-through of its LNG SPA liabilities.

EPC Contracts

The engineering, procurement, and construction contract(s) for the upstream facilities and the liquefaction facilities will need to be negotiated and entered into by the appropriate entity, depending on the project structure. See chapter on LNG Development.

Financing Agreements

If project financing is used, a large number of financing and security agreements will need to be entered into.

Transportation Contracts

Either the seller or the buyer will need to contract for LNG vessels to transport the LNG to the market. The options are: (1) own the LNG vessels, or (2) charter the LNG vessels.

In a vessel-ownership model, an LNG vessel shipbuilding agreement will be required.

A vessel-leasing model will typically be either a bareboat charter (charterer provides crew and fuel), voyage charter (owner provides crew and fuel for a single voyage), or a time charter (owner provides crew and fuel for a set period of time).

Facilities Sharing Agreements (FSA)

This applies to LNG complexes with multiple LNG trains and differing ownership between trains. When any new train is built, in addition to the cost of the train itself, the new entrants are required to enter into facilities sharing agreements. These provide for payment for their share of common facilities, such as LNG storage, power generation, and LNG berths, etc.

Terminal Use Agreement

In an LNG import project, depending on the project structure, the user of the terminal will enter into a terminal use agreement with the terminal owner. There are a wide variety of titles for this agreement, although they accomplish the same purpose - use of the terminal for a fee.

Financing an LNG Export Project

Introduction

Project Finance Structure

The Financing Process

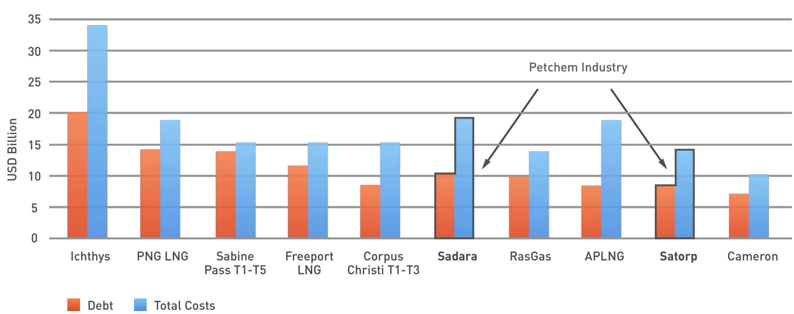
Available Funding sources

Impact of Market Shifts on Project Finance

Introduction

This chapter introduces the basic concepts involved in the financing of LNG export projects and associated infrastructure. Although some projects, such as Nigeria LNG (1 and 2), and Gorgon in Australia, were financed directly by their sponsors, the more common method of raising capital has been through a staged project finance structure. This chapter, therefore, focuses on finance structures followed by a discussion of the finance process, various funding sources, and impact of the current state of the global LNG markets relative to Africa.

The first project financing transaction in the LNG sector was for Australia's Northwest Shelf in 1980. Since then its use has become routine and project finance has been used in Africa in many different types of large projects, including by Nigeria LNG (NLNG 3-6). Ranked by debt, LNG projects occupy eight of the top ten slots for all project financing completed globally over the last ten years, as shown in the chart below:



Source: Poten & Partners' LNG Finance in World Markets, LNG in World Markets, published company reports

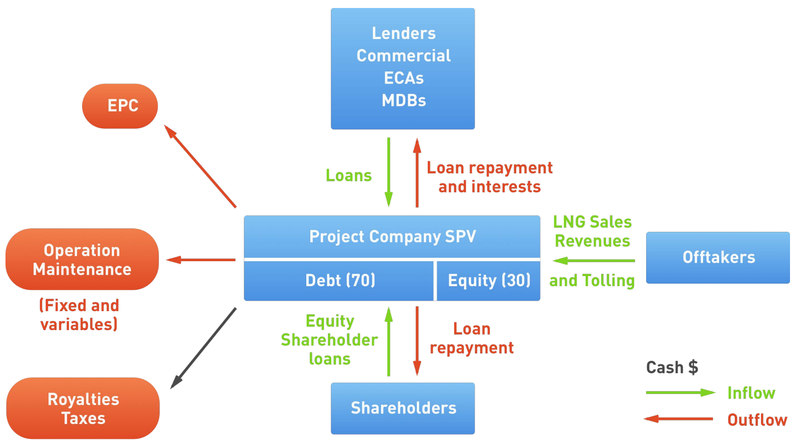
In project finance, all of the development cost, assets, permits and contract rights of the project company are used to support the finance structure. The credit of the project company's counterparties is used rather than the credit of the project sponsors that create and own the project company. The project lenders rely on the cash generated by the project (e.g. LNG sales contract duration/revenue forecast) to pay back the debt and not on the balance sheets of the project sponsors. For this reason, it is also referred to as 'off balance sheet financing' and 'limited recourse financing.'

Given the magnitude of the capital required for LNG projects, most are implemented by more than one project sponsor and require multiple funding sources. Government and corporate sponsors are often unable or unwilling to provide sufficient sovereign or corporate credit to finance LNG projects. Project finance structures provide reasonable protection for all parties and contractually protect against the contingent liabilities of partnership.

To implement a project finance transaction, project sponsors establish a special purpose vehicle (SPV) that allows banks, export credit agencies (ECAs) and other financiers to lend money directly to the project company or specific assets (e.g., LNG Train 3) instead of to the individual project sponsors. Currently, all liquefaction projects require long-term 'take-or-pay' LNG sales or tolling contracts to allow them to raise funding through project and equipment finance structures. Because the assets, permits and contract rights of the project company are the sole sources of debt service, international project finance involves careful analysis of the various risks associated with the project. New insurance products such as first loss policies or environmental protection insurance are bringing new sources of funding such as pension funds. The agreements to which the project company is a party must be precisely drafted in order to ensure that these risks are properly identified and allocated among the project company's counterparties.

Project Finance Structure

The following diagram depicts the relationships between the project sponsors and the financiers and the cash flows:



- **Debt to equity ratio:** As a result of the large cost of LNG projects, they are typically highly leveraged. A target of 70:30 debt to equity ratio is the norm. The project partners will provide the equity and sometimes bring in other financiers to provide equity. The debt is typically provided by banks and other lenders. Consequently, a large proportion of project sponsors look at generating large amounts of debt, but in project finance, this is located off balance sheet. So using project finance will allow sponsors to maintain their corporate debt/equity ratio.
- **Limited recourse to project sponsors:** LNG project finance is essentially based on “limited recourse” finance, which means that the

loan is given to a Special Purpose Vehicle (SPV) instead of the project sponsors. As a result, lenders rather than sponsors assume the lion's share of risk associated with the project. However, during the development phase of the project, the sponsors (or shareholders) usually provide financial cover to the lenders until startup and completion tests are met. This is provided via a completion guarantee. Equally, shareholders would try to pass on some of the risks to the engineering procurement and construction (EPC) contractors. EPC contractors provide the shareholders with security via a lump sum turnkey contract, which means that the contractors have to shoulder the risk if there are problems with plant performance during startup leading to delays. When production starts and targets are met with proper completion tests, financial recourse to sponsors is canceled. This differs greatly from traditional balance sheet based loans.

> **Public-Private Partnerships in higher-risk countries:** LNG projects always require government support, this is for political reasons, risk mitigation, regulatory framework matters, interactions with communities, and contract stability and enforcement. Often the government (national or regional) is a shareholder in the project. The government may not be in a position to access finance to contribute equity or other development costs, and equally, investors may not be willing to cover the government's development costs. The role of project finance is to ringfence the project and enable the project company to borrow money under its own name, accessing terms more favorable than the government would obtain, thereby reducing the impact of the low credit rating of the host country.

> **Special Purpose Vehicle:** In order to successfully implement a project finance transaction, project sponsors typically establish a special purpose vehicle (SPV) that allows banks, export credit agencies (ECAs) and other entities to lend money directly to the project company instead of to the individual project sponsors. By comparison, if corporate finance was used, each sponsor would be required to finance its portion of the project, using a combination of capital on hand and individual loans, which would limit the amount of debt that can be raised by entities with lower credit ratings.

> **Offshore ventures:** In some instances, the project developers also create an offshore account that will receive cash inflows from lenders,

equity from shareholders, and LNG sales revenues. Debt will be serviced from this offshore account. While this does not mean that the SPV is exempt from tax in the host country - which is usually regulated by law and negotiated contractually - this serves to mitigate country exposure both political and economical, as well as facilitating cash flows that could be compromised by host country banking system performance. Offshore ventures are regulated and negotiated contractually to enforce international law and US Foreign Corrupt Practices act agreements and equivalent.

> **Loan tenor/payback period:** Debt is provided by a syndicate of lenders (such as commercial banks, pension funds, investors in the public bond market, export credit agencies and government-backed lending institutions), who differ in terms of the amounts they lend, lending conditions as well as the ranking in the order of repayment. A typical loan tenor (meaning the time left for loan repayment) commercial banks would accept for LNG projects would be 10 years for high-risk countries. The tenor terms are based on a debt service coverage ratio which can be determined using financial models. The loans are priced at a margin applied above the base rate, which is often the London interbank offered rate. The loan pricing or margin will depend on an assessment of a project's risk and on the cost of funding. Multilateral Development Banks (MDBs) such as the International Finance Corporation (IFC), Africa Development Bank (AfDB), and European Investment Bank (EIB), have specific loan products that can offer more favorable tenor terms though they usually constitute a small proportion of the total debt amount. Because of the time necessary to recover the capital investment costs - typically around 7 years - longer tenor terms are favored by project developers.

> **Long-term sales-and-purchase agreements:** Firm long-term agreements among LNG exporters and importers are generally required for up to 80% of the project's capacity. They typically cover contract periods of about 15 to 25 years, thus exceeding the anticipated loan payback period - normally in the range of 7 to 15 years. However, shorter term contracts are becoming more prevalent (see section below).

> **Inputs from ECAs and MDBs:** The lengthy and thorough due diligence process involved in a project finance transaction, together with the

economic development implications and the importance of the political environment, is well suited to ECA and MDB involvement. Since the mid-1990s, MDBs and ECAs have played a growing role in structuring LNG projects. They can finance them through through direct loans, political risk coverage or loan guarantees (see the section on Available Funding Sources below).

- **Risk mitigation:** A key advantage of project finance is that it allows developers to mitigate the risks associated with politically or economically unstable environments. Such projects face a risk of expropriation, political turmoil, labor strikes, land rights issues, and other unforeseen disruptions.
- **Debt recovery and default rates:** Experience has proven that the use of project finance for liquefaction projects has resulted in remarkably low default levels.

It is also important to note that project financing can have its drawbacks. Because banks lend to a project company, with limited recourse to the actual project sponsors, the due diligence requirements take time and money. While these drawbacks are significant, liquefaction project sponsors have historically found project finance advantages outweigh its drawbacks. But they tend to use it only when it allows them to finance projects with weaker credit partners or at the behest of National Oil Companies.

The Financing Process

The time taken to arrange project finance will depend on the development processes, project cost, the risks associated with the project and the host country, and number and type of financiers needed. Also, external market conditions such as commodity prices and the amount of liquidity in financial markets and foreign currency fluctuations will have an impact on timing. The size, complexity, and scope of major LNG projects require a wide range of advisors both on the side of the investors and the host government, together with the commitment of substantial resources throughout the financing process by both the government of the host country and the project sponsors.

This process, from initial discussions to finalizing the financing (financial close), can take as long as two years. In countries with little experience in the sector, or without appropriate policy and regulatory frameworks, the financing process can take much longer. Companies typically appoint a financial advisor to help structure the deal. The financial advisor will be appointed at the same time, usually, as the legal and technical advisors. The financial advisor is often selected from a group of advisors known by the commercial bank community. In addition, development banks, such as the IFC and the African Development Bank, can also be appointed at an early stage to provide advice on financial structuring.

Reserves will be delineated, the project company will be formed and will obtain its permits and licenses, and the project agreements will be structured, negotiated and executed by the stakeholders, including the government. Each of these tasks will require commercial, technical and legal resources. The financing discussions will start concurrently with FEED studies and tenders for EPC contractors. Often companies and their advisors will hold initial talks with the banks - known as "soundings" - in order to gauge their interest in participating in the project financing and to pinpoint any impediments to fund-raising.

Early in the process, the financial advisor will consider equity as a source of finance. Assessing the amount of equity available for the project will determine the "gearing" ratio and the amount of debt that the project needs to raise. The project will reach out to potential interested shareholders, typically parties with a specific interest in the project, such as off-takers, tolling counterparties, or EPC contractors and/or entities that have a large amount of liquidity available and looking for long-term stable returns with limited risks. These entities could include pension funds.

On the debt side, the financial advisor, with input from the project sponsors and their advisors, will produce an information memorandum and financing request for proposal (RFP) which will be sent to banks. This will contain all the pertinent details that are needed by potential financiers to assess the project. It will include details on the LNG offtake or tolling contracts, as encompassed in the sales and purchase agreements or tolling agreements. The information memorandum will include details on project construction, EPC contract, and timeline, plans for shipping, and operations and maintenance details. Technologies used will also be detailed. Banks do not have a strong appetite for exposure to new technology risk, so adequate protections, provided by sponsors, need to be in place if anything untried is introduced. This is the case for early floating liquefaction units, but lenders' concerns can be dealt with by use of a sponsor completion guarantee which is only released once the unit is operating according to parameters specified in the documentation.

The information memorandum will also include environmental protection and remediation.When assessing the environmental and social impact of projects, many financial institutions will use a risk management framework called the Equator Principles. As of the end of 2016, 85 financial institutions across 35 countries had adopted them. They include some of the big commercial banks which can find themselves a target of NGOs if they do not meet social and environmental standards when funding projects.

The financiers will be provided with commercial and financial models in tandem with the information memorandum. They will use various ratios to assess the project's risk, one of the most important being debt service coverage ratio (DSCR). The company and its advisors may provide indicative pricing in the model for the debt, although this will be decided based on market considerations.

Banks will assess the risk of lending to a project and if they decide to go ahead, they will approach their credit committees to get approval. Banks have their own internal rating systems for countries and this will be applied, but a decision to lend to the project is based on a consideration of all of the project's characteristics. They will determine whether the project structure and the project financing are sufficiently robust. They will take a view on the ability of the EPC contractors and project sponsors to implement the project.

Of special significance to the lenders are the offtake or tolling agreements. These need to be of sufficient duration to allow the debt to be serviced across long repayment horizons. They also need to be with creditworthy counterparties. Banks do not want exposure to market risk. Decisions are made by banks whether to fund projects on a case-by-case basis as no two projects are alike.

A critical element of a lender's assessment of the project will include thorough legal due diligence to determine whether there is any fatal problem with the project that could jeopardize the project company's ability to make debt service payments. The scope of legal due diligence should be tailored to the characteristics of each project, but typically will include:

- an analysis of the laws of the host country,
- a contractual alignment review to ensure that the major project agreements have consistent provisions and do not contain any unintended contractual disconnects,
- a review of the project company's permits and licenses to ensure that they are adequate to construct, own and operate the liquefaction project and were obtained in compliance with all applicable laws,
- an analysis of the project company's real and personal property rights.

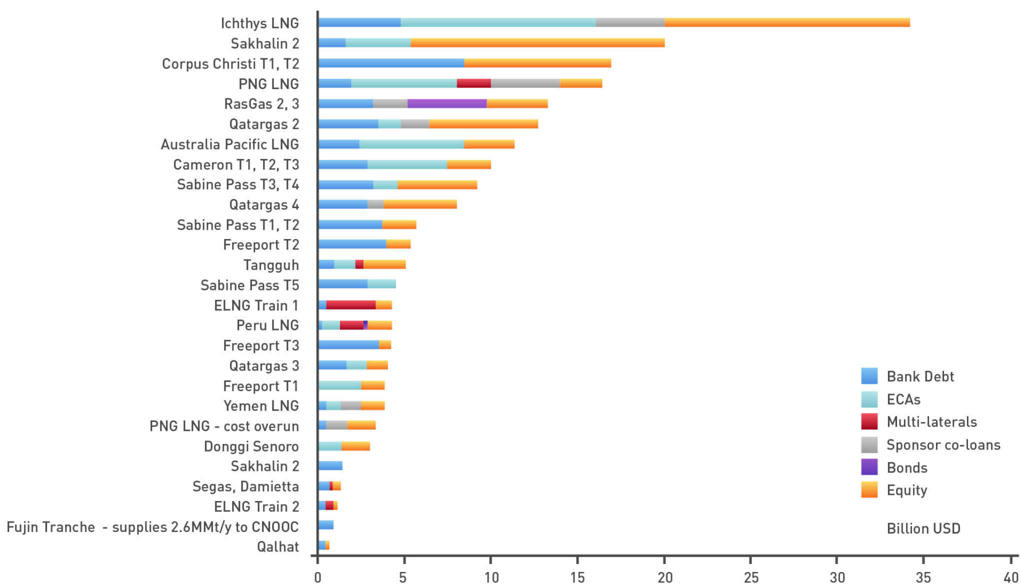
The finance documents, including the mortgage and security documents, will also be carefully reviewed and commented upon by the project lenders and their respective counsel.

Banks will reach a consensus price for the project, expressed in basis points over the London interbank offered rate. Banks also receive other fees for participation, such as up-front fees and commitment fees. When a sufficient number of banks have received credit approval, the financing agreement or term sheet can be signed and the project can move to financial close and the drawdown of funds can begin.

The banks can provide financing as part of a club deal, or there can be a syndication process where a few banks agree to provide funding to the project. They then syndicate this to a wider group of banks. Debt is paid back to the lenders from the project earnings. The loans may be refinanced or repriced to take account of changing market conditions if agreed by the project company and lenders.

Available Funding Sources

LNG projects raise funding from a variety of private and public funding sources as illustrated in the following diagram:



Source: Poten & Partners LNG Finance in World Markets, LNG in World Markets, published company reports.

International commercial banks

Commercial banks have historically been the main providers of funding to liquefaction projects. As projects grew in size due to the need for economies of scale, and thus became more expensive to construct, banks were unable to provide all of the debt required. As a result, more funding sources were tapped. The need for access to other types of funding also became more urgent in the immediate aftermath of the 2008-09 global financial crisis as banks became more constrained due to their increasing internal funding costs. Initially, the problem was the erosion of confidence in banking counterparties - banks stopped lending to each other. Thereafter, constraints arose as a result of tightening legislation enacted to prevent a repetition of the events that triggered the crisis.

The implementation of stricter guidelines has continued. For example, under so-called Basel III guidelines, which are to come into full force by the end of the first quarter of 2019, banks are directed to apply more capital to long-term loans. Project finance loans fall into this category because their tenor typically extends out beyond the Basel III threshold. This is much longer than corporate loans. And it appears that successive revisions of the guidelines, which are published by the Bank of International Settlements, could require the application of more capital against long-tenored loans and loans that are assessed as being of higher risk. A wide range of international commercial banks will invest in LNG project finance transactions, although globally dominant players tend to come from Europe and Asia. But in LNG project finance it is not uncommon to have over 20 banks from several countries lending to a project. Increasingly, banks are selective and will make a decision on whether to provide loans based on whether they see the borrower as a key client who could possibly provide them with further business in the future or ancillary business related to the transaction, such as foreign exchange and interest rate hedging.

International commercial banks will typically provide loans to liquefaction projects in dollars because LNG cargoes are priced in dollars. This minimizes exposure of both lenders and the project entity to foreign exchange risk.

A bank will determine the risk of a project based on its own internally determined country classifications, but it will also take into account many other characteristics of that project. The project will possibly have a lower risk than the country in which it sits if it is being implemented by creditworthy sponsors, has brought in an experienced engineering, procurement and construction contractor, and, crucially, if it has long term offtake or tolling contractors with creditworthy counterparties.

Domestic banks

Domestic banks can be a lot smaller than the international commercial banks which appear frequently on global LNG project finance transactions. They may also have limited access to dollars. However, in some project finance transactions, a separate tranche of loans can be provided in the local currency to allow local lenders to supply funding to the project.

Islamic banks

These banks are governed by Shari'a law and can also provide funding to LNG projects. But this would also be in a separate tranche which would have its own Shari'a compliant structure. However, it would still sit within the debt side of the project financing structure. Islamic banks are mostly, but not exclusively, tapped for funding in countries where common law is Shari'a-based.

Export credit agencies

Export credit agencies (ECAs) became important providers of funding as liquefaction projects grew in size and cost and more sources of funding were required. But after the global financial crisis (see international commercial banks above) they took on an even greater role. ECAs are bilateral lenders and their primary role is to support exports from their host countries. Most of the ECAs supporting projects are from OECD countries. They will be able to participate in a project financing if the project includes content from their host countries. Local content can include equipment, services, expertise and equity participation. They broadly follow similar rules in assessing whether to provide funding and at what level of pricing. The minimum pricing level for all ECAs is determined by looking at commercial interest reference rates and country risk classifications, which are published by the OECD. However, ECAs will also apply discretion when looking at projects. Each project will be assessed on a case-by-case basis. So if the country risk classification is of a certain level, but the project features strong sponsors, engineering, procurement and construction contractors, and most importantly, long-term offtake or tolling by creditworthy companies, the project will have a higher rating than the country in which it sits.

ECAs can support a project in a number of ways. They can provide direct loans, but they can also provide commercial and political risk cover (sometimes up to 100%) for loans to which the banks supply the underlying funding. For loans that are covered by ECAs, the risk to banks then becomes that of the ECA's host country rather than the risk of the country in which the project is located. This has important ramifications for the pricing of the loan since it would be priced based on the ECA's own country credit risk. It should be noted that most ECAs that participate on LNG projects are from OECD countries with high credit ratings. Banks will have to apply less capital, under banking guidelines, to higher rated loans and so ECA cover can help attract more banks to the deal.

ECAs have provided a considerable amount of funding to LNG projects. The Export-Import Bank of the US, for example, over the last 12 years has provided almost $10 billion in direct loans to seven liquefaction projects, These comprise Nigeria LNG, Qatargas II and Qatargas III, Peru LNG, Papua New Guinea LNG, and Australia's Australia Pacific LNG and Queensland

Curtis LNG. NB: Most of this was provided to projects that were using project finance structures, with the exception of QC LNG.

The Japanese Bank for International Cooperation has been a big supporter of LNG projects. Japan is natural resource poor and as it has sought access to LNG, its domestic utilities have participated as offtakers or tolling counterparties or as EPC contractors on projects. For example, JBIC provided a direct loan of $2.5 billion to the Cameroon LNG project and sister agency, Nippon Export and Investment Insurance also provided $1.57 billion of cover to the project. China's ECA, Export-Import Bank of China (China Exim) is increasingly providing funds and cover to LNG projects. China Exim and China Development Bank agreed to provide direct loans of €9.3 billion ($10.54 billion) and RMB 9.8 billion ($1.51 billion) in April 2016 to Russia's Arctic 16.5MMt/y Yamal LNG project. As a result of sanctions implemented against Russia by the EU and US, this is one of the few LNG project financing transactions to receive loans in currencies other than dollars.

Given the large amounts of both cover and funding that can be provided by ECAs, the desire to unlock that support can drive the selection of EPC contractors.

Development Banks

Some come in early to structure projects such as the IFC, the African Development or the EIB. Their roles can include equity participation, due diligence, and benchmarking against international best practices, thanks to thorough social and environmental safeguards, a lending and syndication role as well as offering risk coverage guarantee. In addition, because development banks usually have long-standing relationships with host governments in Africa which may include access to lawmakers, their participation in the project can provide added confidence to lenders as a risk mitigation factor.

The World Bank Group negative pledge clause

When providing loans for infrastructure development projects, instead of taking a lien over the state's assets, the World Bank protects its interests via a broadly-worded negative pledge clause. This clause ensures that any lien created on any public assets as security for external debt that results in a priority for a third-party creditor will also secure all amounts payable by the borrowing state. In short, should such a lien be granted, the World Bank shares in the amounts paid out to the third-party creditor, thus preventing the creditor from enjoying senior creditor status and undermining the value of any later granted lien. As a consequence, the clause undermines the state's ability to engage with other creditors and can end up preventing the state from attracting commercial investment for project financing. This needs to be carefully examined when considering raising debt from the World Bank Group, given the cons might outweigh the pros in assembling the overall debt package for the project.

Sponsor co-loans

These can be tapped for large projects where the funding needs are considerable. Sponsors, in this case, act as debt providers and receive a margin payment for their loans in the same manner as banks. They typically rank *pari passu,* on equal footing, with the other debt providers.

Other providers, debt, and equity

Projects can also raise financing via other means, although these are less common. They can issue bonds, which can sit within the debt side of the project finance structure and rank on an equal footing with other lenders in terms of payback. However, bond investors do not relish construction risk exposure, so bonds are often offered post-construction and are mostly used to refinance bank debt. To issue project bonds, project sponsors will employ a bank or group of banks as book runners. They will promote the project via a 'roadshow' to countries where they expect investor appetite for the project will be strong.

Private equity companies and pension funds are also stepping up participation on LNG projects. Project sponsors can also raise equity for the project through share offers, although thus far this activity in LNG is prevalent in the US.

Impact of Market Shifts on Project Finance

The global LNG industry is undergoing a transformation as technological advances are uncovering massive new gas reserves. LNG infrastructure is changing rapidly with the advent of new technologies, natural gas prices are becoming increasingly decoupled from oil prices, and US LNG exports are introducing new flexibility into global LNG marketing and trading. The number and type of LNG market participants have increased dramatically as lower prices make imports more affordable, with floating storage and regasification units also facilitating the opening of new markets. Short term and spot LNG transactions are making up a greater portion of global LNG trade. The current LNG supply imbalance and low oil price environment have also put downward pressure on global LNG prices.

These changes are impacting LNG project finance. Liquefaction projects are less likely to be structured as point-to-point integrated projects with dedicated shipping where the credit of an investment-grade utility buyer provides the financial underpinning for the entire LNG value chain through a long-term take-or-pay LNG SPA indexed to oil prices. LNG project finance in the wake of this market shift will require innovative structuring and project agreements. Tolling structures with creditworthy tolling customers will likely continue to be used to allocate LNG market risks away from LNG project company borrowers. With respect to integrated and merchant structures, although long-term LNG SPAs will likely continue to be required in spite of the growth of short-term and spot LNG trade and price reopener provisions, international oil companies and LNG aggregators and trading companies are developing shipping and portfolio capabilities that may provide solutions to project lenders.

New countries and companies are seeking to develop new LNG supply projects; construct large numbers of LNG ships; and develop new LNG regasification terminals. Patterns of ownership and project structures are changing and the boundaries of risk allocation between buyers and sellers are shifting. This has a direct impact on the ability to finance LNG projects, at a time when the availability of third-party finance could become squeezed with the implementation of Basel III guidelines which determine how much capital banks must set aside for long-term loans. Moreover, these developments are taking place in an environment of reduced gas prices combined with uncertain price projection scenarios.

Limitations in the availability of third-party debt could lead to greater use of shareholder funds, which in itself will limit the number of companies that can invest in the LNG sector. Projects need competitive lending as a means of mitigating debt costs and improving overall economics. Reduced availability of project finance debt may undermine some LNG project developments. It will also encourage the use of alternative financing structures and expand the role of export credit agencies (ECAs), which are already being used by energy consuming governments as a way of seeking a competitive advantage in sourcing LNG.

On the other hand, there are positive signs for the development of the LNG and natural gas markets, particularly in Africa. First, there are an increasing number of LNG importing countries which provide more opportunities for offtake contracts as well as a diversification of the contracts portfolio to cater for an array of economical and political risks. Second, the reduced LNG price has enabled more customers to access the commodity which provides for an increase in the overall market size and customer base. Third, new technologies such as floating storage regasification units and smaller scale LNG transport mechanisms allow for a more flexible market that can serve a wider array of customers.

Smaller scale LNG also provides a platform for developing the natural gas market in emerging economies. Finally, natural gas has recently been widely recognized as an important cleaner fossil fuel that should play a prominent role in the energy mix towards the shift to clean energies. These trends indicate that the LNG market is maturing and will provide more diverse options for both producing and procuring LNG that could serve a variety of institutional and private customers in Africa.

Risk Management

Introduction

Risk Management and LNG Business

Types Of Risk In LNG

Introduction

Managing risk is important for each organization involved in an LNG project to understand. The host government, local community, project developer, EPC contractor, upstream developer, LNG buyer and financier(s) all have risks they need to understand, manage and mitigate. Risks are generally not eliminated by the decisions that are made, but rather shared between these institutions.

Each entity has certain roles and responsibilities and these come with risks for that party and the other parties. If risk allocation is clear and each entity is responsible for mitigating their own risks, then all parties can confidently proceed with project development. The choice of commercial model, for example, can determine if the LNG project developer bears the upstream cost risk or if that is borne by the upstream entities and whether the allocation of market risks is to the project developer or to a different entity who owns the LNG and takes that market risk.

For an import LNG facility, there is the risk that the local demand and completion of the infrastructure (local distribution, power generation, etc) may not be ready to absorb the imported LNG.

Risk Management and LNG Business

LNG Investment and Risk

Key risk models recognize the intricacies of LNG investment and will also consider risks within Africa. In order to encourage LNG investment in Africa, a robust and effective risk profiling approach is a prerequisite. Price dynamics (Price Risk) will continue to change the fundamentals for key LNG investment decisions, especially in African countries. In today's changing price environment, hedging and managing long-term price risk has become a more complex and challenging part of project implementation.

Unforeseen in-country upstream drilling and completion, facility, pipeline and transportation cost escalation or schedule delays may impact the initial volumes of natural gas available to the LNG facility. This may also be coupled with price dynamics if the transfer price is a factor (for a non-integrated commercial model) that could determine whether an LNG facility bears the risk for upstream capital investment. The costs and completion risks for the LNG plant itself can be shared between the project developer and the EPC contractor.

For the marketing of LNG from an export facility, demand from "traditional" LNG customers is predicated on supply and demand forecasts which are by their nature uncertain, as evidenced by today's LNG supply glut in the marketplace. The four biggest LNG importers, China, India, Japan and South Korea, account for almost two-thirds of global demand but Japan and South Korea are not likely to see significant demand growth in the future. Demand is expected to grow in China and India, but the timing of this growth is uncertain. An alternative for potential African LNG exporters to mitigate market risk may be to pursue a strategy based around smaller LNG export projects. It is worth noting that smaller import market players (< 3 MTPA, Egypt, Pakistan, Eastern Europe, etc) have grown their market share by over 50% over the last two years and now account for more than 10% of global market share. An equal number of smaller markets are actively trying to establish LNG import facilities such as ECOWAS countries, South Africa, Myanmar, and so on.

LNG Risk Structure

When considering LNG investment, it is important to consider the drivers for a successful investment decision through specific risk management methodologies. The primary goal for LNG investment for corporate shareholders is to cost effectively build, and possibly expand the LNG trains or improve export or import capacity, provide at least cost an environmentally sound LNG trains and products stream (LNG, LPG , condensate) for maximum investor return.

LNG Risk Management Methodologies

Methods and tools for portfolio and risk management are locally defined to deliver increased capital efficiency and greater resistance against strategic, operational and market risks. This stage avoids disputes through a proactive and comprehensive framework for managing risks and claims. Risk review supports the project stakeholders' need to understand their tolerance of risk in terms of safety, environmental, financial, reputation, and performance risk in order that risk limits can be appropriately defined and decision-making processes informed.

Types of Risk in LNG

Below is an example of an LNG Risk Register:

Type of Risks	Risk Implication	Risk Mitigation
Market Risk	LNG Market balance and competition	Economic analysis
Political & Regulatory Risk	Policy change, government stability, energy regulatory framework	Engage government as partner to financial and development negotiations
Development Risk	Land rights ownership, FEED study completion, site and land access	Follow known and rigid development processes, leases, contracts, and documentation stages
Financial Risk	Sovereign Guarantees, World Bank guarantees, credit worthiness of LNG off-taker, LNG offtaker financial commitment to upstream, LNG Facility and other auxiliary investment (Power Plant)	Manage financial actions through known, transparent international monetary vehicles. Engage investors willing to support long-term sustainable programs
Environmental Risk	Natural disaster potential, endangered species, air and water quality emissions to populated areas	Follow international environmental standards from World Bank, ISO, and main treaties to mitigate future environmental or regulatory issues

Type of Risks	Risk Implication	Risk Mitigation
Engineering, Procurement & Construction Risk	EPC guarantees and warranties, EPC ability to leverage local content with adequate service delivery, training, and schedule assurance	Engage proven EPCs with track record to include full "sign-off" of EPC terms and Local Content and Social Responsibility mandates
Community Impact Risk	Competition for road access, air, light, dust, and noise impacts, social and cultural impacts, waste disposal, price increase for food, health and sanitation on community	Engage local government, commercial and industry early in development to include full communications planning. Invest early in community-focused programs
Personnel Safety	Worker safety, control of criminal activity, trafficking control	Invest early in community security and safety training programs
Health Impact	Limit community and worker exposure to disease, minimizing strain on healthcare facility availability. Road safety	Invest sufficiently early in community health and education/information programs
Compliance Penalties	Creating a culture of compliance, timely payment of penalties, enforcement of international treaties for compliance (e.g., Child Labor), reporting and monitoring	Develop project management office for full communications, change control, and compliance program requirements
Corporate Reputation	Outreach and reputation to community through low to high tech communications, local content training, community training, primary and secondary school level training, healthcare provisions, revenue investment back to impacted community	Investment in country, community, and communications programs for local and global communications of joint government, corporate, and project successes
Country Reputational Risk	Political reputation federal, state and local, community positive impacts, transparency and visible local investment into society food, water, energy, and human security	Support governmental public policy, marketing, communications and highlight international investment to promote country level success

Below is a sample of a Risk Matrix:

	Most Serious Consequences				
	V. Low	Low	Moderate	High	
Highly Likely	Level 4	Level 5	Level 6	Level 7	HL
Probable	Level 3	Level 4	Level 5	Level 6	P
Unlikely	Level 2	Level 3	Level 4	Level 5	U
Very Unlikely	Level 1	Level 2	Level 3	Level 4	VU
	VL	L	M	H	

Local Content

Introduction

Increasingly, countries are looking for ways to realize the value of natural resources wealth as early in the project lifecycle as possible. At the forefront of this drive is the push for local content policies (LCP) aimed at linking natural resource projects to the deliberate utilization of local human and material resources and services in order to stimulate the development of indigenous capabilities and encourage local investment and participation.

This can result in higher employment, private sector growth through small and medium enterprises (SMEs), increased manufacturing activities due to demand for goods and services, increased export trade, and technology transfer. One important aspect of LCP is the extent to which the output of the natural resource sector generates further benefits to the economy beyond the direct contribution of its value-added, through its links to other sectors.

Many African governments do not have clear policies to capture these benefits. Further, a cursory review of the policy and legal instruments in the region suggests that where policies and laws do exist, the provisions are inadequate to deliver results. For a start, few spell out the mechanisms necessary to capacitate national private and public institutions. Governments need to establish the institutional capacity to help local companies meet industry, technological and safety standards necessary to compete in the global market. Governments also must recognize industry commercial barriers that currently reduce the ability of local firms to compete. Laws and regulations should adequately address institutional, legal and skills requirements for effective implementation and monitoring. Governments must work in close collaboration with local and foreign private sector partners to ensure that policies are implemented in a way that benefits all parties.

This section addresses policy initiatives, stakeholder engagements and infrastructure required for encouraging and facilitating local participation. Training of local personnel, which is critical for the sustainable growth of the industry, is an essential component for local participation and is addressed separately in the chapter on Training in Capacity Building.

Definition of Local Content

There are many possible definitions for Local Content (LC) and it is important for the host country to define local content requirements in a manner that will achieve the policy goals. For example, local content can be defined as the percentage of a product whose added value originates within the country. A more general definition of local content is related to job creation through local procurement, which is the purchasing of goods and services from a local supplier.

It is particularly important to define “local” and “content”. The concept of “local” refers to the geographic footprint that the policy targets as defined by the country’s administrative structures, economic development goal (s) and legal parameters within which the policy will be implemented. It is essential to define these from the outset as they are useful points of reference for guiding policy formulation, establishing targets and predetermining desired economic benefits. Options to define local include:

- The region occupied by the community in the vicinity of the project
- The sovereign state
- A regional economic community (common markets) to which the country is a member.

The definition and intent of "content" may also vary, options include:

- Improving the economies of communities in the vicinity of natural resources projects
- Boosting a country’s manufacturing sector
- Developing national manpower
- Creating R&D and technology centers of excellence
- Boosting the financial sector
- Improving cross-border trade

- Strengthening common markets.

A concise definition of LC is the value created by industrial development through capacity building and promotion of local business to participate in industry operations plus capacity building of local resources for involvement in the industry's companies.

There is a need to have a harmonized definition of local content through different government ministries, and also a clear role and responsibilities for government entities in supporting local content initiatives, as well as the international oil companies (IOCS), national oil companies (NOCS), and private companies to successfully implement Local Content.

Developing an Effective Local Content Policy

In order to define local content policy parameters, short and long-term objectives, as well as managing stakeholder expectations, governments need to compare the capacity of the domestic market against the procurement books and requirements of large companies that invest in the gas industry. The outcome will be the ability to define policy parameters and long-term objectives based on reliable information, as well as the ability to bridge the capacity gap to develop a long-term capacity-building plan in line with the needs. The intention is to ensure the consistency of quality, engineering and maintenance processes across the global operations and provide better reliability and economies of scale. Understanding these requirements is essential for governments and the local private sector to set targets in terms of capacity building to achieve quality standards.

If properly assessed and factored into the decision-making process, the following factors can increase alignment between governments and investors and thereby improve policy effectiveness.

Key considerations are:

- Estimation of the number of jobs created and skills that should be developed
- The structure of global procurement networks in the specific sector
- Identifying the potential capacity gap between the host countries relative to countries from which projects inputs are being sourced as the outcome will enable definition of a capacity building plan.
- Planning for the advancement of local personnel in the investor companies with escalating levels of responsibility
- Understanding the capacity of local businesses

Analyzing the Domestic Market

Analysis of the domestic economy is intended to ascertain the ability of the country's public and private institutions to respond to the opportunities and challenges that the policy creates and to facilitate interventions to bridge the capacity gap. For instance, a focus on employment of citizens provides the opportunity to develop relevant skills. Promoting local content will probably add cost and time to the project, but in the long-run, building local skills will help build local support for the partnership by showing clearer economic benefit to the local community. The absence of such capacity identifies a need for a policy that builds relevant skills to promote employment. In the case of an identifiable skills deficit, the analysis implies the need for the government and the investor to institute corrective measures.

Hence the need for policymakers to consider and assess the following:

- What state institutions exist to enforce policy and monitor performance?
- Can private institutions meet project demand and standards competitively?
- What national firms exist to respond to project requirements for goods and services?
- What are the main opportunities? In many cases, there are quick wins and opportunities that correspond to sectors where the capacity of local SMEs already meets the requirements of the industry.
- What are the main constraints and capacity challenges?
- What levels of resources are necessary to bridge the capacity gap?

This will result in a capacity gap analysis of local SMEs, and individual workers that will pave the way for a roadmap for training.

Implementation of Local Content Policy

Establishing a clear policy direction to guide appropriate legislative and institutional frameworks is key. The goal is to align the policy, legal and institutional frameworks with desired outcomes.

An important consideration in defining the policy and regulatory framework is to maintain attractiveness to foreign investors, given the large capital investments necessary to develop gas projects. A particular consideration is stability and predictability of the legal framework, sometimes more important than the requirements themselves.

Different options are available:

- **Prescriptive policies** that are designed with explicit legal percentage targets for investors to comply with. This approach assumes the ability of state institutions to oversee the activities of investors and ensure compliance with the laws. It also assumes the capacity of governments to monitor project sponsors' activities. Experience has proven that this route can sometimes be challenging and negatively impact the development of the sector if the goal is set too high at the outset and exceeds the local capacity at the time. Policies should be monitored and reviewed if goals are demonstrated to be too ambitious. Changes need to be made in close consultation with the local and foreign private sector partners.
- **Incentive-based policies** that provide guidelines to sponsors of ways (and areas) in which to increase local content in accordance with legal requirements. Through incentive schemes, investors are encouraged but not compelled to increase local inputs to projects. The approach assumes that the incentives provide investors with sufficient motivation and that in return the State is adequately compensated through the resulting increase in domestic economic activity. The

approach recognizes the competitive nature of resource projects. It acknowledges the potential for host countries to use the incentives as an additional vehicle to attract foreign firms to relocate in the country and encourages project sponsors to seek out local suppliers and service providers. Australia is often cited as a good example of this. Incentive-based policies can be more difficult to monitor and enforce to ensure that government goals are achieved.

An example of how local content can be deployed is indicated below in the case of Angola. This example is not intended to judge whether this level of local content was good or bad with respect to development of their LNG project.

> Mandated percentage of nationals in a foreign company's workforce

> List of goods and services reserved for nationally-owned vendors only (Exclusivity Regime)

> List of goods and services requiring partnerships with foreign companies and local companies (Semi-Competitive Regime)

> List of goods and services with no restrictions - these require heavy capital investment and/or specialized know-how (Competitive Regime)

> Local Content integrated into contract award by operators implementing their own tender procedures.

Another example of local content would be the following provisions in Tanzania's 2015 Petroleum Act.

> A license holder, contractors and subcontractors shall give preference to goods which are produced or available in Tanzania and services which are rendered by Tanzanian citizens or local companies.

> Where goods and services required by the contractor, subcontractor or license holder are not available in Tanzania, such goods and services shall be provided by a company which has entered into a joint venture with a local company.

> The local company referred to in subsection shall own a share of at least twenty-five percent in the joint venture or as otherwise provided for in the regulations.

- A license holder, contractor and subcontractor shall prepare and submit to the regulator a procurement plan for a duration of at least five years indicating among others, use of local services in insurance, financial, legal, accounts and health matters and goods produced in Tanzania.
- A license holder, its contractors and subcontractors shall ensure that entities referred to in subsection notify the regulator on matters of:
    - quality, health, safety and environment standards required by license holder and contractor;
    - upcoming contracts as early as practicable;
    - compliance with the approved local content plans.
- The local entities shall-
    - have capacity to add value to meet health, safety and environment standards of petroleum operations and gas activities carried out by license holder and contractor;
    - be approved in accordance with criteria prescribed in the regulations.
- Within sixty days after the end of each calendar year, the license holder shall submit to the regulator a report of its achievements and its contractors and subcontractors' achievement in utilizing Tanzanian goods and services during that calendar year.
- The license holder shall submit to the regulator:
    - a report on the execution of a program under this section as prescribed in the regulations;
    - a detailed local supplier development program in accordance with approved local content plan.
- For the purpose of this section "local company" means a company or subsidiary company incorporated under the Companies Act, which is one hundred percent owned by a Tanzanian citizen or a company that is in a joint venture partnership with a Tanzanian citizen or citizens whose participating share is not less than fifteen percent.

An equally important institutional consideration is the Government's capacity to enforce and monitor these requirements. This requires an outreach capacity at national level, sometimes in remote site locations, as well as regular consultations with local private sector and international investors specifically on the issue of local content. This is sometimes overlooked and doing so undermines the efficiency of the policy as well as the ability to test its effectiveness.

At some stage, it may be necessary to pass a law to ensure that local content policy is properly documented and approved by the whole government and to ensure that it is more difficult to modify policy without consulting with required stakeholders. This law should be formulated in close consultation with stakeholders. When drafting the law it is important to again analyze the government and local private sector capacity to monitor and implement rules and regulations established or mandated by the law.

Stakeholder Engagement

The success of local content policies depends both on the leadership role of governments and the active participation and commitment of private sector project sponsors. There are several other constituents that are also essential for policy effectiveness.

In many ways, the success of any local content policy depends on the alignment of stakeholder views and expectations. On the other hand, success itself can be measured by a policy's ability to meet stakeholder expectations. Therefore, the mapping of stakeholders' concerns is essential at each stage because it ensures that their perspectives and potential contributions are taken on board.

Therefore, the government and also the project sponsors should engage (or consult) key stakeholders to ensure buy-in. In relation to government institutions, the engagement ensures role clarity, complementarity and reduces chances of institutional peer rivalry. In terms of capacity building, the consultations enable the government, investors, and industry associations to agree on areas of responsibility for bridging the market capacity gap and setting local supply targets. It also enables the parties to align national manufacturing (service) standards with international norm. Some of the main stakeholders are:

- Local entrepreneurs
- Implementation and regulatory arms of the government
- Training institutions
- Industry associations
- Financiers
- Development partners
- International trade organizations

Managing expectations is important throughout the life cycle of the project. It is important to provide clear information to local populations before development is underway to allow them to understand the project and the impact on their community. These major projects can involve people from outside their community to come in, disrupting local customs, road traffic, and so on. It should be made clear what is envisioned and when and how the community will benefit from providing goods and services and sharing potential revenues, as determined by the national government. The communication method for managing expectations can be through newspapers, speeches, radio announcements, internet postings, pamphlets, or other media.

Ancillary Infrastructure Development

Large gas projects require infrastructure development. This infrastructure may include roads, bridges, ports, berths, temporary and/or permanent housing, schools, medical clinics, and so on, and will need to be provided by the project developer and/or by the national or local governments. In most instances, these infrastructure developments, such as access roads or port infrastructure, are both multi-user and multipurpose, which means they can be used by local entities for purposes other than servicing the gas project, and this can boost regional connectivity and trade. If the project developer pays for these items, then these contributions will be included in the local content calculations.

In addition, no matter who pays, the construction will employ local workers and involve opportunities for local goods and services to be utilized. Many of these facilities can be solely designed and constructed by local citizens, but some may require outside specialists to ensure technical quality specifications are included and met. In addition, early planning of infrastructure developments is recommended, especially in the case of multiple project developments. The objective is to rationalize infrastructure development through early planning, rationalize cost, and maximize the economic development outcome for the local private sector and communities.

The timing of planning, permitting, and construction of these facilities must be closely coordinated between the project developer and government entities, at all levels, to ensure that the overall project schedule is not negatively impacted by the timely completion of critical path items.

Managing Expectations

African countries generally lack employment opportunities and the required numbers of skilled/qualified human resources with experience in the oil and gas industry. The small number of job openings and the lack of local residents with required skills in local communities where projects are being built can contribute to dissatisfaction and often contributes to social conflicts.

Implementation of local content strategies can be a means that some governments, international oil companies, and stakeholders can use to increase employment opportunities for local people, as well as business linkages between oil companies and local SMEs, particularly those located where the project is developed.

Job opportunities can be offered to the communities over time through local content policies that will increase capacity through local recruitment, training, and purchasing of local goods and services.

Local content can contribute to the fulfillment of expectations that the exploration of oil and gas will help to improve the lives of local communities. Local content policies can also be seen as an important instrument to the oil and gas industry's operational sustainability by helping industry earn the social license to operate within the community.

Other options to manage expectations are:

- Engagement with local communities early in the project development stage in order to access employment and businesses opportunities available for local communities.
- Development of a transparent communication plan highlighting the expected timeline of all these opportunities, including information regarding the collection of revenues and creation of job opportunities.

> Investments from the government side in the provision of poverty reduction, public good, education, literacy, and healthcare which will contribute to the improvement of human capital in the long term.

Comparing Local Content Policies

Country		Angola	Brazil	Ghana	Nigeria	Mozambique
Maturity of E&P in Country	Mature E&P Industry	x	x		x	
	Frontier E&P Region			x		x
Recruitment and Training of Nationals in Workforce	Maximize Nationals - no targets				x	
	Targets for Nationals	x			x	x
	Targets for Different Positions			x	x	
	Positions Restricted to Nationals	x			x	
Sourcing of Local Goods and Services	Preference Local Goods and Services only if Competitive					x
	Margin of Domestic Preference	x		x	x	x
	Guideline Targets for Procurement of Local Goods and Services					
	Mandated Targets for Procurement of Local Goods and Services		x	x	x	
	ICV Leveraged during Tendering Process			x	x	
Development of Domestic Supply Chains	Requirement to Develop Domestic Suppliers	x		x	x	
	Incentivizes to Develop Domestic Suppliers			x		

LNG Import Projects

Introduction

Project Development

Import Commercial Structuring

Commercial Agreements

Financing Import Terminals and FSRUs

Introduction

LNG importation requires regasification import terminals consisting of receiving, storage, and regasification facilities. These LNG import terminals can be land-based, as are most of the existing terminals in Europe, Japan, and Korea. However, offshore terminals have also been constructed and come either as gravity-based terminals, such as the Italian Adriatic LNG Terminal or as floating storage and regasification units (FSRUs). FSRUs have been developed more recently and offer substantial cost-savings vs land-based LNG regasification terminals. In Africa, most of the existing or planned LNG import terminals are envisioned to be FSRUs.

The advantage of the FSRU is flexibility since it can be relocated to another location if it is no longer needed. This can also help countries that have gas reserves that will take some time to develop. They can use the FSRUs as a bridge allowing them to import until they produce their own gas. FSRUs are quicker to deploy to market, especially if they are converted from LNG carriers as opposed to being newly built. They are also cheaper than land-based terminals, costing around $250-400 million depending on the regasification capacity and onboard storage. Floating storage units (FSUs) can also be combined with onshore regasification units.

The LNG-to-power sector, where LNG import projects are coupled with power generation facilities, is undergoing a rapid expansion. Many of these are favoring FSRUs. FSRUs could help fuel more than 15 GW of new power generation capacity expected to start up globally over the next five years. If all of these projects go forward, FSRUs could handle up to 27 MTPA of new LNG demand.

Project Development

For importation of LNG to a gas-consuming market, an LNG regasification terminal is required for receiving, storing, regasifying, and delivering the gaseous LNG into a pipeline for delivery to the end-user.

The Project Development consists of the following considerations:

- **Import Demand Assessment:** An assessment is conducted of the prospective supply and demand for the target natural gas market. The portion of the demand that is not satisfied by domestic supply would need to be met by LNG import.
- **Economic Assessment:** It is also important for the customer to perform a comparative economic assessment of the LNG with that of an alternative fuel, if available, to determine the viability of the LNG import. For example, if the power plant's alternative fuel is an oil product, such as diesel, the delivered LNG price would have to be competitive with the prevailing price of the alternative fuel.
- **Land Based vs. Floating Infrastructure:** In the past, regasification terminals have been exclusively land-based. However, recent developments in marine LNG technology now offer a range of floating regasification facilities which are currently finding favor, especially for small-to-medium scale regas demand. These solutions focus on FSRU technology, but variations including floating storage (FSU) with land-based regas, or a combination of storage, regas and power generation (FSRP) which encompasses a total gas to power solution. These options typically offer lower cost, more flexible financing, and greater optionality. In contrast, a land-based terminal would typically consist of 1) an LNG berth and jetty, with a breakwater if required, 2) a regasification facility normally with aerial coolers, and 3) LNG storage tanks. Analyses are conducted to determine the size of the terminal and location and future expansion options. Locations are determined

based on proximity to end-user markets and pipeline access to such markets.

Key Considerations for an FSRU

- **Determination of Size:** LNG storage and regasification units could have lengths of 100m-300m with storage capacities on the order of 20,000 - 263,000 m3. The gas send-out volumes typically vary from 50 MMscfd to about 750 MMscfd and the associated tariffs usually decrease with increasing send-out volumes. Additional storage could be provided in the form of a floating storage unit (FSU).
- **Location Selection**: The choice of berthing location for the FSRU and the LNG tankers is driven by the location of the targeted market, the meteorological conditions at the port of interest and the availability of local offtake infrastructure including pipelines.
- **Selection of Type of Facility:** Delivered cost of the gas would be affected by the choice of technology employed for the reception and handling of the LNG cargo. FSRUs could be moored close to the port with a jetty and breakwater (if required) or moored in the open sea, typically about 15-20 km offshore, with an associated marine pipeline to bring the regasified LNG to shore.
- **Tariff:** The FSRU in a tolling commercial structure, which is generally built and owned by an independent third party, normally charges a tariff for the regasification service based on contract volume.
- **Gas Price:** Ultimately, the final delivered gas price to the end-user under a tolling commercial structure would be the sum of the LNG price (ex-ship) plus the FSRU tariff plus the cost of transport and handling facilities to the battery limit of the end-user (e.g., a power plant). For example, if the LNG price is $6.00/MMBtu, and the FSRU tariff is $1.50/MMBtu and the transmission tariff is $0.20/MMBtu, then the total delivered gas price is $7.70/MMBtu. For LNG to be competitive, the total delivered price must be less than the alternative fuel price.

Project Development

Independent of the choice of technology (floating or land-based) the following developmental stages will need to be followed:

> **Pre-FEED/Project Definition**: This phase of the project would typically focus on high-level supply/demand, economic feasibility, and project structuring alternatives, prior to investing significant funds in a more detailed project design process

> **FEED:** A FEED is conducted to define in detail the facilities to be installed, and to develop a FEED package suitable for competitive tendering for the EPC. The FEED phase lasts approximately 12-18 months.

> **EPC Bidding:** The FEED package provides the basis for a competitive bid for the EPC. The EPC contractor is selected based on technical and financial assessments. The EPC contract is awarded after all regulatory requirements and permits have been approved, the Gas Sales Agreement, LNG Purchase Agreement, and financing arrangements have been executed, and a final investment decision (FID) has been taken.

> **EPC Stage:** The EPC work for the terminal and the associated pipeline facilities is completed generally within a 2-3 year timeframe and the facilities commissioned.

It should be noted that sometimes FSRU units can be delivered and commissioned more quickly if a vessel exists for lease, if the customer already has the infrastructure in place, and/or the customer already has a well-developed gas market. It is still important to follow the project development steps.

Import Commercial Structuring

Introduction

Project structuring is a critical element of a successful LNG import project. Given the magnitude of the required capital investment and the length of the period of commercial operations, the risks associated with each import project and the functions for the project participants need to be carefully defined and allocated in order to allow debt to be paid off and to generate sufficient returns for investors. It is important to structure each import project correctly from its inception to anticipate project risks over time, to avoid misalignments between stakeholders, and other risks to the project's success.

The structure chosen for each LNG import project will have ramifications for the allocation of the project's risks and the roles of the various project participants. It will also have an impact on whether the project is able to attract further equity investors, if needed, and raise debt funding from financiers. The structure can impact project agreement pricing and financing costs because the allocation of risk generally involves a rate-of-return or pricing tradeoff.

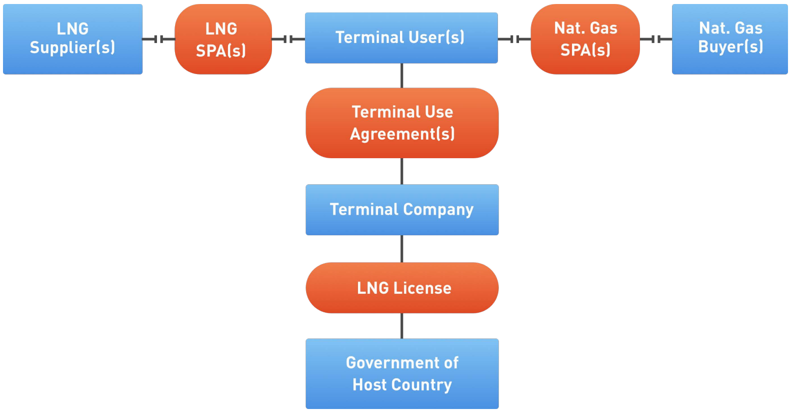
Choosing a Commercial Structure

As with LNG export projects, three basic forms of commercial structures have emerged for LNG import projects - tolling, merchant and integrated. There are hybrid variations of these three models and the potential exists for further changes in the future, but these three structures are the basic prevailing structures currently being used for LNG import projects.

Tolling Commercial Structure

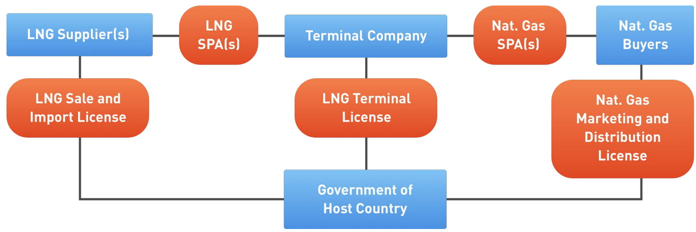
Under the LNG import tolling commercial structure, the user or users of the LNG import terminal are different entities than the owner of the LNG import terminal. The LNG terminal company need not buy LNG or sell natural gas, but rather provides regasification services (without taking title to the natural gas or LNG) under one or more long-term terminal use agreements. The LNG terminal company revenues are derived from tariff payments paid to the LNG terminal company by the terminal users. The payments typically take the form of a two-part tariff: (1) fixed monthly payments cover the LNG terminal company's debt service, return of and on equity, and fixed operation and maintenance costs, and (2) variable regasification service payments are designed to cover the terminal company's variable operation, maintenance and other costs, such as the terminal's power costs. Because the functions of the LNG terminal company generally do not include a commodity merchant function, the LNG terminal company does not bear material commodity merchant risks such as the supply, demand, and cost of LNG and natural gas. The credit of the terminal user or users provides the financial underpinning for the LNG terminal company. Import project tolling structure examples include the Sabine Pass, Freeport, Cameron and Cove Point LNG import projects in the US, the UK's South Hook LNG import project, and Italy's Adriatic LNG import project.

The tolling commercial structure as applied to LNG import projects may be illustrated as follows:



Merchant Commercial Structure

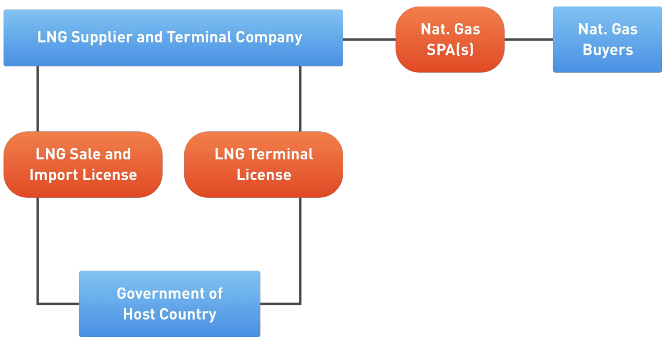
Under the LNG import merchant commercial structure, the LNG supplier and the natural gas marketing or distribution company are different entities than the owner of the LNG import terminal. The LNG import project company purchases LNG from the LNG supplier under a long-term LNG sale and purchase agreement, and sells regasified LNG to the natural gas marketing or distribution company, or directly to a power station, under a long-term natural gas sale and purchase agreement. The LNG import project revenues are derived from the amount by which the revenues from natural gas sales exceed the sum of the cost of regasification (including debt service) and LNG procurement costs. Because the LNG supplier is a different entity than the owner of the LNG import project, there may be more than one supplier of LNG to the LNG import project company, and because the natural gas marketing or distribution company is a different entity than the owner of the LNG import terminal, there may be more than one purchaser of natural gas from the LNG import project company. The credit of both the LNG supplier or suppliers and the natural gas purchaser or purchasers provides the financial underpinning for the LNG import project. Merchant structure examples include the US Everett Massachusetts LNG import project, India's Petronet Dahej and Kochi LNG import projects, and Shell's Hazira LNG import project in India. The merchant commercial structure for LNG import projects is illustrated in the diagram below.



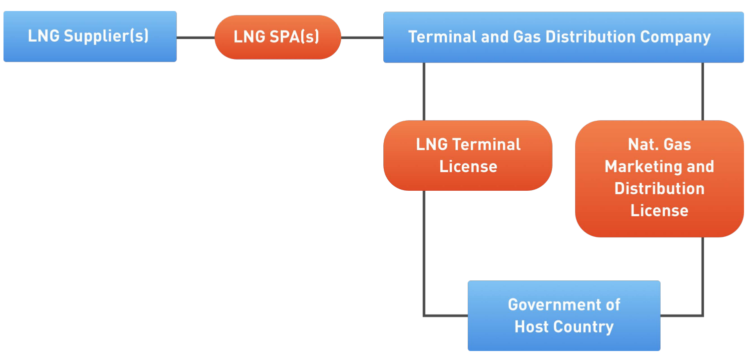
Integrated Commercial Structure ("Merchant +")

The project development for this structure is the same as under the Merchant Structure, except that the terminal is owned by an entity that undertakes a wider role in the LNG chain; e.g. a power plant (TEPCO) or a gas distribution company (Tokyo Gas) or the LNG export company (e.g. RasGas for the Adriatic LNG Terminal). The ultimate commodity sold may be the product of the company; thus gas, power or steel, as in the case of Tokyo Gas, TEPCO or Pohang Iron and Steel Company (Posco), respectively. As with the development under the Merchant Structure, a FEED package is developed, sent out for bid, and an EPC contract award is made to the successful bidder after all commercial agreements and permits are in place and a Final Investment Decision has been taken. After completion of the terminal by the EPC contractor, the terminal is commissioned and placed in service. Under the LNG import integrated commercial structure, the owner of the LNG import facilities is also either the LNG supplier or the natural gas marketing or distribution company (or perhaps a power producer). The project revenues for both commercial functions are integrated into one entity such that there is no need for an LNG SPA for delivery at the terminal with respect to integrated structures that combine the LNG supply and import terminal functions. There is no need for a natural gas sale and purchase agreement for delivery at the tailgate of the terminal with respect to integrated structures that combine the import terminal and natural gas marketing or distribution functions (and perhaps the associated power producer function). Because the LNG supplier or the natural gas distribution or marketing company is the same entity as the owner of the LNG import terminal, there is typically no other user of the LNG import terminal. Examples of the integrated commercial structure for LNG import projects are reflected in the diagrams below.

Upstream integrated structure:



Downstream: integrated structure



Hybrid Structures

Hybrid structures combining some of the attributes of tolling, merchant, and integrated models may be used to tailor LNG import projects to the characteristics and needs of particular host governments and project participants. For example, hybrid merchant-tolling structures may be used to allow the LNG import project company to take title to the LNG and sell natural gas, but receive fixed monthly reservation charges regardless of whether their customers utilize regasification services and actually import LNG.

Commercial Structure Checklist

Commercial Structure	Advantages	Disadvantages
Tolling	• Known and commonly used structure familiar with LNG industry participants • No price or market risk for the LNG import project company or its project finance lenders • Allows ownership in the LNG terminal company to be different from ownership in the LNG supplier or natural gas marketing or distribution company	• Requires scheduling alignment of not only the LNG SPA and natural gas SPA but also the tolling agreement • Need to determine competitiveness of price of the tolling services • Unbundling terminal services from commodity/sales services reduces commercial efficiency
Merchant	• The terminal user merchant function is aligned with the terminal owner and operator function because they are performed by the same entity • Flexibility to allow non-LNG supplier or natural gas distribution investors in the project company	• Requires additional project agreements • Requires negotiation of LNG or regas transfer price • Project financing must address risks associated with the commodity merchant function
Integrated	• Commercial parties are perfectly aligned along the value chain • No need to determine a transfer price	• Complex to include other entities • Project financing must address risks associated with the non-import integrated function
Government Owned	• Owner (government) has full control	• Government may lack experience in developing, marketing and operating LNG import facilities • Government responsible for 100% of equity and equity risk

Driving Factors in Choice of Structure

There are a number of key driving factors that influence the choice of an LNG import project structure for the host government, the investors, the natural gas buyer(s), the project lenders and the other project stakeholders. Some of these key driving factors include:

- **Legal regime and taxes**: The host country legal regime and local taxes often have a major impact on project structure. An LNG import project may fall under different legal regimes in the host country, depending on whether it is integrated with LNG supply or gas distribution functions, acts as a merchant, or acts solely as a terminal owner and operator, e.g. general corporate regime, special mid-stream regime or downstream regime. Additionally, the tax rates may differ for LNG importing, terminal operation, and natural gas marketing and distribution.
- **Governance:** The government, local stakeholders, lenders and the LNG buyers may desire to have more of a direct say in the internal governance and decision making in one import function than another import function. This needs to be reflected in the structure selected. A poorly governed structure in any of the LNG supply, terminal ownership and operation, or natural gas distribution components of the LNG import chain can lead to conflicts among the parties and impact the efficiency and reliability of the LNG import project.
- **Efficient use of project facilities**: The LNG import project structure should encourage efficient use of all project facilities and activities by the project owners and by third parties. In determining the optimal project structure for LNG imports, consideration should be given to the costs and benefits of sharing common facilities, open access to third parties for spare capacity, and reduction of unnecessary facilities and their related costs.
- **Flexibility in Ownership**: There may be a desire by the government, other local stakeholders, LNG buyers, or lenders (e.g. IFC) to have a direct ownership interest in all or specified portions of the LNG import chain. Alternately, some of the participants in the commodity chain may not be interested in owning an interest in the LNG terminal company. The choice of a particular structure can enable different

levels of ownership in companies performing different components of the LNG import chain.

- **Desire for Limited Recourse Financing**: In general, the cost and complexity of project finance are reduced when the functions and risks of the project company borrower are reduced. Consequently, utilizing an LNG import project tolling structure should facilitate project financing by shifting commodity merchant functions and risks away from the terminal company.
- **Operational Efficiencies**: The integrated structure offers operational efficiencies because only one operator is involved in construction, operating and scheduling activities. The operational inefficiencies of having two operators may be overcome through transparency and coordination between the operators. In addition, separate projects can lead to project-on-project risk i.e. where one project is ready before the other or a default relating to one project jeopardizes another project.
- **Regulations**: The choice of project structure will affect the required regulations.
- **LNG and Gas transfer prices**: The LNG transfer price is the price of LNG sold by the LNG supplier or suppliers to the terminal company in a merchant structure. The natural gas transfer price is the price of natural gas sold by the terminal company to the natural gas buyer or buyers in a merchant structure. These are often contentious commercial points. In addition, each segment of the gas value chain may fall under a different tax regime such that the prices may need to comply with an arm's length standard to comply with tax transfer pricing laws and regulations.

Commercial Agreements

Introduction

LNG import projects require different types of contracts at different stages in the LNG import value chain. While a significant number of these contracts are negotiated between private parties, some of the most important ones involve host governments or may be regulated by the host government.

In that context, an understanding of the different types of contracts, their place in the LNG import value chain, and the development of the project, are important. Particular attention should be paid to the technicality and complexity of these contracts. The objective is that governments can prepare effectively for these negotiations, build necessary knowledge to make informed decisions and create dedicated negotiations teams. In addition, contract implementation is equally important and host governments should also build capacity and dedicate resources.

This section aims at providing an overview of the different types and categories of contracts in order to enable governments to prepare accordingly.

LNG Sale and Purchase Agreement

The LNG Sale and Purchase Agreement (SPA) needed for the LNG feedstock for an LNG import project utilizes the same form of agreement discussed in the chapter entitled LNG Sale and Purchase Agreement. The LNG purchaser will, of course, try to negotiate any project-specific terms and conditions in the SPA.

It should be noted that, from the perspective of the project company, an LNG SPA will not be needed in the integrated LNG import commercial structure, which includes the upstream and/or liquefaction developer, or in an integrated tolling LNG import commercial structure. In these structures, the user of the LNG import project already has title to LNG. In the merchant LNG import commercial structure, or the integrated LNG import commercial structure, which includes the downstream user of the LNG, an LNG SPA is required by the project company.

Facilities Use Agreement

In the tolling LNG import commercial structure, an agreement is needed between the user of the terminal and the terminal project company for the use of the terminal. This agreement, which can go by many names, entails the terms and conditions for the use of and payment for specific services offered by the terminal. The key terms to focus on are: the nature and quantum of services to be used; how services can be performed for other customers and what happens in the event of a conflict between customers; the terminal fees and charges for the services (explained in the chapter on Import Commercial Structuring); fuel and lost or unaccounted-for gas; scheduling for LNG receipts; term; LNG vessel requirements, berthing and unloading details; receipt and storage of LNG and redelivery of regasified LNG; invoicing and payment; liabilities; taxes; insurance; and curtailment of services.

Operations and Maintenance Agreement

Depending on the commercial structure of the LNG import project, the terminal owner may elect to engage a third party to actually operate and maintain the terminal. The Operations and Maintenance Agreement (O&M) should include: the services and scope of the services to be provided; the standard of performance; the term of the agreement; the responsibilities and liabilities of the operator and the terminal owner; budgets and necessary costs; payments and incentives to the operator; employees, including local employees, and services, including local services, to be used by operator; rights to suspend and terminate early; and owner's rights to monitor and inspect.

Natural Gas Sales Agreement

The Natural Gas Sales Agreement for the sale of natural gas out of an LNG import project utilizes the same form of agreement discussed in the chapter on Domestic Gas Sales Agreements. While many areas of a GSA are important, the key terms to focus on are: the commitment of the buyer to purchase natural gas and whether there is a take-or-pay obligation; price and payment terms; ability of the buyer to withhold payment or dispute invoices; what constitutes force majeure for the buyer; liability for natural gas that is off-specification; and the LNG import project's liability for delivery shortfalls.

It should be noted that a GSA will not be needed in the integrated LNG import commercial structure, which includes the downstream user of the LNG because the LNG import terminal user is using instead of selling the natural gas.

Port Use Agreement

LNG import terminals often fall under the jurisdiction of a particular port and are subject to the port's port use agreement. Where the terminal is considered its own port, the terminal will adopt its own port use agreement. The port use agreement is a set of rules and requirements applicable to all vessels using the port and address a variety of operational and other topics, including responsibility for damages and other liabilities. The LNG import terminal is then responsible for ensuring that each LNG vessel calling at the terminal agrees to comply with the port use agreement.

Power Purchase Agreement

In many situations today, an LNG import project will be bundled with a power generation option. In such situations, the output of the LNG import project may include electricity. In these situations, a Power Purchase Agreement will be required. To better understand Power Purchase Agreements, please refer to publication Understanding Power Purchase Agreements at the following link:

http://cldp.doc.gov/sites/default/files/Understanding_Power_Purchase_Agreements.pdf

Financing Import Terminals and FSRUs

Onshore LNG import terminals can be financed in a similar manner to liquefaction facilities, typically on a project finance basis. The main difference between land-based regasification terminals and liquefaction facilities is one of scale and cost. Liquefaction facilities cost multiples of billions of dollars, while land-based regasification terminals typically cost to the order of $500 million or more, depending on their regasification capacity, the amount of storage included, and the associated infrastructure that is needed. FSRUs are gaining ground over land-based terminals because they cost less to build.

For onshore import terminals, project finance structures are often used and the lenders to the project generally come from the same sectors that appear on liquefaction projects. The project company may raise the financing from international commercial banks, local banks, development banks, and export credit agencies, etc. Given that LNG import facilities will earn money in local currency, they will be more likely to attract domestic bank participation, if they are sufficiently liquid. For example, in April 2015, a group of 11 Indian banks provided 35.287 billion rupees ($560 million) to fund the 5 MTPA Mundra LNG import project in India's Gujarat state. The project has a total cost of around $730 million and is being sponsored by government-owned Gujarat State Petroleum Corp and Indian conglomerate Adani Enterprises.

Given the positive socio-economic importance of getting gas to underserved and remote locations, development banks will often fund LNG import projects. They will provide funding to land-based terminals, and may also fund infrastructure associated with FSRUs, such as pipelines, jetties, and berthing for LNG carriers. For example, Elengy Terminal in Pakistan, which is a fully-owned subsidiary of domestic company Engro Corp, attracted funding from the IFC and the Asian Development Bank to fund its FSRU-based import operations at Port Qasim. The project cost was $130 million and IFC provided $7.5 million for an equity stake and a loan of $20 million, while ADB provided a loan of $30 million.

For import terminals, funding risk will still be mitigated via the use of long-term contracts, but, in this case, the LNG that comes into the receiving terminal will be sold as gas to power operations and other end-users. Similar due diligence procedures and financing processes will apply. As with liquefaction projects, lenders will look at the features of each project on a case-by-case basis to assess risk (see the chapter on Financing an LNG Export Project).

FSRU Financing

For FSRUs, different financing considerations apply because they are typically chartered to the importing entity from a shipping company and the shipping company will raise the financing. This has the advantage of reducing upfront project expenditure. The project company will, however, have to take a view on whether the life of the charter would make a fixed import terminal more cost effective.

When the first FSRUs started up in 2005, there was a pain barrier to go through as lenders had to assess the technology risk, which was not new, *per se*, but compressed into a smaller space and floating. But the industry now has a good track record and financiers see FSRUs as secure earners because they are usually on long-term or medium-term charters that allow for debt servicing across long-term repayment profiles.

FSRU charters are typically not less than five years and are often renewed after that initial period. This makes it easier to arrange long-term financing. Financiers will sometimes provide financing for FSRUs that do not have a charter, but the loans are priced higher due to the greater risk the lender is taking on. But when they finance uncommitted FSRUs, lenders have to be confident that they will secure a creditworthy charterer. So they will only lend to creditworthy shipping companies with a good track record in the FSRU sector. Hence, they will be assured that the company will be able to place its unit in the market.

While there are only a small number of companies that offer FSRU units for charter – which currently include Excelerate Energy, Golar LNG, Hoegh LNG, Exmar, BW Gas and MOL (and Gazprom which had one unit on order in 2016), others are looking to break into the sector. The funding methods used by the select group of FSRU providers are diverse. Shipping companies have managed to attract funding from banks in the form of loans, both loans and political/commercial risk insurance cover from export credit agencies (ECAs), and also backing from retail and professional investors who have bought the company's shares or bonds. Bank and ECA support for FSRUs can be structured as project finance where a special purpose vehicle is created for the FSRU and the revenue is paid back from the proceeds from its charter, or provided directly to the company for the FSRU in a corporate finance transaction.

Some of the shipping companies have master limited partnerships (MLPs), which are a US tax-advantaged structure with partnership units traded on US stock exchanges. Like LNG carriers, FSRUs can be placed into the MLPs. As FSRUs are often manufactured in Korea shipyards, Korea export credit agency funding, from KEXIM and K-SURE, is widely utilized. Increasingly, Chinese financiers are providing funding, often through lease or sale and leaseback transactions. Golar LNG received an underwritten financing commitment in October 2015 of up to $216 million for the newbuild FSRU Golar Tundra from China Merchants Bank Leasing. The Golar Tundra has been chartered to West African Gas Limited's project in Ghana for an initial period of five years, with the option for a five-year extension.

Financing LNG-to-Power

The LNG-to-power sector, where LNG import projects are typically based on FSRUs coupled with power generation facilities, is creating considerable interest in Africa.

Independent power projects have a long history of successfully attracting funds using project finance structures. This implies that off-take is guaranteed by the government, a government entity or a creditworthy utility and their steady earnings over long periods – power purchase agreements can span out beyond 20 years – allowing for debt servicing over long payback horizons. This approach can be applied to LNG-to-power, although given the extra components, a number of structures could be used. A single project entity could develop the power and gas operations and raise funding as one entity. Separate project entities could develop the power and gas facilities, and the gas could be bought from the LNG providers and regasified via a tolling contract. Funds could be raised separately or as a single financing with the gas and power entities both taking the borrowers' role. In a third possibility, gas is sold directly to the power company and the financing is raised by each entity separately.

One of the main hurdles to overcome is project-on-project risk. If the gas facilities or FSRU are late, the power project will be unable to operate. Or if the FSRU is ready but the power project is delayed, the FSRU will be unemployed. Usually, the risk of delay in completion of the power project is shouldered by an engineering, procurement, and construction contractor via a lump-sum turnkey contract, and by the shipyard for an FSRU, but the two would be unable to assume risk across both components of the project. Typically the power project, not the FSRU, is delayed. This can be dealt with by operating the vessel as an LNG carrier while waiting for the power project to start operating.

Risk can also be minimized by scheduling that allows sufficient time for the power plant to start operating, and possibly by providing flexibility over the initially contracted volumes before any take-or-pay clauses kick in. The power plant may also need backup fuel supply if there are delays in the FSRU's arrival.

Many shipping companies are participating in different parts of the LNG infrastructure chain, including the conversion of LNG carriers to floating liquefaction/regas vessels. Golar LNG is providing infrastructure further down the LNG chain to the power sector. For its newly created unit Golar Power, the company attracted private equity investment from New York which demonstrates the increasingly dynamic nature of the sector. Oil and gas majors, utility companies and EPC contractors are also looking to invest downstream in power to encourage market development for LNG.

New and Emerging LNG/CNG Markets

Introduction

LNG and CNG markets are emerging where they have not traditionally had a presence. This is a result of three primary factors - first because of the environmental benefits of natural gas with respect to both carbon and particulate emissions, second because of its low cost compared to liquid hydrocarbons, and third because of the ease of transporting LNG and CNG.

The attractiveness of gas in these new markets is also providing a major driver for technology change, of which perhaps the biggest feature is the use of smaller scale LNG plants and equipment, both for liquefaction and regasification. This trend is of particular significance in Africa, where the absence of existing energy infrastructure means that with appropriate planning, policy support, and investment, these new natural gas technologies can be rolled out in a cost effective and relatively quick manner.

Considering the likelihood that indigenous gas resources may have to rely more on domestic and regional gas markets to underpin development, the emergence of these new markets is of significance in the context of African gas planning considerations.

LNG by Truck/LNG by Rail

A number of concepts have emerged in recent years relating to the shipment of LNG either by rail or road tanker to supply remote centers of demand, particularly in instances where local transmission and distribution pipelines are impractical or too time-consuming to complete.

One of the better-known applications of LNG by rail is Japan's JAPEX LNG Satellite System, which transports LNG by rail and tank trucks to reach gas consumers in regions not served by a gas pipeline network. One of the industry's first, JAPEX has been using rail to supply imported LNG since 2000 and by tank trucks since 1984. A trial program in Alaska, which started in 2016, is the first example of LNG by rail in the U.S. It involves moving rail-mounted standard ISO containers, each carrying 12,500kg (625 MMBtu) of LNG. The program is designed to enable Fairbanks, which is in Central Alaska near Anchorage, some 300 miles away, to benefit from LNG derived from local gas production.

In Vietnam, a similar concept is under discussion, but using LNG road tankers to transport the LNG from a coastal LNG-receiving terminal to cities inland, where a small-scale satellite storage facility would be located. This is very similar to the well-established road tanker supply business that operates out of the U.S. Everett LNG reception terminal in Boston, MA, which is designed to supply remote towns in the New England area. A similar scheme was operated in Scotland in the 1980s but was suspended as a result of the extension of the transmission and distribution pipeline system to the towns previously supplied by LNG road tankers.

As a step to larger scale roll-out of gas applications and markets, or as a permanent solution linked to other small-scale LNG infrastructure projects, LNG by road tanker represents a proven technology. It has potential applications in many African states, and furthermore, where rail infrastructure is developed, LNG by rail also represents an emerging technology that could offer a proven route to market in the next few years.

Small-Scale LNG

Although LNG has historically been transported in bulk, typically in gas carriers of more than 100,000 cubic meters, there are a number of emerging applications which involve much smaller quantities of LNG, both in respect of production and demand. Anti-flaring regulations, as well as more practical and efficient smaller-scale technologies, have meant that small-scale LNG solutions are now widely available.

China is the largest market where widespread small-scale LNG applications have found success, with over 500 LNG filling stations for trucks and buses and a widespread fleet of LNG-powered ferries and other marine applications. The source of LNG in China is typically smaller liquefaction plants built on the gas transmission system, rather than directly supplied by coastal LNG import terminals. There are over 60 such small-scale liquefaction plants in China, producing approximately 20MTPA of LNG in total, which is the equivalent of more than one large LNG liquefaction facility of the sort that exists in West Africa and is contemplated in Mozambique or Tanzania. In this way, although development has been gradual, a similar strategy in Africa could eventually create sufficient gas demand to underpin one or more of the major gas discoveries currently under evaluation.

A typical small-scale liquefaction unit can produce as little as 25,000 gallons/day, equivalent to gas production of around 2.5 MMcfd, which might equate to the production from a single onshore gas well. However, the economics of such a unit would not be considered viable, other than as a means to dispose of gas that otherwise has a cost associated with it (as may be the case for flaring). Larger plants, of around 100,000 tonnes per annum (200 MMcfd) can rival larger scale liquefaction economics of less than $2/MMBtu, and represent a commercially-viable application, depending on the price of the feedstock and the market being supplied.

One of the benefits of small-scale LNG is that fuels in the destination markets for which it substitutes are often diesel or fuel oil, so the environmental benefits, in terms of CO_2 emissions, and especially particulates, can be substantial, and this is one of the primary elements of policy support that applies in China.

Emerging LNG Marine Transportation Options

For most of the 50 years since the establishment of transoceanic LNG transportation, the size of gas carriers has grown from the 25,000 cubic meters that applied to the first commercial LNG exports from Algeria, through to 260,000 cubic meters which reflect the latest Q-max LNG carriers used to transport LNG from Ras Laffan.

However, a new business model is emerging for LNG, based on the so-called break-bulk approach of shipping the product in smaller units, rather than in standardized containers. The term does not exactly reflect the practice in the container ship industry, as, in fact, smaller LNG marine transportation, for power barges or ship bunkering applications, can often use standardized ISO containers which are loaded onto barges for moving around coastal waterways, or navigable rivers or channels.

In addition to modularized break-bulk applications, small-scale LNG carriers, which are similar in size to the 25,000 cubic meter ships used in the 1960s in the early days of LNG, are also becoming popular for the purposes of reloading LNG from regasification terminals, or for smaller offtake volumes from LNG liquefaction terminals.

The availability of these modularized bunker/coastal LNG barges and smaller scale conventional LNG carriers significantly improves the opportunity to develop niche African markets, such as coastal power stations or floating power barges, and road tanker operations. This, combined with the other emerging market features described in this section, significantly improves the potential for local and regional gas and LNG markets to play a more significant role in underpinning large scale gas resource development.

Peaking and Storage

As African gas markets develop, there will be a need to ensure that the gas supply is available to meet the peak demand in the gas distribution system. In this mode, often it is necessary to have the ability to take natural gas from storage or off the gas distribution network. Peak-shaving LNG facilities liquefy and store natural gas when supply exceeds demand in the pipeline network for eventual regasification during peak demand periods. The storage tank volumes in these facilities can be very large, capable of storing 1.0 to 2.0 BCF of natural gas.

Most well-developed gas transmission infrastructure, such as in North America and Europe, has some degree of LNG-based peak shaving to address relatively short-term changes in gas demand, often as a result of hot or cool weather, in addition to seasonal storage applications which typically do not involve LNG facilities.

LNG may also be transported by truck to nearby power stations that have small regas modules. The array of LNG peak-shaving facilities within the natural gas distribution network may result in other forms of LNG application, including vehicular usage.

Mid-Scale Virtual Pipeline Projects

Most of the population in African countries lives in the countryside in small communities, and connecting these communities in the traditional way using transmission pipelines would be too expensive. The virtual pipeline, filled either by compressed natural gas (CNG) or small-scale LNG, can be the solution to bring natural gas to these communities, through the installation of small Autonomous Gas Units (GAU).

CNG is a low-cost alternative for the transport of small to average gas volumes over moderate distances (+/-2000 km) where the volumes are too small for LNG or too far to transport by pipeline. The gas is compressed to around 250 bar and can be transported to small villages or used to supply natural gas for local vehicles.

A small-scale LNG system is another option to transport natural gas to remote villages, either by truck or small ships. Small regasification units can be built linked to a local gas network, establishing a local GAU. Successful examples of these GAU exists in many countries in the world, including Portugal, and may be replicated in many of the cities and towns in Africa, especially in those countries with recent discoveries of natural gas such as Tanzania and Mozambique.

Such small projects can actually be an opportunity for medium and small enterprises business, with a favorable economic impact on local communities by replacement of imported fuels and reduction of deforestation, given that the majority of those communities currently use wood as the main source of energy.

In Mozambique with the construction in 2014 of a 62 km gas distribution network in Maputo city by ENH, E.P. boosted the development of CNG for vehicles. Currently, the number of vehicles converted to CNG has increased significantly. Initially, the gas was compressed up to 250 bar and transported about 15 km from Matola to Maputo city in trailers, supplying the Mother Station at gas stations, then the vehicles. The gas distribution network in Maputo has eliminated the need for CNG transport from Matola to Maputo, because the gas stations were connected to the pipeline, thereby reducing the initial costs. Similar experiences could be replicated in densely populated cities near the Rovuma gas fields, like Nampula, Nacala, and Pemba.

In Nigeria, Compressed Natural Gas (CNG) facilities serve the growing energy demand of customers unable to access gas pipeline supply in the Lagos area and environs. The CNG Mother Station is designed for output capacities of 150,000 standard cubic meters per day (SCMD) at a discharge pressure of 250 bar, and can serve customers within a 200km radius.

CNG is compressed into mobile tube trailers for onward delivery to customer locations, and the facility also has dispensing points for filling Natural Gas Vehicles (NGV) utilizing CNG as a primary or alternate fuel. Gas supply to the Mother Station comes from a service line that taps into the Greater Lagos gas pipeline distribution system.

Conversion Tables

Natural Gas Conversion

LNG Units Conversion

Natural Gas Conversion

	To Convert billion cubic metres NG	billion cubic feet NG	million tonnes oil equivalent	million tonnes LNG	trillion British thermal units	million barrels oil equivalent
From	------------------ Multiply by -------------------					
1 billion cubic metres NG	1	35.3	0.90	0.74	35.7	6.60
1 billion cubic feet NG	0.028	1	0.025	0.021	1.01	0.19
1 million tonnes oil equivalent	1.11	39.2	1	0.82	39.7	7.33
1 million tonnes LNG	1.36	48.0	1.22	1	48.6	8.97
1 trillion British thermal units	0.028	0.99	0.025	0.021	1	0.18
1 million barrels oil equivalent	0.15	5.35	0.14	0.11	5.41	1

LNG Units Conversion

Units			
1 metric tonne	= 2204.62 lb	= 1.1023 short tons	
1 kilolitre	= 6.2898 barrels		
1 kilolitre	= 1 cubic metre		
1 kilocalorie (kcal)	= 4.187 kJ	= 3.968 Btu	
1 kilojoule (kJ)	= 0.239 kcal	= 0.948 Btu	
1 British thermal unit (Btu)	= 0.252 kcal	= 1.055 kJ	
1 kilowatt-hour (kWh)	= 860 kcal	= 3600 kJ	= 3412

Acronyms and Definitions

ACQ (Annual Contract Quantity) The Annual Contract Quantity (ACQ) is the volume of gas which the Seller must deliver and the Buyer must take in a given contract year.

ADP (Annual Delivery Programme) The Annual Delivery Programme (ADP) is a schedule of gas volumes to be delivered on definite dates or within definite periods in an imminent contract year in a long term contract.

AfDB (Africa Development Bank)

AIPN (Association of International Petroleum Negotiators)

Arbitrage Arbitrage is buying and selling the same commodity in two different locations or markets to take advantage of variances in price.

AG (Associated Gas) Associated Gas is gas which is produced with oil in a primarily oil field.

ALARP (As Low As Reasonably Practicable)

APCI (Air Products & Chemicals, Inc)

BENGAS SA (Beninoise de Gaz)

BL (Base Load) The proportion of delivery (or demand) below which send out (or demand) is not estimated to fall during a given period.

BOG (Boil Off Gas) The small amounts of LNG that boil off from LNG storage tanks in LNG plant operations and are recovered, or during transportation. BOG gas on LNG tankers can be used as a fuel to drive the ships.

BOE (Barrels of Oil Equivalent)

BP (Border Price) The price at which gas is traded at the border between two countries.

BTU (British Thermal Unit)

C&F (Cost and Freight)

C3MR process The LNG refrigeration process using propane and mixed refrigerants as the cooling media.

CEB (Clean Energy Building)

CIF (Cost, Insurance, and Freight)

CMH (Companhia Mocambicana de Hidrocarbonetos, SARL)

CV (Calorific Value) Calorific Value is the quantity of heat produced by the total combustion of a fuel.

CF (Carry Forward) A provision within a long term Take or Pay Contract under which a Buyer which takes more than its Annual Contract Quantity in any year is allowed, under conditions specified in the contract, to balance this against under taking in following years.

CHPS (Casing-Head Petroleum Spirit) An ancillary name for Condensates.

CCGT (Combined Cycle Gas Turbine) A Combined Cycle Gas Turbine (CCGT) is a form of electricity generation plant in which the waste heat produced from combustion of gases is partially captured in the turbine exhaust and used to generate steam for production of additional electricity, significantly increasing the efficiency of the electricity generation.

CHP (Combined Heat and Power) Combined Heat and Power (CHP) is the use of a single combined system to supply both the heat and power obligations of a project hence reducing the waste of heat.

CIF (Cost, Insurance, and Freight)

CNG (Compressed Natural Gas) CNG is natural gas compressed into gas cylinders, primarily used as a substitute for liquid fuels in road vehicles. CNG remains a gas in respective of the amount of pressure.

CBM (Coal Bed Methane) Coalbed methane is methane that is or can be produced from coal seams.

COI (Confirmation of Intent)

DEC (Design Endorsement Certificate)

DCQ (Daily Contract Quantity) The quantity of gas which a Buyer technically undertakes to purchase and a Seller undertakes to deliver within a specified 24 hour period.

DFDE (Dual-Fuel Diesel Electric LNG vessel)

DDR (Daily Delivery Rate) The Daily Delivery Rate (DDR) is the rate at which the Seller's facilities must be capable of delivering gas, expressed as a volume of gas per day, or as a multiple of the Daily Contract Quantity. Also known as the Maximum Daily Quantity.

DES (Delivery Ex Ship)

DOE (Department of Energy)

DQT (Downward Quantity Tolerance) The Downward Quantity Tolerance (DQT) is the amount by which a buyer may fall short of its full Annual Contract Quantity in a Take or Pay gas sales contract without experiencing sanctions.

DSCR (Debt Service Coverage Ratio)

DSO (Domestic Supply Obligation)

EPC (Engineering, Procurement, and Construction)

ECOWAS (Economic Community of West African States)

EDM (Electricidade de Mocambique)

EIB (European Investment Bank)

EIA (Environmental Impact Assesment)

ELPS (Escravos-to-Lagos Pipeline System)

ENH (Empresa Nacional de Hidrocarbonetos)

FEED (Front-End Engineering and Design)

FOB (Free on Board)

FERC (Federal Energy Regulatory Commission)

FID (Final Investment Decision)

FLNG (Floating LNG) Floating LNG is the deployment of purpose built or converted ships to enable liquefaction of LNG to be done offshore.

FM (Force Majeure) A contractual term used to define conditions in which a party to a contract is not obliged to carry out its commitments because of major events outside its control.

FTA (Free-Trade Agreement)

FSRU (Floating Storage and Regasification Unit) FRSU is the deployment of purpose built or converted ships to enable storage and regasification of LNG to be done offshore.

GOR (Gas Oil Ratio) The gas oil ratio is the relationship between the volume of gas produced at atmospheric pressure and the volume of oil produced from a given oil field, or a given oil well.

GCV (Gross Calorific Value) The heat produced by the complete combustion of a unit volume of gas in oxygen, including the heat which would be recovered by condensing the water vapor made. Also known as Gross Heating Value, Higher Calorific Value (HCV) or Higher Heating Value (HHV).

GMP (Gas Master Plan)

HAZOP (Hazard and Operability Study)

HAZID (Hazard Identification)

HOA (Heads of Agreement) A non-binding statement of the main elements of a proposed agreement.

HSE (Health, Safety, and Environment)

HSSE (Health, Safety, Security, and Environment)

HH (Henry Hub) Henry Hub is the biggest unified point for natural gas spot and futures trading in the United States. The New York Mercantile Exchange (NYMEX) uses Henry Hub as the notional point of delivery for its natural gas futures contract. Henry Hub is based on the physical interconnection of nine interstate and four intrastate pipelines in Louisiana.

IFC (International Finance Corporation)

IOCS (International Oil Companies)

JKM Index (Japan-Korea-Marker Index)

JCC (Japanese Crude Cocktail)

KOGAS (Korea Gas)

LAG (Lean Associated Gas) Lean Associated Gas is gas high in methane content (typically 95% or more) and with limited heavier fractions.

LC (Local Content)

LCP (Local Content Policies)

LOI (Letter of Intent)

LPG (Liquefied Petroleum Gas) Liquefied Petroleum Gas is propane, butane, or propane-butane mixtures which have been liquefied through pressure, mild refrigeration, or a combination of both.

LNG (Liquefied Natural Gas) LNG is Natural Gas which has been cooled to a temperature, around the boiling point of methane (-162ºC), at which it liquefies, thus reducing its volume by a factor of around 600.

LDC (Local Distribution Company) A company that distributes natural gas primarily to small, residential and industrial end-users.

LHV (Lower Heating Value) Alternative name for Net Calorific Value.

LCV (Lower Calorific Value) Alternative name for Net Calorific Value.

MDBs (Multilateral Development Banks)

MDQ (Maximum Daily Quantity) An alternative name for Daily Delivery Rate.

MDR (Maximum Daily Rate) An alternative name for Daily Delivery Rate.

MMBtu (Million British Thermal Units)

MCF (Thousand Cubic Feet)

MLPs (Master Limited Partnerships)

MMCF (Million Cubic Feet)

MMcm (Million cubic meters)

MMscf (Million standard cubic feet)

MMscm (Million standard cubic meters)

MJ (MegaJoule)

MGJ/a (Million Gigajoules per annum)

MT (Million tonnes)

MTPA (Million tonnes per annum)

MW (MegaWatt) One million Watts.

MWh (MegaWatt hour)

MOI (Memorandum of Intent) Also known as Confirmation of Intent and Letter of Intent.

MOU (Memorandum of Understanding) A non-binding statement of intent to reach a proposed agreement.

NBP (National Balancing Point) The NBP is a fictional (notional, or virtual) point at which all gas that has paid the entry charge to enter the UK National Transmission System is believed to be located.

NG (Natural Gas) Natural gas is a mixture of generally gaseous hydrocarbons occurring naturally in underground structures.

NGL (Natural Gas Liquids) Heavier hydrocarbons (generally, the components of ethane, propane, butane, and pentanes plus) found in natural gas production streams and extracted for disposal separately.

NGV (Natural Gas Vehicle) A motorized vehicle powered by natural gas. See Compressed Natural Gas.

NOC (National Oil Company)

NNPC (Nigeria National Petroleum Corporation)

NCV (Net Calorific Value) The heat produced by the complete combustion of a unit volume of gas in oxygen, without the heat which would be recovered by condensing the water vapor formed.

NHV (Net Heating Value) Same as NCV

NAG (Non-Associated Gas) Non-Associated Gas is gas found in a reservoir which contains no crude oil, and can, therefore, be produced in patterns best appropriate to its own operational and market requirements.

OML (onshore oil mining lease)

OPEC (Organization of the Petroleum Exporting Countries)

OPL (Oil prospecting license)

PPA (Power Purchase Agreement) A contract between a power station and the electricity purchasing organization for the sale of electricity.

PSA (Production Sharing Agreement) A contract between an international producing company and a host government or state oil company under which the international company acts as risk-taking contractor investing in exploration and/or production facilities in exchange for the right to export or sell a quantity of gas or oil that may be formed from the Concession or Block.

PSC (Production Sharing Contract) An alternative name for a Production Sharing Agreement.

PEP (Project Execution Plan)

POSCO (Pohang Iron and Steel Company, Korea)

Pre-FEED (Pre-Front End Engineering Design

RFP (Request for Proposal)

SGX (Singapore Exchange)

SLiNG (SGX LNG Index Group)

Tenor (Time left for loan repayment or till bond maturity as used in the finance industry)

TEPCO (Tokyo Electric Power Company)

Tonnes (A tonne, or metric ton, is a unit of mass equaling 1,000 kilograms. In American English, a ton is a unit of measurement equaling 2,000 pounds. In non-U.S. measurements, a ton (the imperial measure) equals 2,240 pounds.)

TOP (Take or Pay) Take or Pay is a common provision in gas contracts under which, if the Buyer's annual purchased volume is less than his purchase obligation (the Annual Contract Quantity minus any shortfall in the Seller's deliveries, minus any Downward Quantity Tolerance), the Buyer pays for such a shortfall as if the gas had been received.

TPA (Third Party Access)

TSO (Transmission System Operator)

TCF (Trillion cubic feet)

TCM (Trillion cubic meters)

TTF (Title Transfer Facility)

SPA (Sales and Purchase Agreement)

SSLNG (Small-scale LNG)

SMEs (small-to -medium enterprises)

SPT (Sasol Petroleum Temane, Ltd.)

VRA (Volta River Authority)

WA (Western Australia)

WAGP (West Africa Gas Pipeline)