Central America

Introduction of Liquefied Natural Gas (LNG) in Central America

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The report looks at the feasibility of introducing LNG in the region of Central America, taking into consideration existing electricity generation capacity expansion plans. The study provides a detailed assessment of the economic and financial viability of different LNG business plans, and recommends a suitable strategy for moving forward. The countries included in the study are Costa Rica, El Salvador, Guatemala, Honduras, Nicaragua and Panama.

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Contents

Tables and figures

Tables

Figures

Maps

Abbreviations and acronyms

Bcm	Billion cubic metres
Bcf	Billion cubic feet
BG	British Gas
BOO	Build Own Operate
BOOT	Build Own Operate Transfer
CA	Central America
CAGR	Compound annual growth rate
CCGT	Combined Cycle Gas Turbine
CNG	Compressed Natural Gas
DC	District Columbia (US)
DES	Delivery ex ship
ECA	Economic Consulting Associates
EEC	Estudios Energeticos Consultores
EIA	Energy Information Administration
ESMAP	Energy Sector Management Assistance Program
FOB	Free on board
FM	*Force Majeure*
GNL	Liquefied Natural Gas (Spanish)
FSRU	Floating Storage and Regasification Unit, also sometimes FRSU
FTA	Free Trade Agreement
GDP	Gross domestic product
GSA	Gas Sales Agreement
HH	Henry Hub
IDB	Inter-American Development Bank
IEA	International Energy Agency
IGA	Intergovernmental Agreement
IMF	International Monetary Fund
IGU	International Gas Union
LNG	Liquefied Natural Gas
MER	Central American Regional Electricity Market
Mmbtu	Million Btu (British thermal unit
Mmcfd	Million cubic feet per day
Mtpa	Million tonnes per annum
MWh	Mega Watt hour
NPV	Net present value
OA	Open access

O&M	Operation and Maintenance
PPA	Power Purchase Agreement
PPIAF	Public-Private Infrastructure Advisory Facility
PPP	Public Private Partnership
PV	Present value
PVN	PetroVietnam
SC	Steering Committee
SIEPAC	*Sistema de Interconexión Eléctrica de los Países de América Central* (Spanish), the regional electricity transmission system for the Central American market
SLNG	*Singapore LNG*
SPA	Supply (or Sales) and Purchase Agreement
SPV	Special Purpose Vehicle
ToR	Terms of Reference
TAP	Trans Adriatic Pipeline
Tcf	Trillion cubic feet
TPA	Third party access
US	United States
WAGP	West Africa Gas Pipeline
WTI	Western Texas Intermediate (crude oil)

Introduction

This document was prepared to response to opportunities and interests expressed by the Governments of Central America. It is meant to open up the dialogue, stimulate discussions and provide an initial guidelines to evaluate the feasibility of introducing LNG into the region.

The region of Central America (CA) faces crucial energy challenges, in particular related to managing increasing demand and high dependence on oil (and oil products) to fuel the power sector. Countries in Central America are oil poor and therefore highly dependent on oil imports to supply their energy needs. The use of diesel in the energy mix has risen considerably, rising in the last twenty years from 5 to 32 percent as a share of total capacity. The lack of long term energy planning, high demand growth, and delays in construction of new generation capacity have contributed to this outcome.

The region's high dependence on oil has several negative impacts. First, the cost of electricity generation in the region is high. Costs range from 14-22 US cents/kWh. This reduces the region's competitiveness. Second, the region is highly exposed to oil price volatility. CA's petroleum dependency has had a significant impact on the region's import bill, with imports costing on average $9.5 billion per year over the last three years (2008-2010), or 6% of GDP in CA. Governments have struggled to keep retail residential prices low, in order to avoid political fallout from tariff increases, which has had negative fiscal impacts. Third, high reliance on oil leaves a large environmental footprint.

To reduce dependence on oil imports, improve energy security, and lower costs, countries in the region could benefit from natural gas. In recent years natural gas has become extremely competitive as a fuel for power generation. This has spurred interest in other countries in the Americas to develop conventional and unconventional gas resources, including Colombia and Argentina. Looking forward, the prospect that gas prices will remain low seems increasingly likely. The energy sector authorities in CA have expressed their interest in natural gas as a means to reduce electricity costs.

Updated results (2015 prices)

From the moment the original study was finalized at the end of 2014, global prices of oil and gas have dramatically fallen from over 100 US$/barrel in the first semester of 2015 to less than 60 US$/barrel by the middle of 2015. This significant variation in oil and gas and its derivaties have impacted electricity prices in CA. similarly, the average price of Henry Hub gas price drop from 4.37 US$/mmbtu in 2014 to 2.85 US$/mmbtu during the first semester of 2015. For this reason, the analysis used to assess the economic and commercial feasibility of LNG project has been updated. Although there are some variation in the overall outcomes of the analysis, the results do not change the recommendations on a suitable LNG strategy made in the original report.

Executive Summary

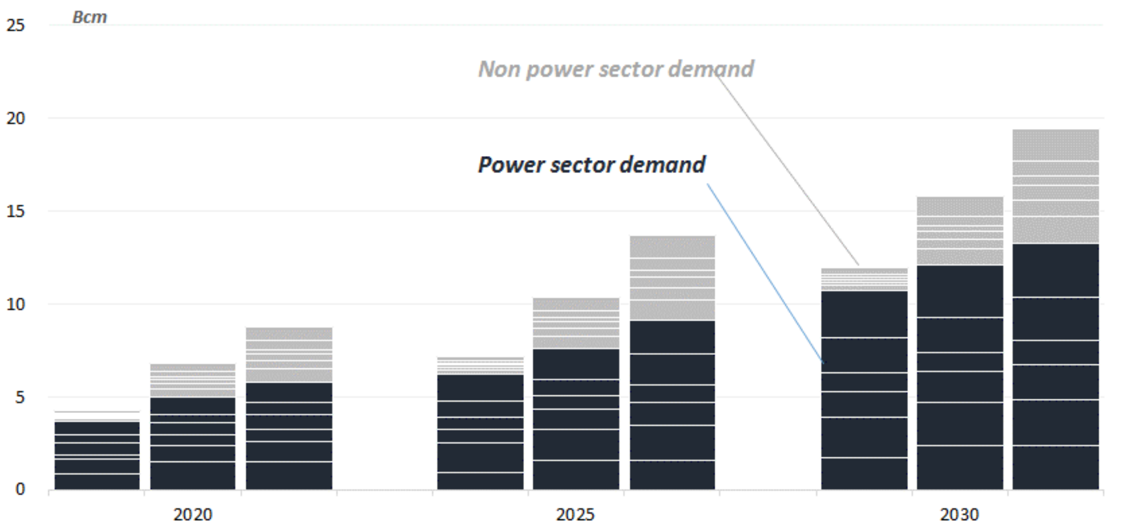
Objective of the study

Electricity prices in the Central American region are high with heavy fuel oil being the main thermal power generation source in the region, burdening government budgets. To alleviate these pressures, natural gas can provide a feasible alternative by reducing electricity prices and generation costs. The objective of this study is to firstly assess the economic rationale of introducing Liquefied Natural Gas (LNG) into Central America and secondly to recommend on a suitable strategy to introduce LNG in the region. The countries included in the study are Costa Rica, El Salvador, Guatemala, Honduras, Nicaragua and Panama.

A similar study funded by the Inter-American Development Bank (IDB) was completed in parallel with this study. This report was carried out in close cooperation with IDB and complements the IDB study by building on its results.

Gas demand

Gas demand in this Report is based on projections in the IDB study. Results in the study show that demand for gas in the region is relatively small and will range between 4 and 9 Bcm in 2020 and 12 and 20 Bcm in 2030. The figure below illustrates the aggregate gas demand projected for the region for three scenarios. The three scenarios vary in the assumptions of fuel to gas switching for existing thermal power stations, the development of hydro power plants and the penetration of gas in the non-power sectors.



Bcm	2020			2025			2030		
	Low	**Med.**	**High**	**Low**	**Med.**	**High**	**Low**	**Med.**	**High**
Panama	0.8	1.4	1.8	1.7	2.4	3.0	2.9	3.9	4.7
Costa Rica	0.6	0.8	1.1	1.0	1.3	2.3	2.0	2.4	3.2
Nicaragua	0.6	0.7	1.0	0.8	0.9	1.3	1.1	1.3	1.8
El Salvador	0.3	0.8	1.0	0.8	1.4	1.9	1.5	2.2	2.7
Honduras	0.9	1.2	1.5	1.7	2.0	2.5	2.4	2.8	3.4
Guatemala	1.0	1.9	2.2	1.2	2.2	2.7	2.0	3.2	3.8
Region	**4.2**	**6.8**	**8.6**	**7.2**	**10.2**	**13.7**	**11.9**	**15.8**	**19.6**

Source: ECA based on IDB study by EEC

Overall the demand projection methodology in the IDB study appear sound. While a more detailed economic analysis could have been undertaken (ie a netback analysis for the main industrial users, economic viability assessment of switching fuel oil plants to gas and a detailed dispatch model for the power sector), the adopted methodology provides a good initial approximation to establish the economic feasibility of gas sector development in the region.

We note however that the demand estimates are skewed towards a higher range of demand estimates. In particular the range of gas to power demand covers optimistic scenarios. This is because of ambitious assumptions on the switching of fuel oil plants to gas and the replacement of planned hydro plants to gas. This becomes evident when comparing the projected gas demand levels, their associated gas to power generation capacity and existing capacities

The 2030 gas to power demand levels in the lowest projection scenario across all countries (11.9 Bcm) corresponds to an increase in power generation capacity of 8,800 MW in 2030. With an existing power generation capacity of 11,900, this means an increase of 73% of power generation capacity in the region over the next 15 years. This is high and seems ambitious, despite the urgent need for additional power generation. We conclude that the Low demand scenario is the most realistic scenario from the IDB study.

LNG supply

Current trends in the global LNG market create opportunities for Central American countries. These include firstly an expected global oversupply of LNG in the medium term, secondly the emergence of nearby market in the US for new sources of LNG exports, thirdly a competitive gas pricing regime in the US resulting in low gas prices, fourthly the increasing relevance of spot or short term markets and fifthly technological advances bringing down the scale of cost efficient transport, storage and regasification.

Among the emerging suppliers in the LNG market, the most likely supplier to Central America is the United States. Significant gas supply volumes, low liquefaction costs, low US gas prices and geographical proximity constitute the key factors that will favour Central American imports from this region. United States exports may also support regional small scale liquefaction and hub trade. Canada could also constitute a supplier region to Central America, as shale gas reserves are also being unlocked, it is relatively close to the region, and there are liquefaction projects under construction.

Mexico is the most likely supplier of piped gas with a planned interconnection to Guatemala.

Other emerging suppliers, such as Australia or East Africa, are less likely to become the main suppliers to the region, as they confront disadvantages in terms of cost or distance. Other large suppliers such as Malaysia, Indonesia or Russia also constitute possible supplier options. However, their likelihood is low, as they are heavily oriented towards the Asian market (which carries a price premium), the distances are greater, and in some cases they confront supply side restrictions.

LNG strategy – model for gasification

Another area of overlap with the IDB study is the proposition of a suitable LNG strategy. The IDB study shortlists three possible strategies of gasification:

- **Strategy A: independent projects in each country—** national regasification terminals would be built in the short-term in each country except Guatemala where a gas pipeline will connect the country to Mexico. Electricity trade would develop via SIEPAC.

- **Strategy B: sub-regional integration—** two regional regasification terminals would be constructed in El Salvador and Panama according to ongoing initiatives. In the longer term, once capacity of the terminals is reached, new terminals would be built at new locations. Energy would be traded in the form of electricity on SIEPAC. Guatemala and Mexico are connected via pipeline.

- **Strategy C: integration with Mexico—** the northern part of the region is initially only supplied via the regasification terminal in El Salvador, and in the medium-term the pipeline from Mexico to Guatemala. The latter would later be extended to reach El Salvador, Honduras and Nicaragua. The southern part will be supplied by means of regasification terminals in Costa Rica and Panama.

Strategy A

Strategy B

Strategy C

On the basis of our analysis, we recommend an approach similar to Strategy B (two regional terminals on the basis of the local electricity demand). However instead of prescribing a regional terminal and market from the beginning, we propose to enable the development of national LNG terminals. Energy would then be traded through electricity via an expanded and strengthened SIEPAC.

The LNG terminal would naturally be developed in the country with the most favourable commercial conditions. If the possibility of electricity trade is given (if limitations to electricity trade are overcome), the LNG terminal could be sized according to cross border electricity demand levels (it is important to mention that the viability of the project does not depend on the trading of electricity between the countries). The risk of six countries developing separate LNG terminals is low, as interest and financing for the LNG terminal would not be secured in each country.

A starting strategy for a regional approach or even sub-regional approach is a considerably riskier gasification strategy with unlikely commercial benefits and a higher degree of uncertainty whether any project would develop. The main reasons include:

- ***No previous example of regional LNG market –*** Our international case studies show that no other region in the world has overcome the difficulties of financing and developing a regional LNG terminal.

- ***No established national gas markets*** - a regional gas market can be developed if there are established national gas markets. However coordinating efforts at such an immature level of gas market development requires an extensive level of regional cooperation, which can be difficult to achieve and timely to implement.

- ***Benefits of initial regional approach not clear –*** the potential gas demand volumes of the region are small, particularly in the short to medium term. The impact on price from collective bargaining would be negligible.

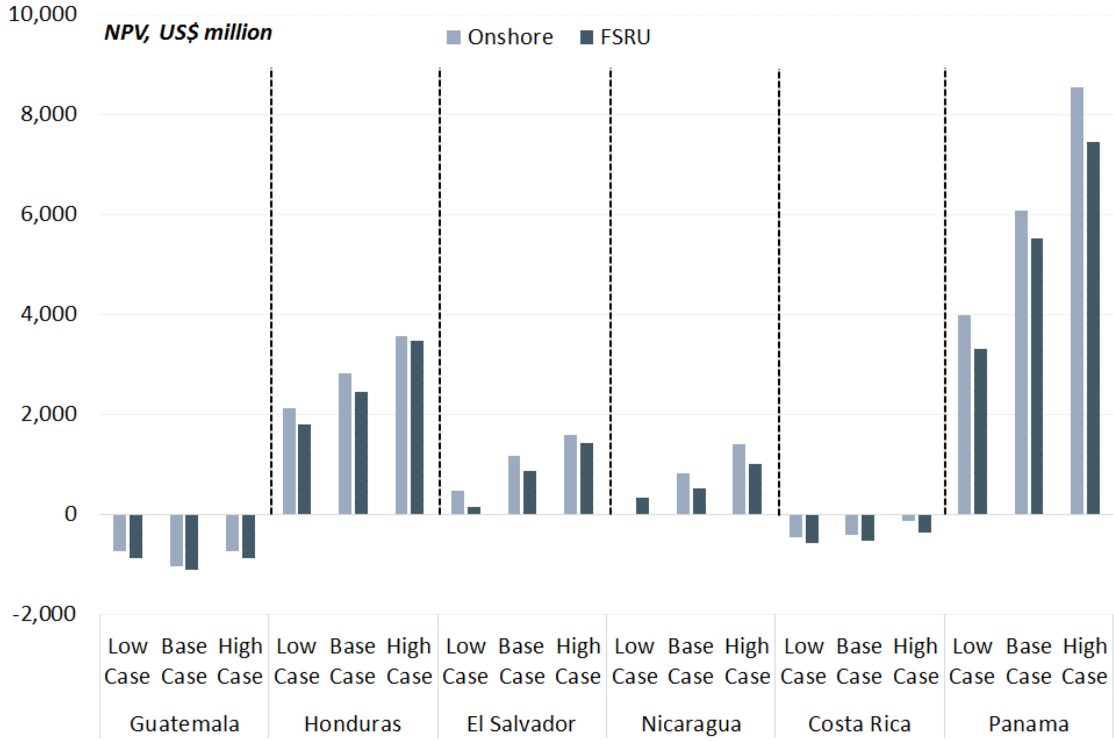
- ***Commercial risks are substantial –*** a regional (or even sub regional) LNG trading arrangement would require a pool of gas purchasers made up of different gas offtakers. These will all have different risk profiles, which will turn off potential gas suppliers from signing gas purchase agreements.

For those reason a regional gas market is unlikely to develop in the medium term. Instead, countries should focus on developing their own terminals (if commercially feasible) and establishing their own national gas market and strengthening regulations for them. Cross border trade should be focused on electricity and not gas – except for Guatemala and Mexico where a gas interconnector is in early stages of development. Efforts at the start should therefore be made to develop a regional electricity market with trading opportunities rather than a regional gas market.

Economically feasible projects

On the basis of a financial and economic netback analysis, we conclude that LNG yields significant economic savings across all six countries compared to a fuel oil scenario. Under base case demand and US gas price assumptions, the economic benefits could range from US$ 3.5 billion (Nicaragua) to US$ 10.4 billion (Guatemala). There is therefore a strong economic justification to introduce LNG and gas into the region's power mix.

Commercially however only four of the six countries provide attractive investment propositions. Costa Rica and Guatemala have too low electricity prices to make a regasification terminal a financially feasible proposition. Panama, El Salvador, Honduras and Nicaragua generally have positive net present values for a regasification terminal at 12% discount rates.



Source: ECA calculations

For Guatemala and Costa Rica to provide financially attractive LNG investment opportunities, electricity prices would have to increase by 10% (Guatemala) and 7% (Costa Rica) overnight and remain at that level in real terms. Alternatively LNG prices would have to be 9.6 US$/mmbtu in Costa Rica and 10.0 US$/mmbtu in Guatemala.

For all other countries an LNG price of up to 17 US$/mmbtu could be sustained without jeopardising the financial viability of their regasification projects. This compares to 2014 year end LNG prices of 13.9 US$/mmbtu in Japan; considered to be one of the highest priced LNG markets.

	Type	Regasification capacity	CAPEX for regasification	Power gen. capacity	Existing power generation
		Bcm/y	*US$ million*	*MW*	*MW*
Guatemala[1]	FSRU	1.5	214	1,300	2,800
Honduras	FSRU	2.1	257	1,600	1,700
El Salvador	FSRU	1.2	186	1,000	1,500
Nicaragua	FSRU	1.0	169	800	1,100
Costa Rica[1]	FSRU	1.2	188	1,000	2,800
Panama	FSRU	2.2	261	1,900	2,000

Source: ECA estimations

The difference in our financial analysis between FSRU's and onshore terminals is small and a more detailed feasibility analysis for each location would have to be done to make a definitive conclusion on which regasification option to pursue. FSRU's are traditionally used as a flexible and lower cost alternative compared to onshore terminals. In light of the difficulty to finance and develop large scale gas fired power generation projects, it might be more suitable to develop smaller scale projects in Central America initially. Particularly when considering the fact that gas is a new fuel in the countries' power mix. The table above shows a recommended investment plan for the most conservative demand projections and its associated power generation investments.

Business models and risk assessment

The economic and financial feasibility of an LNG project is however not sufficient for a project to be developed. The financing risk needs to be minimised and contractual interlinkages between parties involved along the value chain needs to be clear. A major focus of this study, providing complementarity to the IDB Report, is the risk assessment of different business models and a recommendation on the most suitable implementation strategy for introducing LNG in the region.

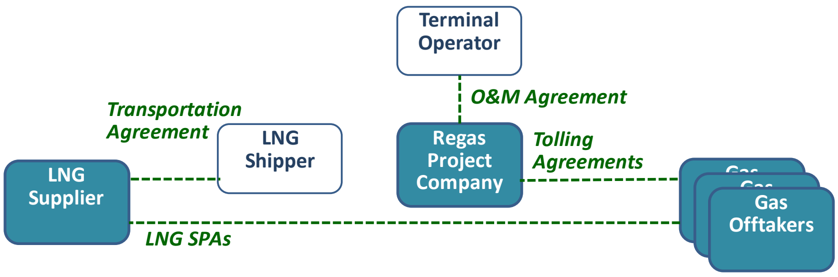
Business models are understood to be the contractual linkages between the different entities along the LNG value chain. Largely three variants of business models have been assessed in the study. These include:

- ***Contractual model***: a model where all entities along the value chain are independent and contracts between the entities govern all trading.
- ***Semi-integrated model***: a model where integration between two parts of the chain exist, the regasification terminal and either the downstream gas offtaker (gas supplier or power plants) or the upstream LNG supplier.
- ***Fully-integrated model***: a model where the chain is fully integrated from LNG supplier to offtaker.

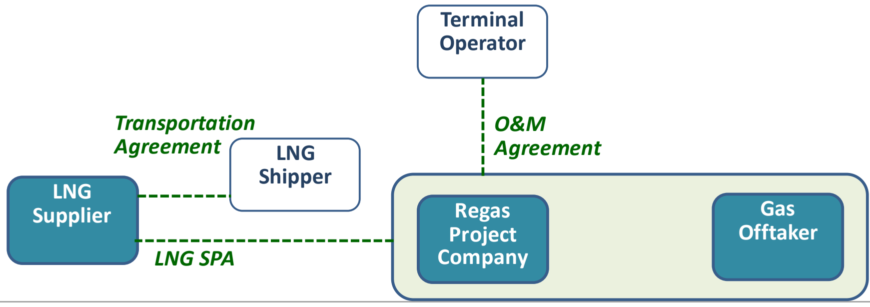
[1] Assuming electricity prices increases or LNG prices can be negotiated to low levels

All three business models considered are shown illustratively below

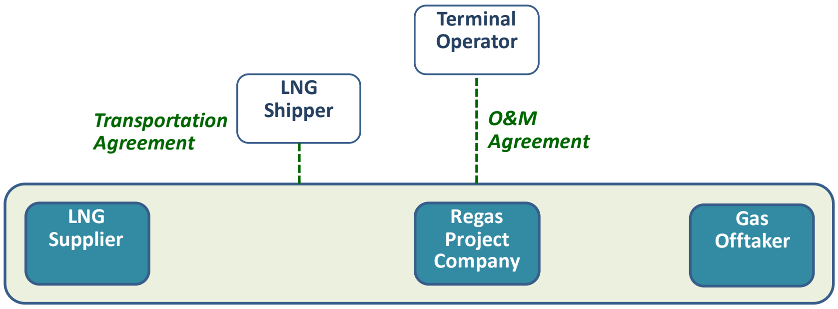
Contractual model facilitating TPA, but complex contractual arrangements



Semi –integrated model combines the benefits of an integrated model without requiring LNG suplpir invcolvement downstream

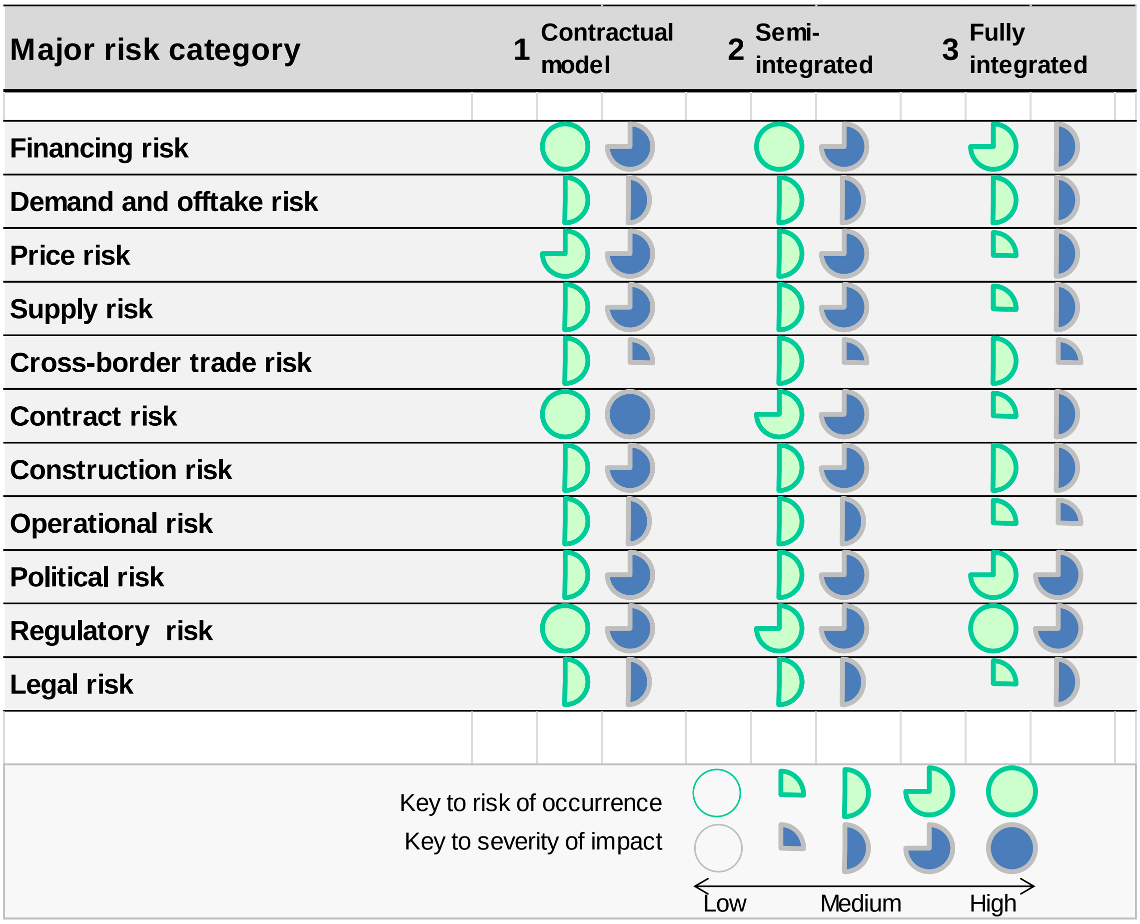


Integrated chain, potentially lower risk but limited possibility for TPA



The feasibility of implementing business models for the preferred strategies depends on their risk profile. A first assessment of the ability to finance and implement a business model can be made after carrying out a high level risk assessment. While many risk categories are common across all similar projects wherever they are carried out, the importance of each will vary according to both the project, project company and country context; ie the risk profile depends on the specific project context.

The Report sets out an initial approach and methodology to assess the key risks for LNG project development. The main risk areas for LNG in the Central American countries and the high level assessment of each for the three business models is shown below.



The risk assessment shows that integrated case is more likely to be financeable, especially as a first-of-a-kind for Central America. Compared to the other two business models, the fully integrated model has a greater chance of reaching financial close, having less operational, supply and contract risk, though higher political and regulatory risk. This last assessment is indicated as a monopoly supplier is more likely to face political or regulatory scrutiny and challenge if the sector performance does not meet objectives.

Key issues to be addressed to finalise LNG strategy

There are a number of other issues that will influence the further development of LNG projects and the choice of business models. These include:

- *Third party access* - The countries have a strong interest to incorporate a degree of competition into the new market by way of open access or third party access (TPA) to the terminal facilities (and gas pipelines). In light of the high debt requirement for the development of any project, the starting point for TPA is likely to be restrictive. This is a typical situation for any gas infrastructure that brings new gas supplies to an area, whether LNG or pipelines. TPA would need to be negotiated, and may come with a slightly higher price. The flip-side of other parties seeking TPA is that the investor (project sponsor) will be looking for upside potential on the project's earnings. A typical financing strategy is to cover the financing repayment obligations with firm, long-term contracts, but then to retain as much capacity as possible for shorter term market transactions.

- ***First mover disadvantage -*** LNG in gas-to-power is not uncommon and the economic scale of LNG projects is coming down. Nevertheless, a project in the CA countries has novel and untested characteristics. These include first project in the region, uncertainty of onward electricity trade and small loads in individual countries.

- ***Level of regional cooperation -*** A well-functioning and strong SIEPAC is key for regional integration of energy markets. It provides the first stepping stone for developing LNG terminals that are large enough to cover regional energy demands. Hence, efforts should be made to ensure a regional electricity market rather than a regional gas market. Also, financially, the risk profile of a regional LNG buyer is likely to be opaque. It is likely that a pragmatic approach needs to be taken to regional cooperation on a project by project basis.

- ***Risk mitigation -*** The starting point for considering the financing of an LNG project in the region is a relatively high level of risk compared to a low or moderate level of demand. The key risks and their mitigants are:

  - Contract risk – this can be avoided by minimising the number of parties in the value chain and the resulting number of contracts.

  - Demand risk - A mitigation approach is to find ways to avoid contracting too long term. The use of FSRUs on short/medium term charter is one very important option to consider. Additionally, a mixture of long term and short term contracting could be opted for. The long term contracts could be for volumes high enough to secure financing and supply, but low enough to minimise demand risk.

  - Regulatory risk - The main regulatory risk relates to both the electricity and gas markets, in the first case to ensure that electricity prices will be set to reflect costs, and in the second case to deal with the gap in all countries in the absence of a regulatory framework for gas distribution and supply. Stability of the regulatory framework is also important, and here the past (in terms of degree of constancy and predictability in the regulatory framework for electricity) is a key indicator.

  - Political risk - Evidence that there will be political support for the complete LNG to power chain (as well as development of gas supply and distribution to other sectors) is a key area to mitigate political risk.

  - Financing risk – Private sector participation along the value chain is key and ensuring the conditions for (timely) enforcement of commercial contracts is a major area to mitigate the financing risks. In many cases the tangible policy support from government will be implemented through PPP arrangements.

- ***FSRU vs. onshore terminal -*** The countries appear to have assumed or preferred land based regasification terminals. The difficulty with this approach is the high and fixed capital cost commitment to a pre-defined volume. The alternative that should be seriously considered is the use of more flexible floating storage and regasification units (FSRU). The advantages of FSRUs include (i) ability to contract short term, from months to a few years, (ii) lower risk of over-investing in unused capacity, due to demand uncertainties, (iii) easy route to scale up volumes as demand grows, (iv) shorter timescale to put in place and (v) lower investment costs may not require the large guarantee facility of a land-based terminal.

LNG strategy – regulatory and legal issues

Guatemala, Honduras and Nicaragua have no specific legislation on natural gas, they have only drafted laws for hydrocarbon exploration and exploitation.

Costa Rica and Panama also have regulations on natural gas exploration and exploitation but, in addition, they also have regulations that are applicable to the sector in the mid-stream and downstream. These rules are very general, indicating responsibilities within the Government, the promotion of investment, and who will be in charge of regulating prices and quality. There are no specific rules for defined projects.

In El Salvador, regulations have defined aspects related to market concentration and tariff criteria, but only for companies dealing with natural gas retailing. Aspects related to LNG storage and regasification have not been developed in detail.

In all the countries there are rules to develop PPAs, so they can be used as instruments to help develop a gas market project which might be on a scale larger than any one country. In all of the countries, the state can aid the execution of such contracts by means of coordinated infrastructure planning.

1 Introduction

This document is the Final Report submitted under the assignment ***Introduction of LNG in Central America***. The assignment is being undertaken for the World Bank with funding provided by PPIAF and ESMAP

Objective of the study

Electricity prices in the region are high and after hydro generation, fuel oil is the main power generation source in the region. This pushes up electricity prices and burdens government budgets. To alleviate these pressures, natural gas can provide a feasible alternative by reducing electricity prices and generation costs. The objective of this study is to firstly assess the economic rationale of introducing Liquefied Natural Gas (LNG) into Central America (CA) and secondly to provide an assessment of the approach that could be followed for the initial development of a gas to power market in the region.

Specifically, the study assesses the commercial options that could be employed for the initial development of a gas market in CA. This includes analyses of the possible business models for the successful development of LNG import terminals in the region, the contractual arrangements necessary under each of these models and an assessment of the risks faced by investors seeking to develop these types of projects in a small country context.

Countries included

The countries analysed are Costa Rica, El Salvador, Guatemala, Honduras, Nicaragua and Panama. Key economic and energy market indicators for each of the countries assessed are shown in Table 1.

Table 1 Key economic indicators for countries assessed

	Population	GDP per capita	Generation capacity	Electricity prices	Per capita electricity demand
	Million	*US$*	*MW*	*US$/MWh*	*kWh*
Guatemala	15.5	2,950	2,800	121	570
Honduras	8.1	2,200	1,700	173	720
El Salvador	6.3	3,700	1,500	160	850
Nicaragua	6.1	1,210	1,100	160	540
Costa Rica	4.9	7,950	2,800	123	1,900
Panama	3.8	7,810	2,000	210	1,900

Source: World Bank development Indicators

Overlap with IDB study

Since the preparation of the Terms of Reference (ToR) of this study, a similar project funded by the Inter-American Development Bank (IDB) started. There was a significant overlap of objectives between the IDB project and the initial ToR of this project. This report is therefore carried out in close cooperation with the IDB study and tasks have been re-focused to avoid unnecessary overlap. In that sense, this study builds upon the results from the IDB study and synergises the efforts of gasification of both institutions.

In particular, this study draws on the demand analysis carried out through the IDB study and the initial assessment of strategies for developing LNG projects and gas markets in the Central America region. Using these results, this reports provides a more detailed implementation strategy for LNG in the region and onward regional gas markets.

The scope of the study has therefore been refocused to aspects not covered extensively by the IDB study – mainly business models, contractual arrangements, risk assessment and, subsequently, the legal and regulatory framework. This refocusing aims to improve complementarity between the World Bank study and the IDB study and has strengthened the partnership of both institutions.

Overview of the study

The study begins by providing a review of the ***gas demand and supply***. The first component consists of an assessment of the approach used in the IDB study to develop the region's gas demand projections which are used as the basis for this report's economic analysis. The three demand scenarios adopted from the IDB study are taken to represent the range of possibilities that arise from the uncertainty regarding demand development in a new market.

The second component presents an analysis of ***global LNG supply*** sources and trends in LNG exports and prices. The analysis shows the global balance of LNG supply and demand, providing an assessment of future LNG liquefaction projects which could potentially become suppliers to the Central American countries. Our review confirms that there is an abundant range of LNG supply options but that its cost is significantly higher when the scale of purchased volumes is low, as it will be in the Central America region. The likelihood is that the development of LNG production in the US is very timely for the region and most likely source of supply. Nevertheless, projects need to be assessed on the assumption that prices are likely to be set at internationally competitive rates, not simply on a cost-plus basis.

The ***strategies to introduce gas to the region*** studied by the IDB's consultant team are presented, describing the 2 shortlisted strategies in greater detail. In relation to these, and using the demand scenarios from that study, this report presents an economic assessment of introducing gas for power generation in the six countries. The key objective is to come up with a first estimate of the value of LNG in gas-to-power. Value is assessed both in financial terms, by comparing the cost of gas to the current price of electricity in each country, and in economic terms, by valuing gas against the marginal or highest cost of power generation which gas would replace, which is oil-fired generation. The outcome of this analysis provides an idea of potential value of introducing LNG in each country.

A further aim of this report is to provide some lessons from international experience; the report includes a ***summary of 14 international country experiences***. The aim of this analysis was to draw lessons for Central America especially where it was possible to find information relevant to small countries with small demands, as well as attempts to establish LNG facilities on a regional basis (however no successful examples of the latter were found). The points covered in the cases include the initiative to develop a gas market, which were the key off-takers and what business models were employed. A further aspect examined was the importance of energy trade and international cooperation.

A key part of the study is the analysis of ***business models and their risk assessment*** within the small country context, to identify the most likely business models for implementation in Central America. Starting from the LNG value chain which shows the cost build-up, a corresponding business model and some variants are examined together with the likely contractual arrangements. From this, an assessment of risks and the risk allocation can be examined, with preliminary conclusions on the ability to finance the project. The set of business models examined and compared range from a disaggregated market structure under which each activity is owned by a separate entity, to some integrated project structures, that is, a single owner from LNG to the gas that is being marketed to power and other sectors. A risk analysis is carried out and compared for each of these business model types. Country specific risk factors are noted although at this stage, without the benefit of detailed project designs in the countries, it is not yet possible to assess risks on an individual country basis.

The penultimate part of the report provides a brief and preliminary analysis of the existing ***regulatory frameworks*** in the country for electricity and gas; the latter are largely absent, highlighting the need for establishing a regulatory framework in anticipation of the development of a gas market. The brief section illustrates the existing gaps in the institutional, legal and regulatory environment which could create additional risks for the development of LNG if not remedied.

In a final section we apply the concepts and methodologies developed in the Report to ***Costa Rica*** by taking into account the country specific context and conditions.

Report structure

The structure of this Report follows the overview provided above. It is structured into the following sections:

- Section 2 presents the analysis of gas demand drawing on the IDB study,
- Section 3 gives a summary of global LNG supply highlighting the key sources of supply. The case study descriptions are set out in Annex A1
- Section 4 presents a brief summary of the strategies for the introduction of gas to the region and moves on to present the economic assessment of the value of gas to each of the countries.
- Section 5 offers a brief overview of the international cases studied and draws key lessons learnt in each of the countries considered. Full details of the international experiences are presented in Annex A3.
- Section 6 includes the presentation of the business models and assesses which ones would be most suitable for the Central American region. The models are then assessed with respect to risks associated with the development of an LNG project in the region.

- Section 7 provides an overview of the key legal and regulatory requirements to develop an LNG terminal in the region, ensure regional electricity trade and potentially regional gas trade.

- Annexes cover further details on the LNG supply options and international LNG case studies. Additionally, Annex A6 includes an application of the concepts to Costa Rica in a detailed case study of an LNG terminal and power generation project in the country taking into account national power generation projects.

2 Demand for gas

There is currently no natural gas supply and therefore no demand for gas in the CA countries, but a successful introduction of gas would stimulate a switch to gas from other fuels, principally oil products used in power, industry and other sectors. This section reviews the potential demand for gas and briefly describes the methodology used to construct the demand scenarios.

Estimating gas demand is key for determining the economics of gas in the CA countries. Besides the economies of scale that can be achieved, high gas demand volumes (in particular from the power sector) can provide anchor demand that can give strong assurance to operators and project developers that LNG infrastructure will be highly utilised.

The region has significant potential for gas demand in the power sector. Power demand is expected to grow substantially and with hydro potential in most countries already maximised, additional baseload power generation needs to be developed. Natural gas provides baseload power generation (together with hydro) at considerably lower costs than the incumbent fuel, heavy fuel oil. Additionally, natural gas is the least polluting fossil fuel option, making it a more favourable option to coal and lignite. With no significant domestic coal and lignite sources, the case for coal is difficult to make. A more detailed analytical case for gas in power generation is made in Section 4.

2.1 Overview of approach

The IDB study carried out a comprehensive assessment of potential demand for gas, coming up with three scenarios. The methodology used by the IDB consultants' team to project gas demand is reviewed, as well as the resulting scenarios. The main finding is that the methodology is a sensible approach. The demand scenarios in the IDB study span a range of demand which is likely to encompass the possible outcomes, once LNG is introduced to the markets. In general however, demand projections seem high and ECA's assessment is that it is more likely that demand is at the lower end of the spectrum of demand proposed in the IDB study.

It should be noted that demand forecasting in a new market requires different approaches to demand forecasting in an existing market. In an existing market, past trends can be used as indicators of future trends. In the case of introducing gas as a new product into the CA countries, an alternate approach is needed based on rules for the switching of demand to gas from other technologies.

The IDB study developed three demand scenarios divided into two sub-sectors of demand:

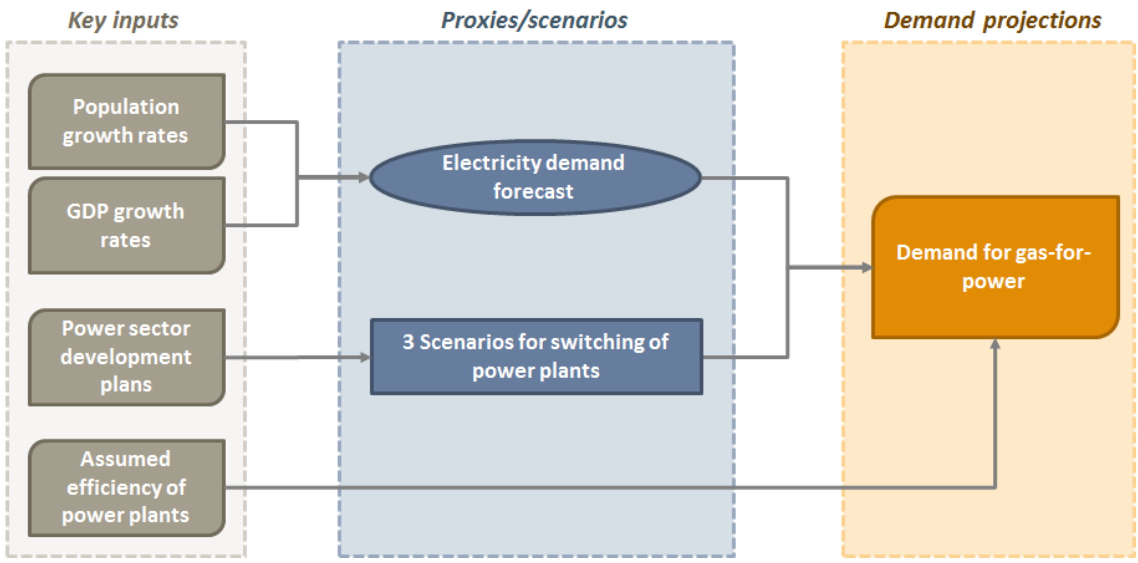
- Gas demand projections for power generation, which comprises the majority of the demand
- Gas demand projections from non-power sectors

Each of the above has its own methodology. As ECA's study takes the IDB's demand projections as a key input for analysis, we present and comment on the methodology used in the sub-sections that follow. We only provide brief summaries of the IDB methodology. Our main focus is on assessing the reasonableness of the methodology and the resulting demand estimations. More details of the estimation method and forecasting procedure are given in the IDB study report.

2.2 Gas to power demand

The following diagram summarises the steps in the methodology employed by the IDB consultant team to develop scenario projections of gas demand for power generation:

Figure 1 Methodology for gas demand projections for power generation



The methodology for gas to power demand is determined by two main two main steps:

- *Project total electricity demand*, using key macroeconomic variables and an estimated demand equation based on historical annual data from 2000
- Apply *a rate of fuel switching* for existing power plants to convert from fuel oil or coal to gas.

The variation across the three gas demand scenarios is based on different assumptions of fuel switching rates.

2.2.1 Electricity demand projections

The starting point for electricity demand projections is the historical power consumption data over the period 2000-2012. This data is extrapolated – through a regression analysis - on the basis of the following macroeconomic factors:

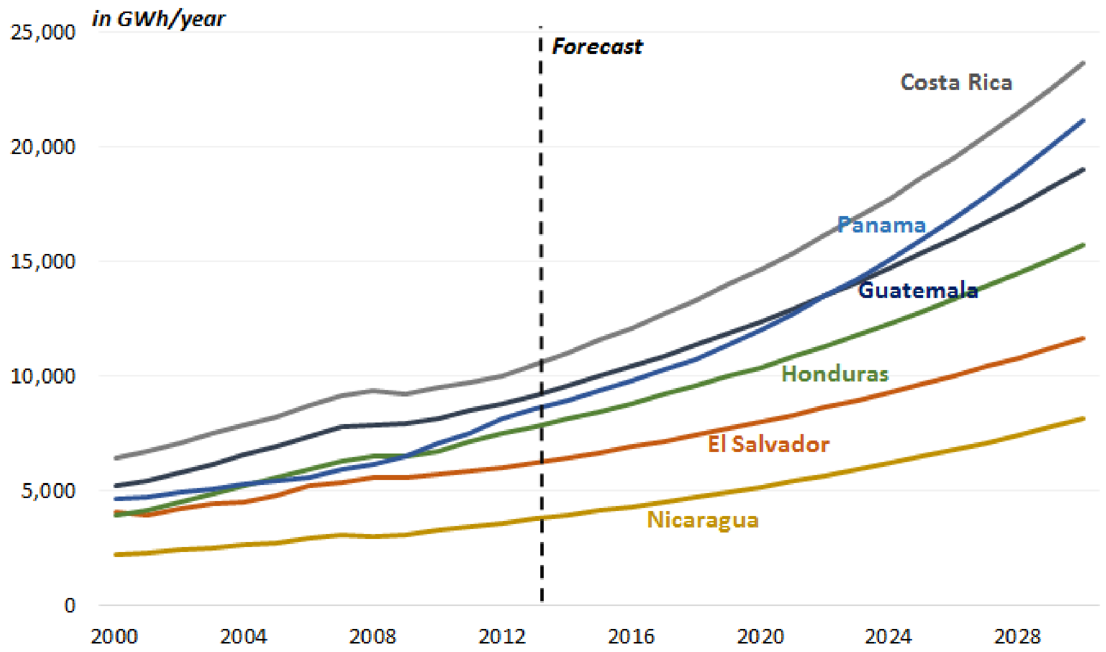
- *Population growth projections* by IMF for 2013-2018
- *GDP growth projections* by IMF for 2013-2018

Beyond 2018 the estimated growth rates were held constant. The historical data and projected figures for electricity demand by country are illustrated in Figure 2 below.

The corresponding average annual growth rates and their comparison with the respective Government projections are shown in the table below the graph.

The growth rates show that the projections from the IDB Report are quite different than Government projections. Relying on official electricity demand projections is however difficult, as it is not clear what underlying assumptions are used across the countries. It is therefore sensible to apply own projections on the basis of a consistent methodology even if these might be slightly different from Government projections. This allows for a direct comparison across power demand projections in all CA countries.

Figure 2 Electricity demand, historical and projected



Av. Annual growth rate	Guatemala	Honduras	El Salvador	Nicaragua	Costa Rica	Panama
IDB	4.4%	4.2%	3.7%	4.6%	4.9%	5.4%
Government base case	7.0%	*n.a.*	4%	*n.a*	4.0%	6.2%

Source: ECA based on IDB study by EEC and Government power sector development plans

2.2.2 Three scenarios for switching to gas

The IDB study's projections for gas demand from the power sector were developed for three demand scenarios. The assumptions of each of these are summarised in Table 2[2].

[2] The term 'converted' is used throughout, though more properly the existing plants are converted but the forecast plants in the power development plans are ***replaced*** by CCGTs

Table 2 Plant conversion assumptions in the three demand scenarios

	Low scenario	Medium scenario	High scenario
Liquid-fuelled thermal power plants	All existing and future/planned liquid-fuelled thermal power plants are converted to combined cycle gas-fired (CCGT) plants.		
Coal-fired thermal power plants	Existing coal-fired plants and those under construction are not converted, only future plants are converted.	All existing and future/planned coal-fired plants are converted to CCGT plants.	
Hydro power plants	Hydro plants entering into operation after 2021 are converted to CCGT.	Only hydro power plants entering into operation after 2017 are replaced by CCGT plants.	

Source: IDB study by EEC

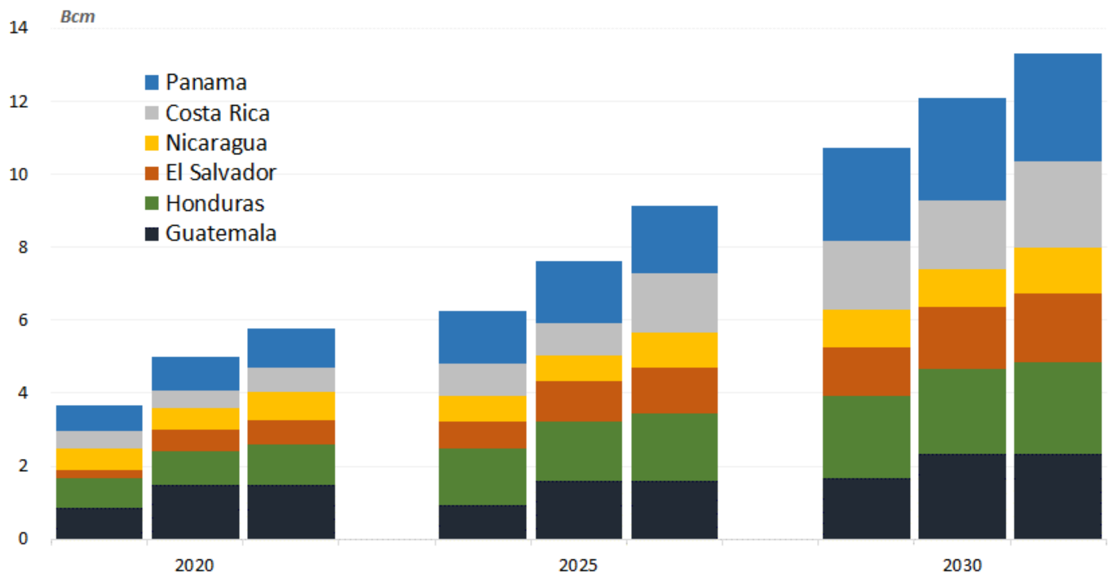
Each scenario assumes a different switching speed for existing and planned/future power plants in the region. An assumption made across all scenarios is that all existing and future diesel-fuelled power plants are converted to gas. This is in line with the IDB study's objective to study alternatives to reduce the cost of electricity generation in the region. Accordingly, the medium and high demand scenarios see all coal-fired plants converted as well, assuming that large gas demands would make generation with gas lower cost than coal. Finally, the replacement of planned hydro power plants with gas is assumed to be in 2017 or 2021 depending on the level of demand.

Note that the resulting gas volumes are not taking into account gas or electricity prices, but simply assume baseload operation across all gas fired power plants.

2.2.3 Projections of potential gas demand for power generation

On the basis of an extensive database of existing and planned power plants for each country, the electricity demand and switching scenarios were used to determine gas to power projections. The resulting potential gas to power demand levels across the six countries are illustrated in Figure 3.

Figure 3 Projections for annual regional gas for power consumption



Bcm	2020			2025			2030		
	Low	**Med.**	**High**	**Low**	**Med.**	**High**	**Low**	**Med.**	**High**
Panama	0.7	0.9	1.0	1.4	1.7	1.8	2.5	2.8	2.9
Costa Rica	0.5	0.5	0.7	0.9	0.9	1.6	1.9	1.9	2.4
Nicaragua	0.6	0.6	0.8	0.7	0.7	1.0	1.0	1.0	1.3
El Salvador	0.2	0.6	0.7	0.7	1.1	1.3	1.3	1.7	1.9
Honduras	0.8	0.9	1.1	1.6	1.6	1.8	2.2	2.3	2.5
Guatemala	0.8	1.5	1.5	0.9	1.6	1.6	1.7	2.3	2.3

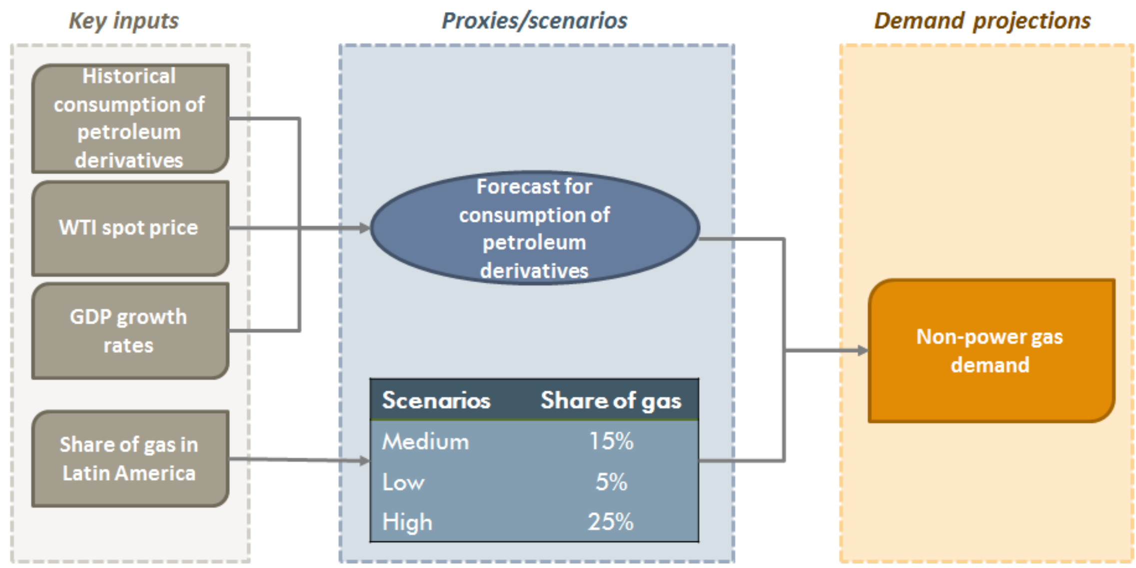
Source: ECA based on IDB study by EEC

Total demand in the region would vary between 3.7 Bcm and 5.8 Bcm in 2020 and increase to between 10 Bcm and 13.3 Bcm in 2030. The countries with the largest demand potential are Panama, Guatemala and Costa Rica. Whether this potential can be exploited on the basis of the economics of LNG in the electricity sector is analysed in Section 4.

2.3 Non-power sector gas demand

A similar approach as for gas to power demand was adopted for projecting the potential demand for gas in non-power sectors. Figure 4 summarises the methodology employed by the IDB consultant team to create projections of gas demand for non-power uses.

Figure 4 Methodology for non-power gas demand forecast



The key driving factor for non-power demand is the assumption regarding the share of potential demand for gas in the sectors where substitution is possible. In reality, the substitution depends on both the particular sectors/technologies and their suitability for gas, as well as the geographic scope of the gas distribution network. Each of the components in Figure 4 is discussed in the following sub-sections.

2.3.1 Consumption of petroleum derivatives

First, a linear regression partial adjustment model was used to project the consumption of petroleum derivatives. The model uses the following inputs as independent variables:

- Data on historical ***consumption of petroleum derivatives*** in the 6 countries.
- IMF data on ***GDP growth projections*** for each of the countries for 2013-2018. Data from 2018 was used for the period 2018-2030.
- The ***crude oil WTI price projected by the IMF*** (95 US$/barrel) was used for 2015-2018.

2.3.2 Scenarios for gas penetration

Second, scenarios were developed to represent different shares of gas 'penetration' in the primary energy matrix of the countries of CA. The basis for these were the shares of gas in selected Latin American countries, as provided in the *BP Statistical review of World Energy 2013*. Some examples are shown in Table 3.

Table 3 Share of gas as primary energy for selected Latin-American countries

Country	Share of gas in primary energy mix
Brazil	9.6%
Chile	15.2%
Colombia	24.3%
Peru	30.3%
Mexico	40.1%
Average	**23.9%**

Source: BP Statistical Review of World Energy (2013)

The IDB study re-based the 24% average by taking into account the share of electricity in the primary energy mix. This results in a medium case scenario of 15%. In other words, the share of gas in primary energy consumption has the potential to reach 15% in Central American countries, based on gas consumption in Latin America. To test the sensitivity around this medium case, scenarios with penetration rates of 5% (Low) and 25% (High) respectively were constructed (Table 4)

Table 4 Gas penetration scenarios for non-power gas demand

Scenario	Share of gas in primary energy mix
Medium	15%
High	25%
Low	5%

Source: IDB study by EEC

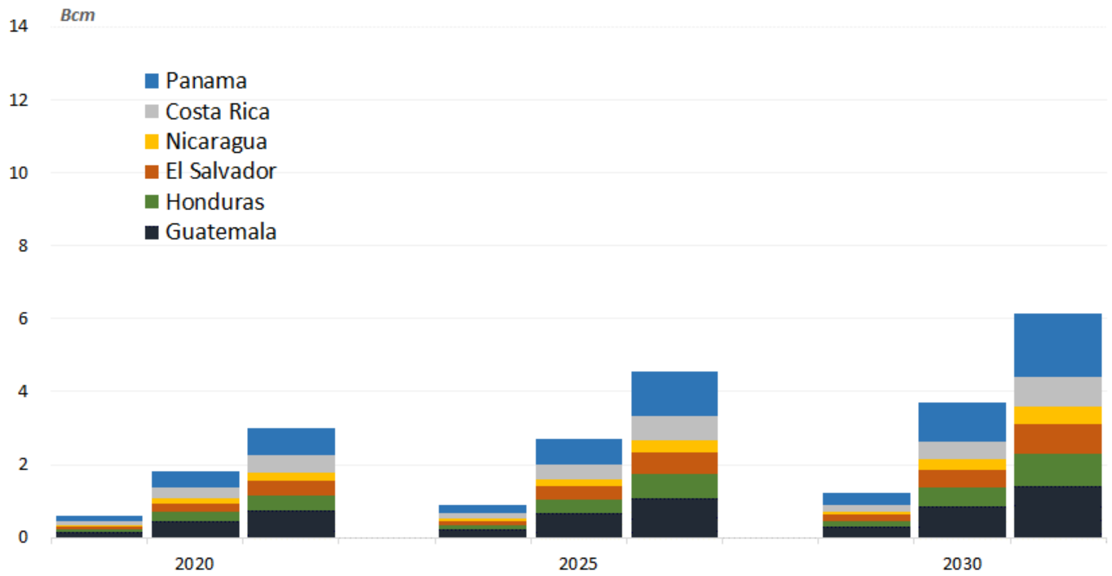
2.3.3 Non-power gas demand

Gas demand for non-power uses is estimated under three scenarios by assuming that gas will gradually start to replace petroleum derivatives as a fuel from 2017 onwards. Each share of gas penetration in the primary energy mix (shown in Table 4) is assumed to be achieved after 20 years.

Figure 5 shows the projected volumes of gas consumption in non-power generation sectors are considerably smaller for the entire region under all three scenarios.[3] Volumes are approximately half of those for the electricity sector in early years, falling to around a third of those for power at the end of the projection period. This is consistent with the expected lags in fuel switching; a general heat/boiler use can be switched quickly to gas, but a power plant conversion requires more forward planning, greater capital expenditure and a longer conversion time.

Figure 5 Projections of regional non-power gas consumption

[3] Projected volumes by country are available in the report's annex.



Bcm	2020			2025			2030		
	Low	**Med.**	**High**	**Low**	**Med.**	**High**	**Low**	**Med.**	**High**
Panama	0.1	0.4	0.7	0.2	0.7	1.2	0.3	1.0	1.7
Costa Rica	0.1	0.3	0.5	0.1	0.4	0.7	0.2	0.5	0.8
Nicaragua	0.0	0.1	0.2	0.1	0.2	0.4	0.1	0.3	0.5
El Salvador	0.1	0.2	0.4	0.1	0.4	0.6	0.2	0.5	0.8
Honduras	0.1	0.3	0.4	0.1	0.4	0.6	0.2	0.5	0.9
Guatemala	0.1	0.4	0.7	0.2	0.7	1.1	0.3	0.9	1.4

Source: ECA based on IDB study by EEC

2.4 Total potential gas demand

2.4.1 IDB total gas demand

The total gas demand projections are the sum of the power and non-power gas demands. Figure 6 below illustrates the aggregate gas demand projected for the region for the three scenarios. As a reminder, the three scenarios are:

- o ***Low demand*** – all existing and planned liquid fuel plants are converted to CCGT's, planned coal fired power plants are switched to CCGT's and all hydro plants planned after 2021 are CCGT plants. In the non-power sector, gas makes up 5% of the total primary energy mix[4].

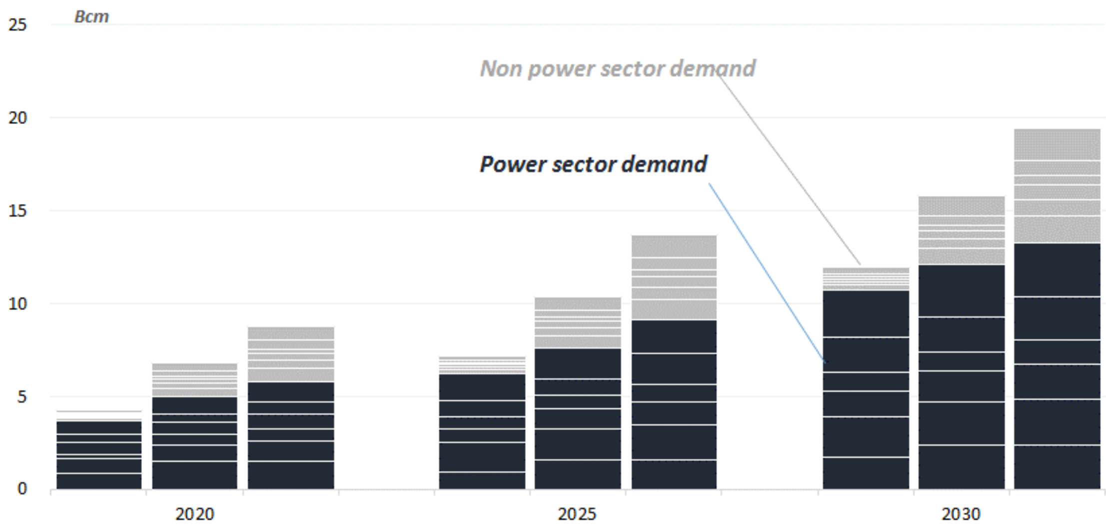
- o ***Medium demand*** - all existing and planned liquid fuel as well as coal plants are converted to CCGT's, hydro plants planned after 2017 are replaced by CCGT's. In the non-power sector, gas makes up 15% of the total primary energy mix.

- o ***High demand*** - all existing and planned liquid fuel as well as coal plants are converted to CCGT's, hydro plants planned after 2017 are replaced by

[4] The share excludes gas to power demand

CCGT's. In the non-power sector, gas makes up 25% of the total primary energy mix.

Figure 6 Aggregate regional gas demand scenarios



Bcm	2020			2025			2030		
	Low	**Med.**	**High**	**Low**	**Med.**	**High**	**Low**	**Med.**	**High**
Panama	0.8	1.4	1.8	1.7	2.4	3.0	2.9	3.9	4.7
Costa Rica	0.6	0.8	1.1	1.0	1.3	2.3	2.0	2.4	3.2
Nicaragua	0.6	0.7	1.0	0.8	0.9	1.3	1.1	1.3	1.8
El Salvador	0.3	0.8	1.0	0.8	1.4	1.9	1.5	2.2	2.7
Honduras	0.9	1.2	1.5	1.7	2.0	2.5	2.4	2.8	3.4
Guatemala	1.0	1.9	2.2	1.2	2.2	2.7	2.0	3.2	3.8
Region	**4.2**	**6.8**	**8.6**	**7.2**	**10.2**	**13.7**	**11.9**	**15.8**	**19.6**

Source: ECA based on IDB study by EEC

Total demand in the region would range between 4.3 and 8.8 Bcm in 2020, 7.2 and 13.7 Bcm in 2025 and 11.9 and 19.4 Bcm in 2030. In the Low demand scenario, the power sector accounts for around 90% of regional demand. In the Medium demand scenario, the power sector accounts for 75% of demand and in the high demand scenario, the power sector only accounts for 66% of total demand.

Demand across all countries is sufficiently high to warrant the development of LNG regasification options. Or at least demand will become sufficiently high in future to warrant LNG development over the medium term. A variety of small scale regasification options exist, which are mainly based around floating regasification and storage units. These can have capacities of minimum of 0.5 Bcm/y. Whether the demand levels across the countries are economically feasible will be assessed in Section 4.

2.4.2 Critical appraisal of IDB demand projections

The methodology for estimating gas demand in the region appears generally sound when considering the scope of the IDB Report. While a more economically driven demand projection could have been undertaken (i.e. a netback analysis for the main industrial users, the economic viability of switching fuel oil plants to gas and a detailed dispatch model for the power sector), the adopted methodology provides a good approximation to establish the economic feasibility of gas sector development in the region.

Overall however, the demand estimates appear high. In particular the range of gas to power demand seems more skewed on the high side. While we think that the demand is likely to lie within the IDB range, it seems more likely that actual demand will be similar to the low demand scenario.

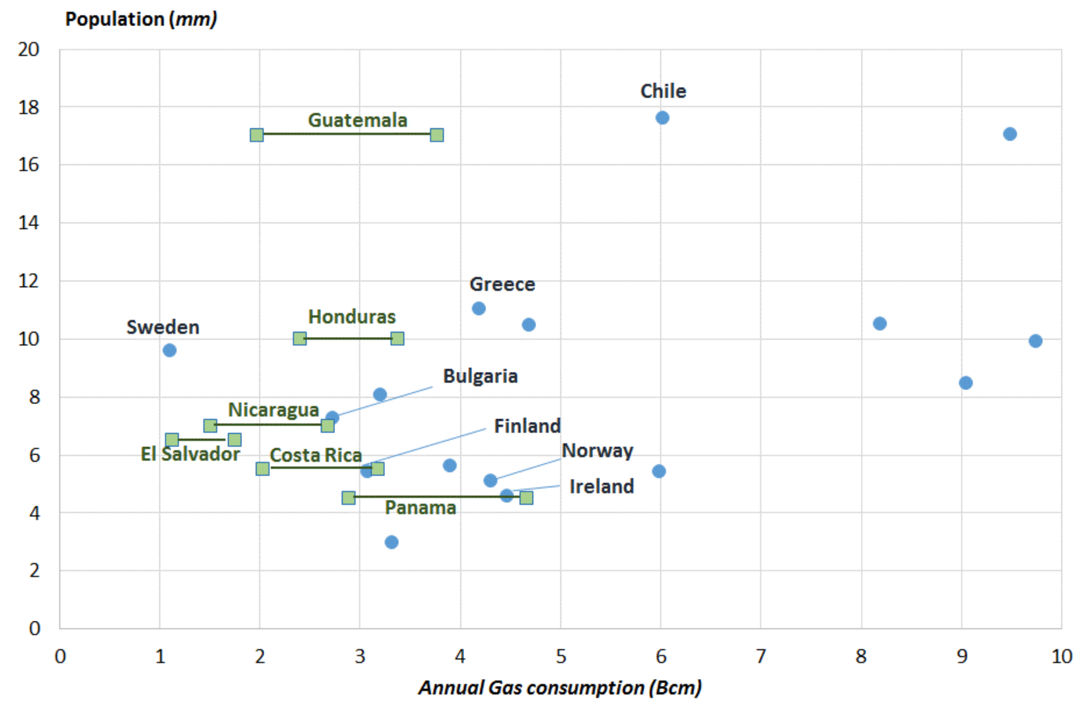
To assess the level of gas demand projections are feasible and potentially over or under estimated, we use here two comparators:

- Firstly, we compare the total level of demand with more mature markets in Europe and Latin America of a similar population size. This gives an approximated check of the gas demand numbers.

- Secondly we compare, the gas to power demand with domestic power generation capacity and implied gas to power generation.

Figure 7 shows the range (Low and High demand scenarios) for each of the six countries and compares the consumption levels with mature gas markets of similar size. While each of these markets will have different drivers for gas demand (temperature, power generation mix, distribution grids, etc…) it is nevertheless a useful initial indication to see whether the range of projected demand is reasonable. On the basis of the diagram it appears that IDB projections are reasonable, although the high demand estimates might be too optimistic. As Central American countries are unlikely to use gas for heating in the residential and commercial sectors, which a large number of the countries in Europe will do, demand is more likely to be on the lower side of the range.

Figure 7 Range of total demand in 2030 compared to mature markets



Source: BP Statistics and World Bank population data

Table 5 shows the range of gas to power demand by country in 2030, the associated installed gas fired power generation capacity and the existing capacity in country. The table shows that in order for the projected gas demand levels to materialise, between 50% and 120% of existing total power generation capacity would have to be gas fired power generation. This includes all existing thermal power capacity switched to gas and new gas fired power plants.

This seems a high estimate given that this capacity is to be developed over the period 2015 to 2030. For most countries this would correspond to four large gas fired power stations. We therefore conclude that the gas demand is more likely to be in the low range. A point that is reaffirmed when considering the ratio of gas to power demand and industrial demand. The split is 90% to 10% in the Low demand case, while it is 50% to 50% in the base case. This seems unreasonable.

The real test for the feasibility of gasification of the countries is however the assessment of the economics of gas integration in the electricity markets. This will be investigated in closer detail in Section 4.

Table 5 Demand and power generation capacity in 2030

	Gas to power demand *Bcm/y*			**Associated power gen. Capacity** *MW*			**Existing power generation capacity -** *MW*
	Low	*Med.*	*High*	*Low*	*Med.*	*High*	
Guatemala	1.7	2.3	2.3	1,400	1,900	1,900	2,800
Honduras	2.2	2.3	2.5	1,800	1,900	2,100	1,700
El Salvador	1.3	1.7	1.9	1,100	1,400	1,600	1,500
Nicaragua	1.0	1.0	1.3	800	800	1,100	1,100
Costa Rica	1.9	1.9	2.4	1,600	1,600	2,000	2,800
Panama	2.5	2.8	2.9	2,100	2,300	2,400	2,000

Source: ECA estimations

3 LNG supply analysis

3.1 Summary and overview of supply issues

This section summarises recent trends in LNG markets, examines how these trends create opportunities and challenges for LNG imports into Central America, and identifies the potential LNG suppliers to this region. More detailed information regarding this analysis is included in the Annex A1.

The analysis of LNG supply to Central America has to take into account the specific features of this region as a potential LNG importer, which fundamentally explain why Central American countries have not been successful up to now in becoming LNG importers. Since these countries are heavily dependent on oil, it is a key objective to be able to substitute it for natural gas through LNG imports. The main barriers to date lie in them lacking the two critical features that other buyers in the LNG market have: large demand volumes and strong creditworthiness. LNG projects have been initiated in El Salvador and Panama but they have not materialised. A more detailed description of these two case studies are described in Section 4.1.

Current trends in the global LNG market create challenges but also opportunities for Central American countries. These include:

- Expected large increase in gas/LNG supply
- Emergence of nearby market in the US for new sources of LNG exports
- Growth in portfolio trading
- Increasing relevance of spot or short term markets
- New pricing schemes
- Technological advances bringing down the scale of cost efficient transport, storage and regasification.

Gas demand will constitute a crucial variable in the determination of LNG import prices in the region. As discussed in the previous section, gas demand is likely to remain low, in particular in the short and medium term (Figure 6). In the highest demand scenario, aggregate regional demand would be 9 Bcm in 2020 (4 Bcm in the low scenario), 14 Bcm in 2025 (7 Bcm in the low scenario), and 20 Bcm in 2030 (12 Bcm in the low scenario). While these are in aggregate not negligible volumes, it is important to note that the demand is spread across six countries, which all have small possible offtakes. The difficulty of coordination will have an impact on the level of import prices – as scale is lower, unit costs will be higher and suppliers will charge a premium for gas deliveries compared to larger volume contracts.

Among the emerging suppliers in the LNG market, the most likely supplier to Central America is the United States. Significant gas supply volumes, low liquefaction costs and geographical proximity constitute some of the factors that will favour Central American imports from this region. United States exports may also support regional small scale liquefaction and hub trade. Canada could also constitute a supplier region to Central America, as shale gas reserves are also being unlocked, it is relatively close to the region, and there are some liquefaction projects under construction. Potential supply could also emerge from nearby countries (Trinidad & Tobago, Peru, Venezuela or Colombia) as well as from other established players in the LNG market, such as Qatar or Nigeria, as they are the dominant players in spot markets.

Mexico is the most likely supplier of piped gas with a planned interconnection to Guatemala. The focus of our study is on introducing LNG and we therefore do not provide a detailed discussion of piped gasification.

Other emerging suppliers, such as Australia or East Africa, are less likely to become the main suppliers to the region, as they confront disadvantages in terms of cost or distance. Other large suppliers such as Malaysia, Indonesia or Russia also constitute possible supplier options. However, their likelihood is low, as they are heavily oriented towards the Asian market (which carries a price premium), the distances are greater, and in some cases they confront supply side restrictions.

In recent years, regional LNG prices - supported by differences in regional demand and supply dynamics - have tended to diverge. Nevertheless, increased supply and competition in the world LNG market is expected to lead to some gas price convergence and lower gas prices in the medium and long term, especially if liquefaction projects in the United States are allowed to export without legal geographical restrictions. Innovative price structures are likely to emerge which could favour LNG introduction in Central America. Nevertheless, Central America’s characteristics in terms of demand (low scale, relatively high risk for the supplier) create particular conditions for prices. LNG suppliers are likely to be primarily concerned with securing pricing netbacks that are sufficient to justify the specific costs and risks of supplying this region. Accordingly, prices will diverge from what would be expected from a pure cost-plus approach to LNG pricing.

3.2 Global supply/demand balance: implications for Central America

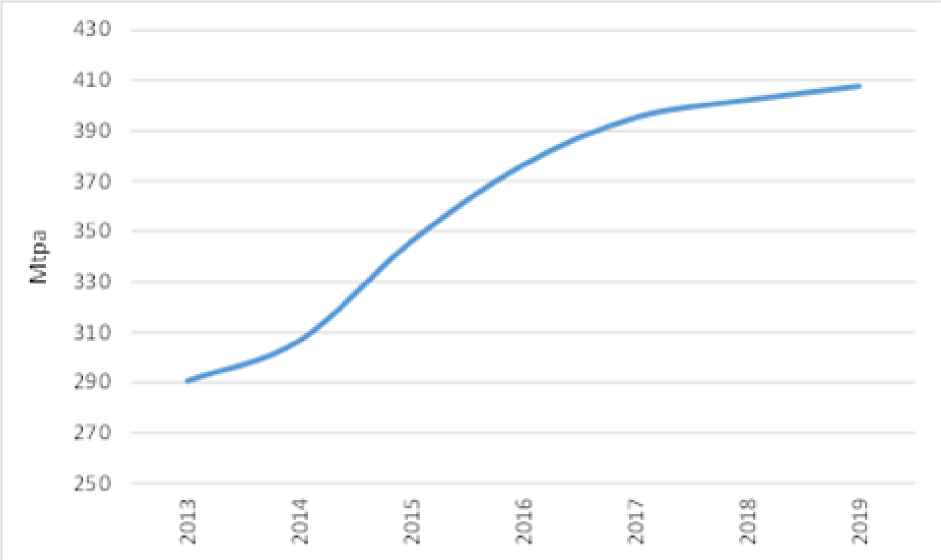
While the Central America countries may be supplied with LNG from a more nearby regional market involving American exports, prices and conditions in this market will not be immune from pricing and other influences in the wider international market. This section analyses recent trends in the world LNG markets, focusing on different aspects, namely supply and demand, prices, changes in regional trade patterns, short term market evolution, and recent trends in small scale LNG trade. The aim of the section is two-fold:

- First, to provide an overview of the world LNG market
- Second, to highlight how recent trends create challenges and opportunities for the development of LNG in Central America.

3.2.1 Key conclusions

Large natural gas reserves will enable continuous growth of natural gas production in the coming years and foster LNG supply. Since 2011 supply has been relatively constrained. However, after 2014 there exists potential for a considerable increase in liquefaction capacity, driven primarily by projects under construction in Australia and the United States. Additionally, planned liquefaction projects in different countries, especially in the United States, but also in East Africa and Russia, could give rise to a substantial reconfiguration and expansion in the long term LNG supply.

Figure 8 Expected growth of global liquefaction capacity, 2013-19



Note: data are constructed from projects currently under construction, which will come online over the period 2014-2019.

Source: ECA from World LNG Report – 2014. International Gas Union.

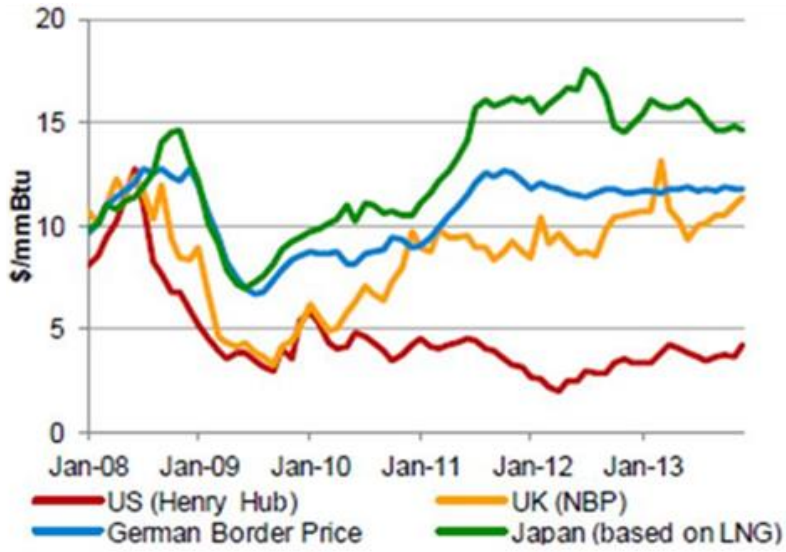
Entry and more supply competition create opportunities for the Central America region, as they may indicate natural gas price decreases and significant commercial gains from oil substitution, increasing incentives to develop the necessary import infrastructure. In addition, more competition and growing trade could contribute to increasing contract flexibility and easing credit conditions.

The demand side of the market continued to grow in 2013, in particular in Asia. Demand is expected to exhibit high growth after 2015. Higher demand growth will lead to market tightness in the short-medium term, until new capacity - mainly from Australia and the United States - enters the markets and fills the supply gap to maintain a supply and demand balance.

Increasing demand from Asia and other regions creates risks for the Central American region sourcing natural gas. Competition from buyers purchasing large volumes and with higher willingness to pay could hinder the ability of Central America to source in the international gas markets. The rate at which liquefaction projects in the United States obtain permits to non-FTA countries will be an important driver in the magnitude of this risk.

In recent years, regional LNG prices - supported by differences in regional demand and supply dynamics - have tended to diverge. In the medium and long term, increased gas supply from countries such as Australia and the United States coupled with arbitrage opportunities will contribute to increasing price convergence in world gas prices.

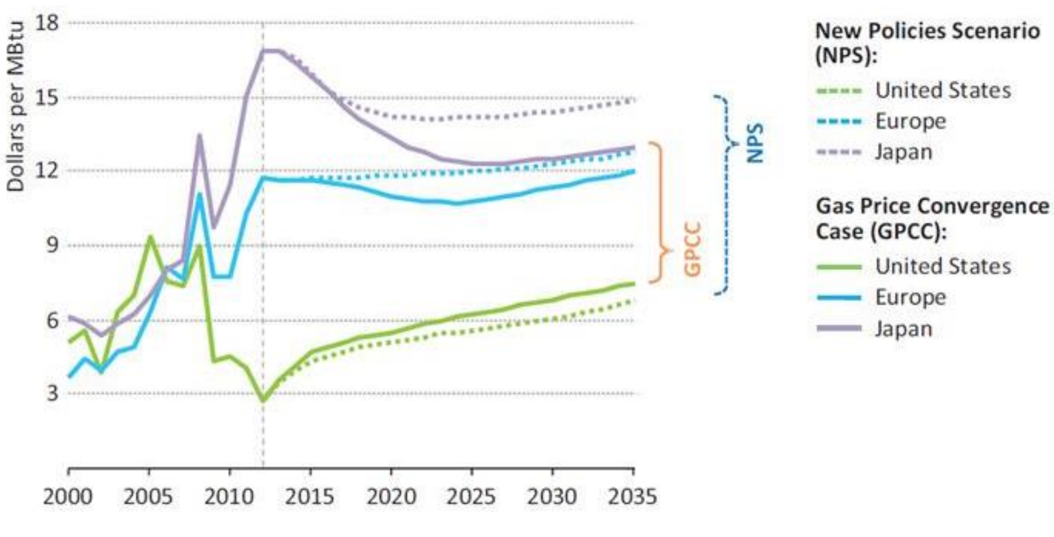
Figure 9 Monthly average regional gas prices, 2008-13



Source: World LNG Report – 2014. International Gas Union.

There are different outlooks for future gas prices. However, one view is that in the medium and long term, increased gas supply from countries such as Australia and the United States, coupled with arbitrage opportunities, will contribute to increasing price convergence in world gas prices (see Figure 10).

Figure 10 Regional gas prices in different scenarios, 2013-35



Source: World Energy Outlook 2013. International Energy Agency.

New entry is likely to favour new contract typologies and innovative price structures, which may present opportunities for the small importing countries of Central America. Nevertheless, Central America's characteristics in terms of demand - low scale, relatively high risk for the supplier - create particular challenging market conditions. LNG supply prices will likely incorporate a price premium to offset perceived risks and the delivery of small quantities, diverging from what would be expected from a pure cost-plus approach to LNG pricing.

Short term trading has notably expanded over the last fifteen years, increasing its share of LNG trade volumes to 33% in 2013. Short term trading has continued to grow, because of increased supply and competition, price arbitrage opportunities, and more shipping capacity.

Increasing short term trade offers opportunities for LNG development in Central America. One of the obstacles for LNG introduction in small emerging economies is long term off-take contracts. Spot LNG trade eases market access for small emerging LNG buyers, as creditworthiness and scale are not as relevant.

LNG markets are increasingly integrated and becoming more liquid and complex. Over the last fifteen years, portfolio trading strategies aiming to exploit arbitrage opportunities in higher value markets have been expanding, a trend that will persist in the future.

Increasing levels of portfolio trading represents an opportunity for Central American countries, as annual flexible volumes with low levels of take or pay are more adapted to their LNG needs. Nevertheless, competing in this market also poses challenges for Central American countries, as in the spot or short term market volumes are sold to the highest bidder and Central American countries would have to compete with buyers in more established and larger markets, facing a premium in terms of scale and risk.

3.3 Potential suppliers

This section provides an overview of potential suppliers to Central America LNG market, focusing on the factors which underlie their export potential, their likelihood of becoming a source of supply to Central America, and the liquefaction projects under construction or planned.

3.3.1 Key conclusions

United States

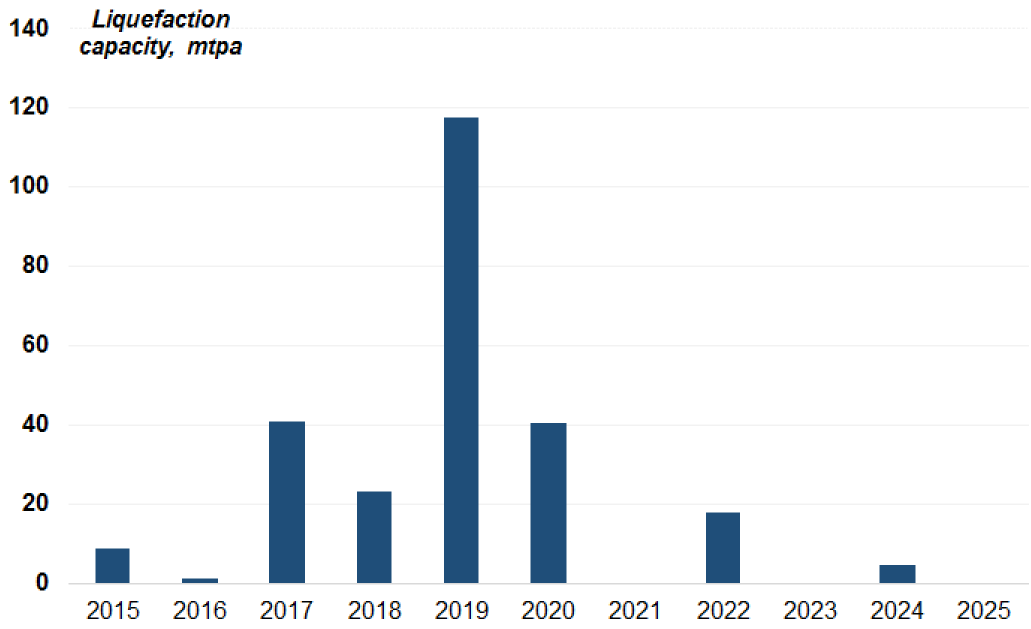
Among the emerging suppliers in the LNG market, the most likely supplier to Central America is the United States. The shale gas 'revolution' has transformed this country from an LNG importer to a potentially massive LNG exporter.

The emergence of unconventional gas resources and increasing export opportunities have given rise to a considerable number of liquefaction project proposals. In June 2014, 29 liquefaction projects had been proposed, representing nearly 287 mtpa (million tonnes per annum) of capacity (190 Mtpa of projects with announced start dates), making the United States the largest country in terms of post-2013 new liquefaction capacity. Most of the terminals are located in the Gulf Coast states: Texas (15), Louisiana (10), and Mississippi (1). Two projects have been proposed in Oregon, two in Alaska and three in the Atlantic coast - in Georgia, Maine and Maryland. Texas and Louisiana concentrate 74% of total proposed liquefaction capacity. In terms of 'coastal location', the majority of the projects and capacity are located on the East Coast (25 projects, 81.6% of total proposed liquefaction capacity). The capacity and expected commissioning date of the projects is shown in Figure 11.

The ability of all the proposed projects to become fully operational faces some risks, namely regulatory. To become fully operational, projects have to obtain the FERC approval. Social and political concerns about increasing gas prices in the United States in case LNG exports are allowed may lead the public authorities to slow the administrative authorization process, what would introduce delays in the development of some of the projects.

Several factors underlie the United States' export potential to Central America. First, geographical proximity, which is a key factor. Distances are slightly lower than those from Canada and considerably lower than those from other large LNG suppliers such as Australia, Malaysia, Indonesia, Qatar or Nigeria. Second, gas supply will be abundant, as well as liquefaction capacity. Third, liquefaction projects in the United States are brownfield, they have cost advantages compared to other supplier countries with abundant gas supply, such as Australia. Fourth, Central American countries have free trade agreements with the United States in the domain of natural gas - with the exception of Costa Rica[5]. As most of the United States projects already have FTA authorization, regulatory risks are lower in the case of exports to this region. Moreover, political pressures could lead towards a limitation of non FTA authorizations, which could impede United States supply reaching the Asian markets.

Figure 11 Proposed liquefaction capacity in the United States, June 2014



Source: elaboration from IGU (2014), FERC, DOE and operators' webpages

Canada

Canada is also likely to become a potential supplier to Central America, as shale gas reserves are being unlocked, it is geographically close, and there are some liquefaction projects planned, the majority in the West coast. Despite its potential, Canada's take off as a significant LNG exporter is expected to be delayed relative to the United States, since its shale industry and its export infrastructure are not as developed. One key

[5] *Natural Gas in Central America*, P. Shortell, Baragwanath K. and Sucre C., Energy Policy Group, Inter-American Dialogue, Working Paper, March 2014.

disadvantage of Canadian projects compared to the United States is their relatively higher liquefaction costs.

Nearby countries: Trinidad & Tobago, Venezuela, Colombia and Peru

Nearby countries to Central America, such as Trinidad and Tobago, Peru Colombia or Venezuela enjoy a shipping distance advantage to supply the region, so could also become suppliers to the region. Moreover, they are already LNG suppliers in the region (Trinidad and Tobago supplies the Dominican Republic and Peru supplies Mexico) or they are developing projects for small scale LNG exports in the region (Colombia).

Middle East and West Africa

The Middle East's main markets for exports are likely to remain in the Asia Pacific region. However, Qatar's role in the spot market increases the likelihood of LNG supplies from this region going to Central America. This could also be the case with Nigeria, another large player in the spot market, with a diversified export portfolio and already supplying to South America.

Australia and East Africa

Emerging suppliers, such as Australia or East Africa, are less likely to become major suppliers to the Central America region. Australia will experience a huge increase in liquefaction capacity in the coming years. However, most of the projects under construction have their capacity contracted and the target market is Asia including China. In addition, it confronts shipping disadvantages to Central America and its liquefaction costs are relatively higher compared to those of competing suppliers. East African projects enjoy some advantages, such as relatively low liquefaction costs -, but they face regulatory risks, depend on less developed infrastructure and have shipping advantages to Asia.

Malaysia, Indonesia and Russia

Other large suppliers such as Malaysia, Indonesia or Russia also constitute possible supplier regions. However, their likelihood is low, as they are heavily oriented towards the Asian market and in some cases they confront supply side restrictions. Indonesia's future export potential will be limited by current government policies aiming to secure domestic supply. Malaysia's exports are likely to be hit by declining natural gas supplies and increasing domestic demand, which is already favouring investment in regasification terminals.

4 Economics of LNG strategy

In this section of the report, we firstly briefly review the LNG strategies proposed in the IDB study and secondly assess the economics of the most likely LNG roll-out in the region. Hence the two questions we aim to answer in this section are:

- How is LNG most likely to be developed in the region?
- Is LNG an economically and financially viable option in the reviewed countries? If yes, what type and size of LNG regasification terminal is most viable?

Note that the analysis in this section is a regional analysis and country specific issues are limited to electricity price and IDB's gas demand forecasts. It is out of the scope of this Report to assess the precise load factors of gas fired power generation in each country and assess the financeability of LNG project for each country individually.

A deep-dive analysis on Costa Rica is provided in Section 8, where the principles outlined in this section and the next section are applied to the specific Costa Rica context.

4.1 LNG Strategies

This sub-section briefly presents the LNG strategies considered in the IDB study and highlights the strategy we are focusing on for the economic analysis.

4.1.1 IDB LNG strategies

The IDB study considered a total of 17 strategies, varying by different gas purchase arrangements (regional vs. national), different modes of supply (LNG, piped gas and electricity), onward energy distribution in Latin America and different demand levels. The details of the proposed strategies from IDB are presented in the Annex. Stakeholders of the IDB study shortlisted three of the strategies as being the most feasible options[6]:

- **Strategy A: independent projects in each country—** national regasification terminals would be built in the short-term in each country except Guatemala where a gas pipeline will connect the country to Mexico. Gas would be used to generate electricity which would then be transported over the national transmission networks or SIEPAC.

6 Large-scale regasification terminal; Regasification terminal; Pipeline

- **Strategy B: sub-regional integration—** two regasification terminals would be constructed in El Salvador and Panama according to ongoing initiatives. In the longer term, once capacity of the terminals is reached, new terminals would be built at new locations. Energy would be traded in the form of electricity on SIEPAC. Guatemala and Mexico are connected via pipeline.

- **Strategy C: integration with Mexico—** the northern part of the region is initially only supplied via the regasification terminal in El Salvador, and in the medium-term the pipeline from Mexico to Guatemala. The latter would later be extended to reach El Salvador, Honduras and Nicaragua. The southern part will be supplied by means of regasification terminals in Costa Rica and Panama.

A summarised discussion of these strategies is provided in Annex A3 and in the IDB Report. While Strategy C could be a long term possibility, the prior developments of LNG projects in Panama and El Salvador suggest that Strategy A and B seem most likely to materialise.

4.1.2 LNG strategy included in our analysis

Strategy B, the development of large regional LNG regasification terminals, might result in marginally lower LNG prices through greater bargaining power, but major difficulties in the practical implementation of a regional strategy remain:

- A high level of political cooperation across the countries would be required with some countries relying on neighbours and cross border electricity transmission infrastructure for their security of supply. The SIEPAC project could provide this infrastructure, however its slow development and low utilisation to date highlights the difficulties of coordinated actions among Central American countries.

- Gas demand volumes and seasonal patterns are likely to be different across countries, requiring a regional gas buying entity that can coordinate supplies and demand across countries. This would require a pooled ownership of several state owned utilities, making the risk profile of a regional LNG buyer likely to be opaque. Consequently gas purchase agreements could prove difficult to establish.

- The financing of power plants relying on long term power offtake contracts supplied through the SIEPAC may also be difficult. SIEPAC is untested and financiers are likely to prefer a lower risk 'domestic' power offtake project.

- The benefits of regional cooperation for LNG purchase are questionable. Total volumes of demand according to IDB are relatively small, particularly at early stages of development and it is uncertain whether these volumes would be significant enough to benefit from a bulk purchase 'discount'.

These observations, explored in more detail in Section 6.4, together with the ongoing efforts of introducing LNG in Panama and El Salvador, suggest that a national LNG terminal development is more realistic (Strategy A). While the (uncertain) benefits of bulk purchase might not materialise, Strategy A has a higher likelihood to materialise in the short to medium term. A domestic regasification terminal (i) requires minimal levels of regional cooperation, which can obstruct project development, (ii) provides a clear risk profile of gas and power offtakers, and (iii) can build on efforts already pursued in the region. Additionally, once established domestic regasification terminals can be expanded to cover regional gas and power demand. As a starting point for a new fuel/technology a domestic approach appears lower risk.

Our focus in this section is therefore to assess the economic viability of Strategy A. We also include an LNG terminal in Guatemala, despite plans of a gas pipeline to be developed to Mexico. The gas pipeline discussions are advanced and a Memorandum of Understanding for the US$ 1.2 billion project was signed in April 2014. Our analysis can complement the analyses for the pipeline and provide a reference point for energy policy makers in Guatemala.

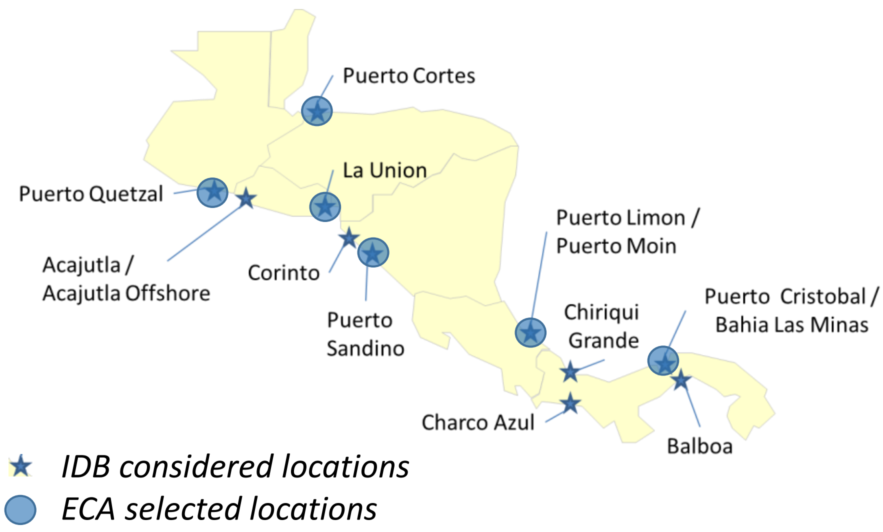
4.1.3 Location of regasification terminals

The location of regasification terminals is used in our analysis to estimate the transportation costs for LNG supplied from a supply point in the US[7] to Central America. While the approach chosen in the IDB study was to estimate an average transportation tariff across different locations in each country, we use only one location to assess the feasibility of concrete regasification projects. Section 4.3 described the calculation of shipping costs in more detail. The locations considered in the IDB study and locations used in our analysis are highlighted in the map below.

There remains significant uncertainty as to where precisely the regasification terminals will be located in Panama, El Salvador and Nicaragua. The final investment decision will depend on technical considerations and the ease of connecting associated power plants with the main transmission grid. Detailed discussions on the technical feasibility of these locations are out of the scope of this Report and are partially included in the IDB study. For Panama and El Salvador we use the locations of the ongoing LNG plans.

[7] Corpus Christi as indicative LNG export point is used in our analysis.

Figure 12 Location of ports selected



Source: IDB study and ECA

In any case, the results of the economic analysis are not sensitive to changes in the location of the regasification terminal, as these only change marginally with location. A more important consideration will be the detailed technical feasibility of these projects on the basis of pre-feasibility analyses.

4.1.4 Ongoing LNG developments in the region

El Salvador

El Salvador was the first country in Central America with a Natural Gas Bill for regulating reception, storage, regasification, transport, distribution, and marketing of natural gas. Introduced in 2008, the Bill and the associated secondary legislation for gas and LNG is still considered to be the most comprehensive regulatory framework for introducing natural gas in the region. El Salvador has experienced a 20- fold increase in its energy subsidy outlays since 2000 due to relying on imports for 50% of its energy use including 40% of its power generation which is currently sourced from fuel oil. In light of an expected electricity price of 120 US$/MWh from the planned gas fired power plant, which compares to a current electricity price of 160 US$/MWh, the Government sees gas integration into the power mix as an urgent and key priority.

El Salvador has had two proposed regasification terminals dedicated for CCGT plants at the port towns of La Unión and Acajutla. The map in Figure 13 shows the location of these facilities.

Figure 13 Location of potential regasification terminals in El Salvador

A proposed project by a consortium of the two private companies Cutuco Energy and Fonseca at the port of La Unión included a 500 MW electricity generating plant, an LNG terminal, a 160,000 cm storage tank, and two power transmission lines. The facility was originally planned to be completed by 2016, but these plans have since been derailed by municipal opposition, as demonstrations have taken place regarding health and pollution concerns. A new mayor has hinted at overturning the outgoing mayor's ban of thermoelectric facilities within the municipality, but local opposition persists. However the chances for this are slim.

In 2013, the Government of El Salvador awarded a contract to Energia del Pacifico (EdP), a consortium made up of private companies Quantum and Wärtsilä, to develop a 355 MW gas-fired power plant by 2018 off the coast of Acajutla. The power plant would source gas from a hybrid floating-onshore LNG terminal capable of receiving 125,000-180,000 cm LNG carriers and includes a 135,000-145,000 cm capacity floating storage unit and a 50,000 cm onshore storage regasification unit. The plant will connect to the national grid and SIEPAC via a 44km, 230 KV transmission line.

Recently an agreement was made by Energia del Pacifico SA to purchase 500,000 metric tons a year (corresponds roughly to 0.7 Bcm/year). Of the US$900 million initial investment requirements, EdP and its strategic partners are expected to contributed US$ 300 million with the International Finance Cooperation (IFC) and other providing the debt. However over recent months, EdP and Quantum were seeking a new strategic investor to take on a 70% majority role in the project. This has slowed down the prospects of the project recently.

Challenges for the project include the same local opposition that scuttled the La Unión plans, as well as the project's feasibility, as more than 25% of El Salvador's planned generating capacity is non-contracted (with the aim being to get this number down to 20%) and will need to be sold on the spot market. Private firms have been reluctant to invest in El Salvador's power market due to the uncertainty added by the lack of long term power purchase agreements (PPA's). Integration of the Central American power market can help alleviate these concerns. The long delayed SIEPAC line might further alleviate some of the concerns with access to regional markets reducing a project's exposure to only one market.

Panama

Panama is currently facing a significant domestic power supply shortage. 46% of Panama's net electricity generation is oil-fired, all of which is imported.[8] This has translated to costly electricity and a government budget burdened with energy subsidies. Given these concerns, Panama's government has been proactive in launching feasibility studies on LNG shipments, a gas pipeline in Colombia, and even domestic gas exploration, while a series of reforms have prepared the economy for the implementation of natural gas.

A law allowing natural gas to be used for electricity generation was introduced in August 2012 and the National Secretariat of Energy presented a *Plan of Incorporation of Natural Gas* in 2013 that included electricity generation, industrial, automotive, and residential use, and a cross-country pipeline.

The most probable project currently being planned in Panama is an LNG terminal and CCGT power plant project located off the coast of Colon. The project is developed by LNG Group Panama. The terminal is aimed to have an initial volume of 40 mmcfd (0.5 Bcm per year) and two lines with capacity of 150,000 cm/hour each are under construction. The regasification plant will supply a CCGT power plant, which will have an initial capacity of 270 MW, with further expansions to 400 MW and 580 MW envisioned. A long term power purchase agreement providing 550 MW of firm capacity and energy was signed

LNG Group Panama subsidiary Panama NG Power had won a government tender to supply 500 MW of power to the domestic market for 2017-2036 with the Colon plant at a price of $80-$130/MWh. The tender had come under criticism for being hastily constructed and restrictive, as Panama NG Power ended up being the only bidder. Panama NG Power has recently suspended the project after being denied a request for an extension on presenting the financial closing. The National Energy Secretariat claims the project could be bid on again early in 2015. It is therefore unclear whether the project will be developed as planned in 2017.

A smaller 60 MW CCGT power plant has recently been proposed by SoEnergy S. de RL Panama, the Panamanian arm of SoEnergy International. The plant would be located in the village of Tocumen but at this point only an environmental impact assessment has been submitted. The map in Figure 14 shows the location of these facilities.

Figure 14 Locations of potential regasification facilities in Panama

[8] U.S. Energy Information Administration, Panama overview.

4.2 Methodology and key concepts for economic assessment

This sub-section outlines our approach and methodology used in the economic analysis and defines some key concepts used to assess the viability of introducing LNG in a country. Additionally we outline the assumptions and inputs used in the analysis.

4.2.1 Approach and key concepts

The objective of the economic assessment is to identify whether the introduction of LNG will deliver economic and financial benefits to the countries. The methodology we will use to make this assessment is based on the economic and financial netback values of gas. These are defined as follows:

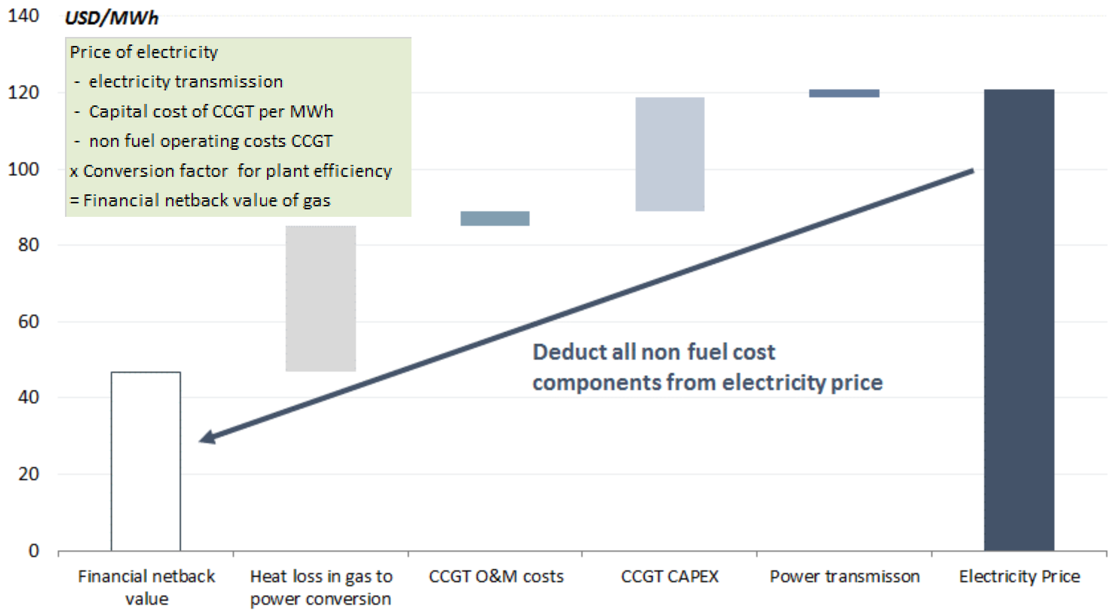
- ***Financial netback value*—** is the maximum unit gas price delivered to a power plant for a power generator to operate at a profit in the electricity market. The financial netback value is calculated by starting from the current price of electricity in each country (as an indicator of the pricing policy each country pursues), deducting the electricity transmission costs, the plant capital costs and O&M costs of generating electricity by gas, to arrive at a financial value of substituting gas into the power system.

- ***Economic netback value*—** is the maximum unit gas price delivered to a power generator to replace the current marginal operator. In the case of Central America, oil-fired generation would be replaced. This cost is taken at an average of 225 US$/MWh for the region, following the values assumed in the IDB report. Taking into account the conversion factor for plant efficiency, from gas to electricity, as well as the capital costs and O&M costs.

The two concepts of netback values are shown illustratively in Figure 15 and Figure 16. The economic and financial value of a project is established by comparing the netback values with the delivered cost of gas**:**

- ***Delivered cost of gas*** – is a 'bottom-up' per unit cost estimate of supplying gas to a power plant. Unlike the netback value, where costs are deducted from a final product price (electricity in this case), the delivered cost of gas is the summation of all costs along the value chain. The delivered cost of gas is the build-up of the following costs: wholesale gas price in LNG exporting country, gas transmission price to bring gas to LNG exporting facility, liquefaction costs, LNG shipment costs, regasification costs in importing country and delivery gas to power plants in importing country.

Figure 15 Illustrative Financial netback value

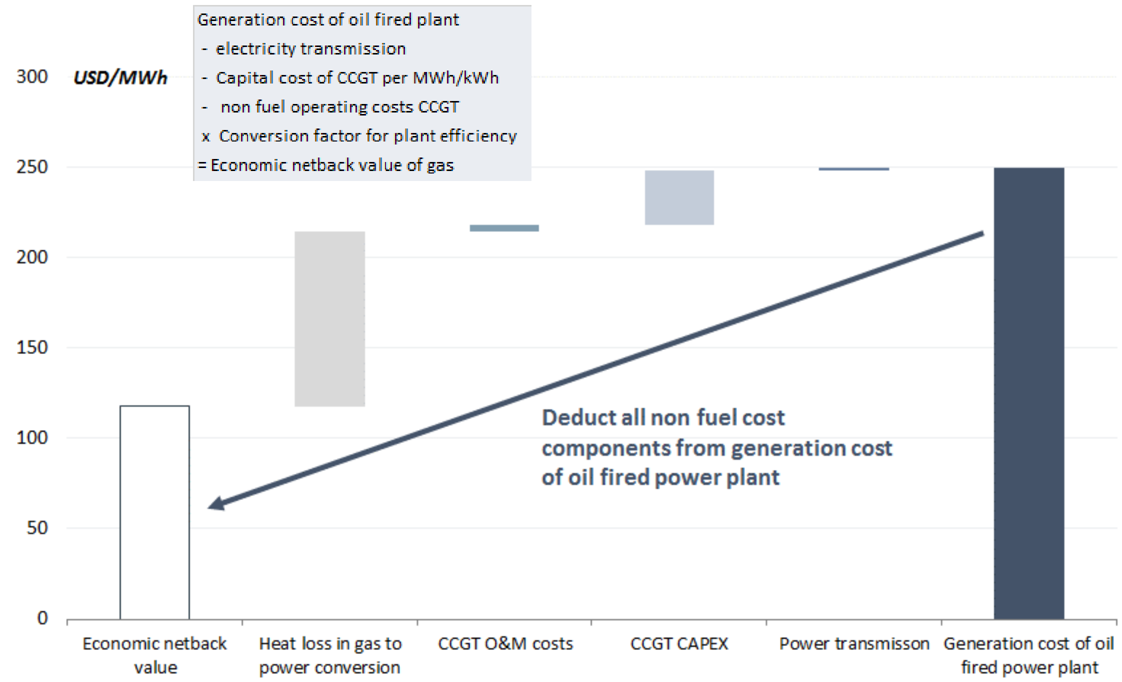


Source: ECA

By comparing the delivered cost of gas and the netback values, we can assess whether natural gas supplied through LNG has economic justification in the region or country. The difference between the netback values and the cost of delivered gas are essentially cost savings. Three scenarios can occur:

- *Netback values > cost of delivered gas* - this would mean that the introduction of gas would result to cost savings and the project is likely to be feasible.
- *Netback values = cost of delivered of gas* - this would imply that gas can just be delivered at the maximum price at which it would compete with incumbent fuels, likely making this project not feasible.
- *Netback values < cost of delivered gas* – this would imply that gas cannot feasibly be introduced in the power generation mix unless electricity prices rise accordingly.

Figure 16 Illustrative Economic netback value



Source: ECA

For **financial cost savings**, i.e. financial netback less cost of delivered gas, the estimate would be close to the financial savings that the country's power sector would make for each unit of gas introduced. Because the price input to the calculation is the electricity price, this is a financial valuation as it is based on cash savings in the power sector. If the current electricity prices in each country reflect the average cost of generating electricity from all sources, then this could also be termed the average financial value of a unit of gas. Total annual value is the unit financial value multiplied by the quantity of gas introduced to the country in that year; the net present value (NPV) of a regasification project is estimated by discounting the annual savings values for each year net of capital investments for a regasification terminal and summing.

The same approach to calculation is taken for the **economic cost savings,** the total economic value per year and the present value over the whole time period. The difference is that the unit economic value is based on the assumption that one unit of gas fired power substitutes for one unit of the most expensive generation in the system, assumed to be the cost of oil-fired generation.

4.2.2 Methodology and general assumptions

Two measures are used to calculate the economic and financial feasibility of LNG introduction in the Latin American countries:

- The ***Net Present Value*** (NPV) – the NPV is a discounted cash flow method where future revenue streams and costs are discounted and added to provide one value in current monetary terms. The revenue flows for the economic/financial NPV are the economic/financial cost saving multiplied by the demand volumes in each year up to 2040. This is done to understand the value of the entire project and whether it is reasonable to finance it with a view to the near future. In the case of this study, the NPV represents the viability of introducing LNG to the region over a 23-year period.

- The ***Internal Rate of Return*** (IRR) - the IRR is the discount rate at which a project with future cash flows has an NPV of zero. It therefore provides a benchmark discount factor above which the project would not be viable. If the discount factor lies below the IRR, the project is viable. The IRR is usually considered a better measure to compare the viability across different projects.

As we are assessing the economic and financial feasibility of regasification investments, we treat the regasification CAPEX as one-of investments. This means we do not treat CAPEX as a per-unit cost in our NPV analysis that is added to the cost of delivered gas, but as a large initial investment outlay. Hence we do not need to impose simplifying assumptions on the utilisation of the gas storage facility. The reason this is done is to have a more realistic revenue and cost flow for the regasification project rather than spreading the capital costs over the entire project lifetime. We do however also calculate the cost of delivered gas including regasification CAPEX and OPEX as a per-unit cost to provide an indication of the full costs faced by power generators. This is done in Section 4.3.2.

The main assumptions we use in our NPV and IRR calculations are:

- A project start date in 2017,
- A time horizon until 2040; assuming a project start in 2017, this would correspond to a project life of 23 years,
- A discount rate of 12% for both economic and financial evaluation methods.
- All CAPEX for the initial regasification capacity is incurred in one year, 2016. For onshore terminals this is based on demand in 2031 and for FSRU's on demand in 2026. More details at the end of Section 4.3.
- Throughput volumes of regasification in any given year are the minimum of demand levels in that year or maximum regasification capacity of the proposed terminal.

4.2.3 Floating vs. onshore terminals

Besides assessing the question whether it is economically and financially feasible to introduce LNG into the Latin American region, our methodology also determines what type of regasification terminal is more feasible. We consider here two different types of regasification terminals:

- ***Onshore terminal –*** a land-based terminal consists of a jetty and mooring facilities with unloading arms, LNG storage tanks which feed LNG to vaporizers that regasify the LNG and send it out to the local gas network. The number of jetties and storage tanks required will be determined by the maximum LNG ship size being unloaded, as well as the volume of LNG to be imported and the send out characteristics required to meet the market requirements. Representative construction stage duration is around 3 to 4 years. Figure 17 shows examples of onshore regasification terminals.

Figure 17 Example of onshore regasification terminals

Source: Poten LNG Study for Lebanon

- o ***Floating Storage and Regasification Unit (FSRU) –*** FSRU's come in different forms and we focus our analysis on permanently berthed FSRU's with gas transfer across a jetty. The FSRU is permanently moored and LNG is transferred from the delivery vessel (which is a conventional LNG tanker) across the jetty by STS transfer. Both vessels are securely moored while the transfer takes place through conventional unloading arms equipped with safety shut-down systems. LNG is vaporized on board the permanently moored FSRU and is sent ashore via a gas pipeline. This option eliminates all onshore development except for the gas pipeline landfall. As a results FSRU's require considerably lower initial CAPEX, but have higher annual operating costs. FSRU's are typically leased rather than bought and this is what we will assume in our analysis. This means that the annual operating costs of FSRU's go beyond maintenance and operation but include leasing rate as well. These are substantially higher than operating costs of onshore terminals. Project lead times of FSRU's are considerably shorter than onshore terminals (16-30 months). However, the send out rates, i.e. annual supply volumes of an FSRU are typically smaller than for onshore terminals.

Figure 18 Example of onshore regasification terminals

Source: Poten LNG Study for Lebanon

A more detailed technical discussion on FSRU's and onshore terminals and on the advantages and disadvantages of the terminals is provided in the Infrastructure Annex of the IDB study.

4.3 Inputs and assumptions of economic analysis

As noted above, the economic assessment of introducing gas in the form of LNG to the Central American region is based on the difference between the following key indicators:

- ***Netback values -*** the financial and economic netback values of gas for the region and for each of the six countries. These are calculated on the basis of electricity prices, gas fired power generation plants cost components and load factors.

- ***Cost of delivered gas –*** the per-unit cost of gas at the entry point to the gas fired power station. This is calculated by the sum of:

  - ***Wholesale LNG prices –*** as in the IDB study, we assume LNG into Central America will be sourced from the US. The following components will therefore determine the delivered cost of LNG: Henry Hub price in Louisiana, gas transmission cost in the US from Henry Hub to the liquefaction point, and liquefaction costs.

  - ***Shipping costs –*** the costs from our assumed delivery point (Corpus Christi in Texas) to ship LNG to the respective terminals in Central America.

  - ***Regasification capital costs and operating costs -*** includes the cost of building and operating a regasification terminal. We distinguish here between FSRU scenarios and onshore LNG scenarios. As noted above, we use total investment costs in our NPV analysis rather than a per-unit cost spread over the lifetime of the project.

The following sections provide more details on the inputs used and assumptions made for each of these categories.

4.3.1 Financial and economic netback values

The economic assessment presented in this sub-section calculates the two estimates of value indicated at the start of Section 4.2.1.

- ***Financial netback value***.

- ***Economic netback value***

The **financial netback value of gas** is calculated starting from the wholesale price of electricity for 2013 for each of the six countries as presented in Table 6.

Table 6 Wholesale electricity prices in Central America, 2013

in US$/MWh	**Wholesale Electricity Prices**
Guatemala	121
Honduras	173

El Salvador	160
Nicaragua	160
Costa Rica	123
Panama	210

Source: IDB study

From the electricity price we deduct the following:

- o ***Electricity transmission cost –*** this is assumed as 2.0 US$/MWh in line with the assumptions made in the IDB study
- o ***Capital cost for gas to power generation -*** 28.9 US$/MWh calculated on the basis of a 60% load factor, a 20 year operation of a CCGT plant and capital cost of 1,230 US$/kW[9].
- o ***CCGT Operation and Maintenance costs -*** 3.7 US$/MWh based on a variable cost assumption of 3.7 US$/MWh and a fixed cost assumption of 6.31 US$/kW/year[10].
- o ***Conversion factor for plant efficiency from gas to power*** – This is the factor of converting energy content of gas into electricity. For CCGT plants, this can be as high as 55%, however we assume here a more conservative 50%. This is in line with efficiency factor applied in the Black & Veatch Cost of Power Generation report, 2012.

We assume all the costs and electricity tariffs to remain constant over time. Without a full country electricity dispatch it is difficult to predict electricity price changes. Additionally electricity prices can be influenced by erratic political factors, making a projection of tariffs difficult.

The **economic netback value of gas** is calculated based on the cost of generation with the fuel that would be replaced by gas. In the case of Central America, gas-fired generation would replace oil-fuelled power production. The formula used to calculate the economic netback value deducts the capital and O&M costs (listed above) from the cost of generating one MWh with an oil-fired power plant.

On the basis of a capital cost of 1,025 US$/kW, a load factor of 40%, an efficiency conversion of 40%, total OPEX of 1.3 US$/MWh, fuel costs in 2015 of 3.5 US$/gallon we calculate a generation cost for oil fired plants of 244 US$/MWh. Over time however the fuel prices are assumed to increase with oil price changes as projected by the International Energy Agency (1.2% per annum). While assuming a uniform fuel oil prices is a simplifying assumption, as different countries will have different fuel oil

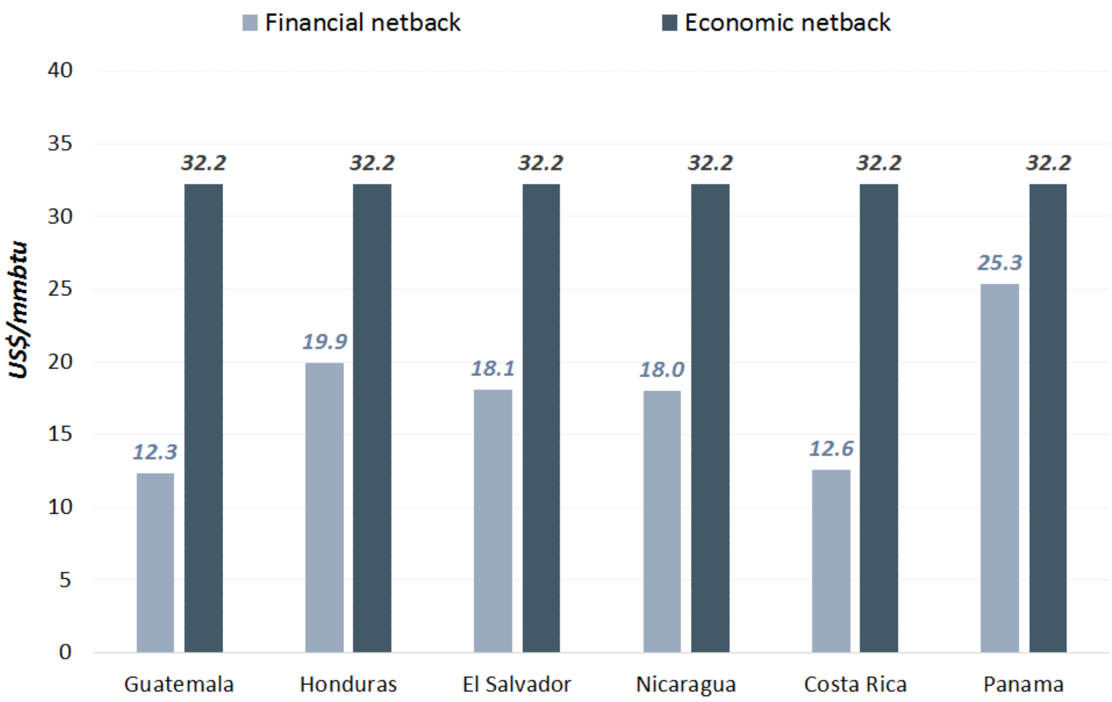
[9] For a representative 580 MW CCGT plant, Black & Veatch Cost of Power Generation report, 2012. CAPEX costs can change as capacity changes and economies of scale are reached, however these differences are likely to be small for power plants in the order of magnitude relevant in this Report. While estimated demand in the countries exceed 580 MW, it is unlikely that all demand would be covered by one large power plant. Instead a number of medium sized power plants would be developed.

[10] Black & Veatch Cost of Power Generation report, 2012

price arrangements and power generation efficiency rates, the differences are likely to be small across countries.

Figure 19 shows both the economic and financial netback values for the year 2020.

Figure 19 Netback values of gas in Central America in 2020



	Financial Netback *US$/mmbtu*	**Economic Netback** *US$/mmbtu*
Guatemala	12.3	32.2
Honduras	19.9	32.2
El Salvador	18.1	32.2
Nicaragua	18.0	32.2
Costa Rica	12.6	32.2
Panama	25.3	32.2

Source: ECA calculations

The results show that the financial netback prices vary between 12.3 US$/mmbtu in Guatemala to 25.3 US$/mmbtu in Panama. The financial values, being based on actual electricity prices, vary by country: Panama has the highest wholesale electricity prices so the value of substituting gas into the power system produces the highest savings. Guatemala and Costa Rica, with the lowest electricity prices, yield the lowest financial netback values for gas. Throughout this analysis, we assume that the financial netback values are kept constant until 2040. For the economic netbacks they increase by the rate of growth of fuel oil prices over time. At any one time they are the same across all countries. In 2020 they are 32.3 US$/mmbtu.

4.3.2 Cost of delivered gas

This sub section outlines the inputs and assumptions made in calculating the cost of delivered gas. We provide a discussion for each component of the cost of delivered gas.

Wholesale LNG prices

The wholesale LNG price is defined here as the price of LNG that could be faced by Central American countries before LNG transportation and regasification, i.e. at the exit of the liquefaction plant. The wholesale price includes the following three components:

- ***Wholesale gas price in exporting country*** – in our analysis this is assumed to be the USA
- ***Gas transmission costs*** of transporting gas within the US
- ***Liquefaction costs*** for converting gas to LNG
- ***Profit margins*** along the value chain

Following the assumptions used in the IDB study, the starting point for analysis is the gas price that could be achieved with a gas purchase agreement for gas sourced from Henry Hub (HH) in the state of Louisiana.

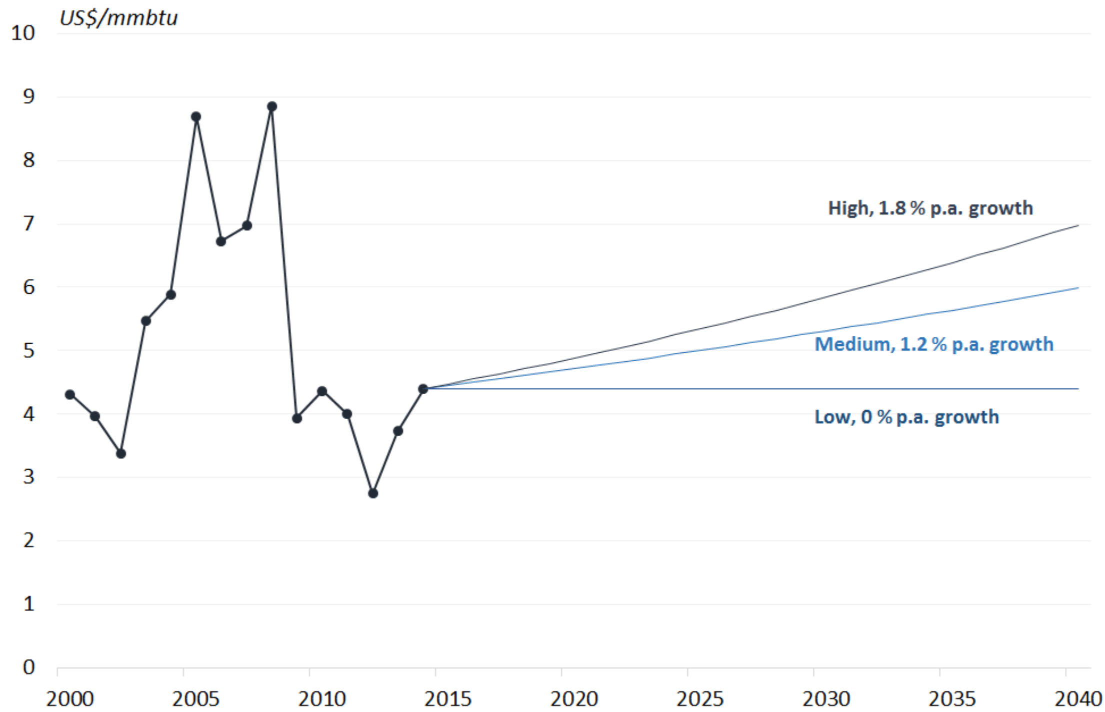
The Central American countries will not be able to buy LNG at the Henry Hub (HH) price plus direct costs, as LNG prices are exposed to different market dynamics than domestic gas prices (e.g. global LNG supply and demand and price differences between regions). Nevertheless, the HH price plus margins is a useful starting point for setting an approximate build-up of costs to the final delivered price. The average HH price on June 30th 2014 (year mid-point) was 4.39 US$/mmbtu and we use this as a starting price.

Three price scenarios are considered to estimate how HH prices may develop over the period 2015 to 2040:

- ***Low gas price scenario*** – gas prices remain constant until 2040. This is a scenario constructed as a best case scenario considering recent HH price development.
- ***Medium gas price scenario*** – gas price growth of 1.2% per annum until 2040. This scenario is based on the HH low gas price scenario of the International Energy Agency’s (IEA) 2013 World Energy Outlook (WEO).
- ***High gas price scenario*** – gas price growth of 1.8% per annum until 2040. This is based on the HH high gas price scenario of the IEA’s WEO.

The development of HH gas prices under the three scenarios is illustrated in Figure 20 together with the most recent trends in HH gas prices.

Figure 20 Gas price scenarios for delivered gas



Source: US Energy Information Administration, IEA WEO

Additionally to the Henry Hub price, importers of LNG will have to cover the costs of gas transmission costs from the gas supply sources to the liquefaction facilities. This is difficult to estimate precisely, as the US does not have a postage stamp transmission tariff but instead different prices across transmission line segments. With uncertainty in the exact location of the export facility, we therefore make a simplifying assumption of 1.50 US$/mmbtu for gas transmission. This is based on an average tariff of gas transmission lines in the US published by the US Federal Energy Regulatory Commission. We assume this price to increase by 0.5% per annum.

The third element to include in the wholesale cost of LNG are the liquefaction costs. These can vary by size of liquefaction trains, year of construction, location and length of contracts. All these are uncertain at this stage and it is therefore difficult to determine the exact fee for liquefaction Central American countries will face. For the purpose of this analysis, we have taken the average fees of five 20 year contracts for LNG supplies from British Gas, Gas Natural, Gail, Korea Gas and Total. Under the five contracts the average cost for liquefaction is 3.00 US$/mmbtu. We assume this price to increase by 0.5% per annum.

As noted above, it would be unreasonable to assume that Central American countries would face cost reflective tariffs independently of global LNG market developments. To account for possible rent seeking from exporting entities and thereby creating a conservative scenario, we assume an arbitrary mark up on the sum of costs of 1.50 US$/mmbtu. We assume this to remain constant over time.

Table 7 summarises all the elements determining the wholesale LNG price.

Table 7 Wholesale LNG prices for Medium gas price scenario

US$/mmbtu	2015	2020	2025	2030	2035	2040
HH price (Medium)	4.4	4.7	4.9	5.2	5.6	5.8
US gas transmission	1.5	1.5	1.6	1.6	1.7	1.7
Liquefaction fee	3.0	3.1	3.1	3.2	3.3	3.4
Possible rent margin	1.5	1.5	1.5	1.5	1.5	1.5
Total	**10.4**	**10.8**	**11.2**	**11.6**	**12.2**	**12.4**

Source: Adapted from IDB demand projections

Shipping costs

Shipping costs are based on the assumptions made in the IDB study. No significant changes in the key drivers for the shipping costs are assumed. The main assumption and parameters used are highlighted in the table below:

Table 8 Assumptions for shipping costs

Cost categories		
Rental costs of tanker per day	US$/day	110,000
LNG capacity	Cubic metres	138,000
Panama Channel crossing costs	US$/ship	1,200,000
Shipping losses @ 0.2% per day	%/day	0.02%
Transport time (return) and offloading[11]		
Guatemala – *Puerto Cuetzal (Pacific)*	Days	13.1
Honduras – *Puerto Cortes (Atlantic)*	Days	6.4
El Salvador – *La Reunion (Pacific)*	Days	12.4
Nicaragua – *Puerto Sandino (Pacific)*	Days	12.3
Costa Rica – *Puerto Moin (Atlantic)*	Days	8.1
Panama – *Puerto Cristobal (Atlantic)*	Days	8.7

Source: IDB study

The resulting shipping costs are summarised in Table 9. The largest components of the costs are the Panama Canal fee rates (for Pacific ports) at 0.42 US$/mmbtu and the shipping costs at 0.04 US$/mmbtu /day. The costs are assumed to change at a rate of 0.5% per year over the period 2015 to 2040.

[11] We assume LNG to be exported from Corpus Christi in Texas

Table 9 Shipping costs, *US$/mmbtu*

US$/mmbtu	2015	2020	2025	2030	2035	2040
Guatemala – *Puerto Cuetzal (Pacific)*	0.98	1.00	1.03	1.06	1.08	1.11
Honduras – *Puerto Cortes (Atlantic)*	0.27	0.28	0.28	0.29	0.30	0.31
El Salvador – *La Reunion (Pacific)*	0.94	0.96	0.99	1.01	1.04	1.06
Nicaragua – *Puerto Sandino (Pacific)*	0.94	0.96	0.99	1.01	1.04	1.06
Costa Rica – *Puerto Moin (Atlantic)*	0.34	0.35	0.36	0.37	0.38	0.39
Panama – *Puerto Cristobal (Atlantic)*	0.36	0.37	0.38	0.39	0.40	0.41

Source: Adapted from IDB Study

Capital and operating costs of regasification

The approach for capital expenditure calculation is based on cost data provided in the IDB study as well as projects that have recently been developed or are in the process of being developed internationally. The data used is based on publicly available documentation. On the basis of these figures we establish CAPEX numbers per unit of Bcm that can be delivered in a year. These are then multiplied by the minimum of demand or maximum capacity of the regasification terminals in each country.

The demand scenarios we use here to identify the regasification capacity requirements are based on the IDB demand scenarios presented in Section 2. These are labelled as 'Low demand', 'Base demand' and 'High demand'. Additionally, ECA constructed a fourth demand scenario, 'Very Low demand' where only 50% of demand from the 'Low demand scenario' are assumed to materialise. Demand under this scenario is likely to be too low for onshore terminals. For FSRU's however, this demand would still be technically feasible. We assess the commercial feasibility of these demand volumes in our financial analysis below.

The time horizon of the study is 2040 and it would be unreasonable to assume that a regasification terminal would be developed in 2017 on the basis of gas demand in 2040. We therefore assess two strategies:

- ***Onshore strategy*** - the initial capacity of the onshore regasification terminals assumed to be built in 2016 is based on gas demand in 2031 (15 years advance).
- ***FSRU strategy*** - The initial capacity of an FSRU assumed to be built in 2016 is based on 2026 demand (10 years advance).

Additionally, we make the following assumptions:

- All regasification units operate at an 85% load factor,
- The minimum capacity for an onshore terminal is 180 mmcfd (or 1.6 Bcm/y with an 85% load factor)

Table 10 shows the regasification capacity requirements for each country under each of our four demand scenarios. By applying a demand driven capacity estimation and capping gas flows at the maximum capacity, we assume regasification utilisation rates cannot exceed 100%. This approach for capacity estimation is a more country-focused approach than that followed in the IDB study, where regasification capacities have not been tailored to country demand.

Table 10 Annual capacities for onshore and FSRU strategy

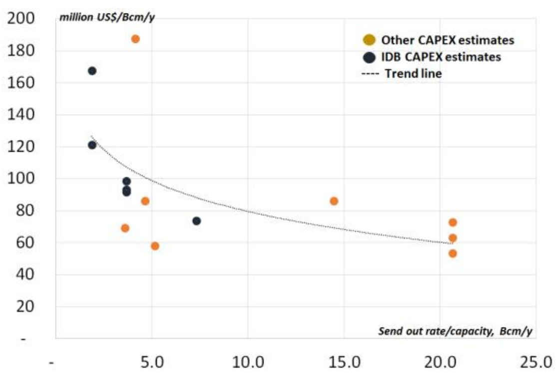
Bcm/y	Onshore				FSRU			
IDB Demand scen. >	**Very Low[12]**	**Low**	**Base**	**High**	**Very Low**	**Low**	**Base**	**High**
Guatemala	-	2.4	3.9	4.6	0.8	1.5	2.8	3.4
Honduras	-	2.9	3.4	4.1	1.1	2.1	2.5	3.1
El Salvador	-	1.8	2.6	3.3	0.6	1.2	1.9	2.4
Nicaragua	-	-	1.6	2.1	0.5	1.0	1.2	1.6
Costa Rica	-	2.4	2.9	3.9	0.6	1.2	1.5	2.8
Panama	1.7	3.5	4.7	5.7	1.1	2.2	3.1	3.9

Source: Adapted from IDB demand projections

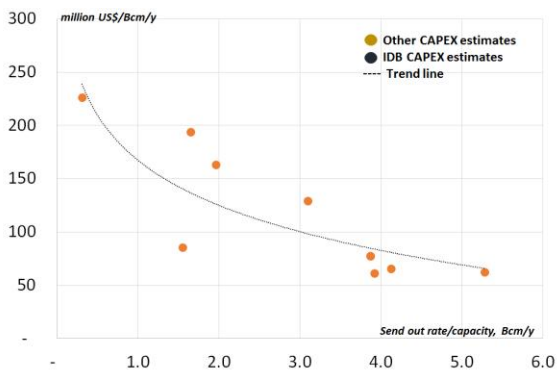
As noted, we multiply the capacity with per unit CAPEX of regasification numbers. To obtain CAPEX data, we compiled a small dataset of recent and proposed regasification projects. The projects and sources are listed in the Annex. The relationship between unit CAPEX (US$ million/Bcm/y) and total project size (Bcm/y), shows that economies of scale in regasification projects are important, both for onshore as well as offshore project. Figure 21 shows the scatter diagram of capacity vs. per unit CAPEX cost and illustrates the importance of economies of scale clearly. As regasification projects become large in size, the unit costs drop significantly. The relationship is particularly strong for FSRU's.

Figure 21 Capacity vs. per unit CAPEX across projects

Onshore terminals



FSRU's



Source: ECA adapted from public sources

[12] No entry means that demand numbers in 2031 are too small to justify the development of an onshore terminal.

The trend line of the cross sectional analyses[13] is used to estimate the total capital costs of regasification across countries and demand scenarios. This means that we do not apply one single US$/Bcm/y measure but instead adjust the CAPEX costs to the size of the terminal. Table 11 shows our applied unit CAPEX numbers across all scenarios.

Table 11 Unit CAPEX used in our analysis

US$ million /Bcm/y	Onshore				FSRU			
IDB Demand scen. >	**Very Low**	**Low**	**Base**	**High**	**Very Low**	**Low**	**Base**	**High**
Guatemala	-	120	106	101	185	143	104	93
Honduras	-	114	109	104	164	121	110	98
El Salvador	-	127	117	111	199	157	128	113
Nicaragua	-	-	130	122	208	166	156	137
Costa Rica	-	119	114	106	198	156	141	104
Panama	129	109	101	95	162	120	98	85

Source: ECA

The resulting total CAPEX numbers calculated on the basis of capacities and unit CAPEX numbers are shown in Table 12. The costs include all components associated with the terminals apart from port excavation costs, as they are assumed to be developed at locations with existing port facilities. For onshore terminal the costs include jetties, storage tanks, ship unloading systems, regasification units and all associated pipelines. For FSRU's they include the costs for jetties, delivery pipelines, moorings but exclude the floating unit leasing costs. These are covered under OPEX. Besides send-out rates, storage capacity is also a driver for regasification CAPEX. However for simplicity, we have not adjusted the cost parameters for different storage options. We are therefore assuming a standard 150,000 cm storage capacity in our analysis.

[13] For onshore terminals this is *Unit CAPEX = 143.6 – 27.8 x ln (capacity)* and for FSRU's this is *Unit CAPEX = 167.2 – 60.9 x ln (capacity)*

Table 12 Total investments for onshore and FSRU strategies

US$ million	Onshore				FSRU			
IDB Demand scen. >	**Very Low**	**Low**	**Base**	**High**	**Very Low**	**Low**	**Base**	**High**
Guatemala	-	283	410	466	139	214	293	314
Honduras	-	329	376	430	173	257	281	304
El Salvador	-	230	308	363	118	186	244	276
Nicaragua	-	-	209	262	106	169	187	225
Costa Rica	-	290	327	412	120	188	217	293
Panama	221	379	471	544	177	261	305	328

Source: ECA[14]

The table shows that FSRU CAPEX numbers are mainly lower than onshore terminal investments. This is due firstly to the fact that overall capacity for FSRU's is lower than onshore terminals (demand in 2026 vs. 2031). Secondly, lower unit CAPEX numbers particularly for the high demand case determine this trend.

The variable operating costs (OPEX) associated with operation and maintenance are usually small both for onshore as well as offshore terminals. In line with Foster Wheeler estimates used in the IDB study, we assume OPEX for onshore terminals to be 3% of CAPEX investments every year. FSRU's require lower operation and maintenance costs and we assume 1% of CAPEX[15].

A more significant annual cost for FSRU's is the annual leasing rate of the floating unit. These will vary by size of the unit and storage. For units with storage capacity of 150,000 cm (as is assumed here) and an average capacity of between 1 and 3 Bcm per year the leasing rates can range between US$ 40 and 60 million per year[16]. As the typical size of the FSRU's investigated in this study is closer to 1 Bcm, we apply a leasing rate of US$ 45 million.

Applying a present value calculation (discounted at 12%) on the actual LNG flows in each country and each demand scenario, we obtain the following per unit regasification costs (Table 13) over the lifetime of the projects.

[14] Discrepancies between the total CAPEX numbers and the product of Table 11 and Table 10 is due to rounding.

[15] See *LNG in Lebanon* Report by Poten published in 2013

[16] See *Curacao CNG-LNG Feasibility Study*, Shaw Consultants, 2012; *LNG in Lebanon* Report by Poten ; Hoegh Company presentation, October 2012; *LNG Feasibility Study in Ghana*, C2HM for Government of Ghana

Table 13 Unit cost of regasification (OPEX and CAPEX), *US$/mmbtu*

US$/mmbtu	Onshore				FSRU			
IDB Demand scen. >	**Very Low**	**Low**	**Base**	**High**	**Very Low**	**Low**	**Base**	**High**
Guatemala	-	1.0	0.8	0.8	3.1	1.8	1.1	1.0
Honduras	-	1.0	0.9	0.9	2.8	1.6	1.4	1.2
El Salvador	-	1.4	1.1	1.0	5.5	3.2	1.8	1.5
Nicaragua	-	-	1.0	0.9	4.6	2.6	2.3	1.8
Costa Rica	-	1.2	1.1	1.0	4.0	2.3	1.9	1.4
Panama	1.4	1.1	1.0	0.9	3.0	1.8	1.2	1.0

Source: ECA[17]

Our analysis does not model the onshore gas pipeline network extension required to meet the gas to power demand in each country. This has been done in more detail in the IDB study. For the purpose of our analysis however, we assume a gas transmission price of 1 US$/mmbtu to be applied for gas being delivered from the regasification unit to the power plant. WE assume this to increase by 0.5% per annum.

Total cost of delivered gas

Bringing all the costs together, allows us to project the delivered cost of gas in each country. The delivered cost of gas here is defined as the likely price power generators would face at 'entry' to the power plant.

As we have a combination of different scenarios – 3 price variations, 4 demand variations, 6 countries, years 2015-2040 and two LNG strategies – we focus in Table 14 and Table 15 on one particular scenario: medium gas price development and base demand level for the year 2020. Over time the cost of delivered gas will change mainly in step with the gas price scenario assumptions.

The results show that for an onshore LNG strategy the gas price would be in the range 13.0 US$/mmbtu to 13.8 US$/mmbtu in 2020. For an FSRU strategy, the gas price would be generally higher and in the range of 13.4 US$/mmbtu to 15.1 US$/mmbtu.

[17] Present Value CAPEX and OPEX

Table 14 Cost of delivered gas in 2020 – Onshore, Medium price, Base demand

	Capacity of terminal	Wholesale LNG	Shipping costs	Regas. costs	Gas trans-mission	Unit cost of gas
	Bcm/y	*US$/mmbtu*	*US$/mmbtu*	*US$/mmbtu*	*US$/mmbtu*	*US$/mmbtu*
GU	*3.9*	10.8	1.0	0.8	1.0	**13.6**
HO	*3.4*	10.8	0.3	0.9	1.0	**13.0**
ES	*2.6*	10.8	1.0	1.1	1.0	**13.9**
NI	*1.6*	10.8	1.0	1.0	1.0	**13.8**
CR	*2.9*	10.8	0.3	1.1	1.0	**13.3**
PA	*4.7*	10.8	0.4	1.0	1.0	**13.1**

Source: ECA estimations

Table 15 Cost of delivered gas in 2020 – FSRU, Medium price, Base demand

	Capacity of terminal	Wholesale LNG	Shipping costs	Regas. costs	Gas trans-mission	Unit cost of gas
	Bcm/y	*US$/mmbtu*	*US$/mmbtu*	*US$/mmbtu*	*US$/mmbtu*	*US$/mmbtu*
GU	*2.8*	10.8	1.0	1.1	1.0	**13.9**
HO	*2.5*	10.8	0.3	1.4	1.0	**13.5**
ES	*1.9*	10.8	1.0	1.8	1.0	**14.6**
NI	*1.2*	10.8	1.0	2.3	1.0	**15.1**
CR	*1.5*	10.8	0.3	1.9	1.0	**14.1**
PA	*3.1*	10.8	0.4	1.2	1.0	**13.4**

Source: ECA estimations

The cost of delivered gas is a very insightful indicator to assess the economic and financial feasibility of gas in the country's energy mix. In particular this indicator can be compared to the netback values estimated in Section 4.3.1. In most countries the cost of delivered gas is below the netback values shown in the table in Figure 19. This would suggest that LNG introduction in these countries is economically and financially feasible. This is the focus of Section 4.4.2 and 4.4.3.

4.4 Results of economic analysis

By comparing the netback values with the cost of delivered in one year and for one given scenario, one can already gain an indication of the economic and financial feasibility of introducing LNG and gas into the countries' power generation mix. We show this in Table 16 for the year 2020 and a base case demand and base price scenario (Base case scenario-see definition of scenarios in next sub-section).

Table 16 Financial netback values vs. cost of delivered gas, 2020, Base case

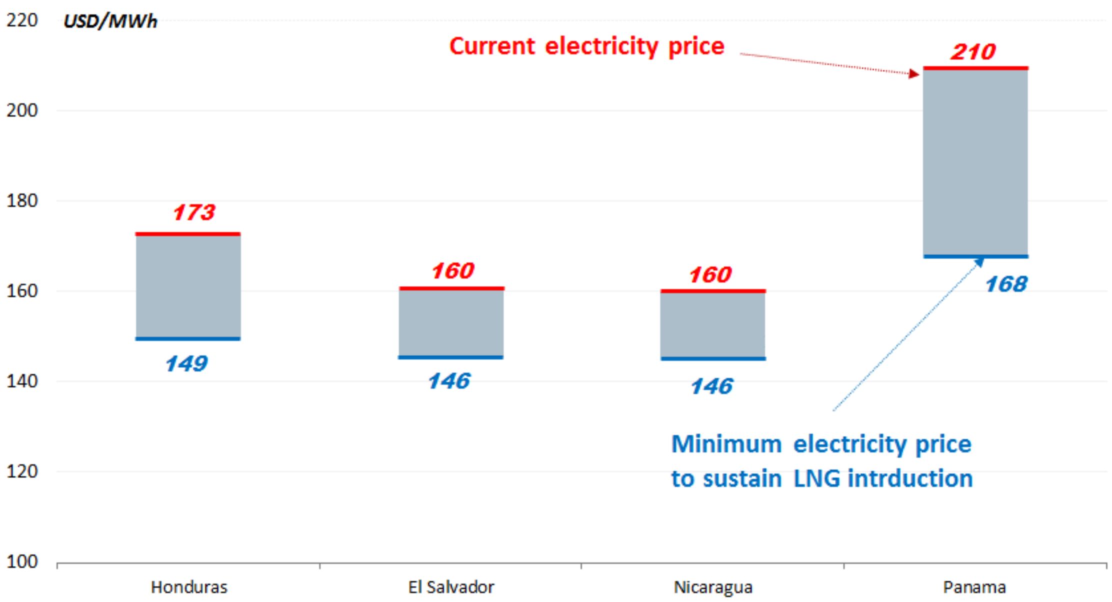
US$/mmbtu	Onshore			FSRU		
	Cost of delivered gas	Rent	Financial netback value	Cost of delivered gas	Rent	Financial netback value
Guatemala	13.6	-1.3	12.3	13.9	-1.6	12.3
Honduras	13.0	6.9	19.9	13.5	6.4	19.9
El Salvador	13.9	4.2	18.1	14.6	3.5	18.1
Nicaragua	13.8	4.2	18.0	15.1	2.9	18.0
Costa Rica	13.3	-0.7	12.6	14.1	-1.5	12.6
Panama	13.1	12.2	25.3	13.4	11.9	25.3

Source: ECA

This representative snapshot of one scenario in one year shows that in all countries, apart from Guatemala and Costa Rica, LNG and gas is financially feasible. Both Guatemala and Costa Rica have the lowest electricity prices in the region accounting for these results. Although indicative, the results only show a particular snapshot of the financial feasibility and the next sub-sections will consider he changes in the difference between netback values and cost of delivered gas over time.

This means that a considerable rent can be achieved from introducing LNG into these markets. If this rent was to be allocated to electricity consumers, electricity prices could be reduced significantly. Figure 22 shows the electricity price range that would sustain the introduction of LNG for each of the four countries with positive rents.

Figure 22 Electricity price range that could sustain LNG introduction



From an economic perspective, the introduction of LNG is overwhelmingly positive: gas fired power generation from gas sourced as LNG is lower cost than oil fired power generation in all countries and for both types of terminals. Table 17 shows the results.

Table 17 Economic netback values vs. cost of delivered gas, 2020, Base case

US$/mmbtu	Onshore			FSRU		
	Cost of delivered gas	**Rent**	**Economic netback value**	**Cost of delivered gas**	**Rent**	**Economic netback value**
Guatemala	13.6	18.6	32.2	13.9	18.3	32.2
Honduras	13.0	19.2	32.2	13.5	18.7	32.2
El Salvador	13.9	18.3	32.2	14.6	17.6	32.2
Nicaragua	13.8	18.4	32.2	15.1	17.1	32.2
Costa Rica	13.3	18.9	32.2	14.1	18.1	32.2
Panama	13.1	19.1	32.2	13.4	18.8	32.2

Source: ECA

4.4.1 Scenarios assessed

A large variety of scenarios have been assessed and tested. For each country scenarios can be varied along the following dimensions:

- ***Gas prices*** – as outlined above, we have assessed three different gas price projections until 2040.
- ***Gas demand level*** – three different gas demand scenarios have been assessed. They are all in line with IDB projections.
- ***Type of LNG terminal*** – 2 different LNG terminal types have been assessed: FSRU's and onshore terminals.

Presenting the NPV and IRR results of the permutations across all scenarios would be difficult and not insightful. Instead, we focus the results in this section on a feasible combination of price and demand scenarios. The following three scenarios are presented for both, FSRU's and onshore terminal strategy:

- ***Low case*** – High gas price scenario and Low demand scenario
- ***Base case*** – Medium gas price scenario and Base demand scenario
- ***High case*** – Low gas price and High demand scenario

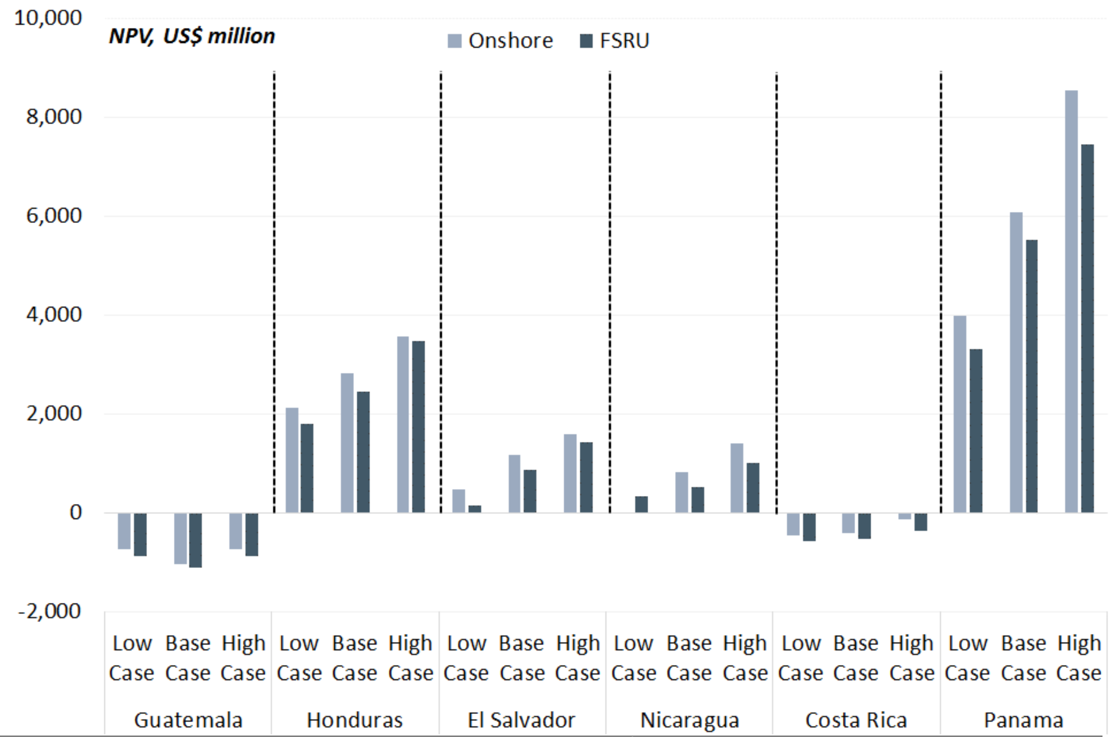
This provides a total of 6 scenarios. Besides covering the most realistic combination of demand and price combinations, the three scenarios represent the width of results from a bad case scenario[18] to best case scenario.

[18] Technically the 'very low' demand scenario would be the worst case scenario, but the demand levels of this scenario are so low that only Hondurasand Panama would have a suitable LNG terminal. This is therefore not as insightful as the low case scenario.

4.4.2 Financial net present value results

In this sub-section, we present the results of the financial net present value (NPV) over the period 2017-2040. The results for the financial NPV results are shown in Figure 23.

Figure 23 Financial NPV, 12% discount rate



US$ million	Onshore			FSRU		
	Low Case	**Base Case**	**High Case**	**Low Case**	**Base Case**	**High Case**
Guatemala	- 745	- 1,026	- 724	- 876	- 1,106	- 865
Honduras	2,120	2,813	3,569	1,796	2,456	3,479
El Salvador	468	1,165	1,581	160	860	1,436
Nicaragua	*n.a*[19]	824	1,406	328	511	1,018
Costa Rica	- 467	- 412	- 119	- 571	- 528	- 363
Panama	3,988	6,062	8,538	3,317	5,522	7,454

Source: ECA calculations

The results show that, apart from Costa Rica and Guatemala, the introduction of LNG can be justified financially in Honduras, El Salvador, Nicaragua and Panama. The results are closely linked to the level of electricity prices with those countries with the highest electricity prices having the highest financial NPV's and vice versa.

Interestingly, the results show that the NPV of FSRU's is always below that of the onshore terminal. While there are more qualitative advantages to FSRU's over onshore terminals (see discussion at the end of this section), the high annual costs of leasing FSRU's are the main reason for the lower NPV's compared to onshore terminals. To

[19] Demand is too small to warrant an onshore terminal

provide a more detailed insights into the results and their sensitivities, we describe the results briefly by country.

Guatemala

- At an average cost of delivered gas over the period 2017-2040 of 13.5 US$/mmbtu and an average financial netback value of 12.3 US$/mmbtu, the financial case for LNG is difficult in Guatemala. Potential investors will not find sufficient rent along the value chain to invest in gas to power generation (on basis of LNG) or a regasification terminal.

- The financial NPV's range between - 784 US$ million and -1,106 million US$. Although the country has one of the highest gas demand potentials in the region, the low electricity price are the main reason for the negative financial NPV. At current electricity prices and assuming they remain constant, investors would not receive any return.

- To make LNG an attractive option and result in an IRR of at least 12%, electricity prices would have to rise by an average of 1.3% per annum over the period 2016 to 2040 or increase by 10% in 2016. In the best case scenario (i.e. constant HH prices and high demand levels), an electricity price increase of 7% in 2016 would be sufficient to make an LNG project viable.

- The analysis assumed an above cost 'mark-up' for LNG exports from the US of 1.5 US$/mmbtu. Even if this is assumed to be zero, the LNG projects would only become financially attractive in the High Case. To make an LNG projects feasible in the Base Case, LNG delivered prices (DES price) would have to be 10 US$/mmbtu in Guatemala. Hence if the Government is able to negotiate a price (including the transportation costs) at that level, LNG could be feasible. This corresponds to close to 2 US$/mmbtu lower price than what we are projecting (11.8 US$/mmbtu).

Honduras

- According to our analysis, Honduras is the country with the second most favourable conditions for investors along the LNG to power chain in the region.

- High electricity prices (172.8 US$/MWh) and significant potential demand (between 2.4 and 3.8 Bcm in 2030) mean that both onshore and FSRU gasification strategies terminals would have overwhelmingly positive NPV's. These range between 1.8 US$ billion and 3.6 US$ billion. The implied IRR ranges between 67% and 97%.

- Only based on the financial NPV analysis, it appears that an onshore terminal strategy is more attractive than an FSRU strategy. With increasing demand, NPV's of and FSRU get closer to onshore NPV, as the fixed annual leasing costs are spread over a greater volume of gas. On balance however the returns are likely to be higher for onshore terminals.

- The result is robust across all our proposed scenarios and even in the worst case scenario of very low demand (1.2 Bcm in 2030) and high HH prices. Although demand volumes would be too low to justify an onshore terminal, the financial indicators of an FSRU remain attractive at 699 US$ million and a 46% IRR.

- The maximum DES LNG price that could be sustained to maintain the project financially viable in the Base Case is 18.6 US$/mmbtu.

El Salvador

- Similarly to Honduras, the financial viability of an LNG terminal in El Salvador can be justified across all three scenarios and the NPV ranges between 160 US$ million and 1,580 US$ million. The IRR ranges from 18% (Low Case FSRU) to 56% (High Case onshore).

- With electricity prices just high enough to result in a positive difference between the cost of delivered gas, the demand volumes are the key driver of the financial feasibility of LNG projects. The low demand volumes at 1.5 Bcm in 2030 provides just sufficient demand to warrant the project.

- If demand becomes only 50% of the low demand case (very low demand scenario), the projects would have negative NPV's. The threshold demand level that would make a project suitable under a base case HH price projection is close to 1 Bcm in 2030 (i.e. a 33% discount on the low demand case).

- The maximum DES LNG price that could be sustained to maintain the project financially viable in the Base Case is close to 17 US$/mmbtu.

Nicaragua

- Introducing LNG in Nicaragua will be financially attractive at current electricity prices and across the three scenarios assessed. NPV's range between 511 US$ million and 1,400 US$ million corresponding to IRR's of 18% (FSRU, Low Case) and 69% (Onshore, High Case).

- Nicaragua's potential gas demand is the lowest in the region. Under the Low Case scenario, demand would be too small to justify an onshore terminal (1.1 Bcm in 2030) and an FSRU terminal should be developed. However even under that scenario, the NPV of an FSRU remains positive.

- The financial viability of an FSRU could even be sustained in the very low demand scenario (50% of demand) at base case HH price assumption.

- The maximum DES LNG price that could be sustained to maintain the project financially viable in the Base Case is close to 17 US$/mmbtu.

Costa Rica

- o Together with Guatemala the only country in the region where a financial justification of LNG cannot be made along our three scenarios. NPV's range between -119 US$ million and -571 US$ million.
- o A more detailed discussion and analysis on the potential for LNG in Costa Rica is given in the Annex.

Panama

- o The high electricity prices, large potential demand volumes and favourable location of LNG terminals on the Atlantic coast, make Panama the country with strongest financial case for LNG terminal development. With NPV's between 3.3 US$ billion and 8.5 US$ billion all types of projects under any demand and price scenario is feasible.
- o Even in a worst case scenario (very low demand and high price), the project remain financially positive.
- o The maximum DES LNG price that could be sustained to maintain the project financially viable in the Base Case is close to 24 US$/mmbtu – more than twice what we are projecting the DES LNG price to be in Panama.

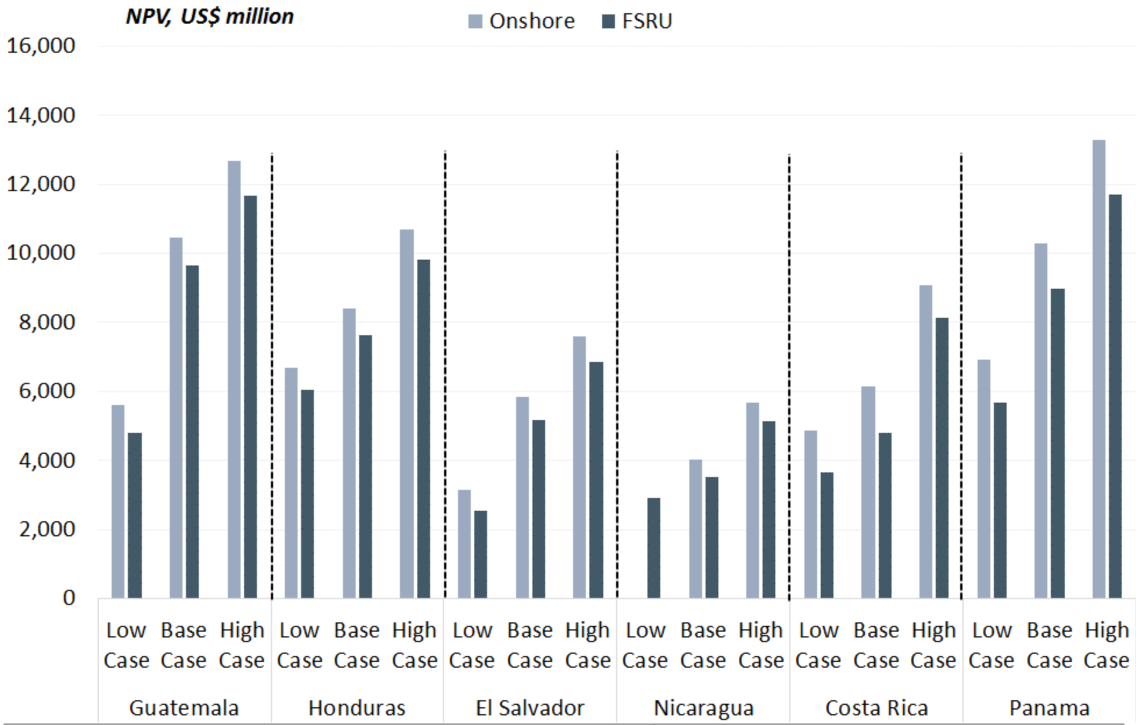
4.4.3 Economic net present value results

From an economic perspective, the case is overwhelmingly positive to develop LNG in all countries of the region. The costs of power generation on the basis of fuel oil will always be higher than those of LNG. This is robust across all scenarios as shown in Figure 24. As for the financial analysis, the onshore terminals yield a higher economic benefit than the FSRU's.

As described above the conclusions to be drawn from the economic NPV are different than those from the financial NPV. While the financial NPV is a measure of the profitability of a project for private investors along the entire value chain, the economic NPV represents the cost savings compared to an alternative scenario. In our analysis this scenario is a fuel oil generation scenario, i.e. we compare the savings of switching from fuel oil to gas for the power sector as a whole. The large part of the economic savings are likely to accrue to the state utilities or Government budgets. The financial savings/NPV on the other hand are more difficult to apportion to one particular entity. It could be the LNG exporter, the gas importing entity, the domestic power generator or the electricity consumer (if electricity prices would fall).

The Economic NPV is therefore an indicator for political justification of an LNG terminal. The financial NPV is an indicator for the likelihood of investors being involved in the LNG to power value chain.

Figure 24 Economic NPV, 12% discount rate



US$ million	Onshore			FSRU		
	Low Case	**Base Case**	**High Case**	**Low Case**	**Base Case**	**High Case**
Guatemala	5,596	10,472	12,670	4,784	9,640	11,675
Honduras	6,698	8,385	10,696	6,053	7,630	9,822
El Salvador	3,141	5,841	7,598	2,547	5,154	6,842
Nicaragua	-	4,031	5,678	2,929	3,530	5,134
Costa Rica	4,876	6,135	9,066	3,645	4,807	8,117
Panama	6,916	10,277	13,273	5,662	8,969	11,712

Source: ECA calculations

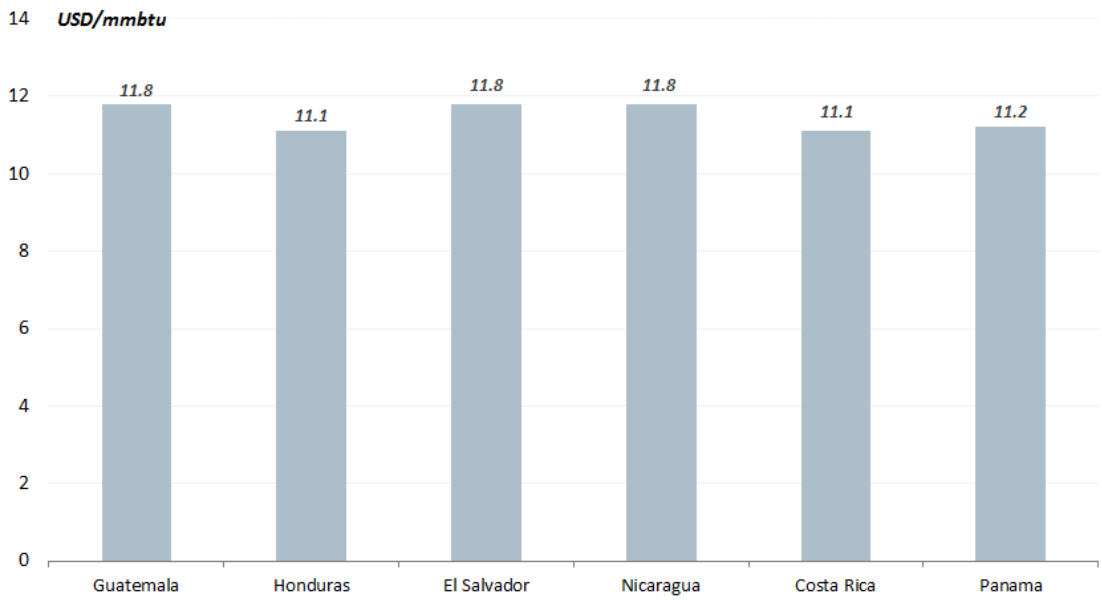
4.4.4 Conclusions and further infrastructure considerations

Our results show that compared to a scenario of fuel oil power generation, the introduction of LNG will yield significant economic savings across all six countries. Under base case demand and HH price assumptions, these could range from 3.5 US$ billion (Nicaragua) to 10.4 US$ billion (Guatemala). There is therefore a strong economic justification to introduce LNG and gas into the region's power mix.

The attractiveness of investments along the LNG to power value chain is positive only in four of the six countries. The low electricity prices in Costa Rica and Guatemala are the major obstacles (besides financing issues discussed later in the Report) for investment in the sector. Electricity prices would have to increase by 10% (Guatemala) and 7% (Costa Rica) overnight and remain at that level in real terms to make LNG investments attractive in these countries.

The price at which LNG can be delivered into the region also plays a key role in the financial feasibility of the projects. The DES LNG price we have estimated and applied in the analysis are around 11.5 US$/mmbtu[20]. The DES prices are shown in Figure 25. To make LNG projects feasible in Costa Rica and Guatemala under base case demand gas price assumptions the DES price would have to be 9.6 US$/mmbtu in Costa Rica and 10.0 US$/mmbtu in Guatemala. All other countries could sustain DES LNG prices up to 17 US$/mmbtu without jeopardising the financial viability of their projects.

Figure 25 DES LNG prices



The calculated unit cost of gas delivered to final consumers[21] will be between 13 US$/mmbtu and 15 US$/mmbtu on average until 2040. The exact cost of delivered gas will change slightly over time and will depend on the type of terminal – higher for FSRU's- and the country - higher for countries with facilities on the Pacific.

Despite both economic and financial NPV's of onshore terminals being higher than FSRU's, one should be cautious of drawing definite conclusions from these results. Particularly, because the differences are relatively small in our analysis. The final decision on the type of terminal to be developed will depend on a number of qualitative factors, which include:

- ***Certainty of future gas demand flows*** – the more uncertain future gas demand is, the more attractive an FSRU is with its flexibility and relatively low initial CAPEX. FSRU's can be re-deployed at other locations and if gas demand levels drop in one particular country, the FSRU could be re-located to another country.

- ***Seasonality of demand*** – we have only modelled gas demand as an annual total volume. However differences in gas demand for power generation might occur within the year, due to hydrological conditions in the Central American countries.

[20] The difference is driven by the locations of the regasification terminals, ie on the Pacific coast or Atlantic coast.

[21] Only those connected to gas transmission, gas distribution is not costed in our analysis

- o *Financing and resources* – Besides being more flexible, FSRU's require typically lower investment outlays and are smaller sized. The ability of investors to finance and the appetite to take on risk is higher for onshore terminals and might also be a factor to consider the final investment decision.

- o *Entry technologies* – FSRU's can be sized considerably smaller than onshore terminals and are therefore good infrastructure options to open a market to natural gas. Once demand is established in the market a longer planning horizon can be taken and onshore terminals can be developed.

- o ***Topographical considerations –*** the technical feasibility of FSRU's and onshore terminals at the selected location should also be considered. Onshore terminals can require significant additional investments (e.g. port excavation, land for storage facilities, etc…) and these should be weighed against the costs of FSRU's.

The analysis has been restricted to the level of investment for regasification capacities on the basis of demand projections from the IDB study. To provide a more complete picture in this Report we briefly highlight the power generation capacity investments associated with the regasification investments. In the Base demand scenario, an average of 50% of demand is expected to be covered by the power sector. This together with our assumptions of 50% efficiency factors and 60% load factors results in power generation capacities shown in Table 18. The table shows regasification capacities of onshore terminals, CAPEX for regasification and existing power generation in the countries.

Table 18 Onshore investment plan for Base Case

	Type	Regasification capacity	CAPEX for regasification	Power gen. capacity	Existing power generation
		Bcm/y	*US$ million*	*MW*	*MW*
Guatemala	Onshore	3.9	410	1,900	2,800
Honduras	Onshore	3.4	376	1,600	1,700
El Salvador	Onshore	2.6	308	1,200	1,500
Nicaragua	Onshore	1.6	209	800	1,100
Costa Rica	Onshore	2.9	327	1,400	2,800
Panama	Onshore	4.7	471	2,400	2,000

Source: ECA estimations

The table shows that the associated power generation capacities, providing 50% will be directed to non-electricity sector offtakers, are relatively high compared to existing power generation. In light of the difficulty to finance and develop large scale power generation projects, it might be more suitable to develop smaller scale projects. Particularly in light of the fact that gas is a new fuel in the countries' power mix. Table 19 shows an alternative investment plan for smaller volumes (Low Case) and FSRU's. Note that under the Low Case 90% of regasification capacity is for power generation. The difference in the delivered cost of gas between these scenarios will be negligible.

Table 19 FSRU investment plan for Low Case

	Type	Regasification capacity	CAPEX for regasification	Power gen. capacity	Existing power generation
		Bcm/y	*US$ million*	*MW*	*MW*
Guatemala	FSRU	1.5	214	1,300	2,800
Honduras	FSRU	2.1	257	1,600	1,700
El Salvador	FSRU	1.2	186	1,000	1,500
Nicaragua	FSRU	1.0	169	800	1,100
Costa Rica	FSRU	1.2	188	1,000	2,800
Panama	FSRU	2.2	261	1,900	2,000

Source: ECA estimations

The capacities shown in the table above takes future demand development into account. Even smaller FSRU units could be developed of course and act as 'pilot projects' or market openers. Our estimate suggest that the minimum commercially viable regasification capacities would be of the order of 0.25 to 0.35 Bcm in Honduras, El Salvador, Nicaragua and Panama. This is equivalent to between 200 MW and 300 MW of power generation. This is only a preliminary conclusion and the true commercial feasibility of such projects, should be assessed on a project by project basis. It will ultimately depend on the technical feasibility of such a project (location, sea depth, etc…), the precise investment costs (although we have included a measure of economies of scale in our estimates, at the extreme ends of this spectre, costs can vary significantly) and the rent that would be lost by purchasing such small and irregular volumes of LNG.

5 International LNG case studies

The review of the international case studies has focused on analysing LNG import strategies in countries where one or more features may have lessons for the CA countries. This could be either a positive or negative experience: a successful project which depended on country characteristics not replicated in CA, or an unsuccessful project trying to pursue an approach that the CA countries might also want to follow.

These case studies of 14 countries – provided in full in the annex A3 - have been divided into two groups according to their relevance and the lessons that can be drawn: *main case studies* and *brief case studies*.

- ***Main case studies*** mainly draw on experience in countries where only one terminal has been developed or is being currently developed/planned. In these cases we have gone into some detail, focusing on the reasons behind the development (actual or proposed) of the terminal and the terminals' main features (type, financing, business model, regional cooperation, opportunities for energy trade, access conditions, etc.). The countries included in this group are: Dominican Republic, Estonia and Finland, India, Israel, Lebanon, Lithuania, Taiwan and Uruguay.

- ***Brief case studies*** adopt a more general approach, do not go into as much into detail and serve to illustrate some specific points of relevance. In some cases, they refer to countries with a broad, large and long standing approach to LNG, such as Japan and South Korea. Although some of these countries' profiles as LNG buyers differ from the typical profiles we find in Central America (especially in terms of scale, but also in terms of credit risk), they offer interesting lessons as regards to LNG introduction strategies. The countries included in this group are: China, Greece, Japan, Singapore, South Korea and Vietnam.

This section is divided in three sub-sections. The first one summarises the main features of the LNG projects from the case studies that are relevant for designing LNG projects in Central America The second part provides a brief overview of each of the case studies. The third part presents the key conclusions and findings from the review, highlighting issues that are particularly relevant to Central America. Full details of all the case studies are in the annex A3.

5.1 Main features of the LNG case studies

This section sets out a high level summary of the main features of the country case studies. The findings are drawn from the 14 case studies; descriptions of each of these follow in sub-section 5.2.

- LNG strategies across countries show a considerable degree of variability. Countries differ regarding the reasons motivating their LNG strategy, the models behind that strategy, the context in which that strategy is deployed, and the effects observed or expected. There is no unique model for LNG introduction. Nevertheless, it is possible to identify some trends across countries.

- The reasons that underlie why countries decide to develop an LNG imports strategy vary. The most common reason is to reshape a country's energy mix. This is the case in oil dependent economies, such as the Dominican Republic, Lebanon, or Uruguay. Taiwan and Japan, which lack domestic natural gas resources and cannot source natural gas imports through pipeline, also relied on LNG imports to change their energy mix. In some cases, such as the Dominican Republic, Japan or Taiwan, LNG introduction has enabled a considerable structural change in the energy mix. A second important reason is to create alternative sources of gas supply, increase competition and ensure energy security. This is the motivation in the case of the Baltic region (Estonia and Finland or Lithuania), very dependent on Russian gas supplies, or – to a lesser extent – Singapore, which aims to diversify its gas supply sources though LNG imports. In other cases the main motive is to tackle gas supply shortages in the short run (Israel) or in the medium and long term (India or Vietnam).

- While in some countries regasified gas incorporates an 'all-purpose use' - usually in countries that depend on a sole gas supplier or confront an unmet domestic natural gas demand - the predominant use of imported LNG is power generation. This is the case in small countries which have recently become or are expected to become LNG importers, such as the Dominican Republic, Israel, Lebanon, Taiwan, or Uruguay.

- Regional cooperation in terminal development is very scarce. All the cases reviewed are 'pure' one-country initiatives, with the exception of two. *GNL del Plata* in Uruguay - expected to start operating in 2015 - was at its origin a regional project between Argentina and Uruguay. However, shale gas discoveries in Argentina led to its withdrawal from the project. Estonia and Finland's project for a 'regional terminal' is another example of a two country project. Nevertheless, it is precisely its regional character which is the fundamental factor that is delaying the project progressing.

- LNG import terminal development is usually domestically driven, that is, its main goal is to tackle a clear domestic natural gas need in the country. However, some projects explicitly incorporate a regional scope in terms of power and/or gas trade. This, for example, is the case in Uruguay. Although the project is motivated by a domestic need, it contemplates the possibility of exporting some of the regasified gas to Argentina. Increased regional power trade could also be an outcome of this LNG project.

- The type of terminal chosen - onshore or offshore – depends on the country's specific features and the moment when LNG was introduced - as both technology and costs have changed over time. Nevertheless, amongst the countries which have recently opted to import LNG or are currently developing an LNG terminal, offshore (floating) terminals are predominant. Israel has an offshore terminal since 2013, and Lebanon, Uruguay and Lithuania are also planning to opt for this model.

- The business models that predominate are the tolling arrangement and the integrated value chain model, with slight innovations in certain cases. Lebanon, Lithuania and Uruguay have chosen tolling arrangement type models for their planned projects. In these cases, terminal ownership and operation will be carried out on a build, own and operate (BOO) basis by a private company (Lebanon and Uruguay) or by a state company (Lithuania). Terminals in the Dominican Republic, India, Japan, South Korea and Taiwan operate under the integrated value chain model, where the owner and offtaker are either private utilities or state companies from the power, oil and/or gas sectors.

- o The main financing of the terminal is usually public, although there are cases, such as the Dominican Republic, Japan, China or South Korea where fully private terminals have been developed.

- o LNG is usually supplied through long term sales and purchase agreements (SPAs). Nevertheless, this type of contracts are now frequently used in combination with short term contracts to tackle unexpected or seasonal changes in demand, as it is the case in the Dominican Republic, Lithuania – expected -, Taiwan, Greece, Japan and South Korea. In the case of Israel, contracts are only short term, in line with the short term nature of the terminal - implemented mainly to address a short term supply shortage[22].

- o Generally, third party access to the terminals is not granted[23], even in the cases where the terminals have been developed using public funds. In some cases, third party access is established by the regulatory framework in more or less strict ways. However, even in these cases there seem to be problems – with varying degrees – for new entrants to access the terminal.

5.2 Overview of individual case studies

The aim of this section is to provide a short overview of each of the case studies. We provide a brief summary of each case study, accompanied by two tables at the end of the section which summarize the main features of LNG terminal development in each country. A more detailed description and analysis of each case study is provided in the annex A3.

5.2.1 Country case study summaries

Dominican Republic

AES Andres is the Dominican Republic's first and only regasification terminal currently operating. It is an onshore regasification terminal located in the southeast of the country. AES Andres is owned by the private company AES Dominicana – a subsidiary of AES Corporation -, one of the main operators in the Dominican market for electricity generation.

AES Andres terminal was developed in 2003 as an initiative of an entrepreneurial decision made by the private company AES Corporation, who believed in the long

[22] It was originally planned as a medium to long term supply, but became a short term option when Noble discovered the giant Tamar and Leviathan gas fields.

[23] This is not the case in long-established markets such as in the US or Europe, where the capacity is partly or fully offered on open access terms with regulated tariffs.

term advantages of natural gas in the Dominican Republic, heavily dependent on relatively expensive oil. The terminal was financed by AES Dominicana.

The business model applied is an integrated value chain model, whereby the power utility owns and operates the regasification terminal. The terminal is owned by AES Dominicana. LNG is bought by AES and gas is used in AES facilities or in other power stations or segments (industrial and residential demand), to which AES sells the gas.

LNG is supplied though long term contracts. At the beginning of the project, AES signed a 20 year long term contract with BPGM for the supply of LNG from Trinidad and Tobago. AES also uses incremental spot cargos in addition to its contract volumes.

The terminal has no regional scope. The obvious cooperation partner for gas and/or electricity trade is Haiti. Despite efforts of cooperation, energy trade between the two countries has been neither materially possible nor economically feasible for the past several years, in particular due to the lack of adequate infrastructure.

Estonia and Finland

Since 2013, Estonia and Finland were in negotiations regarding the possible location of Regional Baltic LNG Terminal in the Gulf of Finland[24]. There is still some uncertainty regarding the location of the terminal, as both countries are interested in having the terminal on their territory. One outcome could be that the terminal ends having operations on both sides of the Gulf of Finland.

The terminal is regional, since it is being proposed as a common terminal for two different countries. Nevertheless, it highlights the difficulties of regional projects, as the two countries have not been able to reach an agreement on the location and the project might end having two sides.

The project could allow for gas trade in the region, as Estonia and Finland have also agreed to build a natural gas pipeline - the Balticconnector - between both sides of the terminal and Estonia has gas pipelines with other countries. Power trade is also feasible as Estonia and Finland have interconnections with surrounding countries.

India

The Dahej terminal is an onshore terminal located in India's West Coast which began operations in 2004. The first regasification terminal built in the country, it was developed mainly by Petronet LNG Limited (PLL), a joint venture promoted by state owned companies operating in the gas and oil industry.

The terminal was developed to meet India's unmet natural gas demand. India ceased to be self-sufficient in natural gas in 2004, when it began to importing LNG. The gas has been used to satisfy the country's unmet demand, both for power generation and other uses.

[24] This project is still at a very preliminary stage. For this reason, there is considerable information which is missing, especially regarding the business model that will be used in the terminal. However, as it is one of the few *regional* LNG projects we have found, we have decided to include it.

The business model is a modified version of the integrated value chain model. PLL owns and operates the terminal. The offtakers are three state owned companies involved in the promotion of the terminal[25]. Unlike most other cases of vertical integration, three offtakers have developed the facility rather than only a single offtaker. However all offtakers are state owned. So, while their offtake risk profiles might be different, they would all be guaranteed by the same state, alleviating potential concerns of the Qatari LNG supplier with who PPL has LNG long term supply contracts.

The terminal was built to satisfy domestic needs and it had no regional scope. India has electricity interconnections with surrounding countries Bangladesh, Bhutan and Nepal. Additionally, there are plans to interconnect with Sri Lanka and initial talks regarding interconnection with Pakistan.

Israel

Hadera is Israel's first and only LNG regasification terminal. It is a buoy based offshore terminal located in the north of the country. It is owned by Israel Natural Gas Lines (IGNL), a state-owned company licensed to build and operate a natural gas transmission system.

The main reason why Hadera terminal was developed was the existence of short term natural gas supply shortages. In 2012, Israel experimented interruptions in the gas supply coming through the Arish-Ashkelon pipeline from Egypt and faced a near depletion situation of the sole gas field in the country, Yam Tethys. As a result, Israel Electric Corporation (IEC) had to turn to alternative and more expensive fuels (coal and diesel), what lead to higher electricity prices. In this context of scarcity, Israel decided to pursue the LNG import option and develop Hadera regasification terminal. The imported LNG is mainly used for power generation, in a context of Israel's electricity mix re-shaping towards more natural gas use.

The regasification terminal is owned and operated by INGL. The purchase of LNG is undertaken by IEC which uses gas for power generation. IEC carries out tenders to purchase LNG on a DES basis for approximately four cargos a year. Contracts are not long term.

The terminal was developed by Israel for domestic needs and it has no regional scope. There exists possibilities of gas trade in the future, as Israel is connected through pipeline with Egypt and Jordan. Power trade limited, as Israel currently lacks interconnections with other countries.

Lebanon

The Lebanese Government is planning and promoting the construction of an offshore LNG import terminal, located in the northeast of the country.

The main reason why the terminal is being developed is to change Lebanon's energy mix. The country relies heavily on oil imports to satisfy energy needs. Domestic natural gas sources have not been developed yet and the Arab Gas Pipeline is the main

[25] GAIL (India) Limited, Indian Oil Corporation Limited (IOCL) and Bharat Petroleum Corporation Limited (BPCL).

channel to source natural gas from Egypt to Lebanon via Jordan and Syria. But disruptions are frequent due to the security environment in the region and thus imports have been intermittent. Gas will primarily be used for power generation.

The project will operate as a tolling facility. The terminal will be operated under build, own and operating basis. The Ministry of Energy and Water (MEW) will enter into a long-term terminal use agreement with the terminal owner and operator and pay a monthly capacity reservation fee – regardless of usage - and a throughput fee for operating costs incurred for actual usage. The terminal owner may also have the right to retain some LNG for use as fuel. In principle, the Lebanese government will stand behind the financial obligation arising from the long-term Terminal Use Agreement. MEW will be responsible for procuring LNG supply to the terminal and will also be the gas off-taker for usage in power generation plants.

No regional cooperation existed for the development of the LNG facility and it has no regional scope. There exists the possibility of gas and electricity trade with other Arab countries. Nevertheless, the achievement of a fully well-functioning regional energy market between these countries still faces several challenges.

Lithuania

The Lithuanian government is developing an offshore LNG regasification terminal in Klaipėda State Seaport, located centrally on the Baltic coast of Lithuania. Commercial operation is expected to begin in December 2014. The terminal is being developed by Klaipedos Nafta - a majority state-owned oil importer.

The main reason why the terminal is being developed is to provide an alternative source of natural gas supply for Lithuania. Lithuania currently sources its entire natural gas supplies from Russia. The terminal will contribute to diversifying energy sources, improving security of energy supply and making import prices reflect the global market price level. Klaipeda terminal is an all-purpose LNG terminal. Imported gas will be used for residential (in particular, to meet demand of first necessity) and industrial consumption, but also for power generation and exports to other countries in the region.

The LNG terminal will be operated by Klaipėdos Nafta, selling regasification capacity to companies. This is in line with European legislation requiring an unbundled gas sector. Capacities will be available for long term and short term duration. During the capacity allocation the priority will be given for the demand of regasification services. The users of the LNG terminal will be able to lend their LNG and trade their booked capacities in the secondary market. At this stage, there is no information on the limits of long term contracts that can be agreed.

The terminal is not regional in nature. However it has a regional gas trade focus. Given dependency on Russian gas supplies in the region, the project incorporates gas exports as a possible use for imported LNG.

Taiwan

Taiwan has two LNG terminals: Yung-An - located in the southwest of Taiwan - and Taichung – located in the north. Terminals begun operating in 1990 and 2009 respectively, and they are owned and operated by the state owned Chinese Petroleum Corporation (CPC), which is the monopolist importer of LNG in Taiwan.

Both terminals were built to increase natural gas utilization in Taiwan's energy mix, as Taiwan lacks domestic natural gas and has no gas pipeline infrastructure allowing for importing natural gas from other regions. Imported LNG is primarily used for power generation.

The business model is a slightly modified version of the integrated value chain approach. The terminals are owned and managed by CPC, who purchases the LNG from suppliers in different world regions. However, CPC is not the power generation company, but the sole trader of wholesale gas. This in combination with a diversified and mature gas market gives CPC sufficient commercial guarantee to take on the risk of LNG purchases.

LNG supply is done through long term sale and purchase agreements with suppliers in countries such as Indonesia, Malaysia, Qatar or Papua Guinea, but also through mid-term and short term agreements with Trinidad and Tobago or Nigeria, to stabilise supply and volumes into the country.

The terminals were developed by Taiwan for domestic needs and they have no regional scope. There are limited opportunities for electricity trade due to lack of power grid interconnections between Taiwan and other areas. Gas trade through pipeline is also restricted as Taiwan does not have gas pipeline connections with other countries.

Uruguay

GNL del Plata is a planned offshore LNG gas regasification terminal that will be built in a location approximately 4 km west of Montevideo's port. The commercial operation of the terminal is expected to begin in 2015. The terminal is being developed to enable a change in Uruguay's energy mix, very dependent on oil. Increasing the share of both renewables and natural gas constitutes one of the key pillars of Uruguay's energy policy. Natural gas supply to Uruguay is limited to imports from Argentina by pipeline – its sole supplier-, so Uruguay is promoting LNG imports as an alternative. Gas will be primarily used for power generation.

At the beginning, GNL del Plata project was a regional terminal project in which both Argentina and Uruguay were involved. However, as new shale gas reserves were discovered in the Vaca Muerta field in Argentina, Argentina finally decided to withdraw from the project. Currently, the project is being solely promoted by Uruguay through Gas Sayago, a joint venture owned by Administración Nacional de Usinas y Trasmisiones Eléctricas (UTE), the state owned power company, and Administración Nacional de Combustibles, Alcohol y Portland (ANCAP), a state owned oil, alcohol and cement company.

The business model functions like a tolling arrangement model. The terminal will be operated under a build, own, operate and transfer (BOOT) basis by GDF Suez. The BOOT contracts will last for 15 years and was signed between GDF Suez and Gas Sayago. The construction and operation of the terminal will be ultimately financed by the Uruguayan State, which will pay monthly fees to GDF Suez over the duration of the 15 year contract and to which GDF Suez will transfer the terminal to Uruguay at the end of the contract. GNL del Plata will provide regasification services to Gas Sayago, the offtaker. UTE and ANCAP, the state companies who own Gas Sayago will purchase the LNG and will guarantee payments made by Gas Sayago to GDF Suez.

There exists regional trade possibilities in gas and power, although there are no formalised regional cooperation agreements regarding gas imported through the terminal. *GNL del Plata* could allow Uruguay to export natural gas to Argentina through pipeline. In case there are potential electricity surpluses, they may also be exported to neighbouring countries. Argentina and Uruguay have electricity trade relations.

China

There are six existing onshore terminals, and eight (onshore) planned ones (by 2015). Of the fourteen terminals, eight are/will be owned and operated by China National Offshore Oil Corporation (CNOOC), state-owned, three by China National Petroleum Corporation, state-owned (CNPC), through its listed arm, PetroChina, and one terminal will be owned and operated by private firm Sinopec.

LNG import prices are oil-linked and determined by bilateral commercial negotiations between importers (primarily CNOOC) and suppliers. The resale price of LNG is not directly regulated. Importers are required to negotiate the sale of regasified LNG at the wholesale level, i.e. with distribution companies or directly to large industry and power companies.

The overall contractual terms require National Development and Reform Commission (NDRC) approval prior to importers obtaining the necessary permits for importing LNG and operating the regasification terminals. LNG importers are required to negotiate the sale of regasified LNG (inclusive of terminal charges) with distribution companies or directly to large industry and power companies. Although these prices are not formally regulated, overall contractual terms require NDRC approval prior to importers obtaining the necessary permits for importing LNG and operating LNG terminals.

Greece

Revithoussa terminal is Greece's first and only terminal. This onshore terminal is owned by Dimosia Epichirisi Paroxis Aeriou (DEPA) – which is the Greek public corporation responsible for gas infrastructure – and operated by DESFA, which is the fully-owned subsidiary of DEPA.

Capacity at the terminal is fully open to third parties and is allocated on a first-come-first-served basis. Third parties using the terminal also need to book capacity on the national gas transmission system which can be difficult to obtain.

The terminal was developed to provide storage facilities, to increase security of supply, and to promote competition, as the terminal provides a convenient entry point for new shippers and suppliers. The terminal is an example of a lightly-used LNG terminal, as its capacity utilization in 2011 stood at 25%.

Until recently, LNG imports were made entirely under a long-term contract between DEPA and Algeria's Sonatrach. In 2010, the terminal saw the first import by a third party, Mytilineos, which was partly used for its own generation and partly resold to DEPA. Further third party imports have taken place since.

Japan

Japan is the largest world importer of LNG. There are a large number of LNG importers, specifically 7 power companies, 8 gas companies and several industrial importers. There are 32 LNG facilities in Japan, mostly adjacent to individual power plants. Some LNG terminals are owned individually by power utilities and gas suppliers while others are owned in co-operation through joint ventures.

Japanese LNG buyers are gas and power companies carrying out business in an integrated manner, from procurement and imports to transmission, distribution, downstream gas and power supply and marketing.

The LNG terminals in Japan have either been developed as merchant operations acting as both importer and marketer or for own gas use by power utilities. Under both types of arrangement, the LNG owners and operators effectively pay for their own services through the margin achieved between the cost of gas and the sales price (either as gas or electricity) into their local market.

The majority of the LNG is bought by power producers under long-term purchase contracts. However, since 2011, power producers have more increased LNG purchases through spot contracts, in order to meet the increasing gas demand.

New purchasing arrangements are being discussed by Japanese importers. In particular, aggregating procurement activities with the objective of improving the country's bargaining position in the global LNG market.

Singapore

Singapore LNG Corporation (SLNG) - a fully state-owned company, owned by its regulator, Energy Market Authority (EMA) – has developed a terminal which began operations in 2013. Singapore has opted for separation of the terminal ownership and use, with only a single private company contracted to purchase and supply LNG. This monopoly situation could change in the future, as Singapore is assessing different options - some of them involving competition among users - as the capacity of the terminal is projected to increase.

The model is on an aggregator basis, with the company selected being free to determine how best to source LNG to meet its contractual supply commitments. A competitive tendering process was conducted to select the LNG aggregator, which was won by BG Group. BG is responsible for marketing LNG to customers and supplying their requirements from its own gas portfolio. BG holds a monopoly for the initial capacity of the LNG terminal. The contract is exclusive until the LNG market reaches a minimum size, which is now close to being achieved.

South Korea

South Korea has four LNG regasification facilities. Pohang Iron and Steel Corporation (POSCO) and Mitsubishi Japan jointly own the only private regasification facility in

Korea, located on the southern coast in Gwangyang and which currently has four customers who import LNG for own use.

In addition to operating three of the four LNG receiving terminals, KOGAS owns and operates the entire national pipeline network, and sells regasified LNG to 14 power generation companies and private gas distribution companies.

Companies wishing to import LNG directly are only permitted to do so for their own use and are prohibited from reselling their gas. To facilitate direct imports the government has introduced a TPA regime on a negotiated basis, despite earlier intentions for a regulated regime. In practice, however, obtaining access has been difficult and, indeed, POSCO decided to construct its own LNG terminal because it was unable to negotiate access to KOGAS' LNG terminals and pipelines.

Most LNG imports into South Korea are delivered according to long-term contracts, usually 20 to 25 years in duration. Until recently, long term supply of LNG to Korea was organised on a take-or-pay basis. South Korea is active in the spot LNG market because of its very seasonal demand for gas.

Vietnam

LNG import infrastructure was introduced in Vietnam in light of the projected supply gap, as an investment by Vietnamese authorities. The country is currently developing two LNG import terminals.

Thi Vai LNG terminal (onshore, expected start date 2014) — developed by PetroVietnam (PVN)[26], who will be the LNG purchaser and gas supplier. Customers for the LNG supplied from the terminal will be independent power plants (IPPs) and industrial customers in surrounding estates. Son My LNG terminal (onshore, expected 2018) — PVN is also responsible for developing the terminal.

Offshore and onshore LNG terminal ownership and operation is planned to replicate the scheme in gas infrastructure. Offshore gas transportation infrastructure is owned either by PVN exclusively or in partnership with international oil companies who operate the upstream field. Onshore infrastructure is owned by PVN and its operation is by a subsidiary of PVN.

5.2.2 Summary tables of features of country case studies

The following two tables summarise the main features of LNG terminal development projects (realised or planned); firstly, the main case studies, and secondly, the brief case studies.

[26] PetroVietnam (PVN) is the state-owned company that carries out petroleum activities. It comprises four main business activities (oil and gas exploration and production; oil refinery; processing, transportation and distribution of natural gas and its products; 10% of installed generation capacity) undertaken by 4 fully-owned subsidiaries.

Table 20 Case study summaries: main case studies

Country and terminal(s)	Business model	Terminal ownership / operation	Financing and main offtakers	Regional aspects [a]
Dominican Republic *(AES Andres, 2003)*	Integrated value chain model.	Terminal owned and operated by the private utility AES Dominicana.	Terminal financed by AES Dominicana. AES Dominicana is the only offtaker.	No regional cooperation in the development of the terminal. No regional energy trade scope.
Finland and Estonia *(Regional Baltic LNG Terminal , planned)*	- [b]	-	-	Regional cooperation in the development of the terminal. Regional energy trade scope: Baltic region.
India *(Dahej terminal, 2004))*	Integrated value chain model.	Terminal owned and operated by PPL, a joint venture created by state owned companies in the oil and gas sector.	Terminal financed by state owned utilities. Main offtakers: state owned companies involved in the development of the terminal.	No regional cooperation in the development of the terminal. No regional energy trade scope.
Israel *(Hadera terminal, 2013)*	Tolling arrangement model.	Terminal owned and operated by INGL, a state-owned company licensed to build and operate a natural gas transmission system.	Terminal financed by the public sector. Offtaker: IEC, a state owned electricity company.	No regional cooperation in the development of the terminal. No regional energy trade scope.
Lebanon *(Terminal planned)*	Tolling arrangement model.	Terminal operated under a build, own and operating basis.	Private (build, own and operating basis) and public financing. Offtaker Ministry of Energy and Water of Lebanon.	No regional cooperation in the development of the terminal. No regional energy trade scope.
Lithuania *(Klaipėda terminal, expected 2014)*	Tolling arrangement model.	Terminal operated by Klaipedos Nafta - a majority state-owned oil importer.	Public financing. Regasification capacity will be under third party access regulation.	No regional cooperation in the development of the terminal. Regional energy trade scope: Baltic region.
Taiwan *(Yung-An terminal, 1990; Taichung terminal, 2009)*	Integrated value chain model.	Terminals owned and managed by state owned Chinese Petroleum Corporation (CPC)	Public financing. The offtaker is CPC, the sole wholesale gas trader.	No regional cooperation in the development of the terminals. No regional energy trade scope.

Country and terminal(s)	Business model	Terminal ownership / operation	Financing and main offtakers	Regional aspects [a]
Uruguay *(GNL del Plata terminal, expected 2015)*	Tolling arrangement model.	Terminal operated under a build, own, operating and transfer (BOOT) contract by GDF Suez.	Private (GDF Suez) and public (Uruguayan State). Offtaker is a public utility (Gas Sayago)	Regional cooperation between Argentina and Uruguay at the beginning of the project. Regional energy trade scope: Argentina.

Notes: (a) regional aspects covers (i) whether the project is a regional (more than one country) initiative and (ii) whether the terminal incorporates a regional scope, that is, if the gas is used/expected to be used for gas exports or for power exports. (b)"-" indicates that it has not been possible to obtain the information. In the case of Estonia and Finland the project is still in a very preliminary stage. For this reason, there is considerable information which is missing, especially regarding the business model that will be used in the terminal.

Table 21 Case study summaries: brief case studies

Country and terminal(s)	Business model	Terminal ownership / operation	Financing and main offtakers	Regional cooperation [a]
China *(6 terminals operarting, 8 planned)*	-[b]	Some terminals owned and operated by state companies in the oil sector. 1 private terminal.	-	No regional cooperation in the development of the terminals.
Greece *(Revithoussa terminal, 2000)*	Tolling arrangemen t model.	Owned by DEPA (Greek public company responsible for gas infrastructure) and operated by DESFA (fully-owned subsidiary of DEPA).	Public financing. Regasification capacity sold to companies in line with European third party access regulation. Main offtaker: DEPA.	No regional cooperation in the development of the terminal.
Japan *(32 LNG facilities)*	Predominan t model: integrated value chain.	Private ownership and operation. In most cases owned and operated by gas and power utilities.	Private financing. Offtakers are power and gas companies.	No regional cooperation in the development of the terminals.
Singapore	Tolling arrangemen t model.	LNG terminal is owned and operated by Singapore LNG Corporation - a fully state-owned company.	Public financing. Offtaker: BG group (selected through competitive process)	No regional cooperation in the development of the terminals.
South Korea *(4 LNG terminals)*	Predominan t model: integrated value chain.	3 terminals owned and operated by KOGAS (public natural gas company) 1 terminal privately owned and operated by Pohang Iron and Steel Corporation and Mitsubishi Japan.	Public and private financing. Offtakers in KOGAS terminals: KOGAS, who resells regasified gas to power and gas companies.	No regional cooperation in the development of the terminals.

Country and terminal(s)	Business model	Terminal ownership / operation	Financing and main offtakers	Regional cooperation [a]
Vietnam *(2 terminals planned)*	Integrated value chain.	Owned by PVN (state-owned company in oil sector) and operated by a subsidiary of PVN.	Public financing of the terminals. Offtaker: PVN.	No regional cooperation in the development of the terminals.

Notes: (a) regional cooperation only covers whether the project is a regional (more than one country) initiative; (b)"-" indicates that it has not been possible to obtain the information.

5.3 Key findings relevant for Central America

The following 7 points are the main conclusions we draw from the case studies. They provide a high level summary of the main opportunities and problem areas for developing viable LNG projects in the Central American countries.

LNG strategies across countries show a considerable degree of variability

The variability of approach basically depends on country characteristics and natural gas needs. Additionally, different models can be successful in terms of LNG introduction. Both the Dominican Republic and Taiwan were effective in increasing natural gas use and changing their energy mix. However, they opted for different models. The Dominican Republic favoured a fully private option, based on an integrated value chain model where a private utility operating in the generation sector developed the terminal for its own use. On the contrary, Taiwan opted for a fully public option, based on a slightly modified integrated value chain model, where the offtaker was the LNG monopoly importer in the country.

Advantages of floating storage regasification units (FSRU)

Floating storage regasification units (FSRU) may have advantages over land based terminals for a number of reasons. Israel provides an interesting example. It needed to develop an LNG import terminal to tackle a short term supply shortage. A buoy based FSRU served that purpose in a relatively low cost and timely manner. Other emerging countries such as Lebanon, Lithuania and Uruguay are opting for this type of terminal, not only because they can be deployed fast but also because they offer other benefits. FSRU increase investors' willingness to invest on LNG in emerging markets, since if they do not receive their payments, the vessel can be redeployed in an alternative and more commercially attractive location. Dominican Republic also provides a very good example as a market opening technology to initiate the development of the gas market with relatively low commercial risks. For these reasons, FSRU are a good option for LNG imports in Central American countries.

Regional projects pose considerable problems

Regional projects may seem appealing. However, they pose severe coordination problems that may delay or even cancel the project. This is highlighted by some 'regional failures' analysed in this section, such as the *GNL del Plata* project at its early stage or the Estonia and Finland project, in which – after a considerable amount of time

- the cooperating countries have not even been able to agree on the location of the terminal – which, ironically, may end up having two sides. The analysis suggests that a regionally coordinated terminal may not constitute the best option for a fast and effective LNG introduction in Central America. That does not mean however that sub-regional integration will and should not occur, instead we see these sub regional developments, ie one terminal for a sub set of countries, to develop naturally. At the heart of initiating the project however will be an LNG terminal developed to cover national demand.

Power or gas trading is potentially a more feasible regional approach

A better option to achieve 'regional results' could be gas and/or power trade. If the necessary infrastructure is in place and there is an adequate regulatory framework, an LNG terminal in one country may have a role in fostering gas and power trade in a whole region. Some of the planned projects studied take into account energy trade issues and could have a clear regional impact. *GNL del Plata* in Uruguay could allow for natural gas exports to Argentina through gas pipeline. The terminal planned in Lithuania could also foster regional power and gas trade in the Baltic region, very dependent on Russian gas supplies.

LNG under short term contracts is a growing trend

In some cases, LNG is supplied under short term contracts, either exclusively (Israel) or in combination with long term contracts (Dominican Republic, Lithuania – expected -, Taiwan, Greece, Japan or South Korea). As short term trading could be a relevant factor supporting LNG imports in Central American countries (scale and creditworthiness are less important in this type of trading), these cases highlight that non long term contracts are usually present – in varying degrees – in LNG import strategies. The term short term contracts is used here for spot market trades as well as annual non-flexible contracts.

A low credit rating is an obstacle but not necessarily a show stopper

Countries with a relatively low credit rating have been able to develop an LNG terminal. The Dominican Republic, a country which is very similar to many Central American countries (oil dependent economy, relatively low level of LNG demand, and with relatively high credit risk) has developed a successful LNG import strategy, adapted to its needs and which has changed the country's energy mix, reducing oil dependency. Moreover, although the spot market is sometimes used, LNG is usually sourced under long term contracts, suggesting that certain 'credit profiles' are not necessarily excluded from the long term LNG market.

It is possible to start a gas market with LNG

LNG can be introduced in cases where the gas market has not been developed or it is in its preliminary stages. The Dominican Republic is again a very interesting case. In 2000, natural gas was basically absent from this country's energy mix. However, in 2012 – nine years after AES Andres terminal became operational - natural gas imports accounted for approximately 14% of the energy mix.

5.4 Summary for LNG strategy in CA

The key findings show that a regional approach for a number of countries in the region would be difficult to implement. The difficulty of coordination among countries, the uncertain creditworthiness of a regional gas purchasing entity and the uncertain bargaining power benefits make a fully regional approach (Strategy B from IDB strategy) unlikely. Instead this regional or sub regional approach is likely to develop naturally without forced coordination through the development of national terminals with onward electricity (or gas) trade.

As electricity transmission interconnections among all countries in the region exist through SIEPAC and therefore electricity trade is possible, countries should consider the gas demand volumes from regional electricity trade when developing LNG terminals. Naturally, the country with the best commercial proposition for LNG and the highest political willingness to develop this terminal will be the first country in the region. This means that a regional LNG terminal approach should not be prescriptively applied, but instead those countries where it makes commercial sense to introduce LNG will likely seize the opportunity to develop gas infrastructure to suit their own needs. Regional electricity (or gas) interconnections should be strengthened to allow trade among the countries. Once gas markets are established, a more regional LNG purchasing procedure can be adopted.

Taking the economic analysis into account, it seems most feasible to develop an LNG terminal in Panama. This could act as a gas market opener for the region. Guatemala is likely to source its gas from a pipeline extension from Mexico and electricity prices are too low to absorb LNG into the power generation mix. Costa Rica's electricity prices are also too low for LNG. El Salvador, Honduras and Nicaragua could develop LNG terminals. However the lack of credit rating and relatively low electricity demand make these countries unlikely 'first movers' in LNG development in the region.

This suggests that a feasible strategy of gasification is the development of an LNG terminal in Panama with a strengthening of onward electricity connections to neighbouring countries. This would also require SIEPAC to be used as electricity trading infrastructure only and not as a balancing tool for national transmission system operators congesting the line. For the northern sub region an interconnection with Mexico is a most suitable alternative with potential onward connections from Guatemala to El Salvador and beyond. This would correspond mainly to Strategy C from the IDB study.

6 Business models

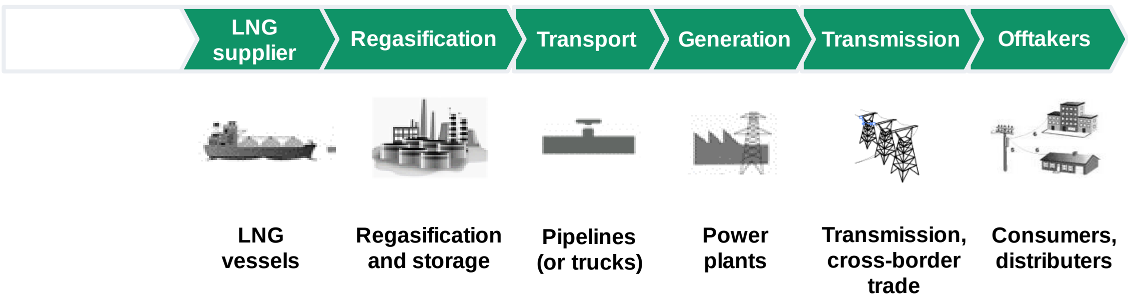
6.1 Business model options and the value chain

This section focuses on the alternate business models and the related risk profiles. The section therefore defines and analyses various business models for the introduction of LNG. While a '*strategy*' for the region defines the long term approach to introducing LNG/gas-fired power generation to the various countries of the region, a '*business model*' is the more detailed structure of a specific LNG project and its related components in the value chain from gas to power generation and electricity (or gas) sales. The business models therefore focus on the ownership, commercial structure and contractual arrangements for each element along the LNG value chain from liquefaction downstream. They also indicate where the significant risks lie and the consequent impact on the project financing.

6.1.1 LNG value chain

The starting point of the analysis is the LNG value chain and understanding the key commercial and contractual risk drivers in each segment. The typical value chain for smaller markets such as in Central America, where the LNG offtakes are expected to be small in the short term and downstream electricity offtake risks could be high, is shown in Figure 26.

Figure 26 Alternate LNG value chain – small offtakers (power)



Note that the value chain starts from purchasing from the LNG supplier/trader. The figure omits the liquefaction plant or indeed gas production. This is because small offtake markets are unlikely to have a noteworthy impact on the development of liquefaction terminal let alone upstream gas production projects. The value chain ends in electricity offtake, the 'gas offtaker' will typically be the power generation plant or in the case of industrial demand, large scale industrial users.

The LNG supplier performs the functions of LNG procurement, aggregating small demands and scheduling deliveries. The LNG may be sourced from a single producer or the supplier may be a portfolio trader, meeting demands by supplying from a portfolio aggregated from a number of contracts with one or more LNG producers.

Two variants of the above gas value chain will be also be included in the discussion of business models in subsequent sections:

- o A bi-or multi country case where power offtakers are also in neighbouring countries. This introduces risks related to cross border trade.

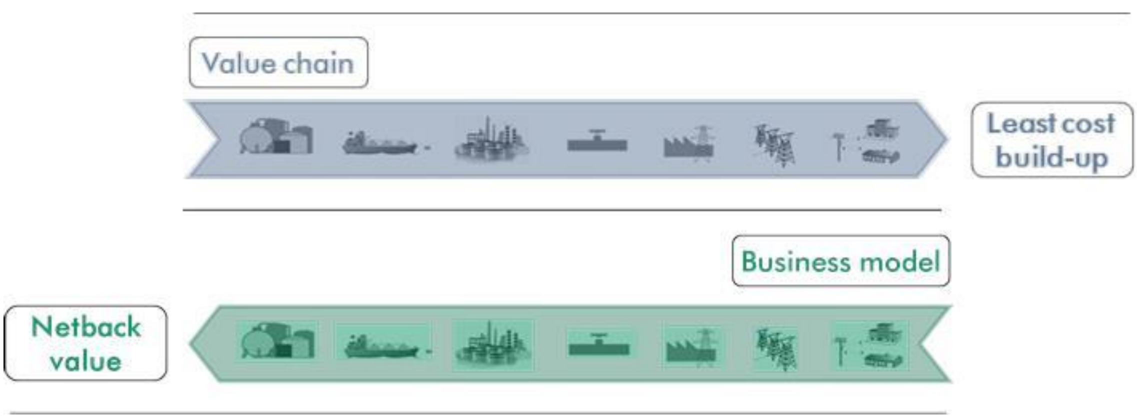
- o Supply of gas to non-power sectors (industry, large commercial etc.) where gas is transported via pipelines to a 'city gate' into a distribution system (lower pressure) and supplied to industrial, commercial and residential users.

The focus of this study covers the above cases, analysing the costs and risks at the transaction points. This starts from LNG procurement from an LNG supplier, regasification, gas transportation and the downstream components of the electricity chain (generation, transmission and offtakers) and/or the gas chain, in both cases including the additional transaction risks when electricity or gas is traded with a neighbouring country. Where relevant, we will take into account the upstream aspect in our analysis to the extent that different sources of supply might imply different LNG costs. However, our main concern is with the risks and financeability of the downstream LNG chain, not with the technical and financial risks of upstream activity.

6.2 Building blocks of LNG business models

While the value chain depicts the physical flow and cost build-up of gas and power in the direction from upstream to downstream, the business model defines the transaction points, contractual responsibilities and the flow of money. These are more conveniently analysed in the opposite direction. Assessment of the business models therefore leads to a focus on the share of netback value in the gas that may be 'captured' by the upstream parties, especially the LNG supplier. On the other hand, the value chain indicates the cost build-up and, for example, the least cost supply that could be obtained in a low risk situation. These contrasting but complementary approaches are illustrated in Figure 27.

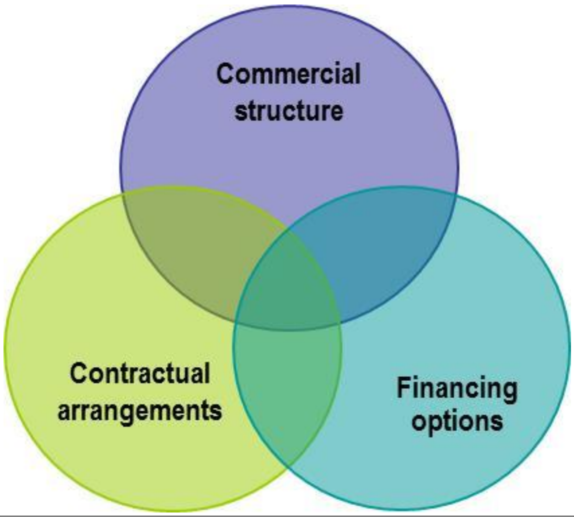
Figure 27 Value chain and business models



The above distinction is important because in Central America the business model/netback approach is likely to be the dominant factor in LNG pricing, given the small initial demands, gradual build-up, nascent gas sector and associated risks. An important issue for project design is to minimise the risks in the business model so that the highest share of the surplus of netback value over least cost supply is retained by the countries; this would represent the economic value of introducing LNG and gas to the energy sectors.

Three types of building blocks characterise the main features of business models. Within each area, there are overlapping issues as shown in Figure 28.

Figure 28 Building blocks of LNG business models



- *Commercial structure*: the commercial structure defines the key entities and ownership in the value chain (public entities or private companies, energy utilities, financial companies, shareholdings) and the transactions for which they are fully or partly responsible. Structures can range from a fully integrated form, with one major party owning and able to efficiently manage the whole chain, to a highly disaggregated structure with different parties at each link of the chain requiring extensive coordination through the contractual (and regulatory) arrangements

  In the simplest case, a single owner of the whole chain easily settles the issue of who captures the surplus profit (or' rent', as economists call it) in the value chain, reducing the risks of investment. In addition, the ability to manage the inter-related risks in the chain improves the prospect for maximising value

- *Contractual arrangements*: the contractual arrangements are concerned with specifying the precise form of commercial arrangement at each transaction point and the consequent allocation of risks and rent. The less integrated the commercial structure, the more the flow of funds and risk allocation depends on the contracts and their enforceability. The contractual arrangements will also reflect the scope and robustness of the regulatory framework for the sector(s), both in-country and cross-border

- *Financing and risks*: The financing options can be considered more clearly once the risks remaining in the 'gaps' between the commercial structure and contractual arrangements have been identified. The sum of costs in the value chain and the financing will be at least cost (provided economies of scale are maximised for the demand level) when the parties in the commercial structure are strong and credit-worthy; commercial relations clearly defined and logical, contracts are comprehensive, industry standard and enforceable; and the regulatory framework is clear, stable and robust[27]. Supply and financing costs will be greater to the degree the actual situation deviates from this '*gold standard*'

The next three subsections briefly discuss the range of choices in each of these building blocks.

6.2.1 Commercial structure

The commercial structure of an LNG option defines the entities, ownership and shareholdings of all the parts of the value chain. Closely linked to the commercial structure is the definition of roles of agents involved in each part of the LNG value chain. Three roles which are particularly important to define are those of the public and/or private offtakers (electricity utilities, gas), LNG suppliers and the LNG regasification (regas) project company. Depending on the drivers of gas demand in Central America and power market structure, the roles of these three agents could to a large extent already be predetermined. The key questions that need to be addressed under this building block of LNG business models are the involvement of these entities in future gas trading. In particular, whether the business model should largely be carried out by private entities or public entities, which entities are developing, financing and operating the regas terminal.

The simplest ownership structure is an ***integrated value chain*** with common ownership of the LNG procurement, regasification, power generation and electricity (and gas) sales. While this vastly simplifies many of the contractual arrangements and minimises many of the risks, it also enables the company to capture much of the rent. An arrangement of this type has been proposed by a few countries in the past. The single project company concept could even be extended to LNG supply across two or more countries. However, a limitation of the integrated structure is that it makes third party access more difficult unless it is agreed within the structure from early on.

At the opposite extreme, a different party is outright or principal owner and operator of each part of the chain. These may be public entities/utilities, private companies or public-private partnerships (PPP). While this disaggregated arrangement maximises the expertise of specialist parties, potentially minimising costs, it introduces multiple layers of transactional, coordination and operational risks. This may offset the efficiency gains of individual parts of the value chain with overall complexity of the whole chain.

The key consideration that should be made when defining the roles and ownership along the value chain is the commercial risk associated with different entities. If, as one envisaged possibility, a regional LNG buying entity is created, the risk profile of this entity will have to be carefully managed to make it commercially attractive for LNG suppliers to enter into contractual agreements with the entity, considering the possible complexity of the downstream arrangements for delivering and receiving payment for LNG from multiple offtakers in different countries.

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[27] A value chain meeting these conditions could be called the 'gold standard'.

The LNG regas company is the novel entity in the LNG-to-electricity supply chain. It is also an entity that has been organised in a number of different ways in the LNG/gas sectors of other importing countries. The main distinction that is made is between two distinct commercial forms: a merchant structure or a tolling structure.

- The key characteristic of the ***merchant structure*** is that the entity owning the regasification terminal (terminal entity) is also the entity purchasing the LNG and selling the gas. The company is then carrying the risks of LNG procurement and gas offtakers, while earning a return on both the LNG to gas trade as well as the regas terminal operation.

- In the ***tolling structure*** the terminal owner/operator in only responsible for storage and operation of the regasification facility for LNG. The procurement of LNG from an upstream producer, transportation, and gas offtake may be done by one or two separate companies.

A key principle here is that the financeability of the chain – whether a single country or multiple countries sharing parts or the whole of the chain – depends on the creditworthiness of the parties in relation to the risks inherent in each part of the chain. In turn, the risks will vary depending on the level of integration of activities and operation. Integration might reduce costs through some economies of scale or scope, but if the risks remain this would offset some of the cost gain.

6.2.2 Contractual arrangements

The building blocks that aim to mitigate and efficiently allocate commercial risks are the contractual arrangements. A number of different agreements and contracts will generally be in place, each specific to the type of commercial structure in the business model. The key agreements depend on which parts of the value chain are integrated as regards ownership. The main types of agreements found in LNG/gas-to-power projects are:

- LNG Supply and Purchase Agreement (SPA)

- Transportation Agreement(s) between shipper and LNG buyer(s)

- Operation and Maintenance Agreement between a terminal owner (project company) and contracted operator (O&M agreement)

- Terminal Usage Agreement (under a tolling arrangement or long term capacity reservation contract)

- Gas Sales Agreement (GSA) between the project company and the gas offtaker(s)

- Power offtake agreement / Power Purchase Agreements (PPA)

- Guarantee Agreements for the financing

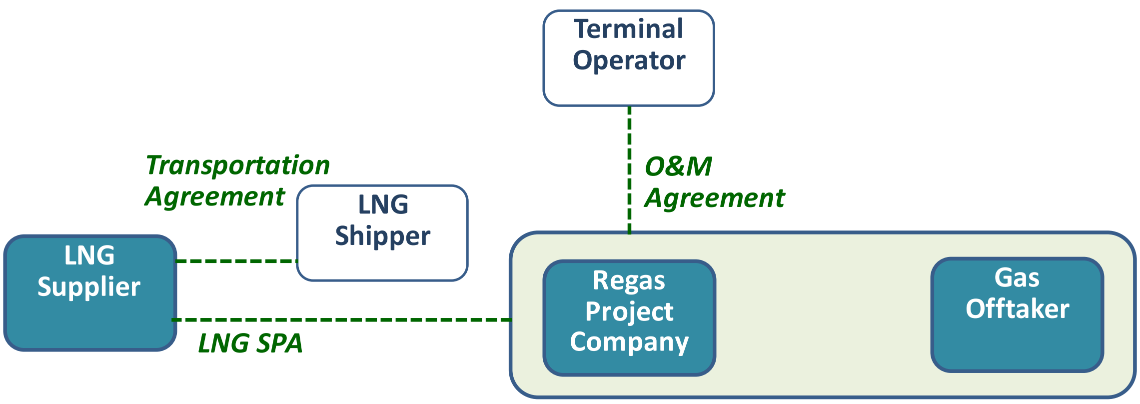
Other contracts will also be part of the whole package structure (see below[28]) but these will have less impact on the viability of the project.

The set of agreements need to clearly and effectively allocate the major risks to the credible party who can best manage them and bear the associated contingent costs. This is straightforward with a single buyer, but complex when multiple parties are sharing parts of the chain.

Three main entities are involved in the business models when LNG/gas is introduced to a power system: the LNG supplier, the terminal project company (the regasification terminal owner) and the gas offtaker(s). Typically the project company will have an operation and maintenance (O&M) agreement with a terminal operator to run the terminal, as this is a specialised activity. Additionally, the LNG supplier or the LNG buyer will have a transportation agreement with the LNG shipper. The form of this agreement will depend whether the LNG buyer buys the gas at FOB (free on board, ie title to the LNG is take at the port of loading) or DES (delivery ex ship, ie title is taken at the port of off-loading to the regas terminal). In typical long term LNG contracts gas is bought DES, however with increasing trade taking place on spot markets, LNG buyers are buying at FOB prices and are therefore increasingly making contractual arrangements with LNG shippers. For the illustrative purposes of the figures below however, we assume DES LNG purchases and therefore transportation agreements between LNG suppliers and shippers[29].

Several different contractual arrangements are possible and these are presented in the Annex. The most likely outcome for the region is a model of partial vertical integration. Under this model of ownership downstream vertical integration exists where the terminal entity, gas network operator and electricity utility are the same (often public) entities. This case is illustrated in Figure 29.

Figure 29 Vertical integration (downstream)



The above case illustrates an arrangement in which market volume and coordination risks (but not credit risks) are substantially removed from the LNG supplier, thus

[28] Other agreements in the full contractual package will include some or all of Port Agreement, Loan Agreement, Equity Agreement, Gas Transportation Agreement, Connection and Transmission Agreement (power plant)

[29] This could be a tanker charter contract or an integrated activity.

facilitating LNG procurement. In this case and the following one, the integration between the regas project company and one of the other parties suggests that third party access (TPA) would be difficult if not impossible, except on a small scale, say 10%-20%. The latter is possible if the financing of the facility can be guaranteed by a throughput of say 80% of its maximum capacity[30]. In a typical project financing the investor would provide 20-30% of the capital in equity. Provided the investor was prepared to put a significant part of this equity at risk, some capacity could be made available to the market.

6.2.3 Financing options and risk analysis

The third building block concerns the financing issues for the LNG facility and other high capital cost parts of the chain, including pipelines and power plants, and indeed whether the project can be financed at all, that is, is it bankable. The specific financing options and structure can only be proposed and evaluated when a detailed project design is specified. At this stage, an initial indication of bankability can be made based on the assessment of project returns compared to risks. The process to be followed during project development, towards the financing objective, should start from an initial risk assessment. To improve the project's risk profile, the next step should be identification of risk mitigation measures (including redesign of project components), leading to a revised risk assessment.

The financial and economic values that might be realised by introducing LNG to each country were estimated in section 4.3.1. The economic values indicate the returns that could be made in the economy as a whole, shared between the parties in the LNG chain and the consumers of gas and products where surplus value is created by the improved production efficiency due to inputs of gas or gas fired electricity into the production process.

This in itself does not guarantee financial viability of an LNG project. The latter requires that LNG in the gas to power activity earns an adequate financial return based on the price at which gas or electricity is sold. The financial values based on current electricity prices also showed a modest return. The question of whether that return is adequate depends on the assessment of the degree of risk in the project, which will to a large extent be influenced by the options chosen in the previously presented building blocks.

Different risks are associated with each type and variant of business model and these need to be assessed against the combination of commercial and contractual arrangements. Among the options, the analysis assesses the scope for implementing a PPP framework to finance the LNG terminal and other parts of the chain, that is, to assess which risks are best assumed by the public sector and which can be best managed by the private sector. A general principle is the overall risks and hence costs are minimised when risks are allocated to the party best able to manage them. This principle can guide the allocation of risks within a PPP structure.

A key principle here is that the financeability of the chain – whether a single country or multiple countries sharing parts or the whole of the chain – depends on the creditworthiness of the parties in relation to the risks inherent in each part of the chain

[30] This was the case, for example, with one of the bidders for the El Salvador integrated LNG and power project in 2011

and assigned to them through the contractual arrangements. In turn, the risks will vary depending on the level of integration of activities and operation. Integration might reduce costs through some economies of scale or scope, but if risks increase this would offset some of the cost gain, in terms of bankability.

The next step is therefore to set out the risk analysis framework.

Risk categories

The feasibility of implementing each of the business models for the preferred strategies depends on their risk profile. A first assessment of the ability to finance and implement a business model can be made after carrying out a high level risk assessment. While many risk categories are common across all similar projects wherever they are carried out, the importance of each will vary according to both the project, project company and country context; ie the risk profile depends on the specific project context.

The main risk areas for LNG in the Central American countries, and therefore the risk categories that will be assessed, are the following:

- Financing
- Demand (offtake)
- Prices
- Supply
- Cross-border trade
- Contracting
- Construction
- Operational
- Political
- Regulatory (price, access to market, cross-border)
- Legal (FM, enforceability, disputes)

Each of these are defined and briefly discussed in the following paragraphs before applying them to assess the business models.

Financing risks

The financing risk can be viewed as the all-embracing risk encompassing elements of each of the subsequent risk categories. It reflects the ability to reach financial close on the project financing (LNG terminal, but also downstream elements such as gas pipelines and generation capacity). However, the specific risks relate to the difficulties of raising long term debt financing and servicing those debts. In turn, that depends on having long term security of payments over the term of the debt and the ability of the borrower to fulfil payment obligations. Key factors are the ability to ensure matching long term contracted payments for the gas, liquidity in the sector and avoidance of related risks such as currency fluctuations.

Downstream from long term contracts for gas offtakes would be the power sector as the major gas user; lenders would also be looking for long term power offtake agreements (PPAs) rather than market exposure. All of these reflect on the credit worthiness of the LNG and gas buyer. If the buyer of regasified gas is not financially secure, the buyer of LNG and/or the developer of the regasification terminal will need additional guarantees to engage in any trade in the first place. Additionally if the risk profile of the LNG buyer is unfavourable, international LNG suppliers are unlikely to engage in long term LNG sales agreements. Therefore the ownership structure of the gas and LNG purchasers and credit worthiness along this chain together with interlocking long term contracts are likely to be required, unless the lenders are prepared to take some market risk on (regulated) market prices.

Demand/offtake risks

Additionally to the financing risk, a major risk area is the assurance of demand to guarantee the revenues for the project. Any regasification project in the region and indeed LNG purchasing contract will have to be backed by long term power purchase agreements (PPA's) to obtain financing. As gas fired power generation is expected to be far cheaper than the oil fired generation it will replace, gas is likely to be in merit and act as baseload. However, demand would be expected to grow over time and the capacities of the regasification terminal as well as the associated power generation plants would have to be developed with the expectations of future demand growth, meaning that initially the infrastructure would be underutilised.

Initial PPA's would therefore not cover the full utilisation of the terminal, unless they include pre-determined provisions of increases in demand which heightens the risk. The challenge is therefore to develop regasification infrastructure large enough to cover future demand and achieve economies of scale, while simultaneously ensuring a base demand level (backed by PPA's) high enough to recover significant parts of costs. The significant risks for this development could be related to two issues:

- In the short term, a key issue for demand is that this is a new activity and therefore there can be large margins of error on the demand forecasts, especially in the short to medium term when demand is dependent on the 'early movers' in terms of converting existing plant to gas or building new plants. In addition, there is a dependence on completion of the gas pipelines and related infrastructure. Delays in these elements could have large financial consequences on the parties in the upstream gas/LNG chain: take-or-pay obligations on the LNG supply and payment for capacity of the regasification terminal.

- In the longer term, if regional electricity trade is incorporated into the project plan and financing strategy, this is another risk area. Given the additional regulatory and contractual elements in selling electricity cross-border on the MER and SIEPAC, this is likely to be seen by lenders as a slightly higher risk source of revenues than domestic electricity sales.

These risks need to be outweighed when negotiating PPA's and long term gas purchase agreements. It is likely that the risks above would increase the purchase price of gas.

Price risks

The price risk should be small but could be problematic in certain circumstances. Based on both the financial value and economic value[31] estimations, gas in power generation has a strong competitive position from a cost point of view and a significant margin before it would be displaced by other fuels. It could therefore expect to be able to be priced into the power (and probably other) markets at a significant premium above purchase cost on regasified LNG. The financial return to the project should be reasonably insensitive to small changes in the selling price of gas, assuming it is initially priced close to its netback value.

The major risk area for price is if gas fired power generation is required to sell on a regulated cost plus basis. The same risk applies to gas sold into the wholesale and distribution markets for other user; industrial and commercial. There would, of course, be a general price risk for gas if electricity prices were to be significantly reduced. This is unlikely to happen in the short but could in the longer term if oil and other expensive fuels were fully displaced from the electricity markets and gas fired power generation became subject to gas-on-gas competition.

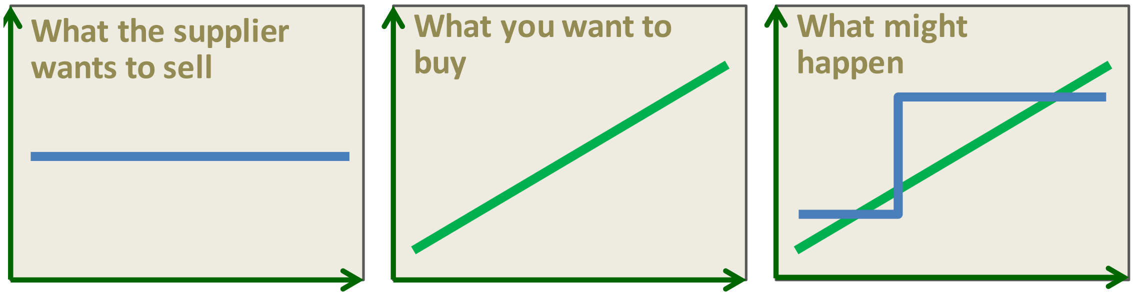
Supply risks

The risks for the supply of LNG will depend on the procurement and contracting strategy. With the growing short term and spot market, as well as the specific development of a large number of LNG projects in America and the region, there is likely to be LNG on offer. Price of supply is of course an issue but the CA countries, as small and relatively high risk buyers, will in any case have to pay a premium to the large long term contracts on offer.

The key supply risk is essentially a contract risk: how can the CA countries contract for the growing volume and shape of gas they will need, given that this is a new market with uncertainty in growth rate. Correspondingly, the LNG supplier is selling capacity in the liquefaction plant and ideally wants to sell a flat contract shape. Although there will be some flexibility around the contract quantity, the uncertainty in demand growth rate is likely to be greater than can be accommodated in normal contract flexibility; the principle is illustrated in Figure 30.

[31] Financial value indicates the maximum price at which gas could be sold and compete with the ***average*** electricity price in the country; economic value indicates the maximum price at which gas could be sold and compete with the ***marginal*** generation in the system –assumed to be oil-fired generation (which gas would generally be directly replacing)

Figure 30 Mismatch between contracts and demand



The lowest contract price for the LNG is likely to be for a flat shape. Predicting the shape of the growth curve is going to be difficult and a further challenge would be finding a supplier that was prepared to sell that shape.

One strategy to partly deal with this problem is to initiate the gas market with a small floating terminal (floating storage and regasification unit, FSRU). These can be chartered for short periods of months or a few years. They can also generally be put in place more quickly than the construction of a land based terminal. An FRSU could be contracted for the start-up phase, lasting say 2-3 years, making it possible to only enter into a 2-3 years contract for LNG. After that time the risks in demand forecasts should be lower and provided demand is projected to grow sufficiently, a larger land based terminal could be constructed and a long term LNG contract procured.

The alternatives are all risky. Contracting for only a few years, say 3-5 years to minimise the forecast errors, would be a major problem for the financing of the LNG terminal which would be looking for long term assured revenues. Purchasing or selling cargoes for the 'imbalance' quantities on the spot market carries price risks.

LNG purchasers could therefore purchase a base demand of LNG based on long term contracts (and backed by PPA's). Any additional demand could then be covered by shorter term purchases, however this would evidently be costlier than purchasing all supplies on a long term basis.

Cross-border trade risks

Either gas or power could be traded across country borders, giving scope for aggregation of demand and achieving some economies of scale in LNG procurement and regas terminal. Currently, gas trade is not being considered. A more likely option would be electricity trade provided that the SIEPAC regulatory framework were able to facilitate longer term trades. Nevertheless, if the expected revenues from traded electricity were required to support the LNG contracting and/or terminal construction contracts, the additional risks of the cross-border contracting are likely to require inter-governmental agreements to underpin the long term PPAs. Even then, they are likely to be perceived as carrying more residual risks than within-country PPAs.

Contract risks

The contractual arrangements for LNG, gas and electricity purchases largely determine where the supply, price and offtake risks lie among the parties in the value chain. The coordination of matching terms in this contract chain is important to be sure that risks are effectively passed to the parties that agree to take them. Other contract related risks will also need to be considered. These include the terminal operator contract, gas transportation agreement and transmission agreement. A related risk is that one of the parties will be unable to secure the appropriate contract or do so only after a long delay.

Construction risks

Construction risks clearly apply mainly to the start-up phase of the project. The two key risks in this area are construction delays and capital cost over-runs well above expectations.

Operational risks

Operational risks apply to each of the main components of the LNG chain. Risks can include technology risks (key technologies may not perform as expected, fail to be implemented or any novel features prove unworkable) and operating risks (any one of the components may not operate efficiently or suffer unexpected or extended shutdowns). A further risk is that weaknesses in coordination of activities will lead to the need to shut down other facilities or delayed operation; this is most obviously the case with LNG deliveries, though this risk can be mitigated with adequate storage.

Political risks

Stability of the government is important to avoid significant changes of the legal, political and commercial environment in which the various long term contracts are operated and ongoing investments undertaken. Stability is also highly desirable in the pricing environment for electricity and gas. The completeness and enforceability of the legal framework for commercial contracts is also important. Finally the general economic background and ongoing outlook for economic growth helps to ensure predictability and performance of the commercial contracts. All these issues are likely to affect currency risk which can have a direct impact on the profitability of the various assets in the LNG chain. They will also be reflected in the sovereign guarantee risk profiles and the countries credit rating, which has a near direct impact on financing costs.

Regulatory risks

In most countries regulators are intended to act independently, even though government influence is seldom totally absent or far away. Nevertheless, the stability and predictability of the regulatory framework for the energy sector, especially concerning regulated prices, is of key importance considering the long term nature of the expected returns from gas to electricity sales. An external risk that will be similar for many business model options is the risk of regulatory changes and the regulatory environment of both the LNG market as well as the electricity market. Some business models might however be exposed further to this risk than others. The risks include price risk as well as supply risk, ie degree of competition from the supply side.

Of particular importance is the regulatory framework for energy prices; firstly electricity prices and secondly – in the future – gas prices to other sectors; industrial, commercial and residential. Electricity prices are the key component to mitigate risks in the LNG value chain: they underpin PPA's, which guarantee revenues for gas purchases agreement, which in turn give LNG suppliers security to deliver gas into the region in the first place. Gas prices for non-power users will become important once they become major gas offtakers, which is likely to be only in the long term (7 to 10 years).

Legal risks

The legal framework is most important in the enforcement of contract terms, especially concerning disputes on contract terms, other disputes and *force majeure*. The latter is particularly important as it can lead to the suspension of contract terms. If the *force majeure* (FM) terms are not replicated and compatible across the set of interlinked contracts, a dispute can leave one party exposed, with FM suspending operation of the terms of contracts on one side of its transactions, but not on the other. The inter-dependency of FM conditions requires back-to-back provisions in all the linked contracts

Table 22 below illustrates the overall assessment of the major risks for a small LNG to gas to power project in the critical areas. The risks areas identified in the above summary descriptions are broken down in the table into a few sub-categories. This is a qualitative assessment of the hypothetical risks in a 'typical' project – but since no project is typical the assessment in this table does not apply to any specific project. It mainly serves to indicate the potential for risks and their relative magnitude in different risk areas.

The first entry in the table, for example, highlights this limitation. With the potential to have up to say 6 different parties in a multi-party chain; the key contracts governing their commercial arrangements, if not adequately containing back-to-back provisions, has the potential to create enormous difficulties to reach financial close and similarly great potential to lead to disputes in operation. If, further, the parties to each contract were not themselves strongly creditworthy, the project might fail to reach financial close.

This means that each component in the chain needs to be financially and contractually secured. If a regional approach is adopted, the costs and risks associated with ensuring this might be significant and are likely to jeopardise the feasibility of a regional project.

On the other hand, an integrated chain, with only one or two principal creditworthy parties and efficiently interlocking contracts with matching terms clearly defining risk allocation, could look strongly bankable.

The table can be taken to be reasonably representative of a well-designed project in the context of the options facing the CA countries.

Table 22 Indicative risk matrix for LNG in Central America

Major risk category	Risk of occurence	Severity of impact
Financing risks		
Long contract chain, multiple parties	◕	◑
Liquidity and payment problems	◑	◕
Currency fluctuations	●	◑
Demand and offtake risks		
Over-optimistic demand forecasts	◑	◑
Delays in new and converted plant	◔	◕
Delays in infrastructure	◑	◕
Uncertain access to regional trade	◑	◔
Price risks		
Regulated prices for power sales	◔	◔
Regulated prices for non-power gas sales	◔	◔
Supply risks		
Mismatch between supply contracts and demand shape	●	◕
Forecast errors in new market	◑	◑
Cross-border trade risks		
Inability to contract and assure long term revenues	◕	◔
Contract risks		
Non-matching terms in contract chain	◑	◑
Failure to close all contracts at same time	◔	◕
Construction risks		
Construction delays	◑	◑
Capital cost overruns	◑	◕
Operational risks		
Technology risks	◔	◑
Coordination risks	◑	◔
Operating risks	◔	◔

	Low		Medium		high
Key to risk of occurrence	○	◔	◑	◕	●
Key to severity of impact	○	◔	◑	◕	●

Major risk category	**Risk of occurence**	**Severity of impact**
Political risks		
Lack of policy stability/continuity in the energy sector		
Lack of political support for the complete chain		
Enforceability of commercial contracts		
Currency risk		
Regulatory risks		
Regulatory risk for electricity prices		
Lack of complete regulatory framework for gas		
Lack of stability in the regulatory framework		
Legal risks		
Enforceability of commercial contracts		
Lack of compatible *force majeure* terms		

Key to risk of occurrence

Key to severity of impact

Low Medium high

Risks in the above table are assessed in terms of their likelihood of occurring (risk of occurrence) and the financial or other major impact if they did occur (severity of impact). The critical areas are those listed items that are either very likely to happen (high risk) or that represent an important financial impact, even if unlikely (severe impact).However, the risk profile of a proposed project needs to be assessed based on the identified major risk areas remaining after careful project design (risk mitigation)

Risk profile characteristics

The risks and risk mitigation measures are discussed in the next section in the context of the options facing the CA countries. However, the risk profile of any LNG project in the CA countries is likely to be somewhat negative, given the most obvious characteristics which give rise to risks that are hard to mitigate:

- A novel project, first of its kind in the region
- Small demands, lacking scale economies
- A gas demand profile rising fast after initial start – a profile which is hard to contract at the beginning given both its shape and uncertainty of growth rate

- o The gas sector is new and all infrastructure needs to be constructed (although on the power side conversions of fuel oil plants to gas is a moderate cost)

- o The countries have low credit ratings; all, apart from Panama, below investment grade

- o The regulatory framework for gas needs to be established, for the (minor part) of gas likely to go to non-power uses

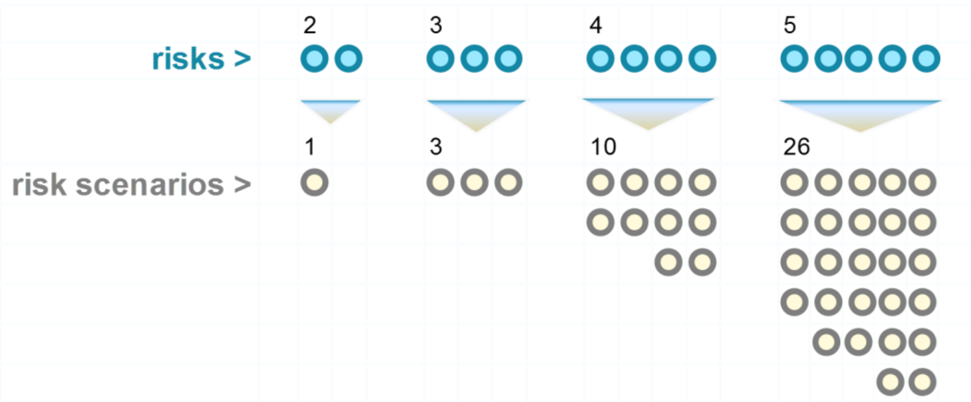
- o There are political and regulatory risks with aggregating demands by trading across borders

- o Contractual frameworks for LNG-gas-power that are untested within the CA legal and regulatory frameworks

By contrast, as an example, for the UK which has the second largest LNG import capacity outside the US and Asia, none of these risks are present.

Projects can be bankable if they only have a small number of residual significant risks (residual after efforts mitigation), but with larger numbers of risks the risk scenarios (combinations of circumstances involving two or more risks) multiply rapidly. For example, with 3 residual risks there are 4 scenarios of risk combinations, but with just one more residual risk (ie 4) there are 10 permutations of risk scenarios (combinations of pairs and triplets of residual risks), and with 5 residual risks there are 26 permutations! This effect is illustrated conceptually in Figure 31, but in reality bankability does reduce rapidly as the number of potentially uncontrollable risk areas increases.

Figure 31 Risk scenarios as combinations of individual risks



For this reason, for a new, first-of-its-kind, LNG project in the CA countries, project design needs to focus strongly on risk minimisation. This might, in particular, lead towards more integrated project structures for the first projects in the region.

6.3 LNG business models for the CA countries

This sub-section applies the risk analysis presented in the previous sections to the CA context. The objective of this and the next section is to provide a practical application of the analytical approach presented above and recommend a suitable business model for Central America.

6.3.1 Country characteristics and risk profile

A hypothetical benchmark

In order to assess and compare the business model options for the CA countries, it is useful to have a benchmark, which can be viewed as the theoretical best case approach. For this, we can imagine a hypothetical case which has the following characteristics

- Large scale, say 4-7 Bcm pa of assured demand (equivalent to roughly 3-5 Mt of LNG); an amount similar to the total demand for gas that is projected for the CA countries during the first 5 years (in the medium demand case)[32]
- New LNG terminal supplying gas into an established gas network and with financially strong power companies to guarantee gas purchases
- Able to sell flat contracts for gas (or capacity) enabling a high level of capacity utilisation
- Not first-of-a-kind project; an established market already having LNG terminals with a tried and tested contractual framework for the value chain
- Established and stable regulatory framework or market for gas and electricity prices providing full cost recovery and adequate rates of return
- Country and gas or power companies with strong investment grade credit rating

The description of the above benchmark could be described as the '***gold standard***' for an LNG project and one that would be easily financeable at competitive borrowing rates.

The *gold standard* LNG to power project could be implemented with any one of the business models. For example, in the merchant of tolling models (see Annex) the disaggregated structure could have separate companies supplying LNG, operating the regas terminal and offtaking the gas to sell into the gas market or direct to power producers. These specialised companies expertise would offset the small contract risk and operational risk that increases slightly with more parties in the chain.

The reliance on stable market conditions (low regulatory, legal and political risks) and industry standard contracts (contract risk) would reduce the risks of trading between the entities to low levels.

[32] Though this is larger than any one country's expected demand

Major risk category	Risk of occurence	Severity of impact
Table 23 Risk profile of the *'gold standard'* project		
Financing risk		
Demand and offtake risk		
Price risk		
Supply risk		
Cross-border trade risk		
Contract risk		
Construction risk		
Operational risk		
Political risk		
Regulatory risk		
Legal risk		

The project would probably be exposed to some price risk in a competitive market, and to the technical areas of construction and operational risks, but these risks would be quite well understood by the lenders and the project's risk of not being able to be financed would be small.

The Central America context

These conditions may be contrasted with the risk profile characteristics of a proposed LNG project in one of the CA countries.

The main factors underlying the country risk profiles in CA are summarised in Table 24 below, covering such indicators as sovereign debt credit ratings, the volume and rising profile of gas demand, income levels as an indicator of current economic situation and affordability, electricity prices for underpinning the LNG purchase and the general shape of the regulatory framework for energy.

Table 24 Country summary indicators

Country	Credit rating (a) (b)	Demand Yr 1 Bcm (d)	Demand Yr 10 Bcm(d)	GDP/cap US$(2000) (e)	Electricity prices $/MWh	Regulatory framework (f)
Costa Rica	BB	0.6	1.7	5,885	123	A
El Salvador	BB-	0.6	1.7	3,033	160	A
Guatemala	BB	1.7	2.5	2,313	121	C
Honduras	B	1.0	2.3	1,583	173	C

Country	Credit rating (a) (b)	Demand Yr 1 Bcm (d)	Demand Yr 10 Bcm(d)	GDP/cap US$(2000) (e)	Electricity prices $/MWh	Regulatory framework (f)
Nicaragua	- (c)	0.4	1.1	1,334	160	C
Panama	BBB	1.0	2.9	7,761	210	B

*Notes: (a) credit rating is obtained from Standard and Poor's Sovereign foreign-currency rating, as of June 2014. (b) a bond is considered **investment grade** if its credit rating is BBB- or higher; bonds rated BB+ and below are considered to be **speculative grade**. (c) Nicaragua is not rated by S&P. (d)) Total projected gas demand, medium demand scenario, IDB study (e) IMF and ECLAC, 2012 (f) ECA assessment on basis of qualitative review of existing frameworks. Due to the limited scope of the project, we have not been able to make a thorough review of all regulatory frameworks, but have considered the transparency of the regulatory framework, the implementation of regulations, cost reflectiveness of tariffs and prices and the independence of regulatory agencies.*

The key characteristics include the demand levels which are first low but then growing, though in a not very predictable way. This suggests the load factors on the plant and facilities would be low overall, while cash flow could be variable. Sales into the power market vary by price in the different countries, and the long term predictability of those prices is likely to be related slightly to the indicators for the robustness of the regulatory framework. These factors combine to make long term revenues for the component parts of the project relatively unpredictable.

More importantly, the low sovereign credit ratings (Panama has a low investment grade rating but the other countries all have ratings below investment grade) indicates financing would be a challenge for any large project. An LNG project, with interdependent, high capital cost facilities, faces challenges of secure and predictable payments along the chain, where market, regulatory, technical or contractual problems could disrupt the flow.

Based on the typical country characteristics, risk profiles can be constructed for potential business models for the region. Clearly individual countries would differ on the degree of each risk; key factors would be the differences in size of potential demand, the electricity prices and the regulatory environment for future prices, and the current sovereign credit ratings. However, they can all be considered as small, high risk countries; these factors are major determinants for the feasibility of different LNG project structures and therefore at this pre-feasibility stage we review the applicability of the different business models for the countries of the region as a whole.

We group the business models into pairs to reduce the number of distinct cases we compare. The first pair we refer to as the contractual model, as ownership is a fully separate and the chain relies fully on contracts between the parties:

- ***Contractual model***: The first two business models illustrated in the Annex each have separate entities for the three main midstream components: LNG supply, regas and offtakers (the merchant and tolling models in and) Contracts between the entities govern all the trading.

- ***Semi-integrated model***: The next two business models (Figure 29, Annex) feature integration between two parts of the chain, the regasification terminal and either the downstream gas offtaker (gas supplier or power plants) or the upstream LNG supplier. In the first case, this implies a monopoly, either over gas supply or over power generation from gas; in the second case, a monopoly of LNG/gas is implied, although there could be alternate downstream buyers of gas

- ***Fully-integrated model***: This case is represented in the Annex, although in some cases the regasification company is not part of the integrated entity but is separate, suggesting the possibility of some third party access (TPA) to the terminal[33]. The fully integrated model gives the company a monopoly of supply to the 'factory gate' (i.e. the power station!) and consequently the ability to recover a higher margin over cost, which would facilitate financing.

The risk profiles of these three types are compared in the risk matrix in Table 25 below.

Table 25 Comparison of business models: risk matrix

Major risk category	1 Contractual model		2 Semi-integrated		3 Fully integrated	
Financing risk	●	◕	●	◕	◕	◑
Demand and offtake risk	◑	◑	◑	◑	◑	◑
Price risk	◕	◕	◑	◕	◔	◑
Supply risk	◑	◕	◑	◕	◔	◑
Cross-border trade risk	◑	◔	◑	◔	◑	◔
Contract risk	●	●	◕	◕	◔	◑
Construction risk	◑	◕	◑	◕	◑	◑
Operational risk	◑	◑	◑	◑	◔	◔
Political risk	◑	◕	◑	◕	◕	◕
Regulatory risk	●	◕	◕	◕	●	◕
Legal risk	◑	◑	◑	◑	◔	◑

Key to risk of occurrence: ○ ◔ ◑ ◕ ●

Key to severity of impact: ○ ◔ ◑ ◕ ●

Low — Medium — High

Compared to the other two, the fully integrated model has a greater chance of reaching financial close, having less operational, supply and contract risk, though higher political and regulatory risk. This last assessment is indicated as a monopoly supplier is more likely to face political or regulatory scrutiny and challenge if the sector performance does not meet objectives.

[33] This is in fact the way the LNG terminal, an FSRU, works in Israel

6.4 Assessing the business models

There are a number of issues that are likely to influence the further development of, on the one hand, the more detailed business model structure by country, and on the other hand, preparations by the countries to facilitate an LNG project. These are discussed below.

6.4.1 Third party access

The countries have a strong interest to incorporate a degree of competition into the new market by way of open access or third party access (TPA) to the terminal facilities (and gas pipelines). If we consider that the typical project financing would have a debt/equity percentage structure of 75/25 or 80/20, the investor will be very focused on having guaranteed and predictable incomes for the debt financing part and therefore needs to be fully contracted throughout the chain for at least 80% of the capacity, and for at least 10 years or the term of the debt.

Therefore the starting point for TPA is likely to be quite restrictive. This is a typical situation for any gas infrastructure that brings new gas supplies to an area, whether LNG or pipelines. The WAGP, which has already been mentioned above, has a 10 year period of assured capacity allocation for the equity holders. However this approach does not only apply to risky markets. A recent landmark project in Europe is the TAP pipeline (Trans-Adriatic Pipeline) that will deliver new sources of gas from Azerbaijan into Italy in Southern Europe via Turkey and the Balkan countries. TAP has a 10 year TPA exemption for 90% of its capacity that is allocated to its equity investment holders.

TPA would need to be negotiated, and may come with a slightly higher price. The investor is likely to accept a slightly lower price for gas if he has assured 100% of the capacity to sell into the market. The investor's target will be a safety margin of cash flows over the debt repayment commitments. If this can be achieved with reserved capacity of 90% or 80%, then the remainder could be offered to the market as TPA to be contracted to one or more other parties.

6.4.2 Upside potential

The flip-side of other parties seeking TPA is that the investor (project sponsor) will be looking for upside potential on the project's earnings. A typical financing strategy is to cover the financing repayment obligations with firm, long-term contracts, but then to retain as much capacity as possible for shorter term market transactions.

This approach may match the market realities that an attractive price for new gas (or power offtakes) may need to be offered to early contractees to entice them to commit long term. Later contracts or market sales may be achieved at progressively (slightly) higher prices. Once the minimum financing obligation is matched, the project sponsor may hold out for higher prices until the plant is commissioned.

Therefore access to the last 10%-20% of capacity may be a tension between the sponsor aiming to get upside on the projects return and the market players trying to get TPA to the capacity.

6.4.3 First of a kind

LNG in gas-to-power is not uncommon and the economic scale of LNG projects is coming down. Nevertheless, a project in the CA countries has novel and untested characteristics. These include:

- First project in the region
- Premised on some regional cooperation to aggregate loads, but there have been problems with the pace of development of regional power trade, and few successful examples of international cooperation on financing of an LNG project
- Small loads in individual countries, nevertheless most if not all countries aiming for their own terminal

This suggests that the risk profile (and possibly capital costs) of the first project may be relatively high, but could fall with subsequent projects as both LNG companies and lenders become more comfortable with the risks. This relates directly to the next sub-topic.

6.4.4 Roll out

The countries have expressed a desire to have separate LNG terminals in each country. The IDB study has proposed three strategies (see section 4): strategy A is premised on individual projects in each country, while strategy B is termed sub-regional cooperation and foresees a development starting with terminals in one or two countries, with cross-border trading, followed by terminals in the other countries. Strategy C is a mixture of pipeline connections (north) and national LNG terminals in the south. Ultimately all strategies end up with a similar configuration, although some of the terminals in the region could be larger and sized to accommodate ongoing trade flows.

However, in terms of the sequencing and roll out of the facilities, there may not be much difference between these two strategies. It seems highly likely that one or at most two terminals in the region will be built first, e.g. Panama first followed by another country. As each successive terminal is built (and successfully put into operation with due performance of payments under all the contracts), the risk profile for subsequent projects will fall.

On the other hand, subsequent countries are likely to be ones starting with a higher risk profile and a lower demand, both nationally and the residual unmet demand in the region. The balance of these opposing factors is likely to make the roll out slow, though there is no reason to believe that an eventual configuration of a terminal in each country (with the exception of Guatemala likely to be supplied by pipeline from Mexico) cannot be achieved at some point. The roll out to all countries may therefore not be much different between the two strategies, as the timing of later projects will be conditioned by the risk/return balance in either strategy.

6.4.5 Regional cooperation

As noted above, a central element to the proposed strategies from the IDB study is the level of regional cooperation required. At one extreme, a regional approach to trading by creating a 'Central American gas buyers' club' would increase the bargaining power of the region and might reduce the price obtained from LNG imports. However total volumes are still small in the early years even if all countries either have their own terminals or buy long term contracts of gas-fired power across SIEPAC. The practicalities of either approach are questionable. The likelihood of several LNG projects reaching financial close at the same time is very small, while long term power offtake contracts supplied through the SIEPAC/MER may be significantly less bankable than 'domestic' power offtakes.

A well-functioning and strong SIEPAC is therefore key for regional integration of energy markets. It provides the first stepping stone for developing LNG terminals that are large enough to cover regional energy demands. However the difficulties of SIEPAC and its congestion due to usage as a balancing tool for national electricity transmission systems, makes trade difficult. A detailed description of SIEPAC and its complications is provided in Annex A1.

Demand fluctuation across countries can probably be handled through adequate storage capabilities and while the hub and spoke model has not been highlighted by the IDB study, it remains a possible option to consider later.

Strong integration of gas-to-power in the countries will also require significant political agreement and close cooperation between the countries, to provide the guarantees for cross border energy projects. This may be novel in LNG projects though in gas pipeline projects covering several countries there is established practice in dealing with inter-governmental agreements (IGAs).

Financially, the risk profile of a regional LNG buyer is likely to be opaque. It would have to be a pooled risk profile of the gas offtakers, ie the electric utilities across all countries. As these are mainly publicly owned companies, the credit rating of the respective countries would be one key element of the overall risk assessment. Since the volumes of gas would have to be allocated by gas offtaker/country and these will fluctuate over the years, the risk profile of the LNG buyer would be uncertain for the joint LNG supplier. There is also the question of whether the gas would then be provided to each involved country at the same price, given that the different risk profiles/credit ratings and quantities are bot factors which could be expected to lead to a slightly different price if contracted separately.

Alternatively, regional cooperation could be confined to electricity trade based on SIEPAC. Each country would then separately trade its LNG and look to trade surplus electricity to its neighbours. This would enable a more clearly defined commercial foundation for gas development in the region, but might not lead to all countries being able to develop their own LNG terminals.

It is likely that a pragmatic approach needs to be taken to regional cooperation on a project by project basis, to avoid the situation where a benefit by load aggregation is more than offset by the additional risks of complex cross-border contractual arrangements.

6.4.6 Risk mitigation

The starting point for considering the financing of an LNG project in the region is a relatively high level of risk compared to a low or moderate level of demand. The initial risk assessments have been shown in the risk tables in Table 22 and Table 25, indicating high levels of risk in all considered models. Therefore every reasonable mitigation option should be identified and considered.

One of the main areas of risk mitigation is to minimise the number of parties in the value chain and the resulting number of contracts. Contract risk is one of the key areas of potential large risk identified especially in the models with non-integrated structures. This could be mitigated through a multilateral partial risk guarantee by institutions such as the World Bank.

The demand risk is also a major area to consider and needs to be considered in conjunction with supply risk. Unless demand can be secured through long term PPA's, gas purchase agreements are unlikely to be finalised and gas supply and subsequently terminal financing cannot be secured. Long term PPA's however require security of demand, which cannot be guaranteed: the markets are new, underlying demand levels are initially small and the rate of growth is hard to predict.

One possible mitigation approach to avoid this circularity problem is to contract a base load of gas demand on long term. This volume would have to be high enough to secure financing and supply, but low enough to minimise demand risk, i.e. be based on conservative electricity demand projections and resulting capacity factors. The additional demand of gas beyond this base load could then be met by short term contracts and/or further long term gas purchase agreements, as and when demand becomes more certain. Inevitably, this is likely to raise the price of LNG due to lower and more flexible volumes of LNG, thereby raising the cost for risk mitigation.

Political and regulatory risk is the third major risk area. Both of these topics cover a wide spread of risk issues but a few stand out. The main regulatory risk relates to both the electricity and gas markets, in the first case to ensure that electricity prices will be set to reflect costs, and in the second case to deal with the gap in all countries in the absence of a regulatory framework for gas distribution and supply. Stability of the regulatory framework is also important, and here the past (in terms of degree of constancy and predictability in the regulatory framework for electricity) is a key indicator.

Political risk covers a broad sweep of potential problems. The overall stability of the policy framework for energy covering approach to pricing, role of the private sector and support to new investment projects is one key indicator. Evidence that there will be political support for the complete LNG to power chain (as well as development of gas supply and distribution to other sectors) is a second important area. Thirdly, the support for the private sector and ensuring the conditions for (timely) enforcement of commercial contracts is another area where the policy framework could support the project. The general direction of policy including financial management of the economy is important for assessing the exposure to currency risks.

In many cases the tangible policy support from government will be implemented through PPP arrangements. Within the region, some of the power sector companies are publicly owned though more are private. In the LNG value chain this could range from direct equity stakes held by public bodies to public sector guarantees on the performance of certain contracts (such as PPAs), including assuming some of the risks the private parties are unwilling to take.

A typical PPP structure would be a Build Own and Operate (BOO) arrangement with a power purchase agreements.

6.4.7 FSRU

The countries appear to have assumed or preferred land based regasification terminals. The difficulty with this approach is the high and fixed capital cost commitment to a pre-defined volume. The alternative that should be seriously considered is the use of more flexible floating storage and regasification units (FSRU). The advantages of FSRUs include:

- Ability to contract short term, from months to a few years
- Lower risk of over-investing in unused capacity, due to demand uncertainties or delays in commissioning of new gas-fired plant or gas pipeline infrastructure
- Easy route to scale up volumes as demand grows; a larger FSRU could be contracted or switch from a floating to fixed onshore facility once demand uncertainty is reduced
- Shorter timescale to put in place, say 1 year compared to 3 years. This also reduces the risk of misalignment between gas demand and regas capacity
- Potentially reduced regulatory requirements, avoiding risks of unexpected delays in the planning and permitting process
- A key point is that the cost of the FSRU contract may not require the large guarantee facility of a land-based terminal. While a land-based terminal can almost certainly not be financed without long term gas and power offtake agreements, an FSRU has a much lower financing requirement which matches the lower financing requirements of power plant conversions from oil to gas (whereas a new build CCGT would require a long term gas offtake agreement that can only be provided by a fixed land based terminal)

Although the short term cost of a FSRU might be higher than a land-based terminal in the short term, in the long run it can reduce costs and facilitate a more efficient build-up of gas and power capacity.

7 Regulatory issues for the introduction of gas

7.1 Requirements for the regulatory framework

The purpose of this section is to provide a brief overview of the main regulatory issues for introducing natural gas into the Central America countries' energy markets. It is not intended to provide a comprehensive guide to the regulatory and legal frameworks for gas markets, as at this stage there is little indication what size, scope and objectives there would be for the eventual gas sector in each country, or the integration between the countries' eventual gas markets. Rather, the aim is to identify the minimum requirements for initiating the gas market and facilitating the early investments, while not precluding the direction the gas regulatory framework would take as the market size and complexity evolves.

There are a number of key components of the regulatory framework that would need to be in place to promote the first steps in establishing a gas market. It should be noted that the shape of the initial regulatory framework for an entirely new and untested market is likely to be quite different from the regulatory framework in a mature gas market. A sensible approach is that the initial framework should not preclude different options for the shape of the market that will develop over time, while recognising that if initial investments are carried out by the private sector, a degree of (time and location limited) monopoly must be conferred to underpin the financing of those investments. On the other hand, if the public sector carries out the initial investments, e.g. to create an import facility, initial gas transmission system and possibly also local distribution networks, the regulatory framework to support multiple gas suppliers[34] needs to be in place from the beginning. Two recent studies provide considerable detail on the approach to, and structure of, required regulatory frameworks given varying objective for the roles of the private and public sectors[35] [36].

While looking for a common approach for the region, it should also be recognised that the countries have different opportunities, constraints and objectives. These impact on broad areas such as the role of private vs public sectors, the focus on power compared to non-power gas sectors, and the degree and form of regional integration.

This section covers two regulatory aspects: first, gas regulation, and second, the conditions to develop power purchase agreements (PPAs) for long term power offtakes to underpin the financing of gas infrastructure.

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[34] If multiple gas suppliers are not intended or realistically achievable in the early years, there is little advantage in putting in place the regulatory framework at the beginning. That could be counterproductive to encouraging the initial investor, given that it might indicate uncertainty over the time and scope of the initial investor's activities that would enable financing of the investments. A common example in markets with clear intention towards full competition, like the EU, is to grant private investors of, typically, new transmission pipelines, a ten year exemption from full TPA with perhaps 10% of capacity required to be offered to the market.

[35] Study on the normative and institutional conditions for the introduction of natural gas in Central America (in Spanish), OLADE 2014

[36] Harmonisation and Integration of Hydrocarbons Market in Central America, R.Priddle (principal author), BID/FOMIN/ECLAC 2000

- o Gas regulation; the current state of the legislative and regulatory framework in each country is reviewed; in particular, if these foresee the creation of a national gas market. The focus is on normative and governance aspects, as well as on tariff issues.

- o Power offtake agreements; the current state of play with respect to PPA agreements in the region, both within country and regionally across SIEPAC

In order for long term investment in gas import infrastructure and gas transmission to be financed, especially if the country is looking to the private sector to do this, either the legal and regulatory framework needs to provide sufficient support for long term offtake agreements for gas and/or power, or a single party needs to own the whole value chain from import to power sales. The latter is the case with the start of the gas market in the Dominican Republic (see annex A8.2).

On gas sector regulation, the conclusions reached are that although some of the countries' legislative frameworks include a national gas/hydrocarbon law, most of them deal with the production of gas and oil in an integrated legal document with a focus oriented towards oil. This implies that the specific characteristics of gas as a fuel are not properly accounted for. More importantly, there is no clear regulatory direction provided in any of the countries for the commercialisation of gas, the role of the private vs public sector, or more specifically, for the import of gas in its gaseous or liquid forms.

On the power offtake issue, although PPAs are a common practice in the region, they are generally of short to medium term duration. Additionally, the regional electricity network SIEPAC, which provides the opportunity to trade power across countries and could thus be a source of regional PPAs, has many unresolved issues with the allocation of capacity, especially important in the long term. This implies that if a long term PPA is signed between parties located in different countries based on transporting their traded volumes over SIEPAC, they have no way to secure the network capacity they need at any specific future point in time.

7.2 Background to the current markets

At present, gas consumption only focuses on small-scale demand for LPG, mainly for residential uses. In the 6 countries in this study, LPG is imported and distributed by either private or state-owned companies. Since LPG is transported as a liquid in containers and bottles, the regulatory framework for the market is far simpler; the fixed infrastructure requirements are far smaller and competition over time is easier to foster.

Four of the countries in this study, Panama, Costa Rica, Nicaragua and El Salvador, are not geographically close to any known oil or gas reserves of their own. Therefore, their legislation does not envisage the possibility of exploiting such resources. The remaining two, Honduras and Guatemala, which are located closer to the Gulf of Mexico, have developed exploration programmes in their territories and on the Atlantic seaboard.

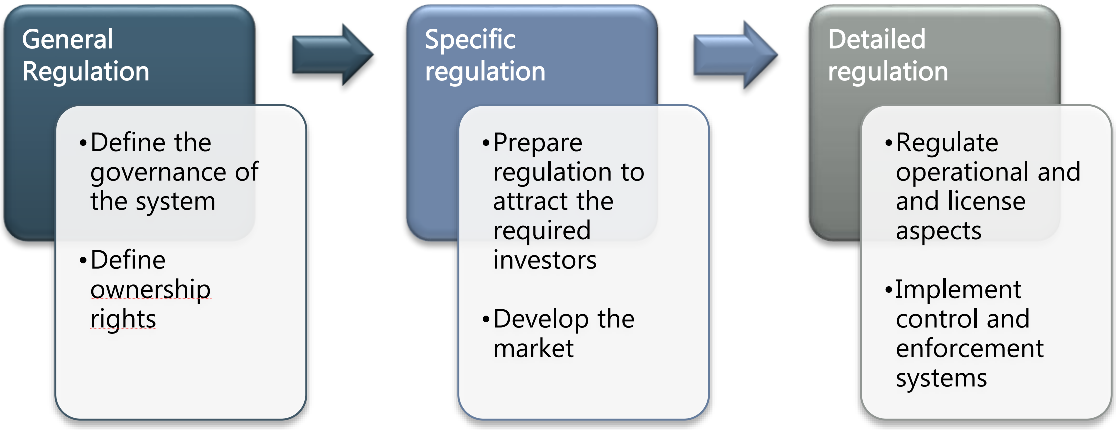
These prospects are reflected on the legislation already developed in each country.

Since the introduction of natural gas in the region requires a large initial investment to provide scale for gas demand, the strategy proposed in Central America has been to develop such demand from electricity. Once it has been established, gas can be used for other purposes, as is the case in the Dominican Republic.

7.3 Steps in the development of the regulatory framework

The development of each country's regulation requires certain steps to accompany the process of attracting investment, from general sector regulation, through regulations for specific activities, finally to detailed implementation regulation. This is described in Figure 32.

Figure 32 Staged development of gas sector regulation



At present in the Central America countries, the lack of a normative and clear regulatory direction to support gas market development will create an uncertain environment for investment. Therefore, the initial normative development that would be required to facilitate establishment of the market would be to establish general rules to attract investors to the business. This would correspond to developing the primary legislation focused on gas and the main sector regulation to reflect the intended structure, ownership and operation of the market. At this stage, it will be important to keep these simple but clear in order to avoid imposing an excessive regulatory burden on new investors or the risk of ambiguity in the interpretation of different parts of the regulatory framework.

In order to attract large private investment in infrastructure, it will be necessary to make some progress with the specific regulation, such as secondary regulations and decrees. These should be focused on defining the activities and rights of investors, as well as the boundaries of their operation and obligations to the public, but without these becoming a constraint to market development. At a later stage, after initial investment has been put in place and as the structure and operation become better defined, it will be necessary to strengthen certain operational aspects and codes to ensure smooth and efficient operation by all parties in the developed gas market. The requirement and scope for this will depend to the extent there is actual or intended competition in various segments of the market. This corresponds to the last stage of regulation and market design.

In the gas sector, unique facilities such as import terminals and transmission networks have the character of natural monopoly. Prices may be set by regulation if publicly owned but for private ownership a defined monopoly is likely to be needed and prices set in the tendering. This condition may not be the same for distribution, where the whole sector can be split into more than one distribution concession or licence area, but the infrastructure investment will still require a firm price commitment (again, generally set in the tendering).

The practice in Latin American countries has been to develop some general regulations on public private participation (PPP), focusing on the process of granting concessions/BOT, BOO, and other management agreements[37]. These can be structured for different activities and components of the sector structure, including regasification terminals, other gas market infrastructure, as well as upstream activities. Depending on the scale of the investment, this may be achieved through specific laws or decrees, but using some of the specific wording proposed in the terms of reference for tendered concession contracts. This approach has allowed private parties to make certain modifications during the concession process and to adapt the provisions to allocate project risk properly between the regulator, the project developer, and the consumer.

7.3.1 General regulation

Any general regulations designed and developed for the energy markets, but also intended to be applicable to gas, can be expected to attract investment to the sector by defining long-term guidelines for investors, thus reducing regulatory uncertainty. The depth of these regulations, however, can also be a constraint or burden for investors, for instance, if they are developed without considering the specific aspects of the gas market. Consequently, it will be key to ensure that any new regulation is clearly focused on activities which need to be regulated and does not create barriers to investment.

A general regulation should identify and define all substantial aspects, such as:

- ownership rights over natural gas and any assets associated with its exploitation, clearly defining whether they are private enterprises or exploitation concessions
- the main conditions for regulation and competition, together with the degree of state supervision
- the relevant entities and their degree of autonomy

Although it will be advisable to compile all related regulations and rules for ease of access and clarity, having a unified regulation drafted into a single document may result in difficulties to introduce small changes later on. If the complete regulatory framework is drafted in several different regulations, there is a risk of creating different interpretations or contradictions. Neither approach is uniquely better for the start of a market, but the guiding principle is that rules which are unlikely to change may be

[37] The PPP contract type is in fact a risk mitigation mechanism , providing clear allocation of the activity risks between the private and public parties

combined into a single 'omnibus' regulation, while those which will change as the market changes, are better left in separate documents.

In the general regulation, it is convenient to include and define the function of an oversight body for the market. This may be entrusted to an existing entity or a new specific entity that is created for this purpose. At the starting stage of the market, a specific regulator may not be necessary as it is unlikely that there will be a competitive gas market. Instead, a regulated monopolist player may prove to be more effective. The key regulatory function is to enforce the conditions of the concession contract, of which the most difficult may be the obligations on investing in infrastructure to build out the network.

With regulated monopolists, such as import terminal, transmission network or distribution concessions, the framework should incorporate an entity to deal with anti-trust matters and the prevention of abuse of a dominant position, excessive concentration, and other actions detrimental to the intended structure and operation of the market as a whole.

7.3.2 Specific regulation

Specific sector regulation is created at the time of initiating the development of the market. In particular, prior to taking part in tenders for or accepting projects, entering into agreements, or granting concessions. At this stage, if gas has so far been included in a general energy or hydrocarbons law, it might be preferable to separate gas out into a primary gas law. This facilitates the ability to make changes in the primary legislation for gas without having to revise the omnibus energy/petroleum law. The objective is clarity and avoiding ambiguity, which might be created by a clause intended to be related to a different subsector (e.g. electricity) but which could be mis-interpreted as a rule affecting (and potentially confusing) the gas sector[38]

Such an instrument can be decided immediately and in its full scope, although it might be more convenient to develop its application to different parts of the sector in several stages, depending on the progress of supply, and covering the different activities: production, imports, storage and regasification, transportation, transit and exports, distribution to large customers, vehicles and residential use.

7.3.3 Detailed regulation

Finally, the detailed regulation stage refers to the instruments and activities related to each initiative, such as permits, licenses, contracts, concessions, investments, import, export or transit authorizations, environmental licenses and so on.

Such instruments are not general, but specific to each activity. Their coherence with the country's general energy strategy should be ensured by their conformity to the national laws (e.g. Gas Law) and other key secondary regulations such as gas market regulation.

[38] It is not always necessary to create a new law. For example, the key provisions for establishing the gas market in Turkey were contained in a one paragraph note in an annex to the Electricity Law! But the intentions and implementability of the new rules were nevertheless clear.

7.4 Overview of current gas regulations in Central America

Following the introduction to the structure and strategy for developing the regulatory framework for a gas market, this section now briefly summarises the current status in each country. This covers an analysis of the current legislation, the forms of governance, and a summary table comparing the main regulations in the countries.

Across Central America, individual initiatives have been based on a series of different institutional, regulatory and public policy decisions in each country, each with the particularities of its tradition, institutional organisation scheme, and public policy model. The review covers, for each country:

- Regulation and the regulatory framework
- Energy market oversight
- Fiscal treatment
- State assets and state-owned companies

7.4.1 Guatemala

Guatemala is an oil producing country, where natural gas reserves have recently been discovered. However, these are not at a commercial scale yet. At present, there are oil companies in the country operating the exploration licences granted by the Ministry of Energy and Mines. As for gas, there are only certain activities related to industrial and residential use of LPG.

Regulation

The situation, described primary legislation below, implies that the country's regulation should contemplate natural gas upstream and downstream activities. The legislative framework contains two relevant laws:

- ***Hydrocarbons Act*** (*Ley de Hidrocarburos*) - Decree No. 109-83 and its Regulation, Government Agreement 1034-83. It refers to exploration and exploitation activities.
- ***Hydrocarbons Commercialization Act*** (*Ley de Comercialización de Hidrocarburos*) – Decree No. 109-97 and its Regulation, Government Agreement 522-99. Its purpose is "to promote the establishment of a free competitive market for oil and its products, providing maximum benefits to consumers and the national economy".
- In addition, there is a memorandum of understanding (MoU) signed by Mexico and Guatemala in December 2009 which covers the terms of natural gas trade and transportation between both countries. This agreement lays the foundations for private investors to build gas pipelines, and exempts gas imports from duty tax. Recently, Guatemala and Mexico have signed an additional MoU which sets out further details to their agreement.

In Guatemala there is no general regulation of the downstream gas sector. Therefore its regulations arise from the interpretation of the abovementioned laws regulating the hydrocarbon market.

The Energy Policy 2013-2027, issued by the Ministry of Energy and Mines, contemplates drafting a specific Law and its Regulation for natural gas, so as to establish the legal and technical provisions for its use and commercialisation.

Energy market oversight

The Ministry of Energy and Mines (MEM) and, in particular, the Hydrocarbons Department (*Dirección General de Hidrocarburos*, DGH), are responsible for energy issues related to energy supply.

The DGH has regulatory functions, however it does not set prices, which are left for the market to set. The current regulation seeks to ensure a free market in the upstream segment of the business.

The power sector is regulated by the CNEE (*Comisión Nacional de Energía Eléctrica*), which regulates power purchasing agreements to expand the power system[39]. The CNEE is a decentralised and economically independent entity whereas the DGH is subordinated to the central government.

Fiscal treatment

Natural gas imports are only taxed at the general VAT rate of 13%, and are duty free and exempt from other taxes.

State assets and public companies

In Guatemala, there is no state-owned company in charge of importing and trading oil and its products. In contrast, the national power utility, the INDE (*Instituto Nacional de Electricidad*) is a publicly-owned organisation which is involved in power generation, focusing on hydraulic energy.

Ownership of the power sector is private; the government supervises the bidding by distribution companies (for PPAs) when system expansion is planned.

7.4.2 El Salvador

El Salvador has the most comprehensive scheme for the introduction of natural gas among the countries in the region. The national Gas Law was passed in 2009 in anticipation of the construction of a regasification plant by Cutuco Energy, in order to obtain a contract for gas supply from Peru, however, the project has been halted since then due to matters related to municipal permits[40].

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[39] The CNEE has accepted the power and gas swap agreement with Mexico for 150 MW to import natural gas-based electric power. This agreement has been entered into for an initial price of 120 USD/MWh. The price is fixed and only adjustable by wholesale inflation (PPI Index).

[40] OLADE, 2013. The Cutuco project was first proposed in 2006 following acquisition by Cutuco of land in 2005

Regulation

In 2008, the Natural Gas Act (LGN) was passed. It establishes the regulation for natural gas reception, storage, regasification, transportation, distribution and commercialisation. Gas production is not covered by the law as the country does not have any identified national gas reserves.

The rules state that permits are required to commercialise gas, that is, to import, store, and transport gas, while concessions are required for transportation assets, such as pipelines. Although the Law provides for the government to issue many concessions, El Salvador is geographically very small to warrant more than one concession.

Additionally, the country joined as a party to the MoU between Mexico and Guatemala in connection with natural gas trade and transportation (7 December 2009).

From a regulatory point of view, the existing framework does not specifically deal with several aspects of the LNG value chain, e.g. LNG import, storage and regasification. Once LNG imports are introduced, the government might consider incorporating these aspects to provide a clearer regulatory environment for investors.

Energy market oversight

The regulation establishes the governance of the gas sector. The pertinent entities to develop this market are the following:

- The Ministry of Economy, under the guidelines of the National Energy Council (*Consejo Nacional Energético*[41]) has the function and responsibility of carrying out gas policy
- *Dirección de Hidrocarburos y Minas* (DHM) is the general hydrocarbons regulator
- The regulation of the power sector is carried out by SIGET[42], (*Superintendencia General de Electricidad y Telecomunicaciones*)

Consequently, there is no specific regulator in charge of overseeing the gas market.

The DHM is subordinated to the central government and is subject to changes in its administration due to government changes. The SIGET is a decentralised, economically independent entity.

[41] The Consejo is constituted by Minister of Economy, Legal Advisor of the Presidency, Minister of Treasury, Minister of Infrastructure, Minister of environment and natural resources, and the Ombudsman.

[42] SIGET has been responsible for the PPA tender that finally granted Quantum a contract to develop the 338 MW thermal generation plant in Acajutla, with an associated regasification plant. The reference price of this contract was 122 USD/MWh, with adjustment mechanisms linked to Brent as from the second year of generation. SIGET is presently analysing the LNG supply contract for Quantum, which indirectly implies it is working on natural gas regulatory aspects.

Fiscal treatment

Natural gas imports are only taxed at the general VAT rate of 13%, and are duty free and exempt from other taxes.

State assets

In El Salvador, there is no state-owned company in charge importing and trading of oil and its products. The government runs the *Comisión Hidroelectrica del Rio Lempa* (CEL), which participates in power generation by producing hydro energy.

The power sector is in power sector ownership; the government supervises the bidding by distribution companies (for PPAs) when system expansion and new investment is undertaken.

7.4.3 Honduras

The Republic of Honduras has carried out initial hydrocarbon exploration activities for about a decade without having reached the exploitation stage yet. No natural gas is produced or imported. Therefore, its regulatory framework refers only to hydrocarbon exploration and exploitation, with no details on the introduction or use of natural gas into the domestic market.

In 2013, a license was granted to BG International Ltd, a member of the BG Group, for off-shore hydrocarbon exploration and exploitation in the maritime area of the country. This contract explicitly includes natural gas.

Regulation

The regulatory framework of the sub-sector is spread over thirty legal instruments, many of which are outdated.

The regulatory framework is mainly defined by the Hydrocarbons Act – Decree 194-84, later amended by Decree 94-85, which establishes the legal system for "the research, exploration, and exploitation of hydrocarbon fields and other associated substances as well as transformation or refining activities, transportation through oil or gas pipelines, commercialisation and storage of such substances."

According to the Honduran government, there is no general law for the gas sector. Once gas is introduced to the economy, it will be relevant to develop such specific laws and regulations

Energy market oversight

The existing laws establish the following governance bodies:

- The SERNA (*Secretaría de Recursos Naturales*) is responsible for the main energy sector policies. The current legal situation, however, has defined functions related to this market in other State entities or bodies[43].

- This situation has led to the formation of an Energy Cabinet composed of the Secretary of Industry and Trade, the Secretary of Public Works, Transport and Housing, and the SERNA.

- In the area of the Secretary of Natural Resources and the Environment, "the Energy Department (*Dirección General de Energía*) is responsible for taking steps towards energy production and use, and other related activities."

- Finally, the National Energy Commission (*Comisión Nacional de Energía*) acts as electric power regulator.

- The Oil Management Commission (*Comisión Administradora del Petróleo*, CAP) was re-instated in 2006 to establish and implement a national policy for the hydrocarbon subsector in order to ensure the supply of oil products and control their prices. The CAP is composed of the Secretary of Industry and Trade, the Secretary of Finance, and the SERNA. The first one is in charge of the "coordination and administration of the oil sector."

A new Electricity Act has been recently passed. It envisages the unbundling of the sector. This has modified the sector substantially and the CNE functions will be reconsidered. Until then, this new situation is expected to generate uncertainty and additional risk for investors. This could lead to delays in the commissioning of projects.

Fiscal treatment

There are no rules on how to tax natural gas activities. At present, both LPG and gasoline are taxed. A special tax of 15 US$c/per pound applies to LPG.

State assets

In Honduras there is no state-owned company responsible for the import of oil (and its products) and its commercialisation. However, the country strongly regulates prices and supply through the CAP.

The power sector is led by the state-owned utility ENEE (*Empresa Nacional de Energía Eléctrica*), in charge of supplying electricity to Honduran consumers (distribution). It therefore conducts generation, transmission, and distribution activities, the former through some of its own operations, and in the last few years through PPAs with private generators. The CNE participates in the supervision of the PPAs entered into with private parties.

[43] In this respect, Honduras was not able to inform about this subject at the time of the regulatory survey carried out by OLADE.

7.4.4 Nicaragua

No upstream or downstream natural gas activities have been carried out in Nicaragua. LPG has been developed for residential use at promotional prices under the agreements between Nicaragua and Venezuela.

Regulation

The current regulation for the gas sector is based on Law No. 277, Hydrocarbons Supply Act *(Ley de Suministro de Hidrocarburos*, LSH) of November 1997, modified by Law No. 742 of January 2011.

The Law regulates imports, exports, refining, transportation, storage, trading, and other services related to oil and gas supply. It also establishes that related activities can be carried out in the context of free enterprise and competition, by any national or foreign individual or legal entity.

According to the Nicaraguan government, there is no general law for the gas sector.

Energy market oversight

The LSH establishes the following:

- The Ministry of Energy and Mining (MINE) and within it, the Hydrocarbon Department (*Dirección General de Hidrocarburos*) is responsible for energy issues. The Hydrocarbon Department takes part in the preparation of PPAs entered into with electricity distributors.

- The Nicaraguan Energy Institute (*Instituto Nicaragüense de Energía*, INE) acts as the gas regulator. The INE also performs regulatory activities in the power sector, and manages PPAs for long term expansion of supply together with the distributors.

Fiscal treatment

There is no specific tax imposed on natural gas or LPG. LPG is only charged with internal VAT.

State assets

In Nicaragua there is no state-run company in charge of oil and the import of oil products and trading. The development of these activities is carried out by private organisations.

In the power sector, the government owns and operates an electric power generation company, ENEL (*Empresa Nacional de Electricidad*). Some of the generation is privately owned; distribution is publicly owned

7.4.5 Costa Rica

The Constitution of Costa Rica states that exploration and exploitation are in the State's domain. The State owns oil resources and deposits and any other hydrocarbon substance. Imports, refining, transportation and trading are also owned and managed as State monopolies. The State can grant licenses and concessions for their exploitation.

Natural gas is not traded in Costa Rica at present and this resource cannot be found in the country. Activities related to exploration, exploitation, processing, imports and exports are described and contained in the Hydrocarbons Act. Other related activities, such as natural gas storage, distribution, wholesale trading, and retailing are not carried out in the country.

As regards the supply of natural gas by means of LNG or pipeline, the participation of *Refinadora Costarricense de Petróleo* (RECOPE) is defined in Law No. 7356[44]. The law grants a monopoly in favour of the state for the import, distribution and wholesale commercialisation of all hydrocarbons. This entity has analysed this business together with the *Instituto Costarricense de Electricidad* (ICE), the national power utility.

RECOPE is the monopolist responsible for the imports of liquid fuels and LPG to Costa Rica.

Regulation

In Costa Rica, there are two Laws regulating downstream and midstream in the gas sector. Law No. 7593, modified by Law No. 8660, establishes the responsibility of government authorities. Law No. 6588 and its amendment, Law No. 7356, refer to the corporate activity in the sector.

Legislation for the gas sector:

- Law No. 7593 creates the *Autoridad Reguladora de los Servicios Públicos* (ARESEP). Public services regulation included, as stated in Article 5, are the supply of electric power in the stages of generation, transmission, distribution and trading; water and sewage; fuels derived from hydrocarbons, among them natural gas for final users, and other services.

- The same Law establishes that the Ministry of the Environment, Energy and Seas of Costa Rica (MINAE) is the pertinent entity to grant the concession of public services to supply fuels derived from hydrocarbons, which in the future would include natural gas, to supply national demand through distribution.

Law on RECOPE's monopoly to carry out corporate activities:

- Law No. 6588, first passed in 1981 and then expanded in 1993, establishes the state monopoly of crude oil imports, refining and wholesale

[44] *"Monopolio en favor del estado para la importación, refinación y distribución al mayoreo de petróleo crudo, sus combustibles, derivados, asfaltos y naftas."*

distribution, including its derivatives, asphalts and petrol. Gas is not included, hence can be assumed to be open to public concession.

Law on oil and gas exploration and exploitation

- As to natural gas upstream, it is regulated under Law No. 7399, Hydrocarbons Act of May 13, 1994, which grants the MINAE the power to carry out oil exploration and exploitation, particularly through hydrocarbon exploration and exploitation contracts.

Energy market oversight

The governance of the sector is defined as follows:

- The MINAE is responsible for gas policy.
- The *Dirección General de Hidrocarburos* deals with aspects related to concessions to explore and exploit hydrocarbons.
- The *Dirección General de Transporte y Comercialización de Combustibles* (DGTCC), establishes the requirements and technical rules related to gas management and commercialisation, particularly LPG.
- The regulation of the power and gas sectors is performed by ARESEP, which is also in charge of establishing rules related to product quality. ARESEP is an independent entity.

Fiscal treatment

As for fuel imports, Costa Rica applies no import duties on natural gas in gaseous or liquid form (DAI=0%). It applies the general VAT rate of 13% + 1% under Law No. 6946.

State assets

Costa Rica has two large state-owned companies in the energy sector, the power utility ICE (there are other distributors, CNFL and cooperatives) and RECOPE. The ICE is in charge of supplying electricity to consumers or to cooperatives or ICE companies such as CNFL. Therefore, it distributes, transports and generates electricity, or it purchases some from third parties through PPAs.

There are three ways of acquiring energy from private parties: one is at a reference price established by ARESEP for small projects; another through PPAs with associated BOT projects in competitive tenders; and a third one through financial trust agreements where private parties finance the projects carried out by the ICE and receive a fixed fee for the capacity they make available[45].

In addition, RECOPE is authorised to refine fuel for all the population.

[45] A tolling arrangement

7.4.6 Panama

In Panama, there are currently no activities related to natural gas, but there are some defined projects, particularly the construction of a gas generation plant in two stages of 300 MW + 300 MW, and a LNG regasification and storage plant proposed in Puerto de San Cristóbal on the Atlantic coast.

In 2013, the National Energy Secretary presented a Plan to Incorporate Natural Gas from imports with regasification on an onshore plant site or offshore vessel. There are four stages of gas utilisation strategies in the gas market development plan: 1) Power generation, 2) Industrial or commercial use, 3) Automobile use, 4) Residential use. A main gas pipeline will cross the whole country, from which there will be supply nodes.

Regulation

The basic rules in the Republic of Panama for natural gas-related activities are the following:

- ***Exploration and exploitation***: Law No. 8 of 1987, which regulates hydrocarbon-related activities and was modified by Laws No. 27 (2006), No. 39 (2007), and Law No. 53 (2013). It regulates the upstream part of the oil value chain and, therefore, also natural gas. The purpose of this Law is to foster and regulate the exploration and exploitation of gas fields, asphalt in its natural state, natural gas, and other hydrocarbons.

- This Law states that any individuals or legal entities dealing with oil and natural gas exploration and exploitation should enter into a contract, eg production sharing agreements or contracts (PSA[46]), with the State through the National Secretary of Energy.

- ***Exports, transit, storage***: Article 94-A in Law No. 8 of 1987, modified by Law No. 39 of 2007, establishes that crude or semi-processed oil, any of its products, natural gas, biofuels, and other products from alternative energies can be introduced, stored, refined, transformed, manufactured, mixed, purified, bottled, marketed, transported, poured, pumped, sold in the domestic market, exported, re-exported, and, in general, operated and supplied in **fuel-free zones**[47].

- ***Investment***: For the purpose of incentivising and attracting investment, the Republic of Panama passed Law No.54, which provides for the "Legal Stability of Investment". Electric power generation activities are included under this meaning that any changes in the law are not applied to

[46] Also referred to as production sharing contracts, PSC

[47] As a result of the existence of the Panama Canal, there are free trade zones, which are tax free, on the Pacific and Atlantic coasts, to supply vessels that sail the Canal. Within these free trade zones, there are hydrocarbon- or fuel-free zones that market duty-free fuel to the vessels and can reintroduce it in Panamanian territory. Natural Gas can be traded free of taxes between the free zones and the country. There is possibility for electricity generated in these areas to have a cost advantage. These zones could also be used to supply bunker fuel operations (LNG used on ships) in response to the need to reduce emissions under the North American Emission Control Area regulations for ships which requires them to use lower-sulphur fuel within 200 nautical miles of the US shoreline

investments made under previous version, they are thus 'protected'[48]. This includes gas-based power generation. This protection includes guarantees in the context of legal stability, national and municipal tax stability, and customs stability, derived from the specific legislation.

- Law No. 41 of August 2, 2012 establishes the incentives regime to foster the construction and operation of natural gas-based generation plants to supply the public service of electricity.

- ***Imports and commercialisation***: Cabinet Decree No. 36 of 2003 establishes the national hydrocarbons policy and introduces other provisions. This Decree creates a natural gas importer-distributor license. Natural gas can be imported and distributed in or from a fuel-free zone to be sold in the domestic market. This license is issued by the National Energy Secretary. It allows the natural gas importer-distributor to sell in the domestic market as wholesaler or retailer.

- Natural gas transmission and distribution: pursuant to Article 8 of Decree-Law No. 10 of February 22, 2006, the Public Services Authority (*Autoridad Nacional de los Servicios Públicos,* ASEP) is in charge of these activities. The application of this article is under review with the General Attorney's Office (*Procuraduría de la Administración*).

There is currently no specific regulation for natural gas activities. Panama has moved to create general legislation and still needs to progress in specific rules such as those related to the specific processing, regasification and use of natural gas for vehicles. In addition to specific detailed regulation, there is a need for general rules such as easements for gas pipelines, charges and tariffs, access to the capacity of existing facilities, technical standards for product quality, security of facilities, environmental conservation, etc.

Panama and Trinidad and Tobago signed a Memorandum of Understanding for Energy Cooperation in 2012, seeking to promote LNG purchases from the state-owned National Gas Company (NGC) for the transition to the use of natural gas to generate electricity in Panama. The agreement is provisional and has not yet achieved much progress.

Energy market oversight

The governance of the sector is defined as follows:

- The National Secretary of Energy (MINAE) is responsible for gas policy.

- The regulatory body ASEP (*Autoridad Nacional de los Servicios Públicos*) is in charge of regulating and enforcing activities in the gas sector. The ASEP is also in charge of regulating the power sector. It is an independent entity.

[48] This 'change of law' provision is an important issue for reducing political risk in a contract

Fiscal treatment

Pursuant to Article 57 of Law No. 6 of 1997 (consolidated text), fuel for power generation can be imported free of tax, duty or rate. Therefore, LNG or natural gas would be exempt from any type of taxation if destined for electricity production.

State assets

The Republic of Panama has two state-owned companies in the power sector, EGESA and ETESA. The former is in charge of power generation whereas the latter operates power transmission.

ETESA and ASEP participate and manage the bidding system for generation expansion through long term PPAs with private generators. Although ETESA does not sign the PPAs, it takes part in the operation and management of the contracts so that they can be implemented.

7.4.7 Comparative summary

The following table summarises the key features of the above sections relating to the regulatory instruments employed in each country's oversight of the gas market.

Table 26 Organisation of the Gas Market

	PA	CR	NI	HO	ES	GU
Specific gas regulation	Law No. 41 of 2012 to promote investment in power generation with natural gas Cabinet Decree 36/2003 creates the natural gas import license Decree 10/2006 grants ASEP the power to regulate gas transportation and distribution.	Law No. 7593 of 1996, ARESEP	Requires a specific law for the sector	Requires a specific law for the sector	Natural Gas Act (LNG) of 2008	Requires a specific law for the sector
Regulation relevant for analysis	Law No. 8 of1987 regulates hydrocarbon exploration and exploitation activities as well as their export, storage and commercialisation. Law No. 54 to protect and foster investment	Law No. 6588 establishes the State monopoly of RECOPE to import and refine hydrocarbons Law No. 7399, Hydrocarbons Act	Hydrocarbons Supply Act of 1997	Hydrocarbons Act - Decree 194-84, later modified by Decree 94-85		Hydrocarbons Act Hydrocarbons Commercialisation Act

	PA	CR	NI	HO	ES	GU
Governing entity for public policies	National Energy Secretary	MINAE	MINAE	SERNA with CAP and the Economy Cabinet	Ministry of Economy	WEM
Regulator	ASEP	ARESEP	INE	CNE	DHN	DGH.
Prices and Tariffs	Not regulated	Set by ARESEP in all stages	- Not regulated	Not regulated	Efficient costs and reasonable return	Not regulated
Transportation and Distribution		Exclusive of the State, could be granted under a concession	Not regulated	Not regulated	Concessions to private parties	Not regulated
State-owned companies with a monopoly of gas	Non existent	RECOPE S.A.	Non existent	Non existent	Non existent	Non existent
Import duties	Law No. 6, Article 57 (1997): fuel that is necessary for power generation is exempt from any tax	General VAT rate of 13% + 1% under Law No. 6946	Tax exemption on LPG	0.15 US$c/Pound	Import licenses, duty free and taxed with VAT rate (13%)	Duty free. Only general VAT rate of 13%

7.5 Coordination of regional market regulatory frameworks

The following section presents regulatory issues which could potentially affect the structuring of financing for a project of this kind by indicating whether demand and sector development will be solely national or could be regional. We discuss whether they should or should not be included in a future *regional regulatory framework agreement* among all countries in the region. Most of these issues are not currently contemplated in the countries' regulatory frameworks.

This relates to the issue of whether gas markets will be developed in individual countries in isolation (with ad hoc trading between neighbouring countries), or a more ambitious regional gas market could be established. The latter would require coordination between the countries across a broad range of regulations. While this is not necessarily expected to be done initially, it is more likely in the long term and could be facilitated by some early consideration of the issues.

None of these aspects have been defined in the countries' existing regulatory frameworks, other than the exceptions described in the text.

7.5.1 Dominant position regulation

An approach to vertical integration and how to deal with regional competition issues around it would need to be agreed by all countries party to a regional agreement. At present, only El Salvador has established rules for vertical unbundling.

There are several options:

- No ban or limits to vertical integration
- Absolute ban on vertical integration
- Partial ban or limits to vertical integration: unbundling.

In the event some partial limitations are established, their implementation could be done through one of several mechanisms implying increasing degrees of functional separation: simple accounting unbundling, functional unbundling, legal unbundling and actual ownership unbundling

7.5.2 Regulation of LNG terminals or supply pipelines

As discussed in earlier sections, a business model, and its regulation, will need to be chosen for the operation of LNG regasification terminals. The regulatory aspects that should be considered relate both to storage and regasification operations:

- No access to third parties
- Regulated access to third parties
- Freely negotiated (open) access to third parties

This is one of the most difficult areas for contemplating market competition. On the one hand, market volumes are small especially in the early years; splitting that volume between two or more parties could increase costs of LNG procurement as volumes fall below the efficient economic scale On the other hand, the financing of the LNG terminal(s) will require contracts from gas offtakers (or power offtakers) that guarantee the financing of the whole facility. In the early years the volumes may below and capacity utilisation small, causing an imbalance between terminal fees and financing payments. Splitting the (small) offtake contracts between multiple parties will add considerably to the riskiness of the project. It therefore seems likely that third party access would either have to be very limited at the start, or delayed entirely until much of the financing was repaid.

Relatedly, if third party access is granted, a mechanism to allocate primary capacity will need to be chosen from the following options:

- Open season
- First-come first-served (FCFS)
- Pro-rata of demanded capacity or other priority systems

- Bilateral negotiation

Open season is now commonly used (for pipelines and LNG) as an effective and competitive process for allocating some capacities. On the one hand, it allows all interested parties to participate; on the other, it ensures full contracting of capacity from the start. However, given the small volumes in the CA region, it is likely that any such offering would either be very small or delayed for a number of years until total demand had built up.

7.5.3 Operating tariffs and prices

A key regulatory aspect to be considered will be whether terminal fees and gas transportation tariffs will be left for the market to set or whether a regulated tariff model will be employed. It would be essential that the tariffs allowed the investor to cover full financing costs, which are likely to be high in the early years before volumes build up. The investor should also be able to use pricing as a tool to help develop the early market, although some regulated price cap mechanism could be contemplated (linked also to the tender and terms bid for the concession – if openly tendered).

Therefore the introduction of regulated tariffs would almost certainly need to be delayed until demand came close to matching capacity and TPA, and the regulation would need to be multi-period and forward looking to ensure regulated revenues were sufficient given financing requirements.

The pricing of natural gas or LNG will also need to cover the terms of the LNG import contract, which is quite likely to contain indexation terms (as well as penalties if quantities fall below a contract minimum). Given the profile of possible growth of gas demand, and its uncertainty, regulation of gas prices would seem to be unsuitable at least for the early years, say the first 5 or 10 years. This makes contemplation of any attempt to regulate gas prices problematic on an ongoing basis, rather they should arise from the tender if applicable.

However, if the main offtake is power and gas prices to power are not regulated (though power prices are), there is an option to regulate the prices to the smaller non-power demands; industry, large commercial etc., Whether this is worth contemplating will depend on the market conditions at the time of tendering/contracting for the terminal. Since gas will be a new and alternate fuel for non-power customers, they are not obliged to switch to gas, while the gas investor (for the distribution areas) would have every incentive to build out their network and connect all potential customers as quickly as possible. The more important regulatory instrument would be the commitment of the investor to undertake investments to expand the gas distribution area to reach more potential consumers.

7.6 Generation expansion – tenders for power purchase agreements

The region has provided an active response to a global energy scenario characterised by fuel price instability. It has given the national public sector a major role in decisions related to developing new power generation to ensure the supply of future power demand at competitive prices.

This response also shows a change of direction in terms of the wide-spread market reforms implemented in the region in the past. The 'competition in the market' paradigm was changed to 'competition for the market' to ensure efficient wholesale power supply. All the countries in the region have moved to a periodic auction system, where generators periodically compete for PPAs to meet the increase in demand in the market. Initially, these were just for 'energy'; more recently, with respect to sector planning and the desirability of a mix of generation technologies, countries have developed tenders focusing on different types of energy, both renewable and based on fossil fuels.

This change is, in itself, an opportunity for this project, since the countries can package part of their demands and allocate them to the development of a regional or joint project to introduce natural gas.

A foreseeable consequence of regional integration would be that governments are more involved in long term sector decisions in order to deal better with the instability generated by international cooperation. In this way, a more regulated market model might be implemented, in contrast to the region's recent trend of deregulating power markets. This might improve the coordination between generation and gas infrastructure investments

In practice, competition for the market has taken the form of Power Purchase Agreements, PPAs. This has been the solution in the region for a while now. Table 27 shows PPA structures used in the region.

Table 27 PPAs in Central America

	PA	CR	NI	HO	ES	GU
Supply Expansion	PPAs originated from tenders	PPAs originated from tenders or reference prices	PPAs originated from reference prices	PPAs originated from tenders	PPAs originated from tenders	PPAs originated from tenders
Buyer, Off-taker	Local power Distributors	ICE	Local power Distributors	ENEE	Local power Distributors	Local power Distributors
Process Manager	ETESA	ICE	INE	ENEE	Distributors and SIGET	CNEE
Supervision	ASEP	ARESEP	MINAE	CNE	SIGET	CNEE
Market Reserve for Renewable Energy	YES	NO	YES	YES	YES	YES
Spot Market existence	YES	NO	YES	NO	YES	YES
Term	15	15	15	15	15	15
Planning Form	Referential	Centralised	Mixed	Centralised	Referential	Referential

7.7 International guarantees

The countries in the region are constitutionally forbidden to provide guarantees of any kind to organisations outside their territory. The restriction also applies to multi-lateral banks. This situation has delayed the construction of SIEPAC for many years, and is part of the problem for guaranteeing long term trading over SIEPAC (that would be needed if the introduction of gas is targeted at increased regional power trade). SIEPAC is briefly described in the Annex.

7.8 Conclusions

Guatemala, Honduras and Nicaragua have no specific legislation on natural gas, they have only drafted laws for hydrocarbon exploration and exploitation.

Costa Rica and Panama also have regulations on natural gas exploration and exploitation but, in addition, they also have regulations that are applicable to the sector in the mid-stream and downstream. These rules are very general, indicating responsibilities within the Government, the promotion of investment, and who will be in charge of regulating prices and quality. There are no specific rules for defined projects.

In El Salvador, regulations have defined aspects related to market concentration and tariff criteria, but only for companies dealing with natural gas retailing. Aspects related to LNG storage and regasification have not been developed in detail.

In all the countries there are rules to develop PPAs, so they can be used as instruments to help develop a gas market project which might be on a scale larger than any one country. In all of the countries, the state can aid the execution of such contracts by means of coordinated infrastructure planning.

ANNEXES

A1 Regional transmission system - SIEPAC

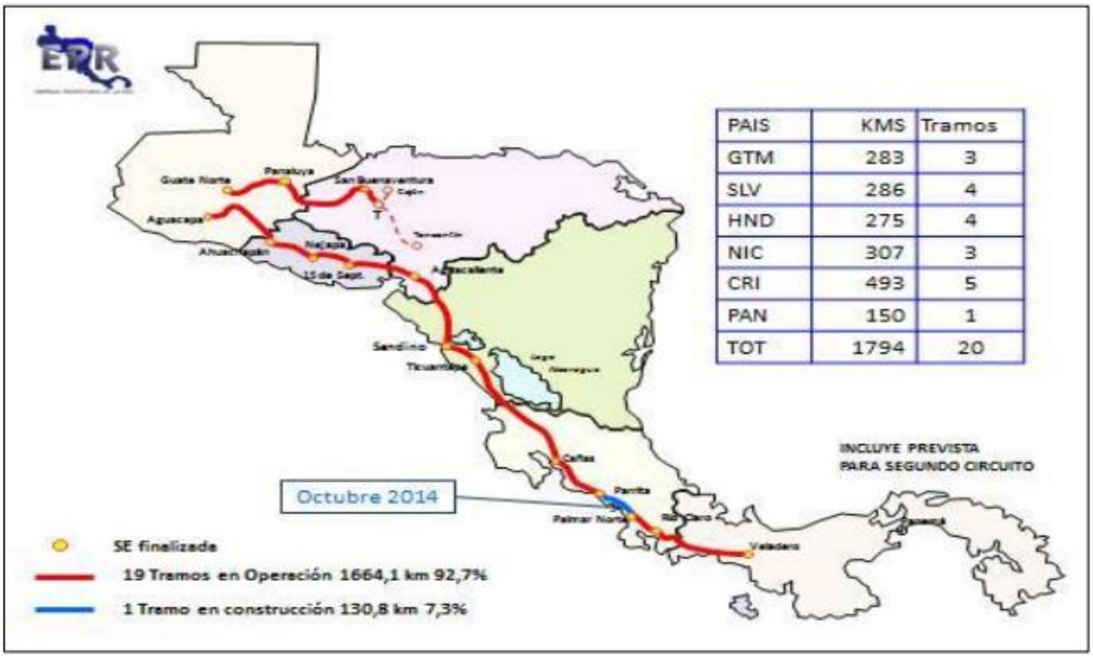
The Central American Electrical Interconnection System (SIEPAC for its Spanish name) is an initiative to create an integrated regional electricity market among six Central American countries. The associated regional electricity market is the MER.

SIEPAC consists of a 1,793 km of 230 kV single-circuit transmission lines, with 15 substations and comprising 20 transmission segments, whose construction was finalised at the end of 2012[49]. With the completion of the system, the capacity of power exchanges between most countries in the region will increase to 300 MW.

SIEPAC includes central lines, built by EPR (Proprietary Network Company), and the national transmission lines that reinforce the system. These lines are part of the transmission systems in each country. These lines use the SIEPAC as part of their security system N-1. Reinforcing national lines allow SIEPAC lines to transmit up to 300 MW between pairs of countries, meeting the criteria Quality, Safety and Performance established by the regional electricity market authority, MER.

The expansion of the SIEPAC system is the responsibility of the EPR and the extension of the other lines is under the responsibility of each country (each country has its own company that is in charge of the national transmission system). Central lines are regulated by CRIE and reinforcing national lines are under local regulator supervision.

Table 28 SIEPAC – May 2014



[49] There is still a small part of the network that has not been finished in Costa Rica from Parrita - Palmar Norte

The stated objectives of the SIEPAC Charter are to:

- improve security of supply by widening reserve margins
- reduce the problem of electricity rationing in capacity-deficit countries
- achieve improved operating efficiency and reduce the amount of fuel consumption needed for generating electricity
- spur greater competition in domestic markets
- lower end-user electricity costs
- attract foreign investment to the region's electricity sector
- contribute to the economic development of the region.

The introduction of natural gas as a source of power is part of the objectives of the SIEPAC and has been defined by its members as an opportunity for accomplishing all the objectives of the charter.

Main restrictions of SIEPAC

This section summarises the main restrictions that the introduction of natural gas to the region could face in relation to SIEPAC. One of the key challenges is that the scale of increase in a country's generation that could accompany a new LNG terminal is very large in relation to the current capacity of SIEPAC. Another is the need to back new gas-fired generation and contracted LNG imports with long term contracts for power exports.

The strategy being developed by the IDB consultants has suggested that the main source of consumption will come from the power sector and with regional gas to power projects. This conclusion is consistent with the level of peak demand, 8000 MW, in the region. Any country base project will deal with a small market that could not absorb all the regasification capacity.

The structuring of a regional project would require that SIEPAC be capable of:

- Giving assurance that electricity transactions between buyer and seller in different countries for both the short term and long term are feasible. This will ensure the delivery of contracted energy and opportunities for trade
- Ensuring availability of transport capacity over the contracting period.

To achieve this an assessment of the existing regulation of MER is necessary to determine its suitability in achieving the above objectives. If MER regulation is to be adjusted, the following two mechanisms could be used to introduce new regulations:

- centralised planning to assure the expansion of the transportation system, in line with the expansion of generating capacity in a country which invests in a LNG terminal
- the introduction of long term financial transmission rights.

PPAs on SIEPAC

There exists the possibility of signing PPAs between parties located in two different countries, for instance between a power generator located in Costa Rica and a purchaser located in Panama. However, the current framework under which SIEPAC operates does not have mechanisms to provide security regarding transmission on its network. In other words, parties to any PPA would not be able to exert congestion rights to secure their electricity is transported. To solve this, a mechanism to mitigate the risk of non-delivery needs to be devised.

At present, PPAs in individual CA countries can be long-term, that is, up to about 15 years. Such contracts are expected to provide sufficient incentives for the development of a domestic gas market. It is assumed that national transmission operators would expand domestic transmission capacity accordingly.

Contracts of this duration, especially if large, are problematic on SIEPAC. Physical capacity cannot be reserved by one party in large amounts for several years; capacity is too limited. One approach to tackling the issue of transmission rights is to establish a framework for long term financial transmission rights. This option is being examined by SIEPAC members.

A2 LNG supply analysis

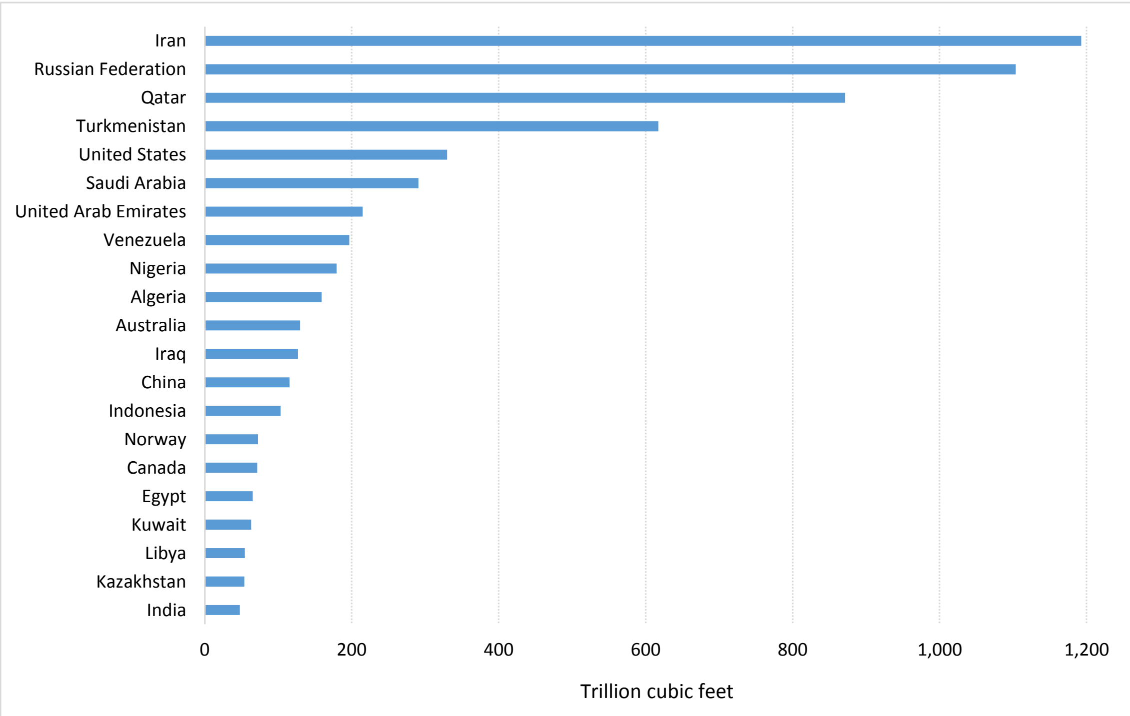
This Annex includes an analysis of recent trends in LNG markets, the opportunities and challenges these trends create for LNG imports in Central America, and the potential LNG suppliers to this region. The key points concluded from this analysis are those included in the LNG supply analysis section of the Report.

A2.1 Global supply/demand balance

A2.1.1 LNG supply

Current and potential suppliers of the LNG in the world market come from those countries endowed with the largest natural gas reserves. Total world gas reserves were approximately 6,560 Trillion cubic feet (Tcf) in 2013. Iran was the first country in terms of natural gas reserves, followed by the Russian Federation, Qatar, Turkmenistan and the United States. In addition to conventional gas reserves, unconventional gas reserves are being unlocked thanks to technological progress, increasing total gas supply. For instance, the US Energy Information Agency (EIA) estimated that 40.1% of US gas reserves corresponded to potential shale gas resources[50].

Figure 33 World natural gas reserves by top 20 countries, Tcf, 2013



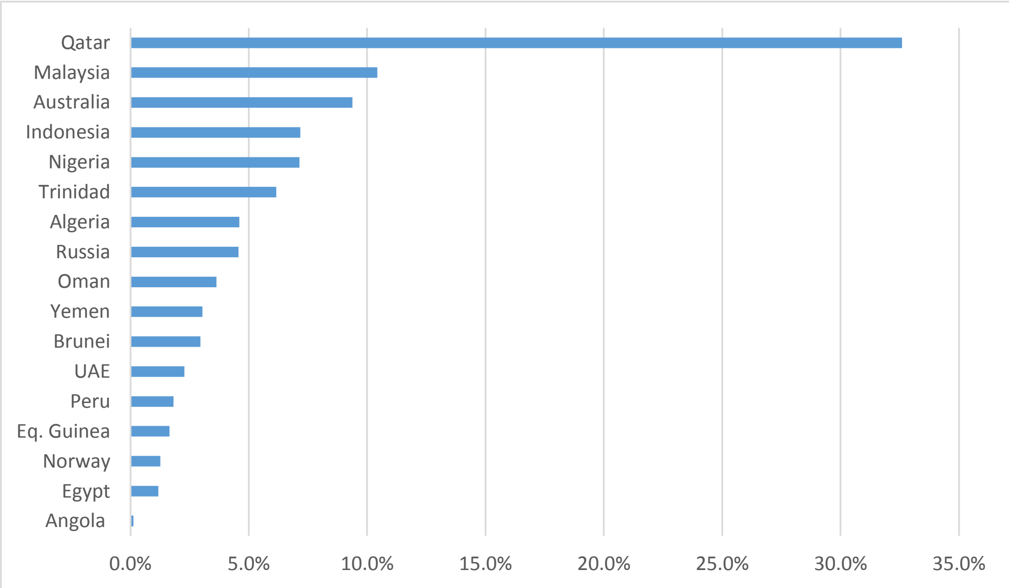
Source: BP Statistical Review of World Energy June 2014.

[50] U.S. Crude Oil and Natural Gas Proved Reserves, 2012. United States Energy Information Agency, 2014.

Large natural gas reserves will enable continuous growth of natural gas production in the coming years. According to the US Energy Information Agency's forecasts', world natural gas production is expected to increase from 111.1 Tcf to 186.8 Tcf in 2040[51].

Total LNG world exports reached 236.8 million metric tons (Mt) in 2013, similar to 2012 levels although below the peak reached in 2011 (241.5 Mt) after the 2009-2011 expansion (59 mt)[52]. LNG exports were supported by growth in the Asia Pacific and the Middle East regions, with the largest increases observed in Yemen, Malaysia, and Australia. These output gains were however offset by supply constraints in the Atlantic Basin. Nigeria was negatively affected by a tax-related blockade by the government and pipeline sabotage and Norway suffered from weaker production due to technical issues at Snøhvit LNG in the first half of 2013. Exports from Egypt dropped due to increasing domestic growing demand.

Figure 34 Share of total LNG exports, by LNG exporting countries, 2013



Source: World LNG Report – 2014. International Gas Union.

The Middle East is the world's most important source of LNG. Growth in this region is largely due to developments in Qatar, where liquefaction capacity increased from 25.5 Mtpa in 2006 to 77.0 Mtpa in 2011, enabling the Middle East region to surpass the Asia Pacific region as the leader in LNG exports – historically, the latter region has been the world's main LNG supplier. Increasing liquefaction capacity in Australia being effective after 2014 could put the Asia Pacific region on lead again. However, LNG prospects in North America, East Africa, Russia or the East Mediterranean could trigger a structural change in the market and re-shape regional market shares in the medium and long term, as explained in more detail below.

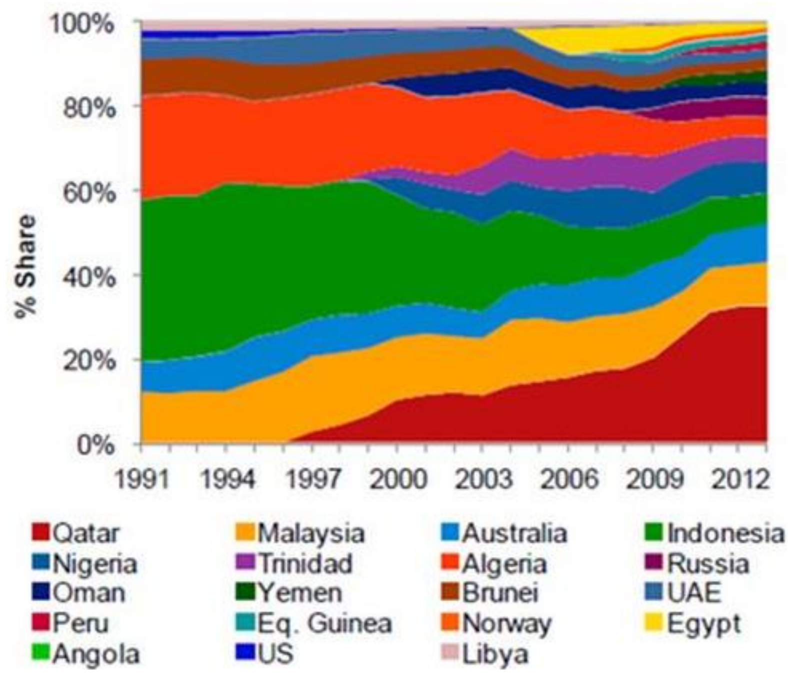
The Middle East supplied 42% of total LNG exports in 2013, followed by the Asia Pacific region (30%). Volumes from Nigeria, Equatorial Guinea, Algeria, Egypt and most recently Angola, made Africa the third-largest LNG producing region in 2013,

51 International Energy Outlook 2013. United States Energy Information Agency, 2013.

52 *World LNG Report – 2014*. International Gas Union. Unless otherwise noted, the data included in this section are obtained from this source.

accounting for 15% of global exports. Qatar (32.6% of total LNG exports in 2013), Malaysia (10.4%), Australia (9.4%), Indonesia (7.2%) and Nigeria (7.1%) were the main exporter countries, accounting for 66.7% of total world exports.

Figure 35 Share of global LNG exports by country, 1990-2013



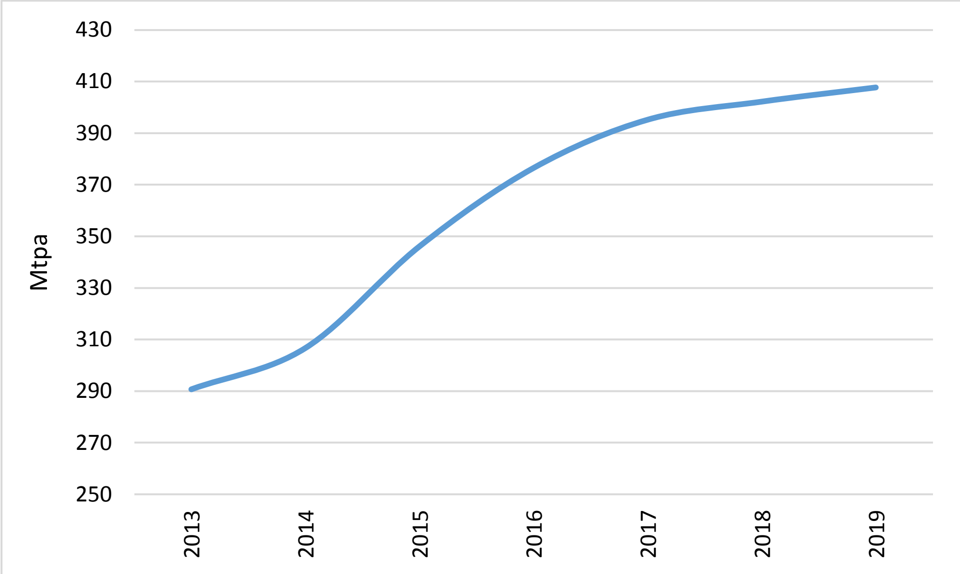
Source: World LNG Report – 2014. International Gas Union.

Since 2011, effective liquefaction capacity has barely grown, as LNG supply projects are costly to develop and they face a high degree of uncertainty. Global nominal liquefaction capacity stood at 290.7 Mtpa at the end of 2013. Capacity utilization has relatively decreased in recent years, from 87% in 2011 to 82% in 2013. Qatar and Indonesia remain the largest liquefaction capacity holders, accounting for 38% of total capacity. In 2014, liquefaction capacity will grow substantially, as new capacity will enter from Algeria, Australia and Papua New Guinea.

After 2014, there exists potential for a considerable increase in liquefaction capacity, driven primarily by developments in Australia and the United States (Figure 36). Australia has several projects under construction amounting to 61.8 Mtpa capacity (53% of total global capacity under construction), that will enable it to surpass Qatar as the largest LNG exporter by 2017. The United States, with 18 Mtpa liquefaction capacity under construction, will follow Australia in terms of liquefaction capacity growth over this decade. Increase in gas supply in the medium term will reduce market tightness.

Proposed liquefaction plans in different countries could give rise to a substantial reconfiguration of the LNG world supply in the coming decades. The United States counts with 265 Mtpa of proposed pre-Financial Investment Decision (pre-FID) liquefaction capacity, while Canada's proposed capacity amounts to 134 Mtpa. Projects in East Africa and Russia could offer an additional source of long term supply growth and change regional LNG export patterns.

Figure 36 Expected global liquefaction capacity, 2013-19



Note: data are constructed from projects currently under construction, which will become online over the period 2014-2019.

Source: ECA from World LNG Report – 2014. International Gas Union.

New entry and more supply competition create opportunities for small emerging country LNG importers as such those in the Central America region. These countries differ from traditional customers in the LNG market, namely those in the Asian and European markets who have very strong credit, have low price sensitivity, and are willing to sign long-term contracts indexed to oil prices[53]. Smaller emerging countries have no domestic energy resources and must import all their fuel. They have few or none relatively energy sources, such as nuclear plants, hydroelectric, and coal plants. Their retail energy costs are relatively higher than those of larger industrialized countries. To justify the cost of LNG import infrastructure and new gas-turbine power plants (which can use oil or gas), developing countries need to source fuel at competitive prices. In addition, most of these countries are locked in in the vicious circle of lack of supply and lack of infrastructure, which reinforce each other.

More supply competition in the medium and long term will favour natural gas price decreases, leading to significant commercial gains from oil substitution and providing higher incentives to develop the necessary import infrastructure. In addition, more competition could favour a higher degree of contract flexibility and ease credit conditions, facilitating LNG introduction in Central America.

A2.1.2 LNG demand

The demand side of the market continued to grow in 2013, in particular in Asia. Ten new re-gasification terminals begun operating in 2013, while Israel, Singapore and Malaysia emerged as new LNG markets. The number of importing countries and

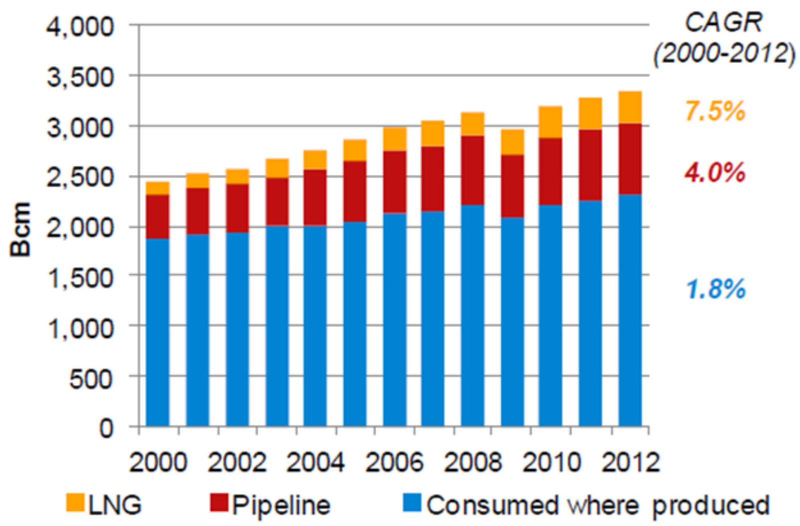
[53] *LNG for power in small emerging markets*, D. Haug, Shawn Cumberland.

regions continues to grow. Since 2008, 11 countries have become LNG importers, and the total number currently stands at 29.

Increasing demand in China and nuclear outages in South Korea were the main drivers of demand growth in 2013. Demand in Japan continued to expand, although at a slower rate than in previous years, when gas-fired power generation had to increase to replace losses in nuclear output after the Fukushima incident. Japan LNG needs in the medium term will depend on its degree of dependency on nuclear power and the ability of offline plants to restart. In contrast, demand in Europe was weak, especially in the UK and Spain. Pipeline imports and competition from coal and renewables in power were the main forces behind displacement of demand. Asian and Latin American markets where the ones that pulled the volumes form Europe.

LNG's share on global gas demand has considerably risen over the last fifteen years, namely driven by the growing use of natural gas in power generation and the emissions benefits of natural gas compared to other fossil fuels. Since 2000, LNG demand has largely been driven by Asia and has grown at an annual average rate of 7.5%, compared to pipeline imports (4%) or domestic consumption (1.8%). LNG share on global gas demand has grown from 4% in 1990 to 10% in 2013.

Figure 37 Global gas trade, 2000-2012



Source: World LNG Report – 2014. International Gas Union.

The Asia Pacific region constitutes the main LNG importer, accounting for 61% of total imports in 2013. Europe is the second region in terms of imports, amounting to 14% of total volumes in 2013. Spain and the United Kingdom constitute the region's largest markets. The Asia region is the third major importer. Combined, these three regions cover 88% of total LNG imports. Japan is the largest LNG importer, followed by South Korea, China, India and Taiwan.

Nuclear disruptions in Japan have impacted global supply-demand dynamics in recent years, increasing market tightness. With insufficient supply coming in to meet the increase in demand, LNG prices have risen, also fuelled by higher oil prices which have impacted LNG traded in oil linked long-term contracts.

Importing countries differ in terms of LNG needs and dependency. Some countries, such as Argentina, the Netherlands or the United Kingdom, have been natural gas producers in the past, but have turned to LNG to maintain supply as their domestic production has matured. On the contrary, other importing countries - with long-standing domestic gas production - have turned to LNG to reinforce security of supply. This is the case of Italy, Turkey, Canada or Mexico. Regarding LNG dependency, countries in the Asia-Pacific region exhibit a high degree of dependency. In the case of Japan, South Korea and Taiwan, LNG imports constitute almost 100% of total gas supply, as these countries lack domestic production or import pipelines.

Demand patterns are changing in several countries and regions. Shale gas supply in the United States has reduced import needs in this country, as well as in Canada and Mexico, which are interconnected to the north-American grid. Europe's share in global LNG demand is decreasing, while Latin America's is increasing – especially in Brazil and Argentina. In Asia and the Asia Pacific region, demand is robust, although future growth will likely come from China and India as nuclear capacity in Japan recovers.

Demand is expected to exhibit high growth after 2015, reflecting, amongst other factors, coal to gas switching in Asia, energy market growth in developing economies and declining European indigenous supply[54]. Asian demand will be primarily supported by high demand growth in China and India, while more mature markets such as Japan and Korea will grow at more steady rates. Latin America's demand is projected to grow over the short and medium term, reaching a plateau around 2020. In the long term, demand will decline as the country develops and exploits its own natural gas resources. Higher demand growth will lead to market tightness in the short-medium term, until new capacity - mainly from Australia and the United States - enters the markets and fills the supply gap to maintain a supply and demand balance.

Increasing demand from Asia and other regions creates risks for the Central American region sourcing natural gas[55]. Competition from buyers purchasing large volumes and with higher willingness to pay could hinder the ability of Central America to source in the international gas markets. The capacity of liquefaction projects in the United States to obtain the permit to export to any country in the world (currently most of these projects have a permit to export to FTA countries, but not to non-FTA countries) will be an important driver.

A2.1.3 Prices

Despite increasing market integration, there is no single global LNG market with a single price. On the contrary, strong regional dynamics - grounded in different supply and demand patterns - are the norm. Markets remain significantly segmented (Figure 38), and segmentation has increased in recent years compared to historical patterns.

Over the last few years, LNG prices have been driven by several factors which have led to different regional price dynamics.

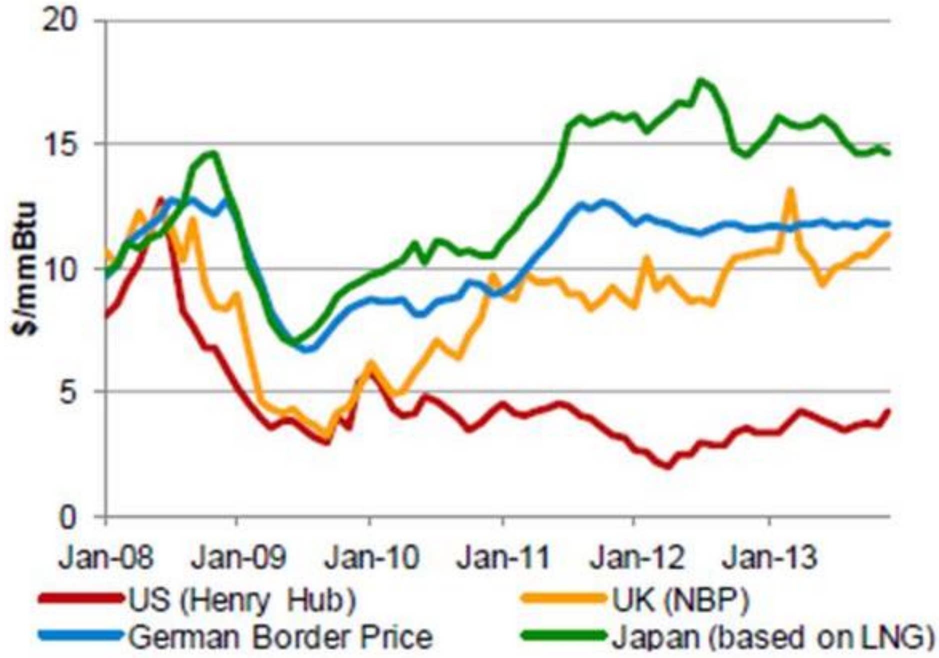
[54] Ghana gas market and LNG market study, Gas Strategies Report (confidential).

[55] *Natural Gas in Central America*, P. Shortell, Baragwanath K. and Sucre C., Energy Policy Group, Inter-American Dialogue, Working Paper, March 2014.

- Weaker demand in Europe and lower import needs in the United States due to increasing domestic gas supply
- Increasing LNG demand in Japan after the 2011 Fukushima incident, as well as in other countries of the Asia-Pacific region
- Oil linked contracts predominance both in Europe and Japan, compared to the situation in the United States, where prices are fundamentally driven by gas-on-gas competition

In North America, the Henry Hub price has decreased substantially since 2008 due to increasing non-conventional gas production. Price differentials regarding prices in Europe and Asia were historically high in 2012, when the Henry Hub reached a minimum trade at $1.9/mmBtu. Since 2012, prices have relatively increased and spreads have narrowed. At the end of 2013, Henry Hub reached a price of $4.2/mmBtu in December, trading at a discount of approximately $7/mmBtu to NBP and $10/mmBtu to Japan.

Figure 38 Monthly average regional gas prices, 2008-13



Source: World LNG Report – 2014. International Gas Union.

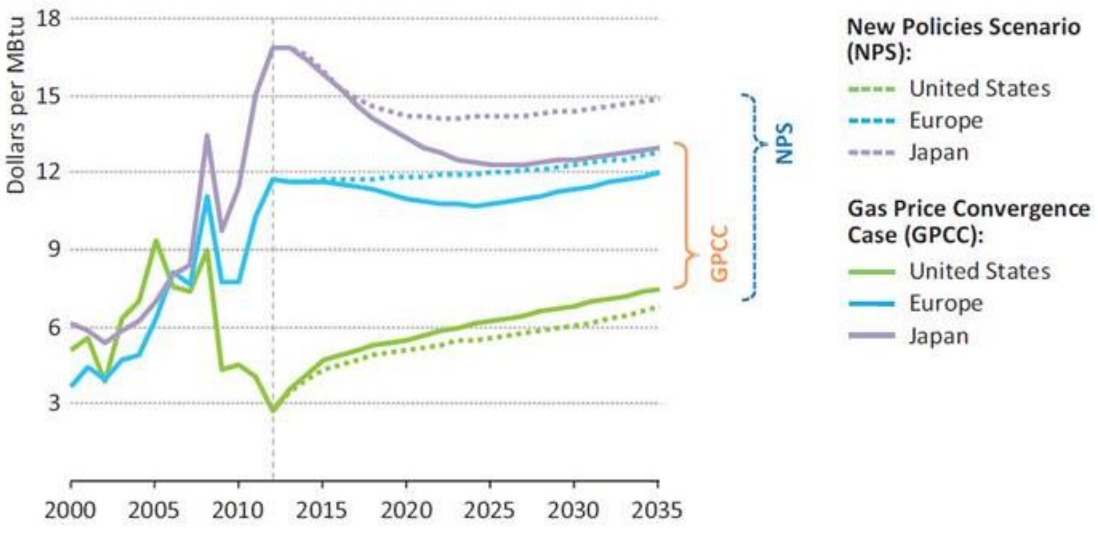
Asian prices have remained relatively stable over the last years after increasing sharply in 2011 and 2012 after the Fukushima incident. The average price in 2013 was 14.5-16.1/mmBtu. The Asian market remains dominated by long term oil linked LNG contracts, what has favoured an increasing trend in prices since 2008, in line with oil price trends. Although Asian buyers are willing to switch to other types of contracts, the opportunities to negotiate non-oil linked contracts on a global scale are still limited. In the medium and long term, increased supply in the world gas market and more gas competition will increase the buyer's ability to switch to other types of contracts.

Most of the gas contracts in Europe are still indexed with a lag to oil and fuel oil, what has favoured an upside trend in prices. However, since 2009 the region has been moving towards a hybrid price system, increasing the share of hub pricing in the formulation of pipeline export prices for certain contracts. During 2009-2010, European prices were more responsive than Asian prices to increased gas supply due to shale production, the economic recession, and relevant volumes of Qatar LNG - previously developed to serve North America and other markets[56]. In 2013, the German border gas price moved around $11.5-12.0/mmBtu. Spot gas prices were relatively lower, on average $10.6/mmBtu.

In the medium and long term, increased gas supply from countries such as Australia and the United States coupled with arbitrage opportunities will contribute to increasing price convergence in world gas prices. IEA's natural gas price scenarios point to this convergence (Figure 39). The degree of convergence depends on factors such as the volume of LNG exports from the United States, new supply breaking the link with oil price indexation, and the level of liquefaction costs and shipping LNG from the United States. The evolution of the price of oil and its relative price compared to Henry-Hub prices will also be determinant in price convergence.

New entry is likely to affect price schemes and structure. Some changes are already underway[57]. In the United States, Cheniere has introduced a new pricing scheme based on two components: (i) the capital invested in the liquefaction, storage and marine facilities, and (ii) the feed gas to be liquefied. In this model, either Cheniere or the buyer can supply the feed gas, and deal with the resulting credit and fuel indexation risk. Other US suppliers appear to want to follow suit.

Figure 39 Regional gas prices in different scenarios, 2013-35



Source: World Energy Outlook 2013. International Energy Agency.

New contract typologies and innovative price structures such as Cheniere's represent opportunities for the small importing countries of Central America. Nevertheless, Central America's characteristics in terms of demand (low scale, relatively high risk for the supplier) create particular conditions in terms of supply and prices. LNG suppliers to smaller buyers are likely to be primarily concerned with securing pricing netbacks

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[56] North American LNG exports: how disruptive for how long? C. J. Goncalves.

[57] LNG for power in small emerging markets, D. Haug, Shawn Cumberland.

that are sufficient to justify the specific costs and risks of supplying these regions[58]. Accordingly, LNG supply prices to this region will likely incorporate a price premium to offset for possible risks and delivery of small quantities, diverging from what would be expected from a pure cost-plus approach to LNG pricing.

A2.1.4 Short term trading

Short term trading[59] has notably expanded over the last fifteen years, increasing its share over LNG trade volumes from 5% in 2005 to 33% in 2013. This performance has been driven by several factors:

- A more complex market, with more exporters and importers and new linkages between suppliers and buyers.
- The growth in contracts with destination flexibility, namely from the Atlantic Basin and Qatar.
- The availability of volumes from destination-flexible producers facilitated diversion to high-demand markets.
- Increases in global regasification capacity and Asian and Latin America's demand.
- Sustained regional price disparities, which have made arbitrage activities more attractive.
- Sudden upward demand shocks in LNG dependent countries such as Japan, Korea and Taiwan.

A reduction in the relative competitiveness of LNG relative to substitute products (such as coal and gas) in certain regions, which has freed up volumes to be re-exported.

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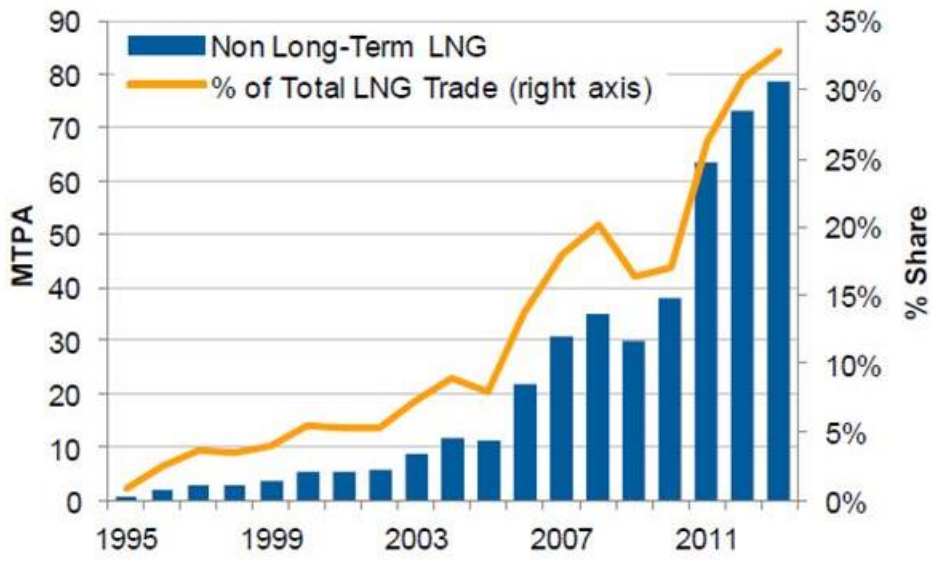
[58] Opportunities and Challenges of Using LNG as fuel in small- to medium-sized power generation, G. van Marcke, A. Dumitras.

[59] There is no agreed definition of what constitutes short-term trading in LNG. Definitions differ depending on the source. The data used in this section come from the International Gas Union, which defines non long term market (which we refer to as short term trading) as cargoes not supported by a long-term (5+ years) Sales and Purchase Agreements, cargoes diverted from their original or announced destination, and cargoes over and above take-or-pay commitments (upward flexibility).

Figure 40 Short term volumes, 1995-2013



Source: World LNG Report – 2014. International Gas Union.

In 2013, there were 27 non long-term importers and 25 exporters. Brunei was the country with the highest growth in spot supply (3.5 mt). On the demand side, China (2.3 mt), Malaysia (1.6 mt), Argentina (1.1 mt) and Brazil (1.5 mt) absorbed the majority of additional spot volumes.

The main factors that will influence the evolution of short term LNG[60] are (i) divertible LNG output, which is favoured by spare capacity in plants as well as more flexible contracts. (ii) market requirement for additional LNG, as we have seen in the Asian markets in recent years, and (ii) shipping capacity.

Short term contracts share on LNG trades is expected to grow and increase its share in total LNG trade. First, as new players such as the United States enter the market, increased supply and competition will contribute to increasing contract flexibility. Second, as natural gas production expands in North America, arbitrage opportunities will also increase in the short term, fostering short term trade. Third, orders for speculative ships have recently increased, which could allow more capacity and flexibility in the shipping market after 2014 - 31 LNG carriers schedules for delivery[61].

Increasing short term trade offers opportunities for LNG development in Central America. One of the obstacles for LNG introduction in small emerging economies is long term off-take contracts, which normally require a relatively high degree of creditworthiness and significant demand scale on the buyer's side. Spot LNG trade eases market access for small emerging LNG buyers, as creditworthiness and scale are not as relevant[62]. Spot markets also allow buyers to operate in the market until an

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[60] LNG Pricing, Markets in Europe and Outlook, D. Ledesma, Presentation to Florence School of Regulation, March 2012.

[61] World LNG Report – 2014. International Gas Union.

[62] *LNG for Power in Small Emerging Markets*, D. Haug, 17th International Conference & Exhibition on Liquified Natural Gas, April 2013.

attractive long term contract is offered, allowing more opportunities to obtain returns on built import facilities and de-risking their construction.

A2.1.5 Interregional trade and other trends

Over the past decade, new LNG exporters from the Middle East and the Atlantic Basins have entered the market and have changed global trade flows. The share of the Intra-Pacific region has relatively dropped, while flows from the Middle East to the Pacific region have rapidly expanded and become more relevant. Currently, Middle East-Pacific LNG flows are similar to Intra-Pacific exchanges, and both constitute the largest inter-basin trade flows.

Table 29 LNG Trade between basins, in Mtpa. 2013

Exporting region / Importing region	Africa	Asia	Asia-Pacific	Europe	FSU	Latin America	Middle East	North America	Re-exports	Total
Asia	2.8	-	8.9	0.1	-	0.1	19.5	-	-	**31.4**
Asia-Padfic	13.8	-	61.7	0.4	10.8	2.5	55.6	-	(0.1)	**144.6**
Europe	15.0	-	-	1.8	-	3.1	17.2	-	(4.3)	**32.8**
Latin America	1.6	-	-	0.4	-	9.1	1.3	-	(0.04)	**12.4**
Middle East	0.4	-	0.1	-	-	0.2	2.2	-	-	**2.9**
N. America	1.3	-	0.3	0.4	-	3.8	2.6	-	(0.2)	**8.2**
Re-exports	-	0.1	0.8	1.0	-	2.2	0.2	0.4	-	**4.6**
Total	**34.8**	**0.1**	**71.8**	**3.9**	**10.8**	**21.0**	**98.6**	**0.4**	**(4.6)**	**236.8**

Source: World LNG Report – 2014. International Gas Union.

Market segmentation is decreasing. Traditionally, LNG markets were regionally compartmentalized, with demand centres in Asia and Europe. Currently, market integration is higher, and markets are more liquid with an increasing number of buyers and sellers.

Since 2000, growing market flexibility and the development of trading hubs in the Atlantic basin has favoured portfolio trading strategies that aim to exploit arbitrage opportunities in higher value markets. Portfolio players, who have increased their presence in recent years, operate a portfolio of LNG contracts and have the ability to optimise between their LNG sourcing and their LNG delivery commitments. They may secure LNG in excess of their delivery commitments and have additional volumes to trade exploiting arbitrage opportunities. Portfolio players offer LNG buyers flexibility and a supply source that is not long term and rigid. Volumes are sold in the spot and short term market. The main portfolio players such as BP, BG Group, Chevron, ConocoPhillips, ExxonMobil, GdFSuez, Gazprom and Qatar Gas. Portfolio players will play a relevant role in short and medium term new LNG supply in the market. According to recent estimates[63], 16% of total capacity under construction will be traded through portfolio operators.

An increasing presence of portfolio trading represents an opportunity for Central American countries, as annual flexible volumes with low levels of take or pay are more adapted their LNG needs. Nevertheless, competing in this market also poses challenges for Central American countries, as in the spot or short term market volumes are sold to the highest bidder and Central American countries would have to compete

[63] *Philippines Natural Gas Master Plan. Phase Two Report: Design of a transactional structure for initial LNG-to-power infrastructure development for Luzon and Mindanao*. The Lantau Group, March 2014.

with buyers in more established and larger markets, facing a premium in terms of scale and risk.

One last recent trend which favour LNG imports from Central America refers to the size of contracts. Traditionally, one reason given for the lack of interest of sellers in demands from relatively small buyers was the size of the LNG contract. However, recent estimates show that in 2012 there 13 mmtpa of LNG was contracted in volumes of less than 0.5 mmtpa and close to 38 mmpta contracted in volumes between 0.5 mmtpa to 1 mmtpa[64]. Even relatively small volumes can attract the interest of LNG sellers.

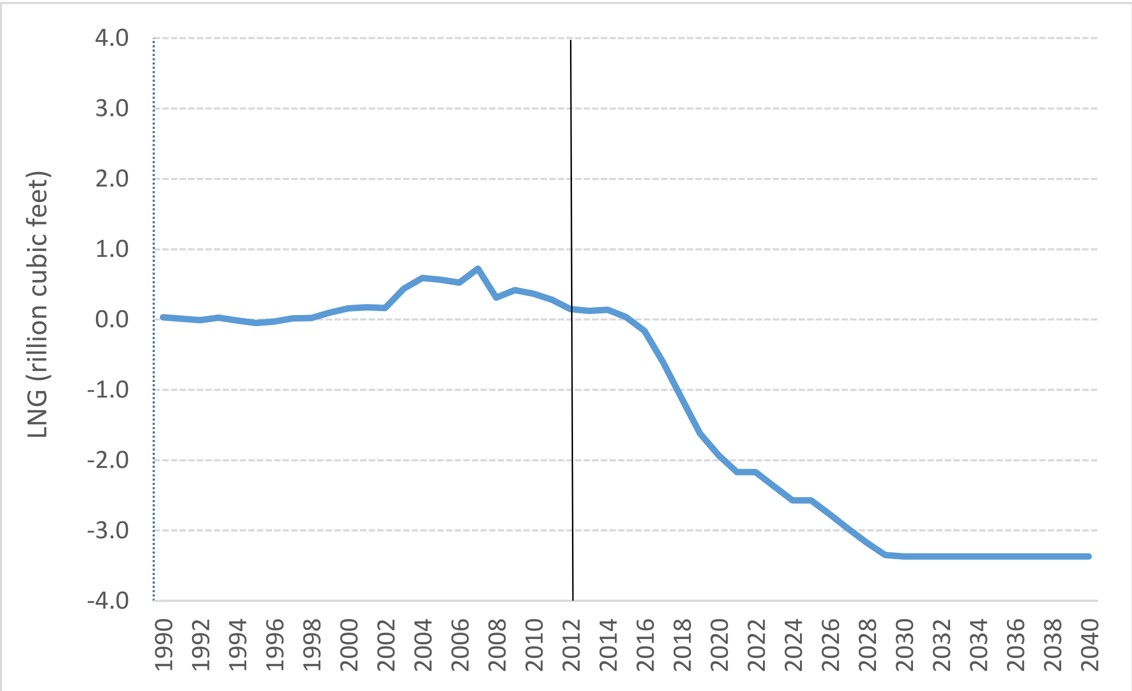
A2.2 Potential suppliers

A2.2.1 North America

United States

The shale gas revolution in the United States has transformed the region from an LNG importer to a potentially massive LNG exporter (Figure 41). In the mid-2000s, confronted with declining conventional production, the United States was planning to increase its LNG import capacity. However, technological progress in drilling techniques and more adequate regulatory environment fostered a significant increase in shale gas production after 2005 (Figure 42). Total gas production increased from 18.1 Tcf in 2005 to 24.1 Tcf in 2012, with shale gas being the main driver.

Figure 41 United States net LNG imports, 1990-2040



[64] *Philippines Natural Gas Master Plan. Phase Two Report: Design of a transactional structure for initial LNG-to-power infrastructure development for Luzon and Mindanao*. The Lantau Group, March 2014.

Note: from 2013 onwards values are those predicted according to the Annual Energy Outlook 2014 reference scenario.

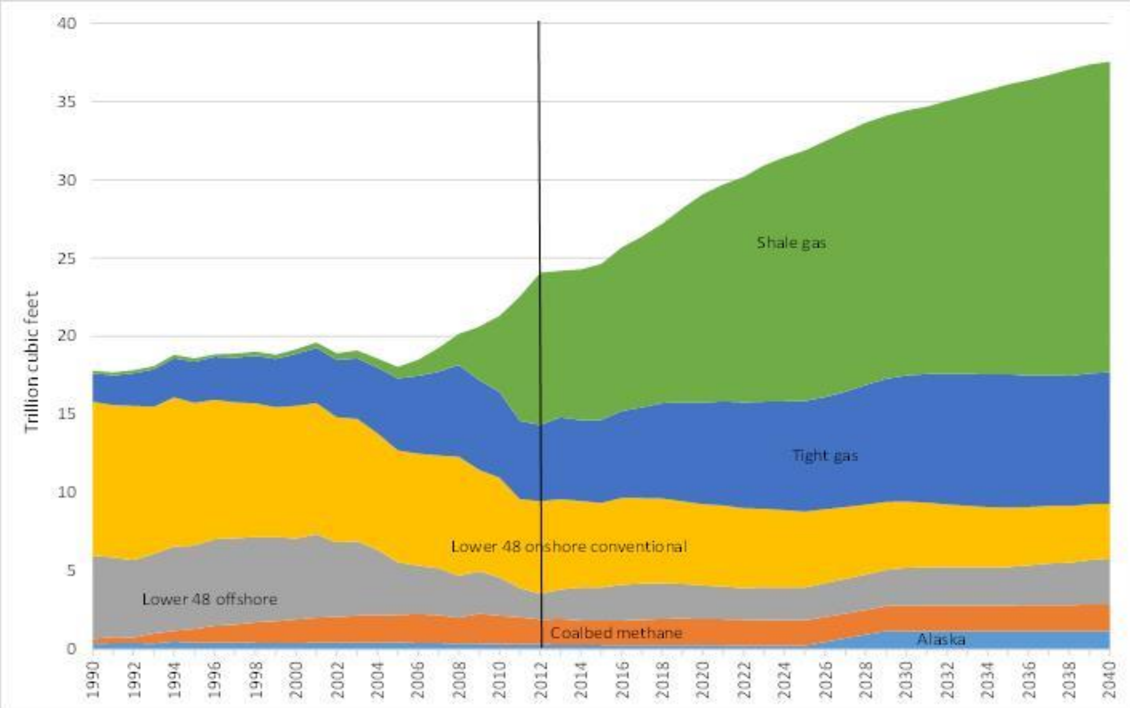
Source: US Energy Information Agency. Annual Energy Outlook 2014.

Growth in gas production is expected to continue. According to the EIA, total gas production will reach 37.5 Tcf by 2040. From 2012 to 2040. 56% increase in total production will result from increased development of shale gas, tight gas, and offshore natural gas resources. Shale gas production is the largest contributor, growing by more than 10 Tcf, from 9.7 Tcf in 2012 to 19.8 Tcf in 2040. The shale gas share of total U.S. natural gas production is expected to increase from 40% in 2012 to 53% in 2040. Given that domestic consumption is likely to grow at considerably slower pace, supply for exports will be abundant.

Several factors make the United States an attractive LNG exporter. First, gas supply will be abundant in the coming years. Second, there exists a substantial price differential between the Henry-Hub price and oil-linked LNG prices, which creates arbitrage opportunities and makes exports attractive. Third, for many LNG buyers, Henry Hub contracts - tied to gas and not to oil - represent a way to diversify contract portfolio, for most users very dependent on oil-linked contracts. Fourth, as LNG imports are dropping in the United States, regasification terminals are becoming increasingly underutilized. Export facilities offer a chance to improve returns on their existing regasification investments. In addition, as liquefaction projects will leverage existing LNG infrastructure (they are brownfield projects), they will have cost advantages compared to other supplier countries.

The emergence of unconventional gas and increasing export opportunities have given rise to a significant number of liquefaction project proposals (Table 2). In June 2014, 29 liquefaction projects had been proposed, representing nearly 287 Mtpa of capacity (190 Mtpa of projects with announced start dates), making the United States the largest country in terms of post-2013 new liquefaction capacity. Most of the terminals are located in the Gulf Coast states: Texas (15), Louisiana (10), and Mississippi (1). Two projects have been proposed in Oregon, two in Alaska and three in the Atlantic coast - in Georgia, Maine and Maryland. Texas and Louisiana concentrate 74% of total proposed liquefaction capacity. In terms of coastal location, the majority of the projects and capacity are located on the East Coast (25 projects, 81.6% of total proposed liquefaction capacity).

Figure 42 United States natural gas production by source, 1990-2040



Note: from 2013 onwards values are those predicted according to the Annual Energy Outlook 2014 reference scenario.

Source: US Energy Information Agency. Annual Energy Outlook 2014.

Sabine Pass is the only terminal which is partially under construction. This project has received both US Department of Energy (DOE) approval to export to FTA (Free-Trade Agreement[65]) and non-FTA countries, as well as the requisite environmental approvals from the Federal Energy Regulatory Commission (FERC). Sabine Pass first four trains will come online by 2017, with total capacity of 18 Mtpa. The rest of the terminals are in a pre-FID situation. Most of them have received DOE approval to export LNG to FTA countries, while just four projects – which nevertheless account for 22% expected capacity - holds authorization for non-FTA countries exports.

[65] Free Trade Agreement countries are those with which the United States has free trade agreements in force. Currently these countries are: Australia, Bahrain, Canada, Chile, Colombia, Costa Rica, Dominican Republic, El Salvador, Guatemala, Honduras, Israel, Jordan, Korea, Mexico, Morocco, Nicaragua, Oman, Panama, Peru, Singapore. Applications to authorize the export of LNG from and to a nation with which there is in effect a free trade agreement requiring national treatment for trade in natural gas are deemed consistent with the public interest and granted without modification or delay (http://energy.gov/fe/services/natural-gas-regulation/how-obtain-authorization-import-andor-export-natural-gas-and-lng). On the contrary, LNG exports to non-FTA countries are presumed to be in the public interest under the Natural Gas Act, but are subject to the United States Department of Energy (DOE) making an official determination that effectively they are in the public interest. Therefore, non-FTA authorizations are subject to more regulatory uncertainty and political circumstances. The recent energy crisis in Ukraine and Russia has led DOE to consider speeding up the process to authorize LNG exports to non-FTA countries.

Table 30 Proposed liquefaction projects in the United States. June 2014

Project		Capacity (in Mtpa)	US State	Status	Latest company announced start date	FERC Filing Status	DOE FTA/Non FTA Approval	Operator
Sabine Pass LNG*	T1-2	9	Texas	Under construction	2015	FERC Authorization	FTA/non-FTA	Cheniere Energy
	T3-4	9	Texas	Under construction	2016-17	FERC Authorization	FTA/ non-FTA	
	T5	4.5	Texas	Pre-FID	2019	FERC Filing	FTA	
	T6	4.5	Texas	Pre-FID	N/A	FERC Filing	FTA	
Freeport LNG*	T1-2	8.8	Texas	Pre-FID	2018	FERC Authorization Pending	FTA/ non-FTA	Freeport LNG Liquefaction
	T3	4.4	Texas	Pre-FID	2019	FERC Filing	FTA/ non-FTA	
Corpus Christi LNG T1-3		13.5	Texas	Pre-FID	2018	FERC Filing	FTA	Cheniere Energy
Cameron LNG T1-3*		12	Louisiana	Pre-FID	2017-18	FERC Authorization	FTA	Sempra Energy
Cove Point LNG*		7.8	Maryland	Pre-FID	2017	FERC Filing	FTA/non-FTA	Dominion Resources
Jordan Cove LNG		6	Oregon	Pre-FID	2018	FERC Filing	FTA	Veresen
Oregon LNG T1-2		9	Oregon	Pre-FID	2018	FERC Filing	FTA	Oregon LNG
Lavaca Bay Phase 1-2 (OS)		8	Texas	Pre-FID	2018	FERC Filing	FTA	Excelerate Energy
Magnolia LNG T1-4		8	Louisiana	Pre-FID	2018-2019	FERC Filing	FTA	LNG Limited
Lake Charles LNG T1-3*		15	Louisiana	Pre-FID	2019-20	FERC Filing	FTA/ non-FTA	Trunkline LNG
Elba Island LNG T1-2*		2.5	Georgia	Pre-FID	2016	FERC Filing	FTA	Southern LNG
Gulf LNG T1-2*		10	Mississippi	Pre-FID	2019	FERC Filing	FTA	Gulf LNG
Golden Pass LNG T1-3*		15.6	Texas	Pre-FID	2018	FERC Filing	FTA	Golden Pass Products
Gulf Coast LNG T1-4		21	Texas	Pre-FID	N/A	No Filing	FTA	Gulf Coast LNG Export
CE FLNG T1-2 (OS)		8	Louisiana	Pre-FID	2018	Pre-Filing	FTA	Cambridge Energy Holdings
Waller Point LNG (OS)		1.25	Louisiana	Pre-FID	2016	No Filing	FTA	Waller Marine, Inc
South Texas LNG T1-2		8	Texas	Pre-FID	2019-2020	No Filing	FTA	Pangea LNG
Main Pass Energy Hub LNG T1-6 (OS)		24	Louisiana	Pre-FID	2017	No Filing	FTA	Freeport-McMoran Energy
Gasfin LNG		1.5	Louisiana	Pre-FID	2019	No Filing	FTA	Gasfin Development
Venture Global LNG		5	Louisiana	Pre-FID	N/A	No Filing	FTA	Venture Global Partners
Eos LNG (OS)		6	Texas	Pre-FID	N/A	No Filing	FTA	Eos LNG
Barca LNG (OS)		6	Texas	Pre-FID	N/A	No Filing	FTA	Barca LNG
Annova LNG T1-2		2	Texas	Pre-FID	2018	No Filing	FTA	Annova LNG LLC.
Delfin LNG T1-4 (OS)		13	Louisiana	Pre-FID	2017-2021	No Filing	FTA	Delfin FLNG
Texas FLNG		2	Texas	Pre-FID	N/A	No Filing		Texas LNG
Lousiana LNG		2	Louisiana	Pre-FID	N/A	No Filing		Louisiana LNG Energy
REI Alaska		20	Alaska	Pre-FID	2019	No Filing		Resources Energy Inc.
Alaska South Central LNG T1-3		18	Alaska	Pre-FID	2023-2024	No Filing		BP, ConocoPhillips, ExxonMobil
Downeast LNG		2	Maine	Pre-FID	2019-2020	Pre-Filing Pending		Kestrel Energy Partners, ETG

** Denotes existing regasification terminal.*

Source: elaboration from IGU (2014), FERC, DOE and operators' webpages.

Some of the projects have already contracted all or a relevant part of their capacity through long term contracts or softer contractual arrangements (Table 3):

- Cheniere Energy has signed 20 year Sale and Purchase Agreements (SPA) for LNG sales from Sabine Pass with BG Gulf Coast LNG, Gas Natural Fenosa, KOGAS, GAIL (India) Ltd., Total Gas & Power N.A, Centrica PLC. Under these contracts users will purchase LNG on an FOB basis for a purchase price indexed to the monthly Henry Hub price plus a fixed annual component. Contracted capacity covered by all the contracts signed amounts to 19.75 Mtpa, close to 75% of total capacity at the terminal.

- Freeport LNG has 20 year binding Liquefaction Tolling Agreements (LTA) with Osaka Gas Co., Ltd. and Chubu Electric Power Co., Inc., BP, SK E&S LNG, LLC (SK). Contracted capacity covered by all the contracts signed amounts to 11 Mtpa (close to 85% of total capacity in the terminal).

- Cheniere Energy has signed 20 year Sale and Purchase Agreements (SPA) for LNG sales from Corpus Christi with PT Pertamina, Endesa, S.A, Iberdrola, S.A. and Gas Natural Fenosa LNG, SL. Under these contracts users will purchase LNG on an FOB basis for a purchase price indexed to the monthly Henry Hub price plus a fixed annual component. Contracted capacity covered by all the contracts signed amounts to 5.35 Mtpa, close to 39.6% of total capacity at the terminal.

- o Sempra Energy has signed 20 year tolling capacity agreements with GDF SUEZ S.A., Mitsubishi Corporation, and Mitsui & Co., Ltd for export capacity use at Cameron LNG. Contracted capacity covered by all the contracts signed amounts to 12 Mtpa (100% of total capacity in the terminal).

- o Dominion has signed 20 year terminal service agreements LNG with Pacific Summit Energy, LLC and GAIL Global (USA) LNG LLC for export capacity use at Cove Point. Contracted capacity covered by all the contracts signed amounts to 7.8 Mtpa (100% of total capacity at the terminal).

- o Veresen signed different independent non-binding Heads of Agreement (HOAs) in 2013 with three, large-scale prospective customers with head office locations in Indonesia, India, and an Eastern Asia country. The volume of LNG capacity requested under each HOA either meets or exceeds a minimum 25% capacity threshold amount, under the initial 6 mtpa offering by Jordan Cove. The contract term under each agreement is proposed to be 25 years, with extension rights.

- o Southern LNG has signed a contract with Shell for full use of capacity at Elba Island. Contracted capacity covered by all the contracts signed amounts to 2.5 Mtpa (100% of total capacity at the terminal).

However, according to the public information available online[66], the rest of the planned projects in Table 2 have not reached firm commercial agreements regarding the use of their export capacity. In quantitative terms, the capacity of these projects amounts to 203.35 Mtpa (71.3% of all proposed capacity).

The ability of all the proposed projects to become fully operational faces some risks and uncertainties:

- o *Regulatory risk*. To become fully operational, projects have to obtain the FERC approval. In addition, to maximize the scope in terms of exports, projects have to be allowed by the DOE to export both to non FTA countries. As the table shows, most of the projects currently lack the FERC authorization as well as the permit to export to non FTA countries. Social and political concerns about increasing gas prices in the United States in case LNG exports are fully allowed may lead the public authorities to slow the administrative authorization process, what would introduce delays in the development of some of the projects. On the contrary, if the approval process is relatively fast, most of the projects could be operational by 2019.

- o *Commercial risk*. US LNG exports will depend on the arbitrage opportunities between Henry Hub prices and oil-linked LNG prices. If price differentials shrink, US LNG demand will be lower and some projects may face commercial risks and could be delayed. In addition, restrictions on shale gas development also impose risks – albeit indirect - on LNG export

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[66] Information has been obtained from the public information available in the companies' webpages. It is however possible that a company has reached an agreement regarding its capacity without making it public in its webpage.

projects since overall supply relative to exploitable gas resources could be constrained.

Table 31 Contracting status of some proposed liquefaction projects in the US

	Commercial agreements (user, capacity contracted and contract type)	Capacity under the agreement	Project's total capacity	Share of capacity under the agreement over total capacity (in %)
Sabine Pass LNG	BG Gulf Coast LNG, LLC - 5.5 mmtpa (20 year, SPA) Gas Natural Fenosa - 3.5 mmtpa (20 year, SPA) KOGAS 3.5 mmtpa - (20 year, SPA) GAIL (India) Ltd. - 3.5 mmtpa (20 year, SPA) Total Gas & Power N.A. - 2.0 mmtpa (20 year, SPA) Centrica plc - 1.75 mmtpa (20 year, SPA)	19.75	27	73.1%
Freeport LNG	Osaka Gas Co., Ltd. and Chubu Electric Power Co., Inc. - 4.4 mmtpa (20 year, LTA) BP - 4.4 mmtpa (20 year, LTA) SK E&S LNG, LLC (SK) - 2.2 mmtpa (20 year, LTA)	11	13.2	83.3%
Corpus Christi LNG	PT Pertamina - 0.8 mtpa (20 year, SPA) Endesa, S.A - 2.25 mtpa (20 year, SPA) Iberdrola, S.A. - 0.8 mtpa (20 year, SPA) Gas Natural Fenosa LNG, SL - 1.5 mtpa (20 year, SPA)	5.35	13.5	39.6%
Cameron LNG	GDF SUEZ S.A. - 4 mtpa (20 year, tolling capacity agreement) Mitsubishi Corporation - 4 mtpa (20 year, tolling capacity agreement) Mitsui & Co., Ltd., - - 4 mtpa (20 year, tolling capacity agreement)	12	12	100.0%
Cove Point LNG	Pacific Summit Energy, LLC - 3.9 mtpa (20 year, terminal service agreement) GAIL Global (USA) LNG LLC - 3.9 mtpa (20 year, terminal service agreement)	7.8	7.8	100.0%
Jordan Cove LNG	Independent non-binding Heads of Agreement (HOAs) were finalized in 2013 with three, large-scale prospective customers with head office locations in Indonesia, India, and an Eastern Asia country. The volume of LNG capacity requested under each HOA either meets or exceeds a minimum 25% capacity threshold amount, under the initial 6 mtpa offering by Jordan Cove. The contract term under each agreement is proposed to be 25 years, with extension rights.	-	-	-
Elba Island	Shell - 2.5 mtpa	2.5	2.5	100.0%

Notes: SPA (sales purchase agreement), LTA (Liquefaction Tolling Agreement); information has been obtained from the public information available in the companies' webpages. It is however possible that a company has reached an agreement regarding its capacity without making it public in its webpage.

Source: elaborated by ECA from companies' webpages.

The United States constitutes a likely supplier to Central America. First, proximity constitutes a key factor. Distance from Sabine Pass (Texas) to Puerto Limon (Costa Rica, Caribbean coast) is 1,424 nautical miles, while to Puerto Sandino (Nicaragua, Pacific Coast) is 2,166 (via Panama Canal). From Coos Bay – a port in the West coast close to Jordan Cove project – distances would be 3,854 nautical miles to Puerto Limon (via Panama Canal) and 3,013 to Puerto Sandino. These distances are slightly lower than those from Canada and considerably lower than those from other large LNG suppliers such as Australia, Malaysia, Indonesia, Qatar or Nigeria. Therefore, transportation costs from the United States to Central America are relatively lower than for other competing regions in terms of supply. Second, gas supply will be abundant, as well as liquefaction capacity. Third, liquefaction projects in the United States are brownfield, they have cost advantages compared to other supplier countries with abundant gas supply, such as Australia. Fourth, Central American countries have free trade agreements with the United States in the domain of natural gas - with the exception of Costa Rica[67]. As most of the United States projects already have FTA authorization, regulatory risks are lower in the case of exports to this region. Moreover, political pressures could lead towards a limitation of non FTA authorizations, which could impede United States supply reaching the Asian markets.

[67] Natural Gas in Central America, P. Shortell, Baragwanath K. and Sucre C., Energy Policy Group, Inter-American Dialogue, Working Paper, March 2014.

Table 32 Nautical miles from the US and other LNG suppliers to Central America

	United States		Canada		Nigeria	Qatar	Australia	Indonesia	Malaysia
	Sabine Pass (East coast)	Coos Bay (West coast)	Canaport (East coast)	Prince Rupert (West coast)	Port Hacourt	Port of Doha (a)	Darwin	Samarinda (b)	Miri (c)
Costa Rica (Puerto Limon, Caribbean coast)	1,424	3,854 (PC)	2,368	4,563 (PC)	5,436	9,440 (SC)	9,549 (PC)	10,098 (PC)	10,160 (PC)
Nicaragua (Puerto Sandino, Pacific coast)	2,166 (PC)	3,013	2,991 (PC)	3,715	5,971 (PC)	13,494	8,860	9,270	9,313

Notes: (a) close to Ras Laffan port; (b) close to Bontang port; (c) close to Bintung port; PC: Panama Canal; SC: Suez Canal.

Source: http://www.sea-distances.org/

The United States offers additional advantages. Even though standard LNG exports confront challenges in the Central American countries (not only commercial, but also logistical), small scale LNG could be more successful in the region[68]. Exports from the United States could be a support for the development of a hub and spoke system of LNG distribution in the region. Small scale projects are already underway in the region, namely the Pacific Rubiales project. The project is driven by the need to monetize gas from the *La Creciente* - onshore field in northern Colombia. The project comprises a 0.5 Mtpa offshore floating liquefaction barge, which will be leased from EXMAR under a 15-year tolling agreement. Exports from the terminal will be carried out on a small scale targeting terminals in the Caribbean Islands[69].

The final price of United States' supplies to Central America will range between United States Gulf Coast export prices and Asian oil-linked prices[70]. In particular, price outcomes will depend on (i) Gulf Coast prices for major buyers, (ii) LNG supplier alternatives (namely Asian LNG prices) and (iii) prices of alternative fuel costs (diesel or fuel gas oil). Demand from Asian LNG buyers will be a determinant driver of final price outcomes.

Canada

In the North American region, Canada is another emerging LNG supplier with notable potential. Canada's proved natural gas reserves amounted to 71.4 trillion cubic feet (Tcf) in 2013[71]. Most of Canada's natural gas reserves are conventional resources in the West Canadian Sedimentary Basin (WSCB). Significant quantities of unconventional gas reserves reside in the form of shale gas, tight gas and coal bed methane, even though their stage of development is not as advanced as unconventional gas reserves in the United States[72]. According to the Energy Information Agency, Canada estimates of technically recoverable shale gas resources amount to 573 Tcf[73].

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68 *Small & Mid-Scale LNG Applications in the Caribbean Region,* Travis Pace (Director Galway Group) Santo Domingo, Dominican Republic, February 2014.

69 *Exmar Group: Leadership Through Innovation*, April 2013.

70 LNG Pricing and Prospects for Supply to Latin America, M. Reimers, Poten and Partners, Platt's Private Power in Central America, June 2012.

71 BP Statistical Review of World Energy June 2014.

72 *Canada – Country Report*, US Energy Information Agency, December 2012.

73 *Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States*, US Energy Information Agency, June 2013.

Many LNG export terminals have been proposed in Canada to harness western Canada's unconventional natural gas potential. According to the International Gas Union, the number of liquefaction proposals amounts to 13, representing approximately 120 Mtpa of capacity (85 Mtpa with announced start dates). Most of the projects are located in West Canada.

Notwithstanding its potential, Canada's take off as a significant LNG exporter is expected to be delayed relative to the United States, primarily because of two main reasons. First, less extensive unconventional gas development. Second, less developed infrastructure. Although four projects are currently conducting preliminary engineering studies, none of them are under construction. The most likely date of any of the proposed projects becoming online is the end of the decade.

Given geographical proximity, a target market for Canadian exports is the Asian market. In fact, Asian companies and potential buyers are involved in Canadian LNG projects, as well as in the shale gas industry[74]. In any event, the massive presence of projects in the West Coast makes Canada a likely medium and long term supplier to possible terminals in the Pacific coast of Central America. After the United States and nearby countries in the region (Trinidad and Tobago, Colombia or Venezuela), Canada is the closest supplier to Central America. Distance from Prince Rupert (terminal in Canada's West coast) to Puerto Limon (Costa Rica, Caribbean coast) is 4,563 miles (via Panama Canal), while to Puerto Sandino (Nicaragua, Pacific coast) is 3,715 nautical miles. From a port in the East coast – such as Canaport – distances would be 2,368 nautical miles to Puerto Limon and 2,991 to Puerto Sandino (Panama Canal). One key disadvantage of Canadian projects compared to the United States is that hey display relatively higher liquefaction costs.

Table 33 Proposed liquefaction projects in Canada, 2014

Project		Capacity (in Mtpa)	Location	Status	Latest company announced start date	NEB application status	Operator
LNG Canada T1-4		24	West Coast	Pre-FID	2019-2020	Approved	Royal Dutch Shell
Kitimat LNG	T1	5	West Coast	Pre-FID	2018	Approved	Chevron
	T2	5	West Coast	Pre-FID	N/A	Approved	
Pacific Northwest LNG T1-T2		12	West Coast	Pre-FID	2018	Approved	Progress Energy (PETRONAS)
West Coast Canada LNG		15	West Coast	Pre-FID	2021-2022	Approved	ExxonMobil
Prince Rupert LNG	T1-2	14	West Coast	Pre-FID	2019-2020	Approved	BG Group
	T3	7	West Coast	Pre-FID	N/A	Approved	
BC LNG T1-2		1.4	West Coast	Pre-FID	2016-2018	Approved	BC LNG Export Co-Operative
Goldboro LNG		10	East Coast	Pre-FID	2018	Filed	Pierdae Energy
H-Energy LNG project		4.5	East Coat	Pre-FID	2020	Not Filed	H-Energy
Kitsault LNG (OS)		8	West Coast	Pre-FID	N/A	Filed	Kitsault Enery
Triton LNG (OS)		2	West Coast	Pre-FID	2017	Filed	Altagas (Assumed)
Woodfibre LNG		2.1	West Coast	Pre-FID	N/A	Approved	Pacific Oil and Gas
Discovery LNG		N/A	West Coast	Pre-FID	2019	Not Filed	Quicksilver Resources
Aurora LNG T1-4		24	West Coast	Pre-FID	2021-2022	Filed	Nexen (CNOOC)

Source: Source: World LNG Report – 2014. International Gas Union.

[74] *Developments in the Global LNG Business*, A. Flower, Report for the World Bank, May 2013 (confidential).

A2.2.2 Australia and Southeast Asia

Australia

As a result of its abundant and increasing gas resources and its proximity to consumer markets, Australia has become a net LNG exporter, ranking the third in 2013 after Qatar and Malaysia and leading LNG exports to the Pacific basic. Since 2000, LNG exports have grown by around 7% on average per year, gaining share over total Australian energy exports.

Australia's primary LNG export destination is the Asian market. Japan is the major importer of Australian natural gas, accounting for 77.2% of Australia's LNG exports in 2012. Most of this supply to Japan is covered in long-term contracts. The main buyers are China (17.3%), South Korea (4.1%), and Taiwan (1.2%). The three main Chinese national oil companies have collaborated with international oil companies on several Australian liquefaction projects and signed gas purchase agreements to reserve supply for the growing Chinese market.

Australia has three LNG export terminal with a total capacity of almost 1,200 Bcf/per year:

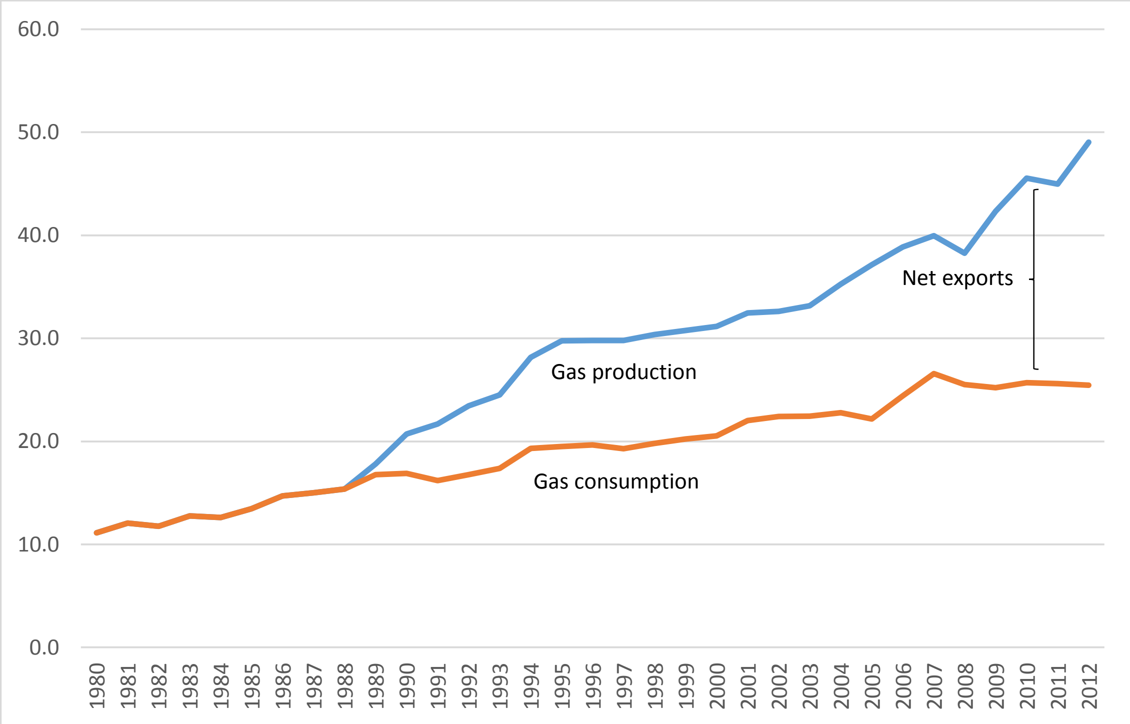
- North West Shelf LNG. Australia's largest terminal and it is owned and operated by a consortium of Woodside, Shell, BP, Chevron, Japan Australia LNG, and BHP Billiton. The facility relies on natural gas supplied from nearby fields in the North West Shelf. Most of the LNG produced is exported to Japan.

- Darwin LNG. It is located on the northern coast and sources natural gas from the Bayu-Undan field in the Timor Sea. Darwin LNG is operated by the consortium composed of ConocoPhillips, Santos, Eni, INPEX, Tokyo Gas, and Tokyo Electric (TEPCO) is. LNG is exported under contracts to Tokyo Gas Corp. and Tokyo Electric.

- Pluto LNG, the most recent one. The terminal is located in the Northwest region and has a capacity of over 200 Bcf/y.

In the medium term, Australian LNG exports are expected to rise substantially, as indicated by all liquefaction capacity under construction and planned. Several factors underlie Australia's LNG export potential.

Figure 43 Gas production, consumption and net exports, Australia, 1990-2012



Source: BP Statistical Review of World Energy June 2013.

Australia has a relatively large gas resource base, raking the 11th country in the world in terms of world reserves. Proven conventional gas reserves have been growing at a fast rate over the last years and they currently stand at 3.8 Tcm. Most of the traditional gas resources are located in the North West Shelf (NWS) offshore in the Carnarvon, Browse, and Bonaparte basins. Also, most of the traditional gas resources are from 10 super-giant fields even though there are nearly 500 fields included in the resource count[75]. Actual reserves and production volumes imply. Additionally, unconventional gas resources are being unlocked and adding to total gas reserves. According to the Energy Information Agency[76], Australia also had an estimated 437 Tcf of technically recoverable shale gas reserves in 2012. These resources are dispersed throughout the country: the inland Cooper Basin, eastern Maryborough Basin, the offshore southwestern Perth Basin, and the north-western Canning Basin[77].

Due to geographical proximity, Australian shipping costs to the Asian market are relatively lower than those of competing suppliers. The shipping distance between Qatar and Tokyo is 6,557 nautical miles, while the Darwin shipping distance is 3,072 nm. Australia also has a distance advantage over potential US Gulf Coast shipments.

[75] *Australia – Country Report*, US Energy Information Agency, June 2013.

[76] *Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States*, US Energy Information Agency, June 2013.

[77] *Australia – Country Report*, US Energy Information Agency, June 2013.

Exporting through Panama, the distance from Houston to Tokyo is 9,247 nm, while travelling around South Africa makes it 15,957 nm[78].

Given the significant increase in potential gas supply and closeness to the growing Asian markets have given rise to a significant number of liquefaction project proposals (Table 4). Most of the liquefaction projects are located in the coastal or offshore Northwest or North Australia and in the north-eastern Queensland region. Their almost exclusive target market is the Asian region. Currently, there are seven projects under construction. Four draw from gas fields off the north coast of Western Australia (Gorgon, Prelude, Wheatstone and Ichthys) and three are in Queensland (Queensland Curtis LNG, Gladstone LNG and Australia Pacific LNG). Total current capacity under construction is 62 Mtpa which is expected to be operational by 2017. The development of the remaining projects are fundamentally dependent on regulatory approval or final investment decisions.

Table 34 Proposed liquefaction projects in Australia, 2014

Australian liquefaction terminals (under construction)					
Project name		**Nameplace capacity (Mtpa)**	**Start year**	**Owners**	**Consumer markets**
Queensland Curtis LNG	T1	4.3	2014	BG, CNOOC	Chile, Singapore, China, India
	T2	4.3	2015	BG, Tokyo Gas	
Australia Pacific LNG	T1	4.5	2015	ConocoPhillips, Origin Energy, Sinopec	China and Japan (Kansai Electric)
	T2	4.5	2015	ConocoPhillips, Origin Energy, Sinopec	
Gladstone LNG	T1	3.9	2015	Santos, PETRONAS, TOTAL, KOGAS	Malaysia and Korea
	T2	3.9	2016	Santos, PETRONAS, TOTAL, KOGAS	
Gorgon LNG	T1	5.2	2015	Chevron, ExxonMobil, Shell, Osaka Gas, Tokyo Gas, Chubu Electric	Long-term contracts with Japan, Korea China, India, Mexico. Spot market
	T2	5.2	2015	Chevron, ExxonMobil, Shell, Osaka Gas, Tokyo Gas, Chubu Electric	
	T3	5.2	2016	Chevron, ExxonMobil, Shell, Osaka Gas, Tokyo Gas, Chubu Electric	
Wheatstone LNG	T1	4.5	2016	Chevron, Apache, Pan Pacific Energy, KUFPEC, Shell, Kyushu Electric	Japanese utilities
	T2	4.5	2017	Chevron, Apache, Pan Pacific Energy, KUFPEC, Shell, Kyushu Electric	
Prelude LNG (Floating)		3.6	2016	Shell, INPEX, KOGAS, CPC	Japan and Asian markets
Ichthys LNG	T1	4.2	2016	INPEX, TOTAL, Tokyo Gas, CPC, Osaka Gas, Chubu Electric, Toho Gas	Japan, Taiwan
	T2	4.2	2017	INPEX, TOTAL, Tokyo Gas, CPC, Osaka Gas, Chubu Electric, Toho Gas	
Australian liquefaction terminals (planned)					
Project name		**Nameplace capacity (Mtpa)**	**Start year**	**Owners**	**Consumer markets**
Fisherman's Landing (2 trains)		2.9	2016	LNG Ltd, CNPC subsidiary	Potentially CNPC
Cash Maple LNG (floating terminal)		2.0	2017	PTTEP (Thailand)	Potentially Thailand
Sunrise LNG (floating terminal)		10.5	2017	Woodside, ConocoPhillips, Shell, Osaka Gas	Not available
Bonaparte LNG (floating terminal)		2-3	2018	GDF Suez, Santos	Not available
Arrow LNG (2 trains)		7.7	2018	Shell, PetroChina	China
Browse LNG (3 trains)		11.5	2020	Woodside, Shell, BP, PetroChina, Mitsui, Mitsubishi	Japan, Taiwan, other Asia
Scarborough LNG (floating terminal)		6.0	2020/2021	BHP Billiton, ExxonMobil	Not available

Source: ECA from International Gas Union and US Energy Information Agency and companies' webpages.

The projects under construction – the first ones to become online over this decade - have already contracted all or a relevant part of their capacity through long term contracts or softer contractual arrangements (Figure 45):

- o Queensland Curtis LNG. BG Group has signed long term sales agreements with China National Offshore Oil Corporation (CNOOC), Chubu Electric, and Tokyo Gas. Contracted capacity covered by all the contracts signed represents 100% of total capacity at the terminal.

[78] http://www.ogj.com/articles/print/volume-112/issue-5/special-report-offshore-petroleum-operations/australia-emerging-as-top-lng-supplier.htmlAustralia emerging as top LNG supplier, R. D. Ripple, Oil & Gas Journal, May 2014.

- o Australia Pacific LNG. Australia Pacific LNG has signed long term sales agreements with Kansai Electric and Sinopec (most of the terminals capacity). Contracted capacity covered by all the contracts signed is close to 100% of total capacity at the terminal.

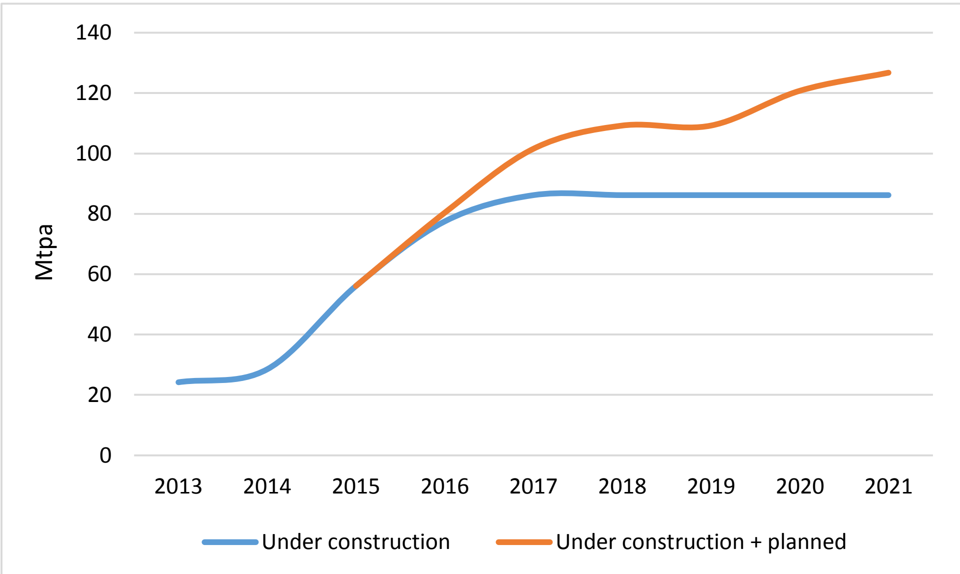
- o Gladstone LNG. Santos has signed long term sales agreements with Petronas and Kogas. Contracted capacity covered by all the contracts signed is close to 100% of the total capacity of the terminal.

- o Gorgon LNG. Chevron Australia has signed long terms sales agreements with Osaka Gas, Tokyo Gas, Chubu Electric Power, GS Caltex of South Korea, Nippon Oil Corporation and Kyushu Electric. Shell has secured several outlets and an Australian subsidiary of ExxonMobil has signed long terms sales agreements with Petronet LNG Limited of India and PetroChina International Company Limited. Further gas sales in the Asia-Pacific region are expected. Contracted capacity covered by these contracts is approximately 65% of the total capacity of the terminal.

- o Wheatstone LNG. Around 85% of Chevron's equity LNG from the Wheatstone Project has been committed to premier LNG buyers under long term contracts.

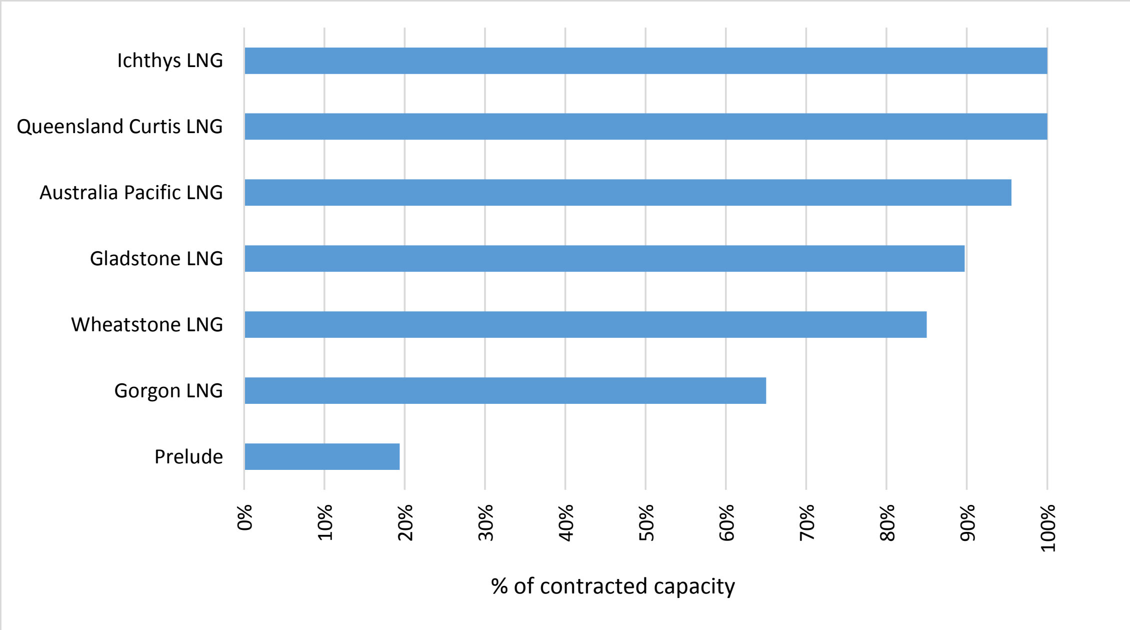
- o Prelude LNG. Inpex Corporation has signed Heads of Agreements (HOAs) with Japan's Tokyo Electric Power Company, Inc. (TEPCO) and Japan's Shizuoka Gas Company, Ltd. (Shizuoka Gas) for the sales and purchase of LNG from the Prelude FLNG project (The Project) in Australia.

Figure 44 Australia, liquefaction capacity under construction and planned, 2013-21



Source: ECA from International Gas Union and US Energy Information Agency.

Figure 45 Contracting status of some proposed liquefaction projects, Australia



Note: information has been obtained from the public information available in the companies' webpages. It is however possible that a company has reached an agreement regarding its capacity without making it public in its webpage.

Source: ECA from companies' webpages.

According to the public information available online, the planned projects which are not under construction have not reached firm commercial sales agreements regarding the use of their export capacity. In quantitative terms, the capacity of these projects amounts to 40.6 Mtpa.

The main risk Australian projects face is commercial. Over the last years there has been a considerable capital cost escalation requiring larger investments for Greenfield projects. Costs have increased due to several factors. First, the Australian energy and mining sectors are experimenting a boom and competing for inputs, leading to prices increases. Second, environmental regulations are becoming increasingly restrictive. Third, the geographical remoteness of some projects has increased infrastructure costs as well as labour costs. Some projects have already experienced significant cost overruns[79]. For instance, Ichthys LNG is one of the world's most expensive liquefaction project on a per unit basis. Economic and resource constraints have caused several equity partners to optimize their project strategy and exit some projects. Additionally, projects in the same locations compete against each other to source gas.

The recent cost developments have increased break-even landed costs (not including shipping costs, insurance or regasification) to levels which are higher than those of countries such as Canada or Mozambique[80]. As less expensive gas is brought online at

[79] *Australia – Country Report*, US Energy Information Agency, June 2013; Australia's LNG Sector Comes Under Strain, Natural Gas Europe, October 2013.

[80] *Extending the LNG boom: improving Australian LNG productivity and competitiveness*, McKinsey&Company, May 2013.

the end of the decade, some Australian planned projects could become non-profitable if global gas prices decrease significantly.

The primary target market for Australian LNG is the Asian market. Australia has traditional commercial links with this region and a shipping cost advantage compared to competing suppliers. Most of the owners of Australian liquefaction terminals are Asian off-takers and most of the contracted capacity is under long term contracts with Asian off-takers. The possibility of Australia becoming the main supplier of Central America, instead of the United States, is highly unlikely. Australia confronts a relevant cost disadvantage to ship to this region[81]. In addition, liquefaction costs are relatively higher and natural gas prices are expected to be lower in the United States, the most likely supplier to the region.

Indonesia

Indonesia had 103.3 Tcf of proven natural gas reserves in 2013 and it ranks as the 14th largest holder of proven natural gas reserves in the world[82]. Historically, Indonesia has been one of the most important LNG exporters. Although this continues to be the case, as Indonesia ranked the 4th in terms of LNG imports in 2013, the country's LNG export potential has been curtailed by some government policies: expected growth in natural gas demand led the government to pursue policies seeking to secure domestic natural gas for the local market[83], This has had a negative impact on LNG export levels and has decreased Indonesia's market share in global LNG exports. After accounting for more than a third of global LNG exports in the 1990's, Indonesia's market share stood at 7.2% in 2013[84].

Indonesian liquefaction plants are located in Northern Sumatra, Kalimantan, and Papua. The combined operating production capacity of these plants is 34 Mtpa. Currently, there are two liquefaction plants under construction:

- Donggi-Senoro, with a total capacity of 2 Mtpa it is expected to become operational in 2015. The owners are Mitsubishi, Pertamina, KOGAS and Medco.

- Senkang terminal, with two trains and total capacity of 1 Mtpa, will become operational in 2014, and its target activity will be small scale LNG. The owner is Energy World Corp.

Indonesia is strongly specialised in Asian markets, being a regional supplier to South Korea, Japan, Taiwan and China. This is likely to remain the case in the future. In particular, the parties involved in the construction of the Donggi-Senoro terminal are Asian companies. Future export potential will be limited because government policies aiming to secure domestic supply are likely to continue. This is consistent with the

[81] Distance from Darwin to Puerto Limon (Costa Rica) and Puerto Sandino (Nicaragua) is 9,549 nautical miles (via Panama Canal) and 8,860 nautical miles respectively. Source: http://www.sea-distances.org/

[82] BP Statistical Review of World Energy June 2014.

[83] *Indonesia – Country Report*, US Energy Information Agency, June 2013; Australia's LNG Sector Comes Under Strain, Natural Gas Europe, March 2014.

[84] Source: World LNG Report – 2014. International Gas Union.

small increases observed in potential liquefaction capacity, as indicated by current projects under construction.

Malaysia

Proven gas reserves in Malaysia were 38.5 Tcf in 2013[85], being the third largest country in terms of gas reserves in the Asia-Pacific region. Most of Malaysia's gas reserves are related to oil basins, which have exhibited a certain decline over the last years. However, Sarawak and Sabah states show an increasing amount of non-associated gas reserves that may foster natural gas production in the short term[86].

Malaysia ranks the 2nd country in terms of LNG exports, after Qatar, although – as Indonesia – its market share on global LNG markets has decreased over the last decade by the emergence of other exporters such as Qatar or Nigeria[87]. The main buyers of Malaysian LNG are Japan (60.1% of LNG exports in 2013), South Korea (17.4%), Taiwan (11.8%), and China (10.7%). All these countries hold medium or long term supply contracts with Malaysia.

Current liquefaction capacity amounts to 23.9 Mtpa[88]. Malaysia is currently constructing new liquefaction terminals which will come online between 2015 and 2018 and will represent 6.3 Mtpa (26.6% of total current capacity). The projects under construction are the following:

- PETRONAS LNG 9, with a total capacity of 3.6 Mtpa and which will become online on 2015. The owner is PETRONAS.
- PETRONAS FLNG, with a total capacity of 1.2 Mtpa and start date 2015. The owner is PETRONAS.
- Rotan FLNG, with a total capacity of 1.5 Mtpa and start date 2018. The owners are PETRONAS, MISC, and Murphy Oil.

LNG exports from Malaysia are likely to remain focused on its traditional market, the Asian market. Medium and long term exports will be hit by declining natural gas supplies[89] and increasing domestic demand, which is already favouring investment in LNG regasification terminals.

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[85] BP Statistical Review of World Energy June 2014.

[86] *Malaysia – Country Report*, US Energy Information Agency, June 2013; Australia's LNG Sector Comes Under Strain, Natural Gas Europe, September 2013.

[87] Source: World LNG Report – 2014. International Gas Union.

[88] Source: World LNG Report – 2014. International Gas Union.

[89] LNG Outlook in ASEAN: Key Driving Factors, T. K. Doshi, 10th ASEAN Council on Petroleum Conference, November 2013.

A2.2.3 Africa

East Africa

East Africa LNG export potential is based on new discoveries in Mozambique and Tanzania. Both are relatively poor countries with limited infrastructure but their geographical location as LNG suppliers puts them within easy reach of the Asian and, potentially, the South American gas markets.

Mozambique is the major producer of natural gas in East Africa. In 2012, natural gas production reached 154 billion cubic feet (Bcf), while natural gas consumption reached 28 Bcf. Most of the natural gas produced is exported to South Africa via pipeline. According to the Energy Information Agency, Mozambique holds 4.5 trillion cubic feet (Tcf) of proven natural gas reserves[90]. However, recent estimates of recoverable gas reserves indicate much higher levels (Figure 46).

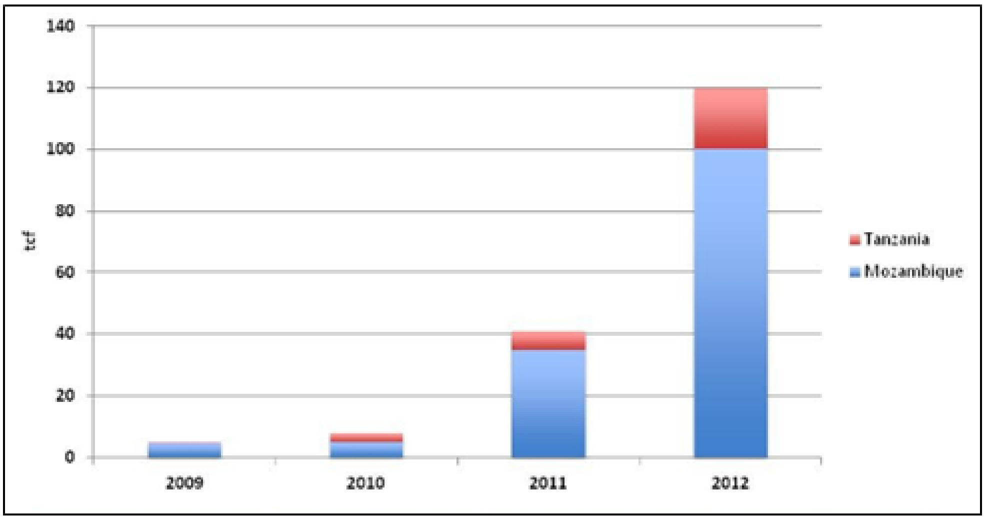
Currently, Mozambique is not a LNG exporter. However, recent natural gas discoveries in the offshore Rovuma Basin will support LNG exports in the medium term. Exploration activities in the region have been developed by Anadarko and Eni, in the form of joint venture on which other partners – most of them Asian companies – have stakes. Anadarko's discoveries contain 17-30 Tcf (Prosperidade complex) and 15-35 Tcf (Golfinho/Atum complex) of recoverable natural gas resources. Eni's natural gas discoveries contain 62 Tcf (Mamba complex) and 13 Tcf (Coral site).

Tanzania produces small volumes of natural gas for domestic consumption[91]. In 2012, natural gas production 33 Bcf in 2012, all of which was consumed domestically. In the medium term, there are plans to expand natural gas production from the Mnazi Bay Concession, located in southeast Tanzania in the Rovuma Basin. A pipeline is being constructed to transport natural gas from Mnazi Bay to Dar es Salaam. According to the EIA, proven gas reserves stood at 0.23 Tcf in 2012, bus as in the case of Mozambique, recent estimates indicate much higher levels (Figure 46). The BG Group-partnered with Ophir Energy - and Statoil – partnered with ExxonMobil – have made significant natural gas discoveries since 2010. As a consequence, Tanzania has the potential to become a LNG exporter.

[90] *Mozambique – Country Report*, US Energy Information Agency, April 2013.

[91] *Tanzania – Country Report*, US Energy Information Agency, April 2014.

Figure 46 Estimates of recoverable gas, Mozambique and Tanzania, 2009-12



Source: East Africa Gas – Potential for Export, D. Ledesma, The Oxford Institute for Energy Studies Working Paper, March 2013.

Abundant gas reserves, coupled high gas demand from Asia, political stability in the region, and small potential gas demand in these countries and their neighbours have prompted companies to develop LNG projects in the East African region, which nevertheless are in their earlier stages and have not reached an investment decision. The target markets lie in East and South Asia.

In Mozambique, ENI and Anadarko are jointly developing a LNG terminal, which is located in the northern province of Cabo Delgado[92]. The terminal is expected to become operational in 2018 with a total capacity of 5 Mtpa. The final investment decision is expected for later 2014. Expected first delivery is 2018-2020.

Prospects in Mozambique point to increasing LNG production. In its published Gas Master Plan, the government of Mozambique states that it expects 10 liquefaction trains to be in operation by 2026, with an overall capacity of 69 billion m /y. This could make Mozambique one of the world's top LNG exporters.

Tanzania's LNG strategy is being defined and there is still some uncertainty. According to Statoil, the Tanzanian government, Statoil, ExxonMobil, BG Group, and Ophir Energy are currently working on plans to develop a joint LNG plant. However, the Tanzanian government could have questioned whether the discovered reserves are sufficient to develop an LNG export project[93].

East African projects enjoy some advantages (abundant reserves, relatively low liquefaction costs[94]). However, they also face some risks, such as an inadequate regulation and infrastructure and potential competition from emerging suppliers. The

[92] East Africa eyes the race for LNG exports, J. Lee, ArticGas, May 2014.

[93] East Africa: the newest LNG frontier, www.lngindustry.com, March 2014.

[94] East Africa Gas – Potential for Export, D. Ledesma, *The Oxford Institute for Energy Studies* Working Paper, March 2013.

potential market of East African LNG is East Asia and South Asia, as high demand and high prices in these markets combine with shipping advantages.

West Africa

With the first Angolan liquefaction plant becoming online in 2013, the West African countries which export LNG area Angola, Equatorial Guinea, and Nigeria. Nigeria is by far the dominant LNG player in the region.

Nigeria's proven gas reserves were 179.4 Tcf in 2013[95], ranking the 9th natural gas reserve holder in the world. Despite the volume of gas reserves, Nigeria produced approximately 1.2 Tcf of dry natural gas in 2012. Since 2003, gas production has grown at a faster pace than consumption, allowing for an increasing volume of net gas exports.

The majority of Nigerian gas exports are in the form of LNG. In 2013 Nigeria ranked the 5th country in terms of LNG exports[96], accounting for approximately 8% of global LNG trade. NLNG is Nigeria's first and only liquefaction terminal. Its total capacity is 21.9 Mtpa and it has six trains which begun operation between 1999 and 2008. The owners are the Nigerian National Petroleum Corporation, Shell, TOTAL, and Eni. A seventh train is currently under construction.

Nigeria has a diversified portfolio of LNG buyers. In 2013, Nigeria exported 54% of its LNG to the Asia Pacific region, followed by Europe and Eurasia (31%), North America (7%), South America (7%), and the Middle East (1%)[97]. By countries, Japan (23%), South Korea (17%), Spain (14%), and Mexico (7%) were the main buyers. Trade patterns have changed in recent years, with Europe and the United States losing share over Nigeria's LNG exports due to higher demand from Asia.

There are prospects to increase liquefaction capacity. However, the number of projects and their characteristics vary depending on the source. According to the Energy Information Agency, there is one proposed terminal: Brass LNG Liquefaction Complex[98]. The terminal is being promoted by a consortium which includes the Nigerian National Petroleum Corporation, Total, ConocoPhillips, and Eni, is developing the Brass LNG Liquefaction Complex. The facility's total capacity is expected to amount to 10 Mtpa. The project is still in an engineering phase. According to other sources[99], there are two additional terminals planned/possible and two additional trains coming in the NNLNG terminal.

Natural gas production is expected to grow in Nigeria[100]. The main risks Nigerian projects confront are political and regulatory risks, which may hinder the development of certain projects, as it has occurred in the Nigerian oil and gas industry. Nigerian exports are likely to remain relatively diversified. Given its actual supply to North and

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[95] BP Statistical Review of World Energy June 2014.

[96] Source: World LNG Report – 2014. International Gas Union.

[97] BP Statistical Review of World Energy June 2014.

[98] *Nigeria – Country Report*, US Energy Information Agency, December 2013.

[99] Natural Gas in Africa: The Frontiers of the Golden Age, Ernst and Young.

[100] *Oil and Natural Gas in Sub-Saharan Africa*, US Energy Information Agency, August 2013.

South America, and that Nigeria is a relevant player in LNG spot markets, Nigerian exports could become a source of LNG supply for Central America.

North Africa

The North Africa region has two main players: Algeria and Egypt. Although Libya also constitutes a LNG exporter in the region, its exports have traditionally been low, primarily because of technical aspects[101]. Potential liquefaction capacity in the region stood up to 40.6 Mtpa in 2013. Terminals in Algeria and Libya were built in the 1960's and 1970's and the one in Egypt begun operation in 2005. Total exports in these countries amounted to 13.7 Mt in 2013[102], with low capacity utilization both in Algeria (46%) and Egypt (23%). Europe and Eurasia accounts for 74.3% of total exports, followed by the Asia pacific region (22.6%). France is the main export destination (28.4%), followed by Turkey (21.4%) and Spain (17.5%)[103].

Production of natural gas has been declining in Argelia since 2005, as many of the country's large fields are depleting[104]. There are projects planned to come online, but delays are recurrent. Currently, there is one LNG liquefaction terminal under construction, Arzew - GL3Z (Gassi Touil), with a total liquefaction capacity of 4.7. The owner is Sonatrach.

Natural gas exports in Egypt have declined since 2009 due to increasing domestic consumption not followed by production[105]. Production may increase in the medium term, due to new discoveries in the deepwater Mediterranean Sea and Nile Delta, along with others in the Western Desert, which have increased proved reserves. There are no liquefaction projects under construction, but, in principle, there is one terminal planned to start on 2018, with 4.8 Mtpa capacity[106].

Prospects for LNG exports in Egypt will be subject to political risks and domestic consumption needs to close the natural gas production deficit in the country. In Algeria, future exports will be conditional on infrastructure development and new discoveries translating in increased production.

A2.2.4 Nearby countries to Central America: Trinidad & Tobago, Colombia, Venezuela and Peru

Nearby countries to Central America enjoy a clear shipping distance advantage to supply the region. Moreover, they are already LNG suppliers in surrounding regions (Trinidad & Tobago and Peru) or they are developing projects for small scale LNG exports in the region (Colombia).

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[101] *Libya – Country Report*, US Energy Information Agency, October 2013.

[102] Libya's terminal was closed during 2013.

[103] BP Statistical Review of World Energy June 2014.

[104] *Algeria – Country Report*, US Energy Information Agency, May 2013.

[105] *Egypt – Country Report*, US Energy Information Agency, July 2013.

[106] Natural Gas in Africa: The Frontiers of the Golden Age, Ernst and Young.

Table 35 Nautical miles from nearby countries to Central America

	Colombia		Trinidad & Tobago	Venezuela	Peru LNG
	Covena (Caribbean coast)	Buenaventura (Pacific coast)	Point Fortin	Guiria	Pisco (a)
Costa Rica (Puerto Limon, Caribbean coast)	436	585 (PC)	1,299	1,315	1,683 (PC)
Nicaragua (Puerto Sandino, Pacific coast)	959 (PC)	786	1,835 (PC)	1,856 (PC)	1,694

Notes: (a) close to Peru LNG. PC: panama Canal.
Source: http://www.sea-distances.org/

Trinidad and Tobago

Trinidad and Tobago's is the largest oil and natural gas producer in the Caribbean. In 2013, it was the 6th largest LNG exporter[107], with a relatively diversified portfolio of buyers[108] but having South and Central America as its main target market (65.8% of total LNG exports in 2013). Argentina (18.3%) was the main export destination, followed by Chile (18.0%), Brazil (12.6%), Spain (10.1%), and the United States (10.0%)[109]. The country has one liquefaction terminal – ALNG – with 4 trains, which started operation between 1999 and 2006. Total capacity stands at 15.5 Mtpa, and the current rate of capacity utilization is 94%. Owners of all or part of the trains are BP, BG, Shell, CIC, and NGC Trinidad (just trains 1 and 4).

Currently, there are no terminals under construction or planned. Trinidad and Tobago could be a likely supplier to Central America, namely to its Caribbean coast. It has a reasonable level of gas supply (12.4 Tcf of gas reserves in 2013[110], relatively high ratio reserves/consumption, gas production double than domestic consumption), Central America would fit in its current marketing strategy, and it has shipping advantages. In fact, Trinidad and Tobago is currently supplying AES Andres terminal in the Dominican Republic[111], a small LNG importer. This model could be used in other countries in the Caribbean with a similar level of demand to AES Andres.

Colombia and Venezuela

Currently, Colombia and Venezuela are not LNG exporters. However, given relatively abundant gas supply, LNG exports are expected in the short and medium term.

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[107] Source: World LNG Report – 2014. International Gas Union.

[108] Export diversification is relatively new, as Trinidad and Tobago's almost exclusive destination has traditionally been the United States. After the advent of shale gas production, demand from the United States decreased significantly. Interestingly, although the LNG had been sold under long-term contracts, exporters in Trinidad and Tobago and exporters in the United States reached diversion agreements under which they share the benefits of LNG sales at higher prices on the spot markets in other regions. As a result, the United States share of total LNG exports from Trinidad and Tobago decreased from 99% in 2004 to 19% in 2011. Source: *Trinidad and Tobago: Selected Issues*, International Monetary Fund, June 2012.

[109] BP Statistical Review of World Energy June 2014.

[110] BP Statistical Review of World Energy June 2014.

[111] See the Dominican Republic case study for detailed information on this supply arrangement.

Colombia's proved natural gas reserves in 2013 stood at 5.7 Tcf[112]. The majority of gas reserves are located in the Llanos basin, although current production is located in the Guajira basin. Natural gas production has increased substantially over recent years. In 2007, it began to exceed consumption and allowed for exports. The Colombian government has plans to increase domestic natural gas production, including production from unconventional gas resources. Expanding natural gas production constitutes a priority for the government[113].

Colombia's natural gas exports are done only through the Antonio Ricaurte pipeline. Nevertheless, prospects of increasing gas production and increased export opportunities have stimulated LNG export initiatives. Currently there is an export terminal under construction which is expected to become operational in 2015, having reached FID in 2012. The Pacific Rubiales project is driven by the need to monetize gas from the *La Creciente* - onshore field in northern Colombia, close to the Caribbean coast. The project comprises a 0.5 Mtpa offshore floating liquefaction barge, which will be leased from EXMAR under a 15-year tolling agreement. Exports from the terminal will be carried out on a small scale targeting terminals in the Caribbean Islands, suggesting a possible source of supply for Central American countries.

Venezuela had 196.8 Tcf of proven natural gas reserves in 2013[114], ranking as the 8th larger reserves holder in the world. Current domestic gas production is relatively lower than gas consumption, so the country is meeting its gas demand with imports from Colombia and the United States. The government is prioritizing developing domestic natural gas production[115].

Venezuela exports gas to Colombia through the Antonio Ricaurte pipeline. LNG exports are expected in the medium term, though they are confronting difficulties. In 2008 Venezuela signed initial agreements to create three joint venture companies to pursue LNG projects along the northern coast of the country. Although Petróleos de Venezuela S.A. signed contracts with investors for these projects, several factors, such as additional negotiations and feedstock concerns are likely to delay its start date.

Peru

Peru is the 13th LNG exporter in the world[116] and the only Latin American country with an effective and operating liquefaction plant in the Pacific Coast. Its main buyer is Mexico (44% of total Peruvian exports in 2013), followed by Spain (25.8%), Japan (17.4%) and South Korea (12.3%)[117]. The country has only one liquefaction terminal – Peru LNG – which started operating in 2010. The terminal has a total capacity of 4.5 Mtpa and its owners are Hunt Oil, Shell, SK Corp, Marubeni. There are plans to build a second and possibly a third train in the medium term[118], which could be used to increase exports to Central America. Peru LNG receives gas via pipeline from Camisea

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[112] BP Statistical Review of World Energy June 2014.

[113] *Colombia – Country Report*, US Energy Information Agency, January 2014.

[114] BP Statistical Review of World Energy June 2014.

[115] *Venezuela – Country Report*, US Energy Information Agency, October 2012.

[116] Source: World LNG Report – 2014. International Gas Union.

[117] BP Statistical Review of World Energy June 2014.

[118] *Peru – Country Report*, US Energy Information Agency, August 2013.

field, located in the eastern side of the Andes. Although reserves are sufficient to allow an expansion in exports, additional investment in the pipeline could be required[119].

Peruvian domestic consumption of natural gas has increased over the last years, driven primarily by government incentives, economic growth, or more demand from the power sector[120]. Increasing demand could hinder export potential due to government intervention to secure domestic supply. In fact, the government has considered limiting LNG exports in the past, although agreements reached with Peru LNG owners concluded that LNG exports would continue provided the domestic demand was met. Recent discoveries of shale gas could increase Peru's resource potential and limit the risks of restrictions on LNG exports. If these risks do not materialise and recent discoveries become commercially viable, Peru could be a likely supplier to Central American countries, as it is relatively close and it is already supplying the region (Mexico).

A2.2.5 Middle East

In 2013, the Middle East supplied 42% of the world's LNG (98.5 Mt)[121]. Qatar - the world's largest LNG exporter - was the main supplier in the region, exporting 77.2 Mt (33% of total world supply). The other Middle East exporters were Oman (10.8 Mt), Yemen (7.2 Mt) and UAE (5.8 Mt). The main destination of Middle East exports is the Asia Pacific region, namely Japan (26.4% of total LNG exports in 2013), South Korea (21.7%) and India (12.0%). Europe and Eurasia concentrate 17.7% of Qatar's exports. Qatar was also one of the top spot exporters, accounting for more than a third of short-term and spot-market sales in the world in 2012[122].

Liquefaction capacity has grown rapidly over the past decade, driven by Qatar. The region held 100.8 Mtpa in 2013, amounting to 36% of the global capacity. Currently, there are no terminals under construction in the region. Additionally, some of UAE's aging terminals will be decommissioned in the coming years. These two factors make Qatar the only world region where liquefaction capacity will decrease in the short and medium term.

Qatar has the majority (over 90%) of its export volumes for 2014-2020 under sales and purchase agreements. LNG production growth in other parts of the world over the coming years could challenge Qatar's spot volumes. However, with the majority of its LNG sold, this should not impact Qatar's export volumes in the medium term.

In the coming years, Qatar – with abundant gas reserves – will nevertheless be surpassed as a world LNG leader by Australia, an emerging competitor. Additionally, other structural changes will take place in the Middle East region. This region has developed its LNG business on the area of the Persian Gulf. However, the Eastern Mediterranean will emerge as a new frontier for the industry[123]. New discoveries in

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[119] Pre-Feasibility Study of the Potential Market for Natural Gas as a Fuel for Power Generation or Energy Intensive Industry in Central America, final report draft to IDB, J. Bayley.

[120] *Peru – Country Report*, US Energy Information Agency, August 2013.

[121] Source: World LNG Report – 2014. International Gas Union.

[122] *Qatar – Country Report*, US Energy Information Agency, January 2014.

[123] The Middle East LNG story, P. Kiernan, www.energyglobal.com/, October 2013.

Cyprus (Aphrodite) and Israel (Tamar and Leviathan) will enable these countries to develop LNG exports, taking into account the relative size of the reserves in terms of their small energy markets. Other regions in the Middle East becoming LNG exporters is much more unlikely, even if some, as Iran or Saudi Arabia have a considerable amount of gas reserves.

Main markets for exports in the region are likely to remain in the Asia pacific region. Exports within the Middle East region could also increase, given energy needs in the region and several regasification terminal projects planned (such as projects in Jordan or in Lebanon). Qatar's role in the spot market increases the likelihood of LNG supplies from this region going to Central America

A2.2.6 Russia

Russia constitutes the 8th largest LNG exporter, with total effective liquefaction capacity of 10.8 Mtpa. Its main customers are Japan (81.8% of total LNG exports in 2013), South Korea (17.6%) and Taiwan (0.6%)[124]. Russia is one of the largest countries in terms of natural gas reserves, holding 1103.6 Tcf in 2013.

Massive natural gas reserves coupled with the recent liberalization of LNG exports will support the Russian LNG market in the future. Russia liberalized LNG exports on December 2013, what led to the end of Gazprom's gas export monopoly[125]. After the introduction of the new law, the Novatel Yamal LNG project reached FID. This terminal is currently under construction and it will have three trains, of 5.5 Mtpa each one that will become online between 2017 and 2019. The owners are Novatek, Total, and CNPC. Although there are other projects which have been proposed, most of them confront serious obstacles that will impede them from reaching FID in 2014. The only exception would be the addition of a third train in the two-train Sakhalin 2 terminal. Depending on how quickly negotiations between the partners develop, the project could reach FID in 2014.

As for current Russian exports, target markets for future Russian exports are likely to be the Asian markets, in particular China, Japan, India, South Korea and Taiwan[126]. Indeed, the Yamal LNG project in Russia has introduced an innovative shipping solution - the ice breaking LNG carrier[127] – in order to be able to ship LNG across the Northern Sea Route, most likely to the Asian markets.

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[124] BP Statistical Review of World Energy June 2014.

[125] Source: World LNG Report – 2014. International Gas Union

[126] Russia activates the LNG sector, Szymon Kardaś, Centre for Eastern Studies, December 2013.

[127] It is the first ship of this kind. It a high Ice Class notation (ARC7) and an innovative propulsion system (3 azimutal thrusters). It is being built in a Korean shipyard. IGU (2014).

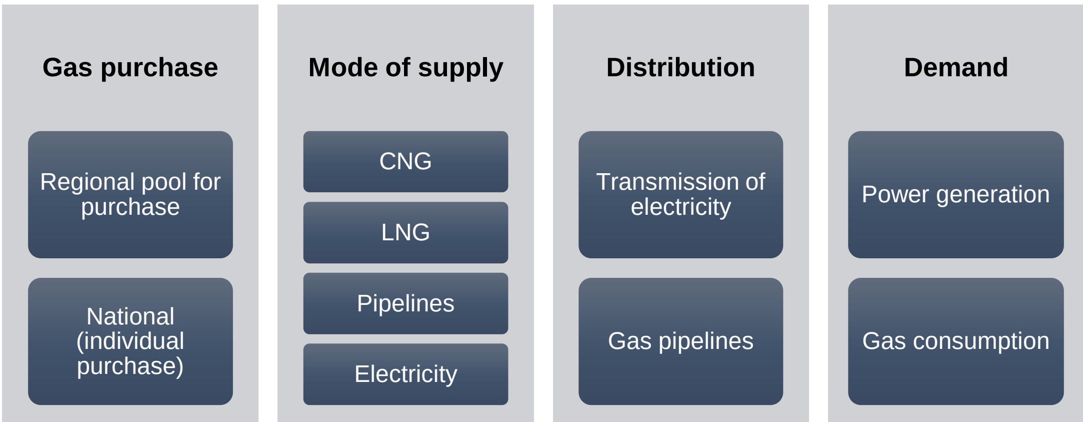
A3 LNG Strategies and economics

A3.1 IDB LNG strategies

The purpose of this Annex is to present the different strategies proposed by the IDB study and highlight the three most viable options. The IDB project team investigated 17 strategies to deliver gas to Central America, with several variants of each. In the IDB report and here '***strategies***' are defined as ***'technical solutions for delivery of energy (gas or power) to the Central American region'.*** The strategies vary across different elements in the value chain. The options considered in the IDB study along the value chain are shown in in Figure 47. They include the following four components:

- *Gas purchase* – both regional as well as national gas purchasing are considered as separate options.
- *Mode of supply* – The study extends beyond LNG imports into the region and includes options of electricity imports, gas pipeline imports and CNG imports. One of the key objectives of the study is to reduce energy costs in the region and it therefore considered all possible energy import options.
- *Distribution* – this is the onward trade of gas through the region once landed at an LNG or CNG terminal or once delivered via pipeline at the main import hub.
- *Demand* – the type of demand considered will also define a strategy option and in particular the question whether gas will be used for power generation or in the industrial sector.

Figure 47 Strategic options considered in the IDB study



Source: IDB Report No. 1 'Actualización de la Estrategia de Introducción del Gas Natural en Centroamerica'

By combining the different options at each stage of the value chain, the following 'long list' of 13 strategies shown in Figure 48 were initially considered.

Figure 48 'Long list' of considered gasification strategies

LNG	1	Terminals in all countries + power generation + national electricity distribution
	2	Terminals in all countries + national gas distribution
	3	Multiple regional terminals + regional gas distribution
	4	Multiple regional terminals + power generation + regional electricity distribution
	5	1 Regional terminal + power generation + regional electricity distribution
Pipelines	6A	Gas pipelines from Mexico or Colombia + regional gas distribution
	6B	Gas pipelines from Mexico or Colombia + regional electricity transmission
Electricity transmission	7	Regional electricity transmission from Mexico to Panama
CNG	8	Terminals in all countries + power generation + national electricity distribution
	9	Terminals in all countries + national gas distribution
	10	Multiple regional terminals + regional gas distribution
	11	Multiple regional terminals + power generation + regional electricity distribution
	12	1 Regional terminal + power generation + regional electricity distribution

For each option, the IDB project team calculated different variants of demand, trading and LNG supply. This lead to an estimate of a delivered cost of gas and associated electricity prices. Based on this analysis, three 'shortlisted' strategies for gas infrastructure were determined by a Steering Committee (SC) including representatives of each country for the study, taking into account:

- The strategies involving CNG were ruled out: the SC agreed with the consultants' opinion that CNG would impose a higher risk as a new technology being used for the first time.
- All representatives except Panama agreed that the supply of natural gas from Colombia should also be ruled out: Colombia's reserves are limited and are expected to be more expensive than alternative options.
- Guatemala and Mexico are in the process of signing an agreement for the construction of a gas pipeline between the two countries. The IDB study incorporated as a firm option this into their analysis.
- Mexico is interested in being involved in the Central American gas market as a potential source of supply for either gas or electricity.
- The Dominican Republic, which was not initially considered in the study, is interested in a joint purchase agreement for LNG to increase its bargaining power on the international market.

From the above strategies, the country representatives, the IDB and the consultants jointly agreed to focus on the following three concepts. The three shortlisted concepts and associated strategies are:

A. **Independent projects in each country—** National regasification terminals would be built in the short-term in each country except Guatemala where a gas pipeline will connect the country to Mexico. Gas would be used to generate electricity which would then be transported over the national transmission networks or SIEPAC.

B. **Sub-regional integration—** Two regasification terminals would be constructed in El Salvador and Panama according to ongoing initiatives. In the longer term, once capacity of the terminals is reached, new terminals would be built at new locations. Energy would be traded in the form of electricity on SIEPAC. Guatemala and Mexico are connected via pipeline.

C. **Integration with Mexico—** the northern part of the region is initially only supplied via the regasification terminal in El Salvador, and in the medium-term the pipeline from Mexico to Guatemala. The latter would later be extended to reach El Salvador, Honduras and Nicaragua. The southern part will be supplied by means of regasification terminals in Costa Rica and Panama.

Table 36 summarises the three strategies and their development over time:

Table 36 Development of selected IDB strategies

	Strategy A	Strategy B	Strategy C
Short-term	Regasification terminals are built in each country except Guatemala which is connected to Mexico via pipeline. All developments take place in the short-term.	The pipeline to Guatemala is built and two regasification terminals (Panama and El Salvador).	The pipeline to Guatemala is built and two regasification terminals (Panama and El Salvador).
Medium-term		Terminals are also constructed in Honduras and Costa Rica	The pipeline is extended through El Salvador to Honduras.
Long-term		A fifth terminal is built in Nicaragua and the existing terminals in El Salvador, Honduras and Panama are expanded to 'large scale regasification terminals'	Pipeline is further extended to Nicaragua and a second regasification terminal is built in Panama. The latter would be a 'large scale' plant. In an even longer timeframe, the pipeline from Mexico could be extended to Panama.

These three shortlisted strategies are illustrated in Figure 49.

Figure 49 Shortlisted strategies

Strategy A: Independent projects in each country

National regasification terminals would be built in the short-term in each country except Guatemala where a gas pipeline will connect the country to Mexico. Gas would be used to generate electricity which would then be transported over the national transmission network or SIEPAC.

Strategy B: Sub-regional integration

Two regasification terminals would be constructed in El Salvador and Panama according to ongoing initiatives. In the longer term, once capacity of the terminals is reached, new terminals would be built at new locations. Energy would be traded in the form of electricity on SIEPAC. Guatemala and Mexico are connected via pipeline.

Strategy C: Integration with Mexico

The northern part of the region is initially only supplied via the regasification terminal in El Salvador, and in the medium-term the pipeline from Mexico to Guatemala. The latter would later be extended to reach El Salvador, Honduras and Nicaragua. The southern part will be supplied by means of regasification terminals in Costa Rica and Panama.

Large-scale regasification terminal | Regasification terminal | Pipeline

Source: EEC study for IDB

These strategies are analysed in the consultants' report under the demand scenarios presented in the previous section. The outcome of their analysis is the cost of delivered electricity. The key conclusions reached are:

- Average prices are higher for Strategy A due to lack of scale in infrastructure and in the gas market
- Under Strategy B, prices are competitive and regionally integrated

- Under Strategy C, competitive prices are integrated to the North American market.

Further details of the implementation requirements of the three strategies are shown in the following three figures: Figure 50, Figure 51 and Figure 52. These summarise each of the strategies identifying the requirements in terms of assets and legal structures needed for their implementation.

Figure 50 Strategy A: implementation requirements

Strategy A: Commercial integration

- the creation of a regional entity that will buy and sell LNG to the power producers in each country. This entity will try to get a long term contract from a liquefaction producer;
- the construction of small size regasification terminal in each of the 6 countries
- electricity generation in each country

Assets required	- 1 regasification plant in each country with a storage facility of 75.000 m3 of LNG and send-out capacity of 5 Mm3/day. - Panama will require 150.000 m3 storage capacity and 5 Mm3/day in the first 10 years. - Combine Cycle Power Plants in each country. Around 6000 MW in the region. - Increase in the regional transmission network
Legal structure	- A regional organisation procuring the LNG and the contracting of ships to transport LNG. - A regasification capacity contract - SPA agreement between the regional organization and the LNG provider. - Contract between the power producers of each country and the regional organization to provide gas - Contract between the distribution companies and power producers in each country. PPA agreements - A regulatory system that allows the regulatory body to bid the PPA agreements.

Figure 51 Strategy B: implementation requirements

Strategy B: Sub-regional integration

- the construction of 1 or 2 regasification terminal in Panama and El Salvador that will buy LNG in the short and medium term LNG markets
- the construction of a pipeline from Mexico to supply gas to the northern part of the region;
- the production of electricity in Guatemala, El Salvador and Panama

	Southern Hub:	Northern Hubs:
Assets required	- Regional LNG terminal in PA: 150.000 m3 of LNG storage and send-out ratio of 10.Mm3/day - procuring natural gas for PA and selling electricity to CR during its drought season - Power plants in PA, 2000 MW - Increase in the regional transmission network	1) Regional pipeline MX-GU: 36 inches width, approx. 700 km extension. 2) LNG terminal in ES: 75.000 m3 of LNG storage and 5 Mm3/day of send-out ratio. - Power plants in GU and ES, 3000 MW. - Increase in the regional transmission network
Legal structure	- SPA agreement between the PA operator and LNG producer. - A regasification capacity contract - Contract between the power producers of PA and the local LNG terminal - Contract between the distribution companies of PA and CR with the power producers of Panamá. PPA agreements - A regulatory system that allows the regulatory body to bid the PPA agreements.	1) A natural gas procurement contract between MX and the power producers 1) A transportation capacity contract between power producers and pipeline operator (or between the operator and Pemex) 1) PPA agreements between the power producers of GU and the distribution companies in HO, NI. 2) A regulatory system that allows the regulatory body to bid the PPA agreements. 2) LNG El Salvador: same as southern Hub

Figure 52 Strategy C: implementation requirements

Strategy C: Electricity supply from Mexico - the construction of a transmission line from the south of MX to PA - the production of electricity in MX.	
Assets required	- An increase in the regional transmission network from MX to PA. This strategy will required the construction of four lines of 400 KW with a final extension of 1800 km each. - Power plants in MX, 6000 MW.
Legal structure	- Contract between the local distribution companies and the regional electricity market - A contract from the regional electricity market and the power producers in México.

In subsequent discussion, the IDB consultant team has suggested that strategy C may not be considered further and the focus should be on strategies A and B.

A3.2 LNG Regasification capital costs

The capital costs applied in our analysis are based on a cross sectional analysis of past regasification projects. The capital costs of onshore terminals, their capacity and the location are listed in the table below. It is important to note that the listed projects have been commissioned over the period 2008 to 2014, hence price differentials across projects might not be fully attributable to size, but also to steel price developments. In light of a lack of reliable and extensive data for 2014, we have opted to broaden the time horizon of our analysis.

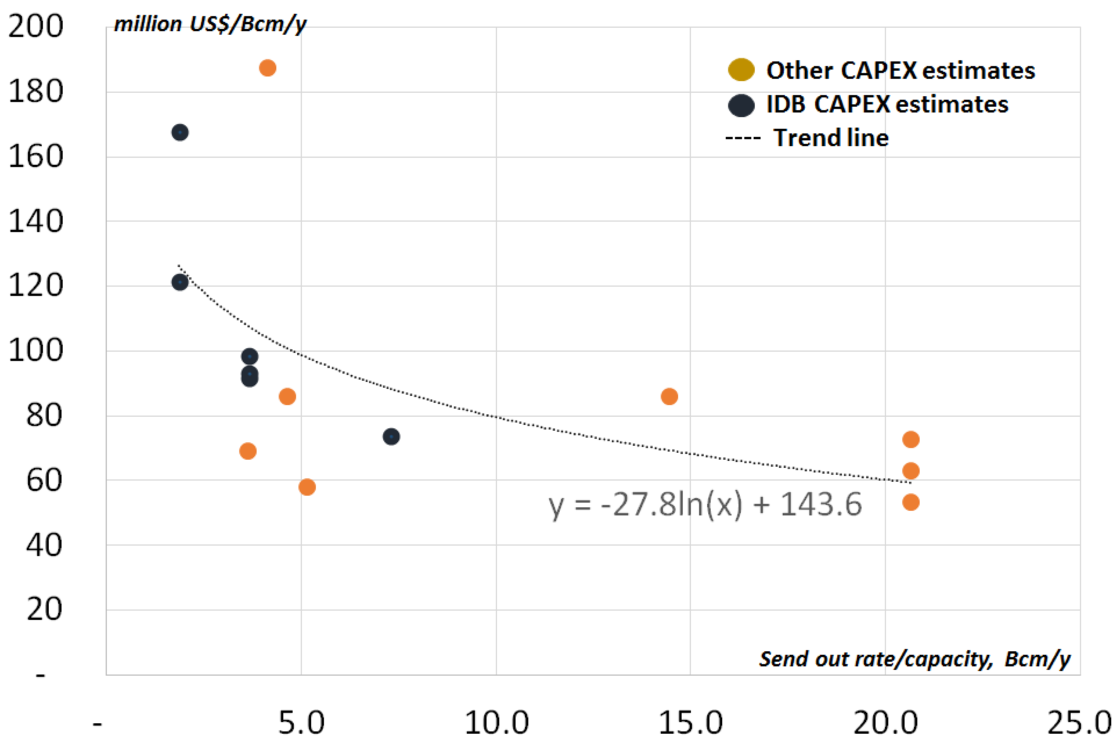
Table 37 Onshore terminal costs

Country	Capacity	CAPEX	Per unit CAPEX
	Bcm/y	*US$ million*	*US$ million/Bcm/y*
General	5.2	300	58
Lebanon	4.6	400	86
United States	20.7	1100	53
Wales	20.7	1300	63
China	3.6	250	69
Chile	4.1	775	188
Netherlands	14.5	1244	86
General	20.7	1500	73
Central America	1.9	226	121
Central America	1.9	312	168
Central America	3.7	335	92
Central America	3.7	340	93
Central America	3.7	360	99
Central America	7.3	540	74

Source: Various LNG feasibility studies, Wartsila presentation by Gerald Humphreys CBI, IDB LNG feasibility study

The correlation of capacity and per unit CAPEX is shown in Figure 53. The spread around the line of bets fit is quite significant suggesting that the true CAPEX of regasification are difficult to estimate on the basis of capacity only. A number of other external factors (e.g. type of onshore facility, storage size, topographical conditions, and maritime conditions) will also influence CAPEX. For the prupose of this analysis, the cross section below is sufficient.

Figure 53 Onshore CAPEX vs. Capacity



The table below shows CAPEX, capacity and location for offshore terminals. Figure 54 shows the correlation graphically. Note that these costs only include CAPEX and not the annual leasing costs of FSRU's.

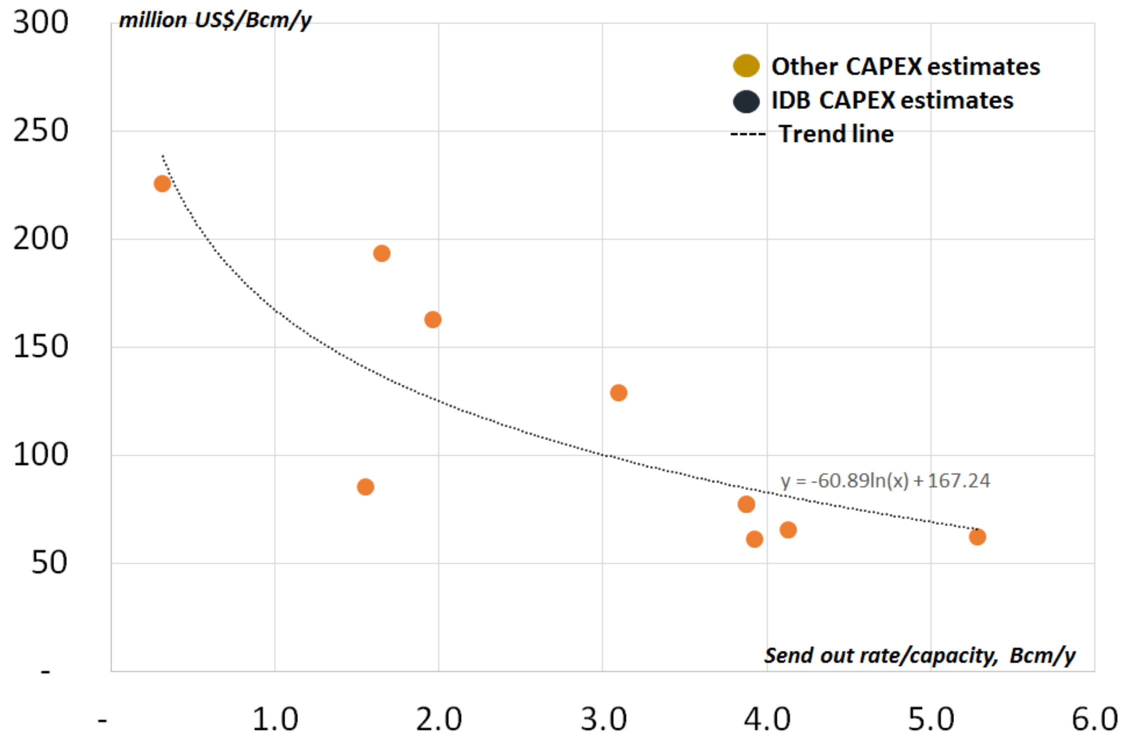
Table 38 Onshore terminal costs

Country	Capacity	CAPEX	Per unit CAPEX
	Bcm/y	*US$ million*	*US$ million/Bcm/y*
Curacao	1.5	132	85
Jamaica	1.7	320	194
Jamaica	2.0	320	163
Lebanon	3.9	240	61
Indonesia	3.9	300	77
Lithuania	5.3	330	62
Chile	3.9	300	77
Caribbean general	0.3	70	226
Colombia	3.1	400	129

Country	Capacity	CAPEX	Per unit CAPEX
	Bcm/y	*US$ million*	*US$ million/Bcm/y*
Ghana	4.1	270	65

Note: Apart from 'Caribbean general' all terminals assumed fixed berth and mooring facilities as assume din the Report
Source: Various LNG feasibility studies, Hoegh LNG corporate presentation

Figure 54 FSRU CAPEX vs. Capacity

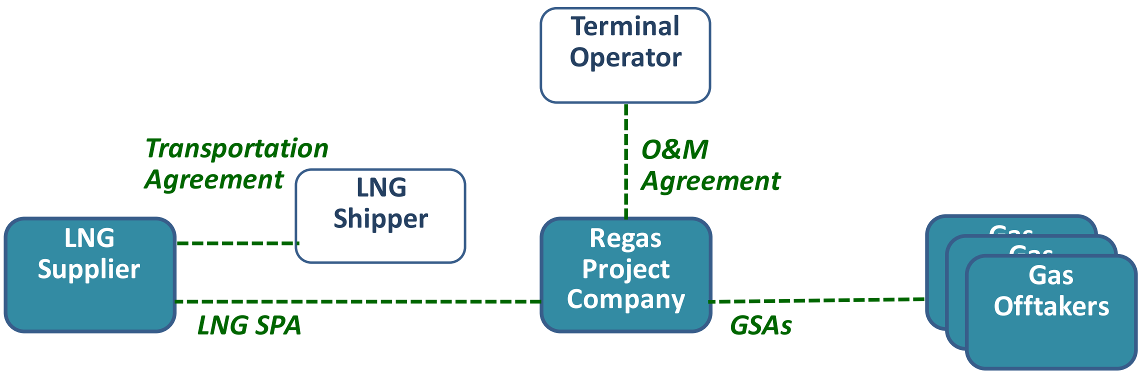


A4 LNG business models

Merchant model – unbundled value chain

In the first example we show the value chain with three significant independent parties; the LNG supplier, the regas terminal and the gas offtaker (there could be several gas offtakers as shown below, either in the same country or for supply to neighbouring countries). In this merchant approach case, the LNG terminal project company (Regas project company) is the merchant gas supplier, contracting to buy the LNG and selling gas to one or more gas offtakers.

Figure 55 Contractual arrangements for LNG - merchant model



This model can expose the project company to significant risks, of two major kinds:

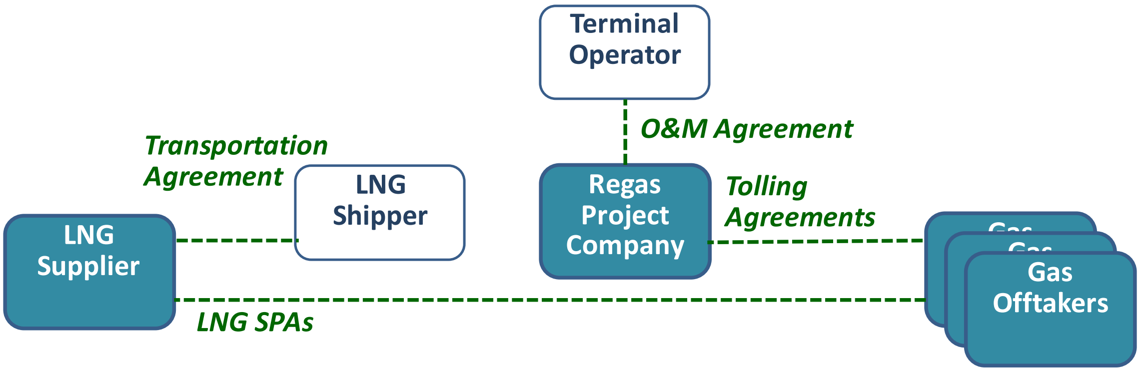
- The coordination of the LNG procurement with the gas offtakes
- The uncertainty of the capacity and volume needed to match the medium term build-up of demands, given that these are new markets starting from zero and with uncertainty over the forecasts of future volume increases

The risks are likely to be significantly greater with multiple gas offtakers, than with a single offtaker. Although the short term coordination role is mitigated by having adequate LNG storage volume, the medium and long risks are substantial in both volume and price uncertainty. In general, the risks in this model might be too high to be taken by a private company on its own; which suggests it might need to be implemented by a publicly owned company or a PPP arrangement where the public sector under-writes some of the offtake and coordination risks.

Tolling arrangement

Under a ***tolling arrangement***, the final user of the gas (eg power utilities) or a gas trader will be the signatory of the SPA. The terminal entity is then simply a provider of regasification services, which receives a fee covering operation expenses, debt service, taxes and shareholder returns.

Figure 56 Tolling arrangement



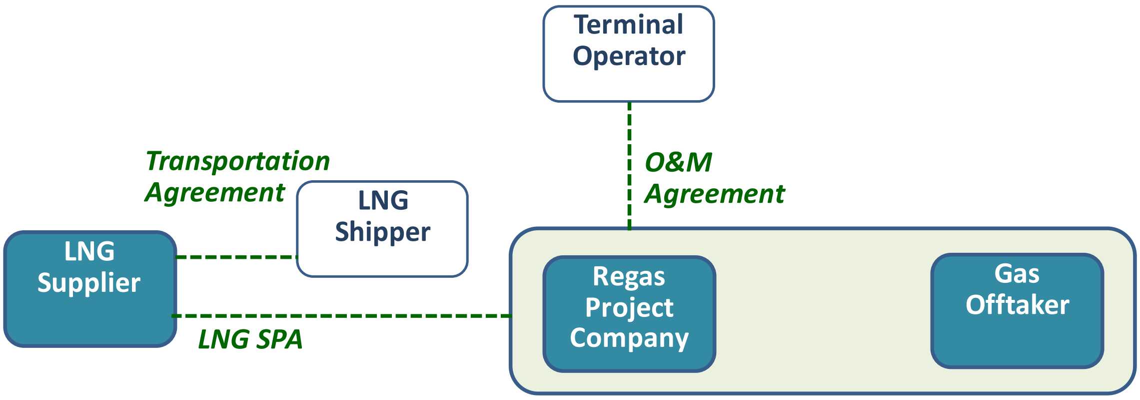
In this arrangement, the risks for the project company are substantially reduced, as it is not exposed to the price risks of either LNG or gas. It does, however, have a significant volume risk on the utilisation of the terminal, unless the tolling arrangement covers sufficient capacity on firm payments to fully underpin the terminal financing.

In this model, the gas offtaker must be financially strong, as it is directly guaranteeing the long term contracts with both the project company and the LNG supplier.In both this case and the previous one, there are three parties in the gas supply chain, implying both complexity and significant contract risks in the structure.

Partial vertical integration

However it is not necessarily the ***downstream*** user of gas that is the tolling contractee, but instead can be the ***upstream*** LNG supplier. The liquefaction operator or upstream producer might want to be responsible for the marketing of the regasified gas and would therefore pay the regasification terminal company a fee for converting LNG to gas. In many international cases, the tolling arrangement is the most commonly used commercial structure, unless downstream vertical integration exists (***integrated value chain***) where the terminal entity, gas network operator and electricity utility are the same (often public) entities. This case is illustrated in Figure 29.

Figure 57 Vertical integration (downstream)

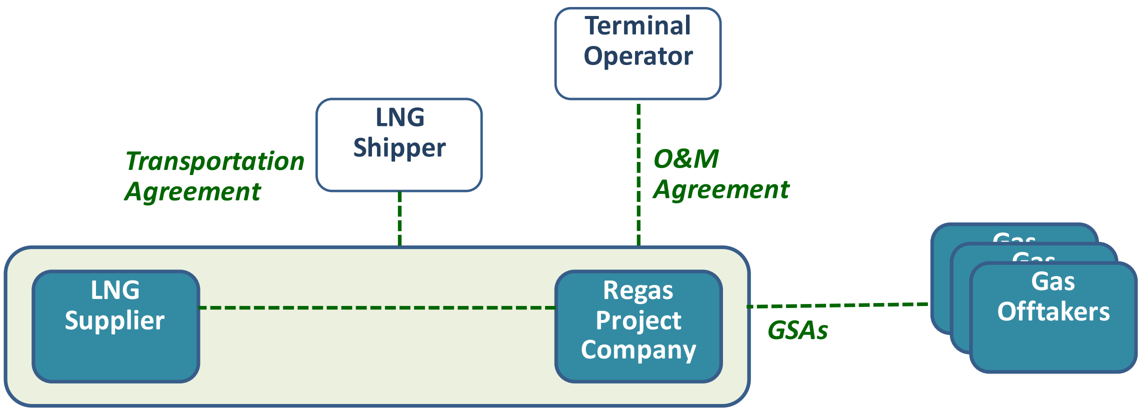


The above case illustrates an arrangement in which market volume and coordination risks (but not credit risks) are substantially removed from the LNG supplier, thus facilitating LNG procurement. In this case and the following one, the integration between the regas project company and one of the other parties suggests that third party access (TPA) would be difficult if not impossible, except on a small scale, say 10%-20%. The latter is possible if the financing of the facility can be guaranteed by a throughput of say 80% of its maximum capacity[128]. In a typical project financing the investor would provide 20-30% of the capital in equity. Provided the investor was prepared to put a significant part of this equity at risk, some capacity could be made available to the market.

Of course, TPA requires not only access to regas capacity but also an independent LNG supply, which is hard to imagine in a system already starting with very small demand. The gas offtaker would be a power plant and their generation would also need to be contracted through long term PPAs. The same arrangement could apply to the power offtakes: the financing could be guaranteed by long term PPAs covering say 80% of the capacity and the remaining 20% could be offered on a merchant basis to the market.

There are cases in the market where upstream LNG producers are looking to secure markets and show interest in investing in LNG terminals, for example some of the Middle East producers. This could lead to an upstream integration model as shown in Figure 58, in which the LNG supplier is assuming the gas offtake risks through also owning the regas terminal.

Figure 58 Vertical integration (midstream)



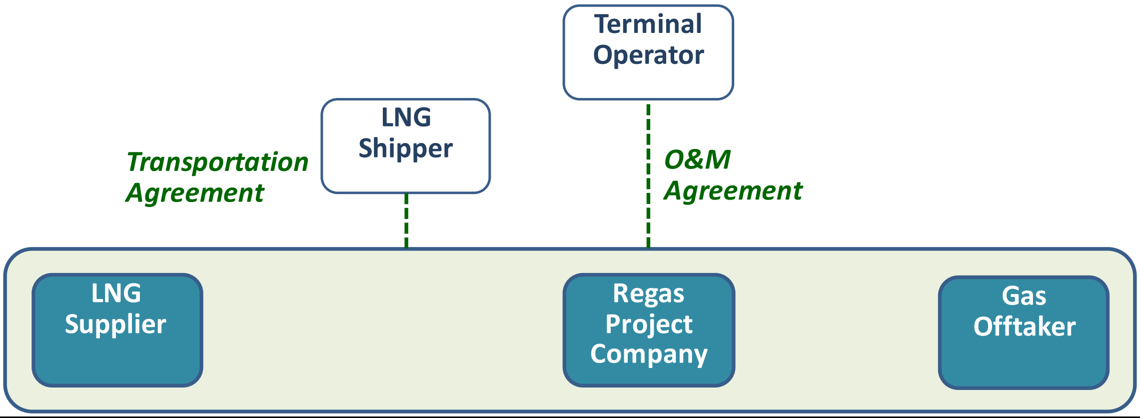
Full vertical integration

There is beginning to be a trend in the industry where some of the (financially strong) upstream LNG (and gas) producers are looking at ways to increase the monetisation of their resources by moving downstream in the value chain. While this is likely to be less attractive as a proposition in the small markets in CA, this model should not necessarily be dismissed outright. The same is the case for the more fully integrated model shown in Figure 59 which could come under consideration, especially in a PPP

[128] This was the case, for example, with one of the bidders for the El Salvador integrated LNG and power project in 2011

structure in which the government assumes or provides certain performance guarantees for a substantial part of the non-technical (especially volume) risk.

Figure 59 Integration across the gas value chain



A5 Annex to Costa Rica case study – ICE generation plan

A6 Application to Costa Rica

The principal objective of this case study is to assess the economic case, business model options and financing risk for a new LNG terminal in Costa Rica supplying a gas to power plant. The case study complements the main Report by applying the concepts and methods outlined in the main Report to one country. This allows to focus the analysis on country specific issues. In Costa Rica's case this is in particular to investigate the impact on the economic and financial viability of such a scheme if the proposed PH Diquís hydropower plant is developed.

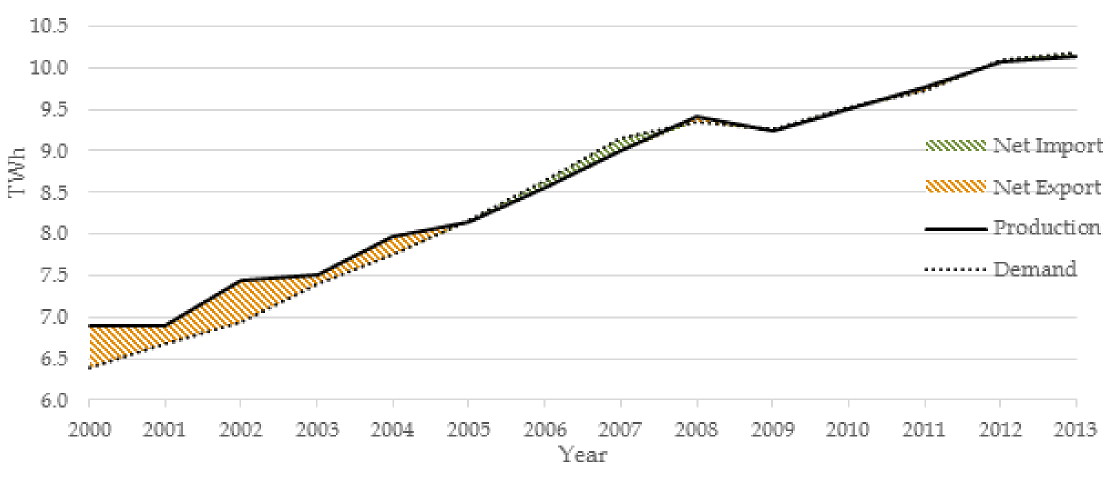
Unlike the results in the main report, where we rely on gas demand estimates form the IDB study, we assess in this case study, possible load factors of power generation plants on the basis of a dispatch model.

A6.1 Background

A6.1.1 Supply-demand situation in Costa Rica

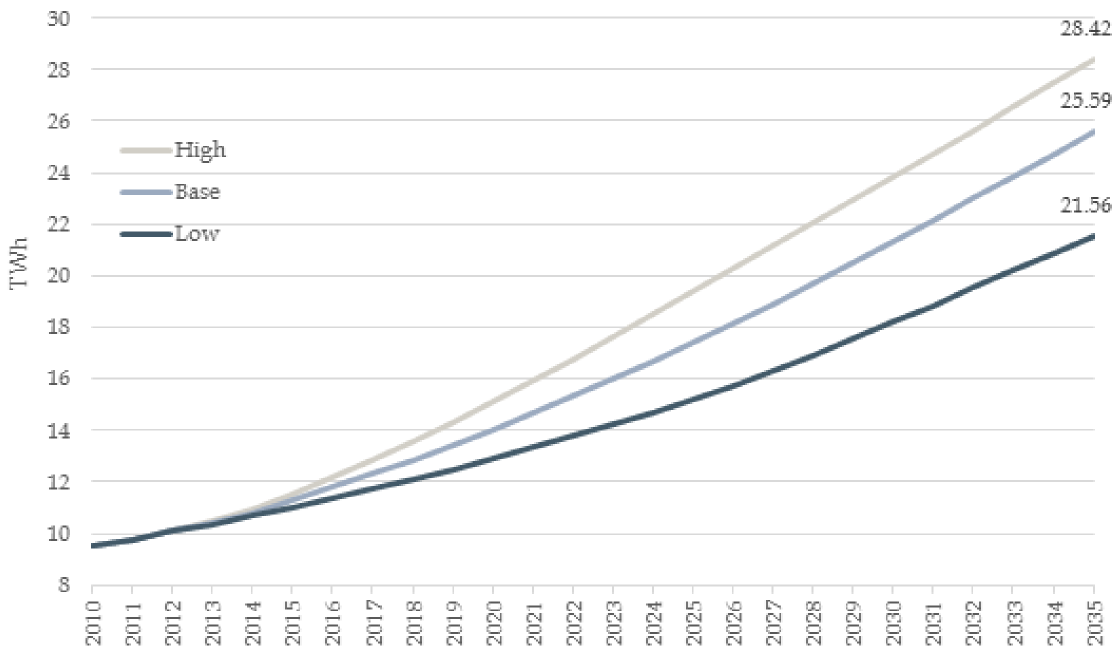
Figure 60 below shows the historic growth of supply and demand of electricity in Costa Rica. As is evident, net exports have decreased since 2000 as the country's demand has increased. As of 2013, domestic power generation matches demand.

Figure 60 Demand and supply of electricity in Costa Rica



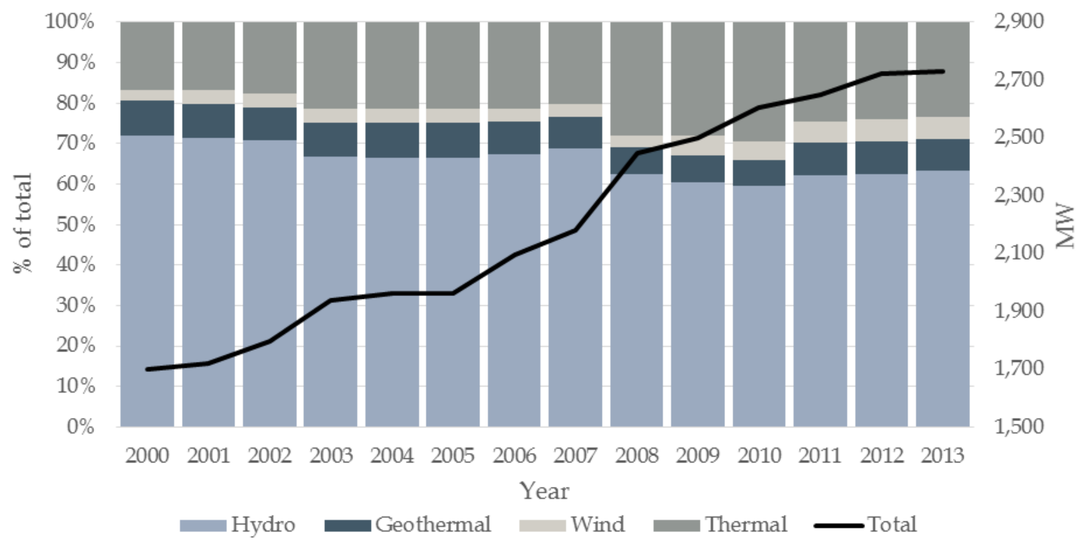
The Costa Rican Institute of Electricity's (ICE) official generation expansion plan provides three demand growth scenarios: high, base and low. In the base scenario, ICE expects Costa Rica's demand for electricity to increase by over 250% from just over 10,000 to 25,590 GWh by 2035. These growth scenarios are illustrated in Figure 61 below.

Figure 61 Costa Rica electricity demand projections



The main source of electricity generation in Costa Rica is hydro. Hydro accounts for 66% of installed capacity and produced 67% of electricity supply in 2013. It is used for base load generation together with geothermal and wind power. Geothermal accounted for 15% of energy production in 2013 and wind only 5% as can be seen from Figure 62.

Figure 62 Installed capacity by fuel source in Costa Rica 2000 - 2013



Most significant is the increasing reliance on thermal generation. This is currently exclusively met by expensive oil derivatives, which are usually restricted to very low load peaking plants in countries with developed power systems. This increasing reliance on oil-fired generation with an expectation of substantial future demand growth is the key rationale for seeking to introduce gas, via LNG, into the power system.

A6.1.2 Characteristics of the proposed LNG terminal

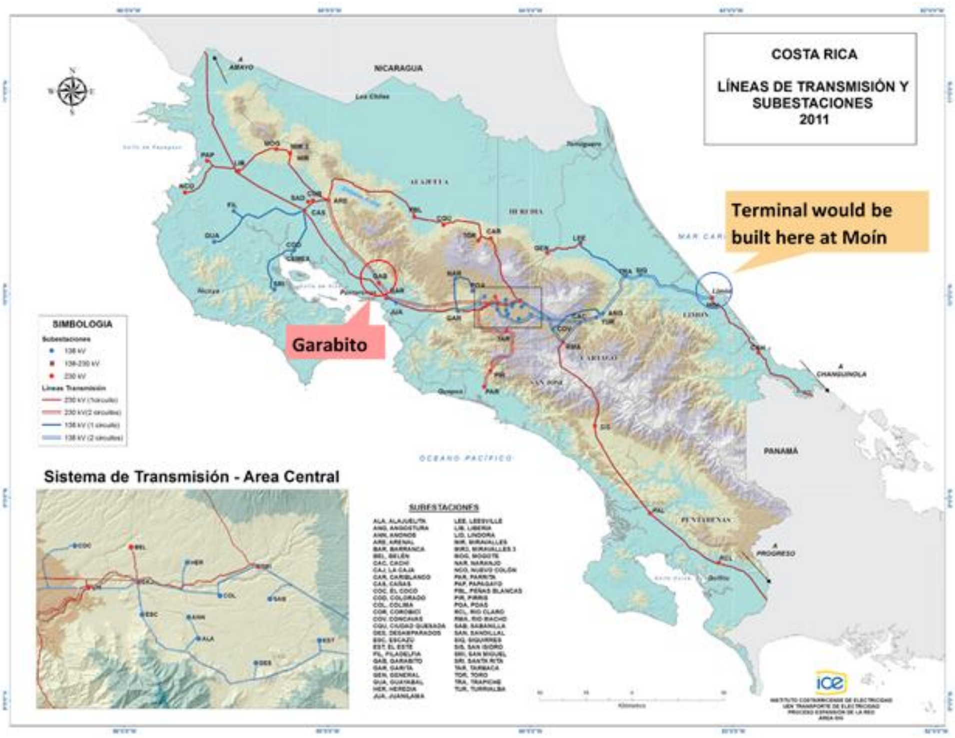
Because of the low and variable amount of thermal generation used in Costa Rica the potential of having sufficient demand to warrant a permanent land-based LNG regasification plant is low. As described in the main Report a floating storage and regasification unit (FSRU) is likely to be a better suited option for supplying LNG to Costa Rica.

Previous studies by the Government of Costa Rica have identified Port of Moín as the best location for an LNG terminal. This is due to several factors:

- There is an existing diesel generation plant which is planned to be upgraded to combined cycle. The proximity of the plant means that there would be minimal capital expenditure required for pipelines and new transmission. This generator would be converted to natural gas if the project was to go ahead.
- There is sufficient space at the port for the installation of an FSRU.
- The RECOPE refinery at the port is considered a potential non-generation source for gas demand.

Another site that has been considered is the previously mentioned Garabito plant near the Pacific coast. This location however, would need considerable investments in pipelines as well as conversion costs. The two locations are shown on the following map of the Costa Rica transmission system.

Figure 63 Costa Rica transmission lines and proposed locations for LNG terminal



A6.1.3 Previous studies

Three key studies have been considered for this case study:

- Perspectiva sobre el uso potencial del gas natural en Costa Rica Estudio SNC Lavalin, 2010

- *Actualización de la estrategia de introducción del gas natural en Centroamérica*. BID

- *ICE evaluacion del uso del gas en la generacion termica*, 2012 ICE

The three studies provide the following key insights:

- Unlike the other cases, Lavalin's study includes a large amount of non-generation LNG demand coming from the transport and industrial sectors. This kind of demand would only be achievable if there was industry wide uptake in the use of natural gas as a fuel source in vehicles which we consider a very low probability scenario. The focus of this case study will therefore be on the reol of gas in the power generation mix.

- The LNG scenario in the ICE study involved commissioning 900 MW of gas powered generation in three separate installations. In this sense the study compares separate expansion plan scenarios as opposed to comparing methods of introducing LNG into Costa Rica.

- The consensus across all studies is that the port of Moín is the best location for an LNG terminal in Costa Rica and that the supply would come from the United States due to the proliferation of shale gas.

Considering the main results of the studies above, the following questions have not been assessed and are addressed in this case study:

- What is the feasibility of commissioning **one** gas fired plant in order to establish demand for LNG in Costa Rica?

- Is the project still profitable if PH Diquís is commissioned?

- What are the price points for both LNG and electricity that would make a gas project feasible with and without PH Diquís?

- What is the business model that would be used in order to bring LNG into the country?

A6.2 Approach and scenarios

The key issue when considering Costa Rica's generation expansion plan is whether or not the proposed 623 MW hydro plant 'PH Diquís' will be commissioned. This plant, if introduced in 2025 would be the largest generation plant in the country and has the potential to greatly affect the load factors of marginal thermal generation including gas fired power generation.

Therefore when choosing our scenarios it is important to model the effects of the introduction of PH Diquís to the generation mix as it has the potential to make the LNG project unviable. The two generation expansion scenarios modelled are:

- ***Scenario 1 (with Diquis)***: 300 MW power plant and associated LNG terminal commissioned in 2022 with PH Diquís commissioned in 2025

- ***Scenario 2 (no Diquis):*** 600 MW power plant and associated LNG terminal commissioned in 2022 without the commissioning of PH Diquís.

All other minor generation projects have been left equal in both scenarios. There is some potential for LNG use outside of the power generation market, especially with the possibility of demand from the RECOPE refinery near Moín. However, due to the small size of this source of demand we have not included it in our analysis. Instead, our analysis is focussed on the commissioning/conversion of a single gas powered plant (CC Moín).

The two scenarios are assessed against three electricity demand scenarios (Low, Base and High) from the 2014 ICE generation expansion plan given in Figure 61. We apply for each scenario the economic and financial netback approach described in the Section 4 of the Report to assess financial and economic viability of the regasification and power plant project.

A6.2.1 Input data

Input data came from several sources. Future installed capacity data is from ICE's official expansion plan document *'Plan de expansion de la generacion electrica periodo 2014-2035'* April 2014 and is repeated in Annex A4. All cost data and price assumptions are taken from Section 4 of the Report and repeated here in summarised form. Note however that we assume a higher margin along the LNG value chain, resulting in a total cost of delivered gas for the power generation plant of 12.73 US$/mmbtu.

Table 39 Input cost data for LNG project

Cost item	Value	Unit	Source
Opex			
CCGT variable	3.67	USD/MWh/year	*ECA analysis*
CCGT fixed	6.31	USD/kW/year	*2012 B&Veatch report*
FSRU	Capex * 1% + 45m (leasing)	USD/year	*ECA & Hoegh*
Capex			
CCGT	1,230	USD/kW/year	*2012 B&Veatch report*
FSRU	167.2 – 60.9*LN(cap. in bcm)	USD/bcm/year	*ECA cross sectional analysis*

Table 40 Price and cost data for LNG project

Cost item	Value	Growth	Source
Henry Hub price	4.39	1.2%	*Average HH price in Sep 2014*
US gas transmission	1.50	0.5%	*Based on 5 20-year contracts for LNG supply*
Liquefaction	3.00	0.5%	*ECA assumption*
Margin	2.50	0.0%	*ECA assumption*
Transmission in LAC	1.00	0.5%	*ECA assumption*
Transportation to Moín	0.34	0.5%	*IDB-Puerto Moín*

Cost item	Value	Growth	Source
Total (USD/mmbtu)	**12.73**		

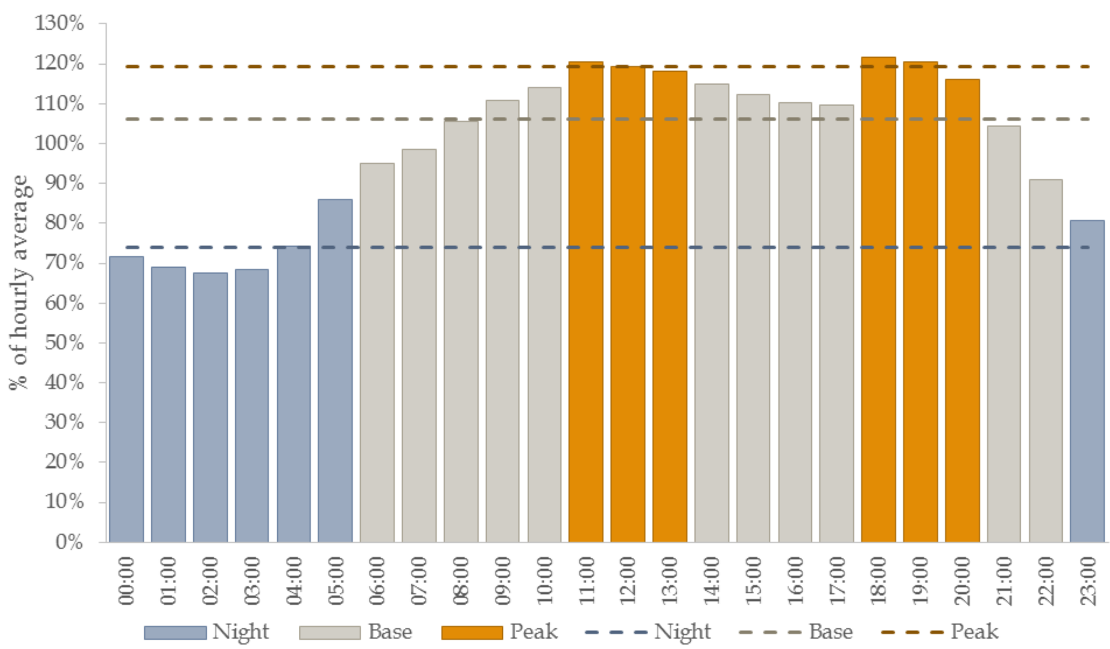
To assess the load factors of operation of the gas fired power plants we apply data published by ICE. Assumptions on the seasonality of wind and hydro effects and their respective capacity availabilities have been derived from the ICE GEP report, with sanity checks on dispatch and merit order effects made against a sample of daily dispatch data from the year ending 31 October 2014 downloaded from 'Posdespacho Nacional'[129].

A6.2.2 Modelling

The case study uses scenario analysis based on the potential development of the LNG regasification unit serving a gas-to-power plant, with and without the proposed PH Diquís hydropower plant. The results are then reviewed in the following sections to judge the financial risk associated with the investment and suitable commercial structures and business models. Our modelling approach contains the following steps:

- ***Step 1: Model shape of a daily demand curve*** on the basis of a historic sample of dispatch data by generator. This was done by randomly selecting 3 days spread across each month of the year ending 31 October 2014. From this information we obtained an average daily demand curve as shown in Figure 64 below. Demand was broken down into three separate blocks representing base, overnight, and peak demand. The hourly average demand from each of these blocks was then projected forwards using the three electricity demand scenarios.

Figure 64 Assumed daily demand profile



Source: profile based on a review of sample days from historical dispatch data

129 https://appcenter.grupoice.com/CenceWeb/CenceMain.jsf

- *Step 2: Break down yearly demand into four main season*. We broke up the year into four distinct seasons as shown below. Breaking up the data into seasons enables us to use observed seasonal load factors as provided in the ICE GEP report as a proxy for seasonal plant availability.

	Wet	Dry
Windy	December	January – April
Still	June – November	May

- *Step 3: Model electricity dispatch*. Using the hourly and seasonal demand figures, we assume a merit order (across all assumed power plants) to create a simplified dispatch model multiplying blocks by number of hours and seasons by number of days. This was calculated for both expansion plan scenarios as well as all three demand scenarios.

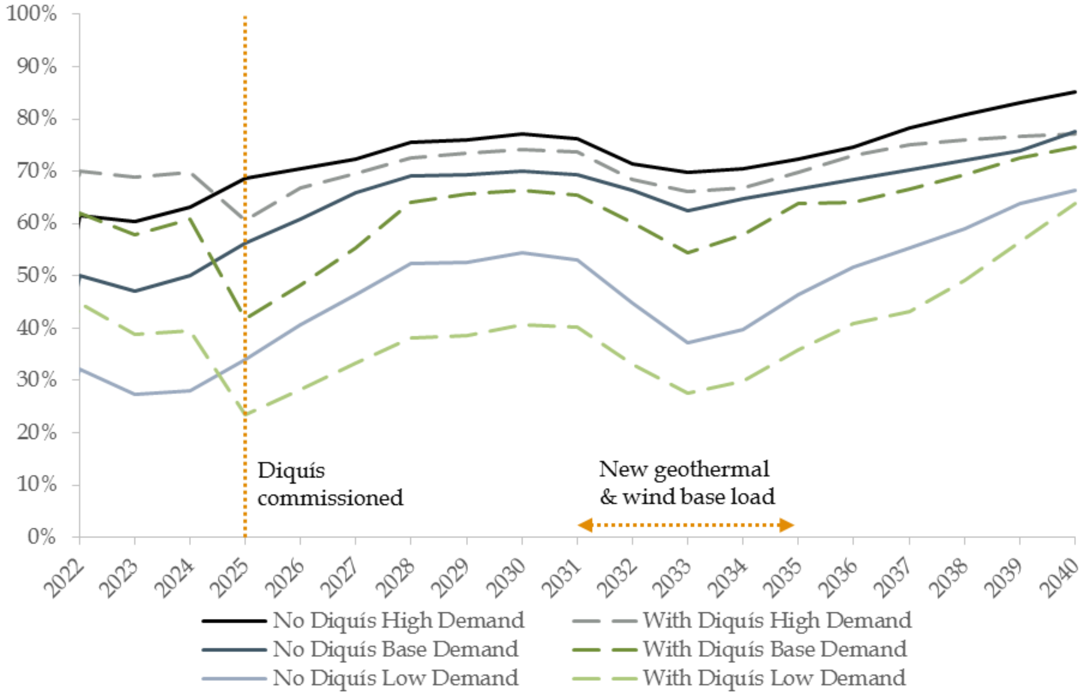
- *Step 4: Calculate electricity output and multiply with netback values*. Once we establish the utilisation of gas fired power plants, we multiply the load factors with the capacity and maximum yearly hours to obtain annual power generation outputs. These are then multiplied with the netback values (see main Report) to obtain economic and financial indicators.

The final output of the approach is a net present value, in 2014 US$, of developing an LNG regasification terminal as well as the gas fired power generation. Note however that we model here gas fired power generation explicitly. Something we did not do in the economic and financial analyses in the main report.

A6.3 Economic and Financial analysis

Figure 65 below shows the load factors across our six scenarios: High, medium and low electricity demand for a scenario with a power plant of 300 MW and commissioning of Diquis (Scenario 1: With Diquis) and a scenario with a power plant of 600 MW and no commissioning of Diquis (Scenario 2: No Diquis). The results show that load factors of the CCGT plants drop significantly for the scenario with Diquis from 2025 onwards and then remain consistently below Scenario 2. The initial higher load factors of Scenario 1 compared to Scenario 2 are due to the difference in capacity of the included CCGT plants between the two scenarios.

Figure 65 Annual average load factors for gas plant supplied from LNG



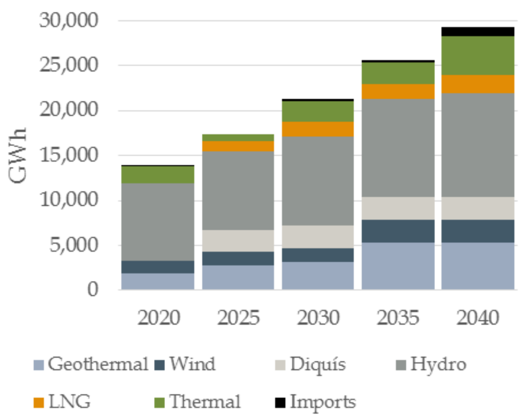
Interestingly, the high and increasing load factors over the period 2025 to 2030 suggest the need for thermal power generation to meet electricity demand. As new geothermal and wind generation comes on stream, load factors drop marginally, before picking up again, as electricity demand increases. This suggests that the CCGT plant would significantly contribute to security of supply in Costa Rica.

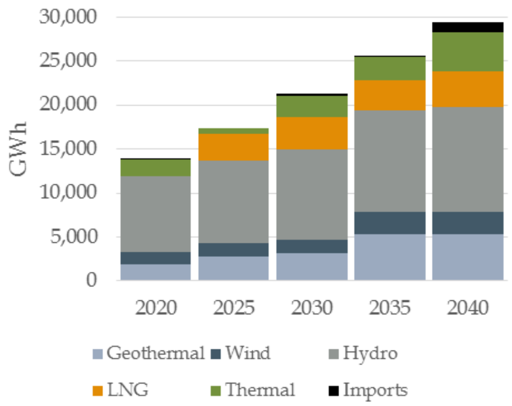
Figure 66 illustrates the projected power generation mix for a base demand scenario for Scenario 1 and 2. For scenario 1, the lower capacity means notable additional thermal generation (and/or imports) beyond that supplied by the gas plant remains required from the year of commissioning in 2022. From 2025 with the introduction of PH Diquís, the CCGT plant is pushed again to temporarily operate more frequently at the margin resulting in the drop in load factor seen above.

Figure 66 Generation mix under Base Demand Scenario

Scenario 1: with Diquís

Scenario 2: No Diquís





The results of the economic and financial analysis (for a detailed discussion of the difference of these analyses, please see Section 4 in main report) are shown in Table 41. The figures are calculated over a time horizon of 18 years from 2022 to 2040.

The results confirm the high level results from section 4 in the Report. Financially, an LNG terminal and a gas fired power plant is not feasible in Costa Rica. NPV's are negative and IRR's never become positive across all electricity demand scenarios. Economically however LNG and a gas fired power plant is beneficial in Costa Rica with the exception of the low electricity demand case and a scenario where Diquis is developed.

Table 41 Economic and Financial results

		IRR (%)				NPV (million US$)			
		Financial		Economic		Financial		Economic	
		No Diquís	With Diquís	No Diquís	With Diquís	No Diquís	With Diquís	No Diquís	With Diquís
	Base	-15%	NA	87%	91%	-311	-239	1,453	618
Demand	Low	NA	NA	43%	37%	-388	-283	828	257
	High	-9%	NA	136%	137%	-273	-218	1,753	790

A6.4 Business models and financing

A6.4.1 Economic and financial case for an LNG terminal in Costa Rica

Attractiveness of investment

The range of results provided in Section A6.3 highlight the uncertainty regarding the financial case for investing in an LNG terminal for a gas-to-power project in Costa Rica. The principal constraint is the cost reflectiveness of the electricity tariff, compared to the economic value a gas-to-power plant may deliver the Costa Rican economy. Under the financial case, none of the demand or supply scenario combinations deliver a sufficient return to attract investment, with the calculations estimating these will be loss-making even before considering financing costs (IRR < 0).

However, due to the potential for significant savings through the reduced use of oil derivatives in power generation, running the calculations based on the full economic value of power supply (i.e. the cost of oil-fired generation to be displaced by gas) indicates much higher estimated IRRs. These show that an LNG and associated gas-to-power plant provide an attractive economic return under all cases.

None of these calculations attributes any additional credit for the added security of supply such a plant may bring. In fully developed electricity markets security of supply credit would typically manifest either through scarcity pricing in the energy market up to the value of lost load or via a separate capacity mechanism. The economic value results presented here may therefore be considered conservative with respect to the full benefits. This would therefore make an even stronger case, from an economic viewpoint, of introducing LNG and gas into the power mix.

Therefore, the results derived from this investigation suggest that an FRSU LNG terminal serving a 600 MW gas-to-power plant in Costa Rica **is economically viable** should the PH Diquís hydro development not proceed, and will likely remain viable for a 300 MW plant even if the PH Diquís hydro plant is developed. However under our base cost and price input assumptions, the project **is not financially viable** under either scenario due to the low electricity tariff.

There are a number of options to bridge this finaciability gap. These include:

- Raising the electricity tariff to enable an adequate return
- Negotiating a lower LNG price than assumed within our model
- A combination of the above
- Cross-subsiding by ICE from cheaper generation forms with a smaller price increase based on regulatory cost estimates
- Some form of Viability Gap Financing (VGF) which provides the missing revenue stream from other sources (likely via taxation)

Electricity tariff and LNG prices needed to attract private investors

In order to estimate the magnitude of any increase in electricity tariff, or decrease in LNG price, which must be achieved to make the project financeable, we have performed a sensitivity check on the results provided in Section A6.3. These show that:

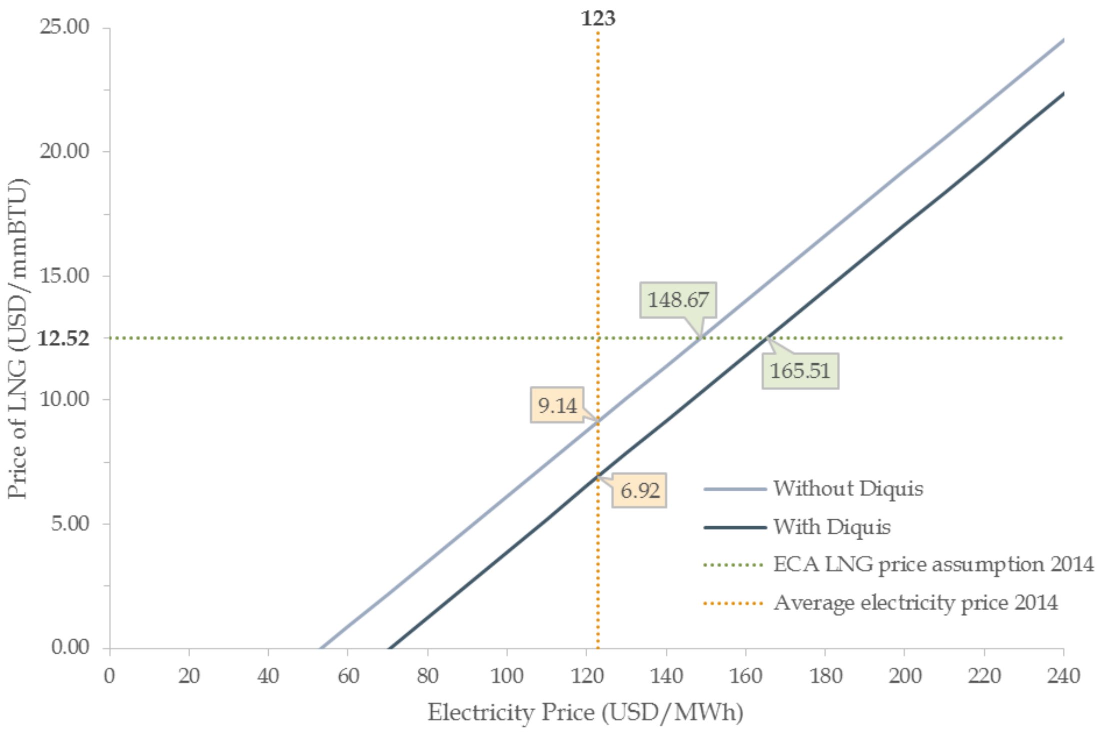
- To achieve a hurdle rate of 10% IRR, under the base case demand scenario with the 600 MW gas plant and no PH Diquís development, the estimated required tariff is US$149/MWh (holding the LNG price constant). This would represent an increase of close to 20% from current prices.
- Under the same scenario, to achieve the same hurdle rate of 10%, holding the electricity tariff constant and changing only the LNG price, LNG imports are estimated to need to be secured at no higher than $US9.14/mmbtu.

These estimates represent the extreme solutions whereas a combination of the two approaches can be used to reach the target hurdle rate. For example, if LNG can be imported at US$11/mmbtu, then the tariff required for an IRR hurdle rate of 10% to be achieved is estimated at approximately US$137/MWh.

Figure 67 shows the LNG price and electricity changes needed to ensure a 10% IRR hurdle rate, which would attract private investors to the project.

Should adjustment to the electricity tariff reform and/or negotiation of the LNG price be insufficient to reach the hurdle rate required, then some form of financial support which is exogenous to the specific project will be required. The regulation of ICE's electricity tariffs in Costa Rica already implicitly require cross-subsidisation between generation forms as they are derived from the estimated weighted average cost of generation. This would allow the added rent from cheaper generation forms (primarily hydropower) to cross-subsidise the gas plant and thereby allow for a more marginal increase in electricity tariffs. The project could then either be financed via general corporate debt directly by ICE, or under a PPA between the project owner(s) and ICE. The viability of the former course of action is dependent on ICE's ability to raise additional debt, while the latter would require clear cost pass-through provisions into the calculation of the electricity tariff to protect ICE's exposure.

Figure 67 Trade-off of LNG and electricity price requirements for an IRR of 10%



A6.4.2 Commercial structure, contractual arrangements and risk assessment

The previous section has demonstrated that under cost reflective conditions, a project consisting of an LNG regasification facility serving a gas-to-power plant in Costa Rica, is economically viable. However, the assumed hurdle rate of 10% included in the above calculations only considers systemic risk, based on the country and industrial sector in question (i.e. energy firms and utilities). It does not consider atypical risks specific to the project at hand. Should project risk be substantially higher than the norm due to the particular conditions faced by a potential investor, then either the hurdle rate may increase substantially or the project may simply be deemed un-financiable. There should therefore be a focus on ensuring the controllable project characteristics are designed in a manner which minimises avoidable project risk.

A primary source of relevant risks are derived from the commercial structure and contractual arrangements in place for the project. In order to best assess these it is revealing to step along the LNG value chain in reverse, starting from end consumption highlighting where key risks lie.

Credit risk

Power generation and distribution in Costa Rica is dominated by the state-owned vertically-integrated utility, ICE which acts as a single buyer in the market. As seen in the inputs to this Case Study in Section A6.3, the current tariff is based on the average cost of generation and thus substantially below the marginal cost of generation from mid-merit and peaking oil plants/imports. Should power generation from oil derivatives be relied upon to meet the increasing demand, the average cost of generation will rise sharply and may become politically untenable to transfer in full to the regulated tariff, placing substantial pressure on ICE and/or government finances.

As the sole buyer, should the power plant have a private owner, ICE will be the counterparty to any Power Purchase Agreement (PPA). The most likely route, however, is the conversion of ICE's existing oil-fired plant at Moin. ICE will therefore themselves be the owner of both generation and distribution and thus vertically-integrated, reducing contractual interfaces and related contractual risk at the PPA staging point. Nevertheless, the main effect of this arrangement would simply be to transpose the issue of financial security upstream along the value chain to the next main contract point – the Gas Sales Agreement (GSA) between the regasification company (if different) and the gas offtaker. Therefore under either approach the credit worthiness of ICE is a key risk variable which will be heavily influenced by their ability (or inability) to demonstrate a secure financial position.

The presence and nature of the GSA will depend on the commercial structure used. Should the regasification unit be operated on a merchant basis, then the entity owning the unit will also act as the purchaser of LNG and seller of gas. If this is a separate entity from the power plant owner, they will therefore be the counterparty in any GSA to the power generator and thereby take on the credit risk of the offtaker (as mentioned above, likely ICE). The sensitivity of the project to such credit risk will be of particular concern for a stand-alone re-gas company supported via a project finance approach.

Should a tolling structure be adopted then the re-gas company is only responsible for operation and storage of the facility (but not ownership and trade of the gas). However, the company will still require a long-term capacity reservation agreement with the offtaker, ICE, and thus be susceptible to their credit risk. Also in this arrangement ICE will directly sign a long-term LNG Supply and Purchase Agreement (SPA) with the LNG supplier, again placing emphasis on their financial credibility. The same will be true should an integrated downstream commercial structure be adopted whereby ICE take ownership of the re-gas facility, power plant and power sales.

Therefore under either the merchant or tolling approach the key criteria for credit worthiness is the financial position of ICE, and the government of Costa Rica should they provide supporting guarantees. ICE generated revenues of US$2.5 billion and an EBITDA of US$ 853 million in the twelve months to June 2014[130], reflecting a reasonably strong regulatory framework and market position.

ICE's credit rating is supported anyhow by its linkage to the sovereign rating of Costa Rica due to its state-owned nature and the implicit and explicit support it receives from the government. Indeed, while the government does not guarantee all ICE's debt obligations, ICE's diversified portfolio and reasonable financial position (due partly to its telecommunications business) mean the entity carries the same credit rating as the sovereign rating with agencies Fitch (BB+) and Moody's (ba1).

These ratings reflect the likelihood of government intervention should the entity hit financial distress due to its strategic importance in the economy. Moody's estimate ICE's endogenous credit rating, i.e. excluding the possibility of supportive intervention, at ba3 on a scale ranging from aaa to c. "Ba.n" is a mid-way rating "judged to have speculative elements … subject to substantial credit risk"[131]. Moody's assess ICE's regulatory framework to be "overall credit supportive and stable albeit subject to some inconsistencies" but the rating is tempered by "weak governance" of the entity and factors in the "modest size of the ICE's operations and service territory" as well as "its reliance on the capital markets to refinance its debt"[132].

The increased leverage through ICE's ongoing debt-financed large capital expenditure program, together with a lag in regulated tariffs to reflect the increasing importance of oil-fuelled generation and imports, are noted risk areas in the coming years.

In summary ICE has the potential to be a reasonably strong offtaker, provided political interference is demonstrated to be minimised and clear processes are enabled to ensure timely tariff adjustments that reflect the costs of thermal generation.

Price risk

Strongly related to credit risk as introduced above is the price risk. We have already discussed the importance of tariff adjustment processes to be reflective of changes to the industry's cost base. Historically these have suffered from political interference but since 2013 tariffs have been adjusted quarterly to reflect fuel costs with proposals in place to include net import costs into the equation. Both these factors will help strengthen the position of ICE and thus lower the credit and price risk they offer. The plant is also reasonably assured of its place in the power dispatch merit order as the alternatives are either clearly cheaper (e.g. hydro) or more expensive (oil) helping lend some degree of predictability to load factors.

Furthermore, gas-fired competition is highly unlikely in the foreseeable future as the only realistic route would be providing third party access to the LNG terminal. Such

[130] https://www.fitchratings.com/creditdesk/press_releases/detail.cfm?pr_id=905614

[131] https://www.moodys.com/sites/products/AboutMoodysRatingsAttachments/MoodysRatingsSymbolsand%20Definitions.pdf

[132] https://www.moodys.com/research/Moodys-downgrades-ICE-ratings-to-Ba1-stable-outlook--PR_308349

access would be harder to enable where the downstream (re-gas facility and power generation) is integrated under ICE, which is the expected commercial structure for the reasons described above. Even under an independent owner, in order to lower financing risk in a new market with fluctuating and uncertain demand, a long-term capacity agreement with a single offtaker will be the preferred option, leaving little room to provide third party access. The higher price and uncompetitive position of any third party off-taker relative to ICE would therefore likely discourage gas-on-gas competition.

However, the use of regulated cost-plus tariffs will inevitably create additional price risk to ICE compared to a situation whereby the full economic rent could be reflected directly in market prices based on marginal cost of generation. This risk increases with increased uncertainty in the LNG price. The quantities of LNG required for this project are low with the purchaser relatively high risk and thus ICE will be a price-taker paying a premium, likely from an LNG aggregator. Forecasts of LNG spot market price indicate in the near to medium-term, substantial new capacity means prolonged upswings are unlikely.

This means that the price risk in Costa Rica is contained. The electricity tariff adjustments signal prices to move in the right direction and a stable regulatory regime; the gas plant can expect to have stable and relatively high load factors (depending on development of Diquis and electricity demand development) and LNG prices are unlikely to rise significantly in the medium term.

Demand risk

The other key power sales related risk is the utilisation of the gas-to-power plant and thus the demand for gas. As seen in the results discussed above, the expected utilisation of the plant will be sensitive to which growth scenario for the demand of power transpires to be closest to reality.

Under a low demand growth scenario the projected IRR is substantially lower and indeed fails to reach our assumed hurdle rate under the case where the PH Diquís hydro plant is also constructed. Furthermore, the average load factors estimated in our modelling disguise sizable changes over the life of the power plant. Under the "no Diquís" scenario, predicted load factors more than double between 2022 and 2040, while with the PH Diquís plant they show a substantial dip in the years immediately following its commissioning before demand growth picks up the slack.

The possibility of low utilisation in early years may delay the commissioning of the plant beyond that which is optimum from a social welfare perspective, particularly if it is to be built under a project financing structure due to the stranded asset risk. One option for government is to provide a revenue smoothing mechanism, offering a minimum revenue in early years in return for payback in later years when the utilisation rises (dependent on it doing so). This form of support should not be necessary under an extension of the cost plus regulatory structure as performed at present for ICE.

Demand risk is particularly problematic for a re-gas company operating on a merchant basis. While some fluctuation may be accommodated by storage, the company must be strong enough to manage the cash flow risk such variable demand entails. Given this is a first-of-its kind venture, reliant on uncertain demand growth expectation, this risk would seem much more manageable either under a tolling or downstream-integrated commercial structure.

Other risks

There are a number of other risk factors which will affect the project including contract risk, construction risk and operational risk. Effective management of these risks will largely be dependent on the project being well-designed and executed in accordance with industry best practice.

Political risk in Costa Rica is low by regional standards with the country having enjoyed much greater stability of governance than its neighbours. Indeed Costa Rica was ranked 7th most politically stable nation in a 2009 index by the Economist Intelligence Unit.

As discussed above, the regulatory regime in Costa Rica is also seen as relatively strong. Nevertheless, LNG will inevitably result in the need to extend or adapt the current regime to cover this new fuel source, while the nature of regulated tariffs, despite recent improvements in cost reflectiveness, will always inherently contain a degree of added regulatory risk.

A6.4.3 Preferred business model

The main risk factors discussed above point strongly towards an integrated downstream business model structure being adopted with ICE as the owner of the re-gas facility supplying their own gas-to-power plant, converted from oil use. This model minimises the contractual interfaces, while low utilisation during early years and managing the required uplift to average tariff prices are more easily borne by ICE within its diverse portfolio than by a stand-alone project owner. Furthermore, the model helps guard against stranded asset risk due to one entity within the value chain being unable to deliver on its commitments in a timely fashion.

However the large capital investment program ICE is pursuing may constrain its ability to raise the required debt to fully finance the regasification project itself on a balance sheet basis. Under these circumstances, the example of the Reventazon Hydro Dam which used a special purpose vehicle (SPV) – the Reventazon Finance Trust – to secure partial funding from private banks and international lending agencies on a project-finance basis, may offer a template. Assuming the SPV operates only the regasification unit (not the power station) on a tolling basis (managing demand fluctuations would render a merchant approach highly risky), this latter route would require a long-term Terminal Usage Agreement reserving sufficient regasification capacity so as to make the project viable for project-financing, while the cost would be added to ICE's regulated generation portfolio.

The main drawbacks of the downstream integrated approach are the heightened regulatory and political risks as the single monopoly entity will attract substantial political scrutiny. As discussed above, the regulatory framework and political situation in Costa Rica, while not perfect, are reasonably attractive, particularly for a developing nation in Central America. These risks should therefore not be perceived as likely "show-stoppers". Meanwhile the dangers of providing additional monopoly power to ICE are muted given the entity is already the dominant entity in the sector.

A6.5 Conclusions for Costa Rica

The following conclusions are have been drawn from this case study:

- In the absence of the construction of the PH Diquís hydro plant, an LNG regasification facility serving a 600 MW gas-to-power plant is estimated to be an **economically viable proposition** under all likely future demand scenarios.

- Even assuming the PH Diquís hydro plant is constructed, an LNG facility serving a 300 MW plant **remains economically attractive** under all scenarios.

- The economic attractiveness is heightened when considering the **security of supply benefits** the gas fired power plants will have for Costa Rica.

- However, the project is **not financially viable** unless it can secure a long-term PPA at a price substantially above the current regulated electricity tariff level.

- Potential solutions include raising the electricity tariff, negotiating a lower LNG price, **cross-subsidising by ICE as the single buyer** within the generation portfolio, external subsidy, or a combination of these actions.

- Of these options the option of ICE **cross-subsidising** between its generation forms with the regulated tariff accounting for LNG and gas-to-power in the same manner as it currently does for oil derivatives, appears the most likely to be successful.

- Due to the large demand uncertainty and fluctuations in early years, either a **downstream-integrated arrangement or a tolling arrangement** with a long-term capacity contract from the single offtaker, ICE, offer the lowest risk.

- ICE offers a **reasonable credit risk** by regional standards, however its large capital expenditure program may limit its ability to finance the venture entirely through corporate debt.

- The **price and demand risk** is contained by regional standards, due to a stable regulatory framework and high prospective load factors of the gas fired power plant.

- The downstream-integrated approach is further supported by the **relatively strong regulatory framework and low political risk** in Costa Rica by regional standards.

- An alternative approach should balance sheet financing by ICE prove difficult, is setting up an **SPV project company** for the regasification unit on a tolling basis, with investment both by ICE and third parties as in the Reventazon Hydro Dam example.

A7 Costa Rica case study material– ICE generation plan

Short Term Plan

Year	Project name	Technology	Capacity MW	Installed MW
2014	Cachí	Hydro	-105	2,622
	Cachí 2	Hydro	158	2,780
2015	Chucás	Hydro	50	2,830
	Torito	Hydro	50	2,880
	Anonos	Hydro	4	2,883
	Río Macho	Hydro	-120	2,763
	Río Macho 2	Hydro	140	2,903
	Chiripa	Wind	50	2,953
2016	Capulín	Hydro	49	3,002
	La Joya 2	Hydro	64	3,066
	La Joya	Hydro	-50	3,016
	Eólico Cap1 Conc 1a	Wind	50	3,066
	Orosí	Wind	50	3,116
	Reventazón	Hydro	292	3,408
	Reventazón Minicentral	Hydro	14	3,422
2017	Eólico Cap1 Conc 1b	Wind	50	3,472
	Eólico Cap1 Conc 2	Wind	20	3,492
	Hidro Cap1 Conc 1	Hydro	37	3,529
	Hidro Cap1 Conc 2	Hydro	50	3,579
	Moín 1	Thermal	-20	3,559
2018	Hidro Proy D5	Hydro	50	3,609
2019	Pailas 2	Geothermal	55	3,664

Long Term Plan

Year	Project name	Technology	Capacity MW	Installed MW
2021	Hidro Proy D4	Hydro	50	3,714
	Turbina Proy 1	Thermal	80	3,794
2022	Turbina Proy 2	Thermal	80	3,874
2023	Borinquen 1	Geothermal	55	3,929
	Eólico Proy D1	Wind	50	3,979
	Hidro Proy G2	Hydro	50	4,029
	Hidro Proy G3	Hydro	50	4,079
2024	Borinquen 2	Geothermal	55	4,134
2025	**PH Diquís**	**Hydro**	**623**	4,757
	Diquís Minicentral	**Hydro**	**27**	4,784
2029	Hidro Proy D1	Hydro	50	4,834
	Hidro Proy D6	Hydro	50	4,884
	Hidro Proy G6	Hydro	50	4,934
2030	Geotérm Proy 1	Geothermal	55	4,989
2031	Geotérm Proy 2	Geothermal	55	5,044
	Geotérm Proy 3	Geothermal	55	5,099
2032	Eólico Proy D2	Wind	50	5,149
	Eólico Proy D3	Wind	50	5,199
	Geotérm Proy 4	Geothermal	55	5,254
	Geotérm Proy 5	Geothermal	55	5,309
	Geotérm Proy 6	Geothermal	55	5,364
	Hidro Proy G4	Hydro	50	5,414
2033	Eólico Proy G1	Wind	50	5,464
	Eólico Proy G2	Wind	50	5,514
	Eólico Proy G3	Wind	50	5,564
	Hidro Proy D2	Hydro	50	5,614
	Hidro Proy D3	Hydro	50	5,664
	Hidro Proy G1	Hydro	50	5,714
	Hidro Proy G5	Hydro	50	5,764
	Hidro Proy G7	Hydro	50	5,814
2034	Eólico Proy G4	Wind	50	5,864

	Eólico Proy G5	Wind	50	5,914
	Hidro Proy G8	Hydro	50	5,964
2035	Turbina Proy 3	Thermal	80	6,044
	Turbina Proy 4	Thermal	80	6,124

A8 International case studies in LNG

This annex provides details of the proposed or implemented LNG projects in 15 countries. The case studies describes the experiences of several countries that succeeded in introducing LNG to their energy markets, as well as some examples of 'work-in-progress' – countries that are planning and proposing LNG projects though not yet implemented. The list of countries is split into two parts, with the first 8 main case studies going into more detail, while the latter 6 are presented in a brief form to illustrate further specific issues. The list of countries covered is set out in Table 42. Since managing risk and credit-worthiness are major factors in being able to finance LNG and gas-to-power infrastructure, we also list the current credit ratings.

Table 42 List of country case studies and credit ratings

Main case studies	Credit rating (a) (b)	Brief case studies	Credit rating (a) (b)
Dominican Republic	B+	China	AA-
Finland and Estonia	AAA; AA-	Greece	B-
India	BBB-	Japan	AA-
Israel	A+	Singapore	AAA
Lebanon	B-	South Korea	A+
Lithuania	A-	Vietnam	BB-
Taiwan	AA-		
Uruguay	BBB-		

*Notes: (a) credit rating is obtained from Standard and Poor's Sovereign foreign-currency rating, as of 9 June 2014. (b) a bond is considered **investment grade** if its credit rating is BBB- or higher; bonds rated BB+ and below are considered to be **speculative grade***

A8.1 Overview and summary of cases

The main report section 5 discussed the cases and identified 7 key lessons of particular relevant to the implementation of LNG in the Central American countries. In the Table 43 below we identify which country cases best illustrate the key lessons.

Table 43 7 Key lessons from case studies

Key lesson	Countries which illustrate the issues
LNG strategies across countries show a considerable degree of variability	Dominican Republic, Estonia and Finland, Greece, India, Japan, Lebanon, Singapore, Taiwan
Advantages of floating storage and regasification units (FSRU)	Israel, Lebanon, Lithuania, Uruguay

Key lesson	Countries which illustrate the issues
Regional projects pose considerable problems	Estonia and Finland, Uruguay
Power or gas trading is a potentially more feasible regional approach	Uruguay, Lithuania
LNG under short term contracts is a growing trend	Dominican Republic, Greece, Israel, Japan, Lithuania, Taiwan, South Korea
A low credit rating is an obstacle but not necessarily a show stopper	Dominican Republic, Greece, Lebanon, Vietnam
It is possible to start a gas market with LNG	Dominican Republic, Taiwan

The case studies, in alphabetical order, present the business models under which LNG was introduced in the country, how financing was arranged and whether third party access is accounted for. Gas utilisation is described at the initial stages as well as in the medium term, considering the effect of the introduction of gas on the national energy mix. Consideration was also given to the opportunities for energy trade, in the form of gas or electricity, as well as cooperation in developing the LNG terminals.

In the following short paragraphs –as an introduction to the detailed case studies included in this Annex - a brief summary of each case study is presented; the full case studies are given from section A8.2 onwards.

Dominican Republic

Fully private terminal financed and developed by AES Dominicana, a private electricity generation company. The business model is an integrated value chain model. The development of the terminal has been determinant in reducing the oil dependency of the Dominican Republic economy. This case highlights how a small emerging economy, with low natural gas demand and relatively high credit risk can develop a successful LNG strategy.

Estonia and Finland

Planned terminal between Estonia and Finland, seeking to create an alternative source of supply to Russia - currently its sole gas supplier. Due to its regional character and coordination requirements, the effective development of the terminal is experiencing delays. The terminal has the potential to foster regional energy trade in the Baltic region. This case highlights the coordination problems that may arise in regional terminal projects.

India

Case study on the first terminal to be built in the country, fundamentally through the public sector initiative. Promoters and owners are state owned companies operating in the gas and oil industry which also constitute the terminal's off-takers. The business model is a modified version of the vertical integration model, with different offtakers and possible differences in offtake risk profiles.

Israel

Offshore terminal fundamentally developed to tackle a short term natural gas shortage and ensure natural gas supply. Use of relatively new and simple technology to grant gas supply in the short term. Terminal fundamentally developed by the public sector, in a context where Israel is re-shaping its energy policy to significantly increase natural gas use. LNG supply contracts are short term. This case shows the advantages of FSRU over land based plants when developing an effective LNG import strategy in a relatively fast way.

Lebanon

Planned offshore regasification terminal which is being promoted to satisfy Lebanon's expanding power generation capacity. Build and operating structure with private sector involvement in the construction and operation of the terminal. The project will operate as a tolling facility and LNG and gas trade risk will be borne by public entities. This case provides a good example of FSRU planned terminal in a relatively small country, with an oil dependent economy and a relatively low credit rating.

Lithuania

Planned LNG terminal to provide an alternative source of natural gas supply for Lithuania, currently exclusively sourcing from Russia. Terminal developed and operated by a majority state-owned oil importer. Regasification capacity will be sold under third party access and imported gas will have an all-purpose end. The terminal could have a considerable impact on regional gas trade and gas supply contestability in the Baltic region. This case is a good example of a one country terminal project with regional energy trade scope.

Taiwan

Terminal promoted, developed and owned by CPC, holding the public monopoly for LNG imports in Taiwan. The business model is a slightly modified version of the integrated value chain approach. Although CPC owns and operates the terminal, it is not the power generation company, but the sole trader of wholesale gas. The development of LNG terminals in Taiwan has come along a structural change in the country's electricity mix.

Uruguay

Building, ownership, operation and transfer structure (BOOT) with private sector involvement in the construction and operation of the terminal. LNG and gas trade risk borne by public power utility and shielded from regasification terminal operator. LNG terminal used for power generation with the objective to diversify gas supply sources. The project could allow for gas and power exports to Argentina. This case highlights the difficulties inherent to regional projects – the project was a common initiative of Argentina and Uruguay in its early stage- and provides a good example of a one country terminal with regional energy trade scope.

China

Six existing onshore terminals and eight onshore planned ones. Most of the terminals are owned and operated by state owned companies in the oil sector. There is no mandated access to LNG and limited scope for the development of competition and gas trading. LNG import prices are oil-linked and determined by bilateral commercial negotiations between importers and suppliers.

Greece

First and only LNG terminal in the country. Onshore terminal, owned by public corporation responsible for gas infrastructure and operated by one subsidiary owned by the former. Capacity is open to third parties, although some access problems have been reported. This terminal is an example of a lightly-used LNG terminal, as its capacity utilization stands at 25%.

Japan

Japan is the largest world importer of LNG. There are 32 LNG import terminals, mostly adjacent to individual power plants. Some LNG terminals are owned individually by private power utilities and gas suppliers while others are owned in co-operation through joint ventures. The predominant model is the integrated value chain model, the main offtakers being power and gas companies. Most of the LNG is supplied under long term contracts. The development of LNG terminals in Japan has come along a structural change in the country's energy mix. This case highlights how long a long standing buyer in the LNG market is increasingly using short-term contracts to buy LNG.

Singapore

Onshore terminal developed, owned and operated by a fully state owned company. The terminal's ownership and use are separated. There is only a single private company contracted to purchase LNG and sell regasified gas, selected through a competitive process. This monopoly situation could change in the future, as the capacity of the terminal is projected to increase. Singapore's case is the only case where the user of the terminal – albeit the only one- has been assigned through a competitive tendering process.

South Korea

Four LNG regasification terminals, most of them owned and operated by the public natural gas company. The predominant model is the integrated value chain model. Most of the LNG is supplied under long term contracts, although recently producers have increased LNG purchases through spot contracts, in order to meet seasonal changes in demand. Therefore, this case is another example of a long standing buyer in the LNG market which is increasingly using short-term contracts to buy LNG.

Vietnam

Two onshore terminals currently being developed to tackle an expected natural gas supply gap. The terminals will be owned by a state owned company in the oil sector, which will also be the offtaker. The terminals will be operated by a subsidiary of the former's company. Re-gasified gas will be sold to independent power plants and industrial customers. This case provides another example of a country with a relatively low credit rating which is developing an LNG strategy.

The case studies, in alphabetical order, present the business models under which LNG was introduced in the country, how financing was arranged and whether there is any provision for third party access. Gas utilisation at the initial stages as well as in the medium term are also described, considering the effect of the introduction of gas on the national energy mix. Consideration was also given to the opportunities for energy trade, in the form of gas or electricity, as well as cooperation in developing the LNG terminals.

A8.2 Dominican Republic

AES Andres is the Dominican Republic's first and only regasification terminal. It is situated at the southeast tip of the Caucedo peninsula, to the south of the ports of Boca Chica and Caucedo (See Map 1 below). AES Andres is owned by the private company *AES Dominicana* [133], one of the main operators in the Dominican market for electricity generation. In 2013, *AES Dominicana* supplied around 40% of the Dominican Republic's energy demand.

Currently, a project for a second regasification terminal is being developed. The project is promoted by *Antillean Gas Ltd*, a consortium of companies from Colombia, Singapore and Dominican Republic. The terminal will be located in San Pedro de Macoris, in the eastern part of the country, close to AES Andres (Map 1). Construction works began in February 2014. At the initial stage of operation, gas will be used in the power stations located in San Pedro de Macoris.

[133] AES Dominicana is a subsidiary of AES Corporation, which began operations in 1997 the Dominican Republic. The AES Corporation is a global power company that owns and operates a diverse and growing portfolio of electricity generation and distribution businesses, which provide reliable, affordable energy to customers in 21 countries.

Map 1 Location of AES Andres regasification terminal

Source: elaborated from Mapa Eléctrico y Energético. República Dominicana 2013, Comisión Nacional de la Energía.

Reasons for developing the terminal

Developing *AES Andres* was an entrepreneurial decision made by the private company AES, who believed in the long term advantages of natural gas in the Dominican Republic. In 2000, natural gas was basically absent from Dominican Republic's energy mix. As natural gas would displace expensive fuel oil, AES decided to invest in a regasification terminal to import natural gas. In 2012, natural gas imports reached 1.28 Bcm and accounted for approximately 14% of the Dominican's Republic energy mix and 16% of installed power generation capacity.

AES Andres was promoted by *AES Dominicana*. In 1999, *AES Dominicana* made the decision to invest in the first LNG plant in the Dominican Republic. In 2001, it signed a long term contract with BP Gas Marketing (BPGM), under a Take or Pay (ToP) agreement with a base quantity of 0.99 Bcm/year. The terminal received its first cargo in February 2003.

The terminal was financed by AES Dominicana, which partially completed financing with support from Dominican financial institutions as well as international financing institutions. Details of the financing structure are not publicly available.

Gas utilisation

In 2003, gas was mainly used for power generation at AES Andres power station and Dominican Power Partner (DPP), a simple cycle electrical central unit owned by AES located in Los Mina (in the eastern part of the country). The use of gas in the country expanded to other sectors and in 2005, AES signed its first contract to sell natural gas to third parties in the industrial and commercial sectors. In 2008, it started using a cryogenic distribution terminal to supply demand located far from AES facilities.

The terminal has no regional scope. The obvious cooperation partner for gas and/or electricity trade is Haiti. Despite efforts of cooperation, energy trade between the two countries is neither materially possible nor economically feasible for several years, in particular due to the lack of adequate infrastructure.

Type of terminal and main characteristics

AES Andres is an onshore regasification terminal, which has an associated 319 MW combined cycle generation station owned by AES. It has an LNG storage capacity of 160,000 m3, and it also connects to a 34 km gas pipeline to the power generation plant DPP. DPP dispatches its electricity through long term Public Purchase Agreements (PPA) with *Empresa Distribuidora de Electricidad del Este* (EDEEste) [134].

Business model

The first terminal is owned by AES Dominicana. LNG is bought by AES and gas is used in AES facilities or in other power stations or segments (industrial and residential demand), to which AES sells the gas. The model applied is therefore an integrated value chain model, whereby the power utility owns and operates the regasification terminal.

At the beginning of the project, AES signed a 20 year long term contract with BPGM for the provision of LNG from Trinidad and Tobago[135]. This contract calls for approximately 11 cargos per year. AES also uses incremental cargos in addition to its contract volumes. For instance, in 2011 AES secured four spot cargos from BP for 2011 and 2012.

A completely private terminal, AES Andres does not grant third party access. The Dominican Republic lacks regulations regarding open access to regasification terminals. To our knowledge no plans exist to regulate access to the LNG terminals.

The power sector

Power generation in the Dominican Republic is largely based on thermoelectric power generation. Over the last years, plants using coal and natural gas have increased their presence. Currently, Haiti and the Dominican Republic lack power interconnections, even though in 2013 government representatives from both countries signed an agreement to work on this.

The main participant in the power sector is CDEEE, which has a dominant role in the transmission and distribution activities, as well as in hydroelectric generation. Non hydro generation is distributed among 12 private companies (80% of non-hydro generation) and mixed companies (with state participation). Non-hydro generation represents 80% of the National Interconnected Electricity System.

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[134] EDEEste is one of the three Dominican Republic's distribution companies. It is owned by the Dominican state through *Corporación Dominicana de Empresas Eléctricas Estatales* (CDEEE) y el *Fondo Patrimonial de las Empresas Reformadas* (FONPER).

[135] Pricing under the BP Contract is at a premium to the Henry Hub natural gas price per MMbtu on the NYMEX Index.

Electricity rates to final consumers are fixed monthly by the *Superintendencia de Energía*, the regulatory body in the electricity subsector. Distribution companies are not able to adjust tariffs to fully reflect changes in energy prices. There is a system of subsidies enacted by the Government to compensate distributors for possible differences between energy supply prices and regulated retail prices.

Summary of key points

- Fully private terminal financed and developed by AES Dominicana, a private electricity generation company. This was feasible due to the competitive position of LNG in the power sector displacing expensive fuel oil at the beginning of the 2000's.
- The business model is an integrated value chain model, whereby the power utility owns and operates the regasification terminal. The terminal does not grant third party access.
- Re-gasified LNG is used in the power utility's facilities or in other power stations or segments (industrial and residential demand).
- The development of the terminal has been determinant in the structural change observed in Dominican Republic's energy mix, significantly increasing natural gas use in a very oil dependent economy.
- Notwithstanding recent efforts for regional cooperation, there are limited possibilities for gas or electricity trading between the Dominican Republic and Haiti, mainly due to the lack of adequate infrastructure.

A8.3 Finland and Estonia

During 2013, Estonia and Finland were in negotiations regarding the possible location of an LNG terminal that would diversify gas supply and lower dependency on Russian gas supplies. There is still some uncertainty regarding the location of the terminal, as both Finland and Estonia are interested in having the terminal on their territory. In February 2014, Estonia, Finland and the LNG Terminal Promoters (Gasum Oy[136], representing Finngulf LNG Oy, and AS Alexela Energia[137], representing Balti Gaas Oy) signed a Memorandum of Understanding (MOU) on the implementation of the Regional Baltic LNG Terminal in the Gulf of Finland.

Reasons for developing the terminal

Both Estonia and Finland, as well as Latvia and Lithuania, lack gas connections with other European Union countries. They are 'energy islands', incapable of sourcing gas

[136] Gasum Oy is engaged in the import and transmission of natural gas primarily in Finland. It is involved in the wholesale trade of natural gas. In addition, it operates an online marketplace for secondary market trading in natural gas and for its short-term products and it is also engaged in the retail distribution of natural gas to small-scale users. Gasum Oy has four owners: Fortum Heat and Gas Oy (31% of shares in March 2013)), OAO Gazprom (25%), the Finnish State (24%) and E.ON Ruhrgas International GmbH (20%).

[137] Alexela Energia is a private Estonian energy holding that belongs to the Alexela Group.

in competitive terms. Taking into account this context, the MOU underlies how the Regional Baltic LNG Terminal is aligned with the fundamental aims of European energy policy: increasing European market integration, ending energy isolation of some EU Member States, fostering energy security, and ensuring access to main European hubs and the LNG market, so as to enable competition and natural gas price contestability.

Development of the terminal and financing

The MOU incorporates two fundamental points of agreement. First, Gasum Oy and AS Alexela Energia commit to undertake discussions regarding the form of cooperation and technical features of the Regional Baltic Terminal. Second, in May 2014 the promoters will present to the Ministries of Finland and Estonia as well as the European Union the results of the discussions.

Some other important elements of the MOU are the following:

- The terminal will have operations on both sides of the Gulf of Finland, though locations still need to be determined.
- Project promoters will be independent from the incumbent supplier.
- The Estonian state holds the possibility to acquire majority stakes in the installations located on the Estonian side.
- In case Gasum Oy and AS Alexela Energia fail to reach an agreement, the ministries of Estonia and Finland and the European Commission will be notified.

According to some sources, the Finnish terminal could be located in Inkoo or in Porvoo and the Estonian terminal in Paldiski (see Map 2). In principle, both countries have also agreed to build a natural gas pipeline - the Balticconnector - between both terminals, the cost of which would amount to approximately 130 million US$.

The European Union could fund up to 40-50 percent of the whole project percent, provided it is a project of common interest.

Map 2 Location of projected terminals in Estonia and Finland

Source: adapted from Google Maps

A8.4 India

Due to insufficient domestic supply of natural gas, India is increasingly relying on imported LNG to meet demand levels. In 2012, domestic natural gas supply amounted to 40.2 Bcm while consumption reached 54.6 Bcm, and India was the fourth largest LNG importer. Despite the increase in domestic gas production, dependency on imported gas is likely to increase[138] in the long term. Accordingly, LNG import capacity is notably expanding in India.

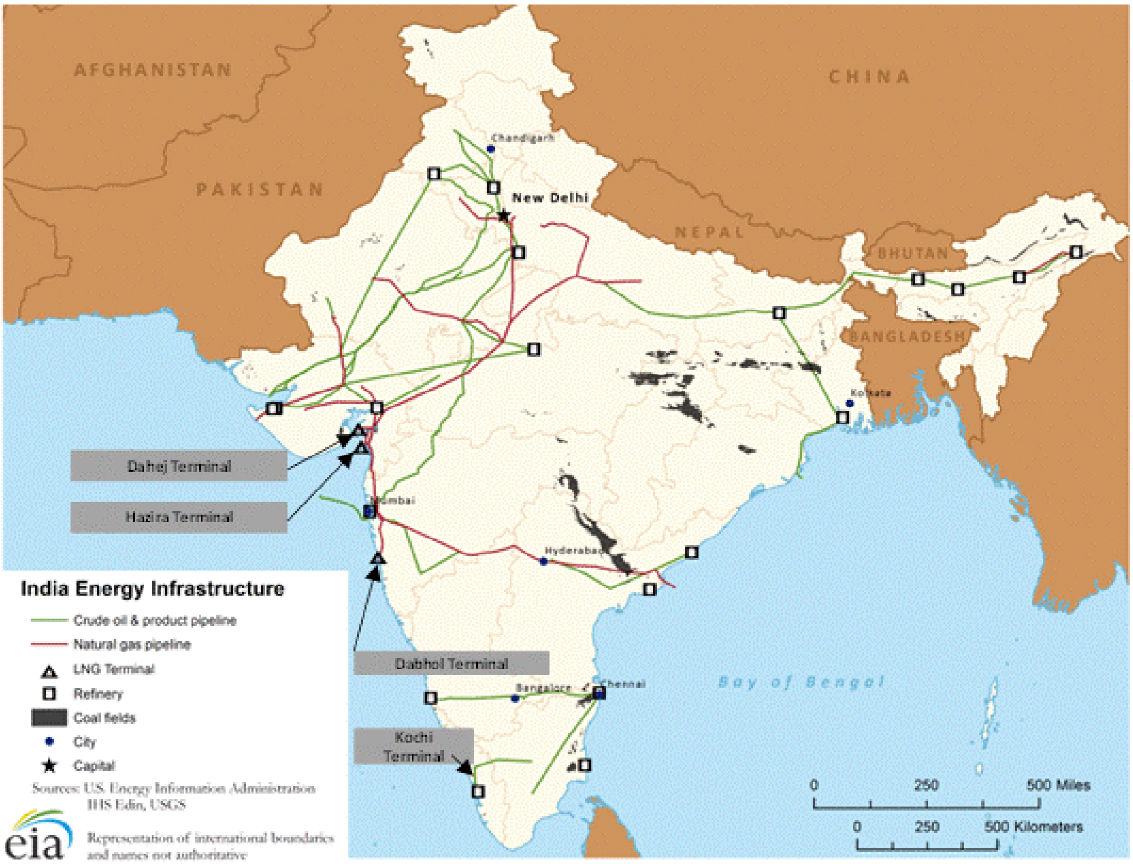
Natural gas imports are sourced through LNG terminals, since India lacks gas pipeline connections to other surrounding countries[139]. More than 35% of total gas demand in the country is supplied through four regasification terminals located in India's West Coast (Map 3): Dahej, Hazira, Dabhol and Kochi. In addition, there are several terminals planned, such as the ones in Enore, Mangalore, Mundra and Gangavaram.

138 In 2030, LNG imports will amount to 67% of total demand according to Petronet LNG Limited (PLL).

139 There is an ongoing project to connect Iran, Pakistan and India through a gas pipeline.

This case study focuses on Dahej regasification terminal, the first one to be built in India.

Map 3 Location of currently operating regasification terminals in India



Source: adapted from Analysis Briefs – India, US Energy Information Administration, 2013.

Reasons for developing the terminal and use of the gas

Natural gas in India mainly serves as a substitute for coal in electricity generation. The country was self-sufficient in natural gas until 2004, when it began to import LNG through the Dahej terminal. Amongst other reasons, the location was selected because (i) some of the terminal promoters had port facilities in that location and (ii) it was close to demand and to the Hazira-Bijapur-Jagdishpur gas pipeline (owned by one of the promoters of the terminal, GAIL).

Since the terminal became operational, gas has been used to satisfy the country's unmet demand, both for power generation and other uses[140].

[140] In 2010, the main users of natural gas in the country were the power sector (45% of total gas demand) and the fertilizer sector (28%). The government labelled these as priority sectors for domestic programs, which ensures that they receive larger shares of any new gas supply before other consumers.

Type of terminal and main characteristics

Dahej terminal is an onshore terminal which has two tankers of 138,000 cm each. Over time, it has increased its capacity from 7 Bcm in 2004 to 14 Bcm in 2009. It is expected that it will reach 21 Bcm in 2016.

Development of the terminal and financing

Dahej was developed by Petronet LNG Limited (PLL)[141] and began operations in 2004. The company achieved financial closure by syndicating its long-term funds requirement on limited recourse basis with a consortium of banks and financial institutions. PPL brought in the Asian Development Bank as a 5.2% shareholder.

Business model

PLL owns and operates the terminal and has a LNG long term supply contract with Ras Laffan Liquefied Natural Gas Co. Ltd. (RasGas) from Qatar. PLL is responsible for the arrangement of transportation services of LNG from RasGas to PLL's Regasification Terminal at Dahej.

There are three off-takers: GAIL (India) Limited[142], Indian Oil Corporation Limited (IOCL)[143] and Bharat Petroleum Corporation Limited (BPCL)[144]. The off-takers also constitute the three promoters of both PPL and the terminal, and they are classified as companies of the Government of India, considering the strategic nature of their industry and fundamental strengths.

The model is therefore a vertical integration model where offtakers own and developed the terminal. Unlike most other cases of vertical integration, three offtakers have developed the facility rather than only a single offtaker. However all offtakers are state owned. So, while their offtake risk profiles might be different, they would all be guaranteed by the same state, alleviating potential concerns of the Qatari LNG supplier.

Accessibility to the terminal by third parties

Accessibility to Dahej terminal by third parties seems unlikely. In recent years, expanded capacity has be sold to the original promoters of the terminal and current off-takers.

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[141] PPL was formed as a Joint Venture by the Government of India to import LNG and set up LNG terminals in the country, it involves India's leading oil and natural gas industry players. The promoters of PPL are GAIL (India) Limited (GAIL), Oil & Natural Gas Corporation Limited (ONGC), Indian Oil Corporation Limited (IOCL) and Bharat Petroleum Corporation Limited (BPCL). The promoters hold 50% of equity. In addition, GDF International (GDFI), a wholly owned subsidiary of GDF Suez and the Asian Development Bank (ADB) hold 10% and 5.2% of the equity respectively.

[142] GAIL (India) Limited is a state owned company which has a significant presence in natural gas transmission, marketing and processing, petrochemicals, City Gas and E&P. GAIL also has presence in the power sector.

[143] Indian Oil Corporation Limited is an Indian state owned gas and oil company with activity in all the segments of the hydrocarbon value chain.

[144] Bharat Petroleum Corporation Limited (BPCL) is an Indian state-controlled oil and gas company.

Power sector

Electricity generation in India relies on coal (58.7% in 2013), hydro (17.4%) and renewables (12.3%). Natural gas represents 8.9% while nuclear and oil amount to 2.1% and 0.5% respectively. India has electricity interconnections with surrounding countries Bangladesh, Bhutan and Nepal. Additionally, there are plans to interconnect with Sri Lanka and initial talks regarding interconnection with Pakistan.

The Indian electricity sector is still dominated by the central and state sector utilities. Central and state utilities represent 68.1% of total electricity generation, while private sector amounts to 31.9%. Power Grid Corporation of India Ltd (PGCIL), the central transmission utility, is the largest transmission company in India, and the State Electricity Boards amount for more than 90% of the distribution network.

Tariff setting is partially guided by social and political considerations rather than by economic and efficiency criteria. Tariffs for the agriculture sector are highly subsidized.

Summary of key points

- Due to insufficient domestic supply of natural gas, India is increasingly relying on imported LNG to meet energy demand levels. Accordingly, LNG import capacity is notably expanding, with several terminals currently operating or planned.
- Dahej terminal was the first one to be built in the country, fundamentally through the public sector initiative. Promoters are three state owned companies operating in the gas and oil industry which also constitute the terminal's off-takers.
- Presence of a foreign strategic player (GDF Suez) and participation of a financial institution (Asian Development Bank).
- The model is a modified version of the vertical integration model where the state owned oil and gas companies, some of them not present in the electricity sector, have pooled resources to build the terminal and import LNG to then distribute gas to end users.
- Gas is used satisfy unmet demand, both for power generation and other uses.

A8.5 Israel

Hadera is Israel's first and only LNG regasification terminal. It is located in the north of Israel, in the Mediterranean Coastal Plain, approximately 45 Km. from the major cities of Tel Aviv and Haifa (See Map 4). It is owned by Israel Natural Gas Lines (IGNL), a state owned company. The first cargo arrived in January 2013 from Trinidad and Tobago.

Reasons for developing the terminal and use of the gas

Israel started using natural gas in 2004. Natural gas consumption reached 5.3 Bcm in 2010, of which 90% were assigned to electricity generation. The main users were Israel Electric Corporation - a state owned utility - and large industrial users. Fast growth in natural gas demand is expected to continue in the medium and long term, growing up to 18 Bcm by 2030 - 85% of which is expected to be used by the power sector and industrial users.

Historically, Israel has been an importer of natural gas[145], even though discoveries of offshore natural gas fields will probably allow the country to become an exporter of natural gas in the next decade.

The main reason why Hadera terminal was the existence of short term natural gas supply shortages. In 2012, Israel experimented interruptions in the gas supply coming through the Arish-Ashkelon pipeline from Egypt and faced a near depletion situation of the sole gas field in the country, Yam Tethys. As a result, Israel Electric Corporation (IEC) had to turn to alternative and more expensive fuels (coal and diesel), what lead to higher electricity prices.

In this context of scarcity, Israel decided to pursue the LNG import option and develop Hadera regasification terminal. The basic objectives were two. First, to solve the temporary shortage until Israel could benefit from its large offshore deposits, in particular the ones in the Tamar and Leviathan fields[146]. Second, to contribute to creating adequate natural gas reserves and strengthen the country's energy independence and security of supply on a long term basis.

As with natural gas originating in other sources (fields or pipeline from Egypt), the imported LNG is mainly used for power generation, in a context of Israel's electricity mix re-shaping towards more natural gas use.

Type of terminal and main characteristics

A buoy based offshore terminal with sub-sea pipeline headed for Israel's gas grid. The offshore buoy based approach was selected because it was found to be the only technology capable of facilitating the supply of LNG to Israel on a short term basis. The floating terminal has an annual capacity of 2.5 Bcm per year, approximately half of current natural gas demand in Israel.

Development of the terminal and financing

In February 2011, Israel's Minister of Energy and Water Resources announced the plan to build the LNG regasification terminal. The task of constructing the LNG receiving terminal was assigned to Israel Natural Gas Lines (INGL), a state-owned company licensed to build and operate a natural gas transmission system.

[145] According to US Energy Information Agency, in 2011 domestic production amounted to 4.3 Bcm while domestic consumption reached 5 Bcm.

[146] Output on the Tamar field begun in 2013 while output in the Leviathan field is expected to start in 2017.

In October 2011, INGL signed a deal with Italian marine contractor Micoperi to build the Hadera terminal at a cost of US$ 140 million. The construction of the terminal started in the second half of 2012 and was finished by the end of the year.

Business model

The regasification terminal is owned and operated by INGL. The purchase of LNG is undertaken by IEC which uses gas for power generation. In principle, industrial enterprises and other consumers will be allowed to order LNG shipments independently or through joint use of the tanker ordered by IEC. IEC carries out tenders to purchase LNG on a DES basis for approximately four cargos a year. Contracts are not long term.

Map 4 Location of Israel's Hadera regasification terminal

Source: adapted from Israel Natural Gas Lines.

Accessibility to the terminal by third parties

Since industrial enterprises and other consumers are in principle allowed to order LNG shipments independently, there might be third party access to the terminal.

Power sector

In 2010, 61% of Israel's electricity production relied on coal. Natural gas represented 36.5% and gas oil and diesel 1.5% and 0.9% respectively. Israel remains an electricity island, as it does not have electricity supply connections with surrounding countries.

The electricity value chain remains dominated by state owned companies which confront low competition. Some independent power producers (IPPs), both conventional and renewable, are operating. However, IEC continues to dominate. In the rest of the segments, IEC is the sole provider.

Summary of key points

- The terminal was fundamentally developed to tackle a short term natural gas shortage and ensure natural gas supply. Use of relatively new and simple technology, to grant gas supply in the short term, as needed.

- Terminal fundamentally developed by the public sector, in a context where Israel's Government is re-shaping Israel's energy policy to significantly increase natural gas use. Israel Natural Gas Lines, a state owned company, was assigned to build and operate the terminal, while Israel Electricity Corporation, a state owned electricity company, is the purchaser of LNG.

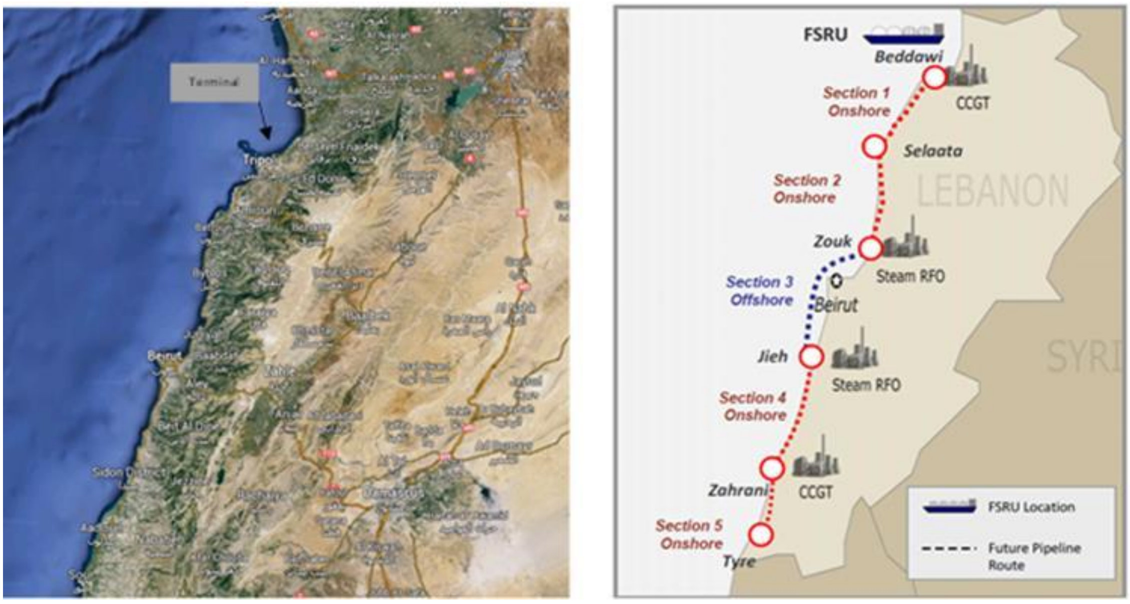
- Gas is primarily used for power generation, to reduce consumption of relatively more expensive oils.

- There exists possibilities of gas trade in the future, as Israel is connected through pipeline with Egypt and Jordan. Power trade limited, as Israel currently lacks interconnections with other countries.

A8.6 Lebanon

The Lebanese Government is promoting the construction of an LNG import terminal, located offshore from Beddawi (See Map 5). The FSRU will be located northeast of the Port of Tripoli, around 2.4 km. east of the Tripoli Harbour breakwaters and around 3.2 km west of Beddawi existing power station.

Map 5 Location of Lebanon's projected LNG regasification terminal



Source: adapted from Google Maps and Call for Expressions of Interest for a Liquefied Natural Gas Import Project in Lebanon, 30 March 2012, Ministry of Energy and Water of Lebanon.

Reasons for developing the terminal and use of the gas

Natural gas is fundamentally absent from Lebanon's energy mix. The country relies heavily on oil imports to satisfy energy needs. Domestic natural gas sources have not been developed yet and the Arab Gas Pipeline is the main channel to source natural gas from Egypt to Lebanon via Jordan and Syria. However but disruptions are frequent due to the security environment in the region and thus imports have been intermittent.

The Lebanese Government is promoting the regasification terminal due to its expanding power generation capacity. Accordingly, gas will primarily be used for power generation, in a first stage providing service to Deir Amar power plant, which currently uses fuel oil. In the near future, gas is planned to be distributed through a coastal gas pipeline to both current power plants and projected power plants. LNG requirement by 2022 is expected to reach 4.9 Bcm/year.

Type of terminal and main characteristics

The terminal is planned as an offshore terminal composed of an FSRU and a berth. The minimum size of the FSRU is 125,000 cm, with ship-based LNG vaporization at regasification capacity of up to 4.9 Bcm/year of LNG.

Development of the terminal and financing

In 2012, the Ministry of Energy and Water (MEW) published a call for expressions of interest to build the terminal. Initially, both the tender and the final award were expected in 2013, but regional political instability delayed the project. Finally, the bidding process started in 2014 and the terminal is expected to become operational in 2015.

According to the call for expressions of interest, the project consists of two main parts. First, the procurement and operation of an LNG FSRU vessel starting in 2015 for a period of 12 years or more. Second, the construction and operation of an offshore LNG unloading berthing structure to allow for the FSRU to be permanently berthed on one side of the jetty, while LNG supply tankers berth and unload on the other side.

Business model

The project is still at very early stages of development, so only limited information is available. According to the call for expressions of interest published by the Lebanese Government, the project will operate as a tolling facility. The MEW will enter into a long-term terminal use agreement with the terminal owner and pay a monthly capacity reservation fee – regardless of usage - and a throughput fee for operating costs incurred for actual usage. The terminal owner may also have the right to retain some LNG for use as fuel. In principle, the Lebanese Government will stand behind the financial obligation arising from the long-term Terminal Use Agreement.

MEW will be responsible for procuring LNG supply to the terminal and will also be the gas off-taker for usage in power generation plants.

There is private participation in the project on a build, own and operating basis of the terminal.

Accessibility to the terminal by third parties

It is likely that MEW will be the only and allowed user of the regasification terminal.

Power sector

Lebanon's electricity production is based on thermal power plants (88% of total electricity production), hydro-electrical plants (4.5%) and electricity purchased from Syria and Egypt through regional power interconnections (7.5%).

The Ministry of Energy and Water is the major regulatory entity for all energy related issues and the electricity sector is dominated by the monopoly position held by the public utility Electricité du Liban (EDL). Private investment is limited.

There exists a legal framework for privatization, liberalization and unbundling of the electricity sector which has not been applied yet. EDL still retains exclusive authority in the generation, transmission, and distribution areas.

Diesel fuel is heavily subsidized, which leads to important annual transfers from the Lebanese state to the current vertically integrated monopolist EDL.

Summary of key points

- Recurrent delays in the effective development of the terminal due to political instability in the region.
- Build and operating structure with private sector involvement in the construction and operation of the terminal.

- The project will operate as a tolling facility and LNG and gas trade risk will be borne by public entities. Lebanon's Ministry of Energy and Water will be responsible for procuring LNG supply to the terminal and will also be the gas off-taker for usage in power generation plants.

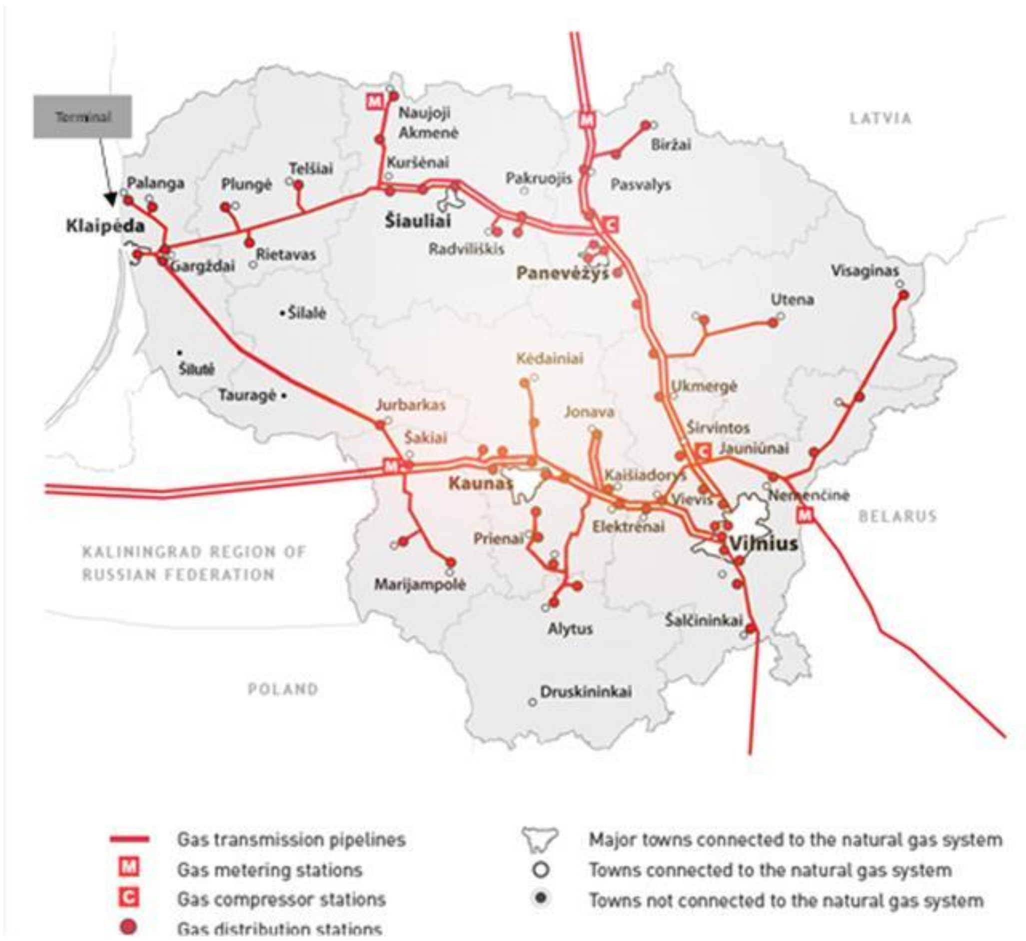
- The regasification terminal is being promoted to satisfy Lebanon's expanding power generation capacity. Accordingly, gas will primarily be used for power generation, now very dependent on oil imports.

- There exists the possibility of gas and electricity trade with other Arab countries. Nevertheless, the achievement of a fully well-functioning regional energy market between these countries still faces several challenges. No regional cooperation existed for the development of the LNG facility.

A8.7 Lithuania

An LNG regasification terminal is currently planned in Klaipėda State Seaport, located centrally on the Baltic coast in Lithuania (See Map 6). The commercial operation of the terminal is expected to begin in December 2014.

Map 6 Location of Lithuania's LNG regasification terminal



Source: adapted from AB Amber Grid (the operator of Lithuania's natural gas transmission system) *www.ambergrid.lt/en/transmission-system/gas-transmission-system-in-Lithuania*

Reasons for developing the terminal and use of the gas

Lithuania currently sources its entire natural gas supplies from Russia. In 2012, Lithuania's total natural gas imports reached 3.3 Bcm. The LNG terminal is expected to provide an alternative source of natural gas supply. After the shutdown of Ignalina Nuclear Power Plant in December 2009, Lithuania became strongly dependent on natural gas, and in particular, on a sole source of supply: gas transported by pipeline from Russia through the Republic of Belarus[147]. Given this security of supply considerations, several projects are aiming to diversify gas supplies in the region, including the Klaipėda's LNG terminal[148]. The terminal is expected to help diversify energy sources, improve security of energy supply and make import prices reflect the global market price level.

In terms of gas use, Klaipeda terminal is an all-purpose LNG terminal, aiming to create competitive pressure on the current sole source of gas supply. Imported gas will be used for residential (in particular, to meet demand of first necessity) and industrial consumption, but also for power generation and exports to other countries in the region.

Type of terminal and main characteristics

The planned LNG terminal will be an FSRU with a capacity of 11 Mcm a day. The terminal's annual capacity will reach 2-3 Bcm. It will be leased from Hoegh LNG for 10 years, with a purchase option. The terminal is also composed of an offshore jetty facility - located in the southern part of the Port of Klaipeda – and an 18 km long gas pipeline that connects the FSRU to the gas grid. Both the jetty and the pipeline are still under construction.

The basic functions of the terminal will be (i) LNG storage, regasification and gas supply to the country's gas-main networks and (ii) LNG fuel supply to small consumers (ship fuel, reserve fuel for boilers, small power plants). It is envisaged that the terminal will also create opportunities to small scale LNG activities, such as transhipment to small scale vessels.

Development of the terminal and financing

The project began in 2010 and is being developed by *Klaipedos Nafta* - a majority state-owned oil importer[149]. The terminal is being financed through different channels, namely commercial banks loans, credits from international financial institutions and increases in the gas transmission tariff (a new component – called the *LNG terminal supplement* – has been added). Recently, the European Investment Bank announced that it would be lending 87 million EUR to Klaipedos Nafta (KN) for the construction and

[147] Lithuania, like Latvia, Estonia and Finland, does not have interconnections with the European Union gas network. It only has an interconnection to Latvia.

[148] Other projects would be the development of an interconnection with Finland and with Poland, the development of a Baltic regional LNG terminal or the improvement of gas storages capacities.

[149] SC Klaipėdos Nafta was appointed to develop the LNG terminal Project in Lithuania by the Resolution of the Government of July 2010.

operation of the terminal. The Lithuanian Government is providing public aid in the form of government loan guarantees and the creation of the *LNG terminal supplement*.

Business model

In principle, the LNG terminal will be operated by Klaipėdos Nafta, selling regasification capacity to companies[150]. This is in line with European legislation requiring an unbundled gas sector.

Capacities will be available for long term and short term duration. During the capacity allocation the priority will be given for the demand of regasification services. The users of the LNG terminal will be able to lend their LNG and trade their booked capacities in the secondary market. At this stage, there is no information on the limits of long term contracts that can be agreed.

According to the Lithuanian Law on the Liquefied Natural Gas Terminal, companies engaged in state-regulated electricity and/or heat production business will be obliged to purchase natural gas through the LNG terminal. Purchased volumes will be determined by the Lithuanian Government. In principle, this scheme will be in effect for 10 years, even though this period could be shorter if the natural gas market becomes more developed and integrated so as to assure security and efficiency of natural gas supply.

Accessibility to the terminal by third parties

In compliance with EU regulation, the operator of the terminal will be obliged to provide regasification services to any third party, applying regulated tariffs and non-discriminatory conditions.

Power sector

Gross electricity generation relies on natural gas (55.4% of the energy mix in 2010), renewables (29.0%) and crude oil and petroleum products (11.3%).

Lithuania is not directly connected to the European electricity grid and is currently one of the countries working on the Baltic Energy Market Interconnection Plan (BEMIP)[151]. Plans are in place to build the Nordbalt interconnector to Sweden by 2015 as well as an interconnection to Poland by 2016.

The closure of Ignalina NPP in 2009 removed a monopoly power supplier and created room for entry and competition in the market. However, competition is limited and the electricity market remains concentrated. In 2010, INTER RAO Lietuva UAB[152] and

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[150] SC Klaipėdos Nafta received the right to perform capacity allocation procedures and other certain rights of the LNG terminal operator by the Resolution of the Lithuanian Government of November 2013.

[151] On 17 June 2009, eight Baltic Sea Member States signed a Memorandum of Understanding on the Baltic Energy Market Interconnection Plan (BEMIP). The BEMIP is the fruit of nine months' work at the initiative of the European Commission (EC) to look at concrete measures to connect Lithuania, Latvia and Estonia better to wider EU energy networks.

[152] 51 percent of INTER RAO Lietuva shares are owned by Finland's company RAO Nordic OY and 29 percent of shares are held by Lithuanian investment company UAB Scaent Baltic. Free float represents 20% of INTER RAO Lietuva shares.

Lietuvos Energija AB[153] each had a 40% share of the wholesale electricity market while 18 other market players had a combined market share of 20%. Competition is also limited in downstream retail markets.

Summary of key points

- Lithuania currently sources its entire gas supplies from Russia. The planned LNG terminal is expected to provide an alternative source of natural gas supply for Lithuania.

- The terminal is being developed and will be operated by Klaipėdos Nafta, a majority state-owned oil importer. Klaipėdos Nafta will sell regasification capacity to different companies applying regulated tariffs and non-discriminatory conditions.

- Imported gas will be used for residential and industrial consumption, but also for power generation and exports to other countries in the region.

- The terminal will foster regional power and gas trade in the Baltic region – very dependent on gas supplies from Russia – as well as gas supply contestability and competition in this regional market.

A8.8 Taiwan

State-owned Chinese Petroleum Corporation (CPC) is the sole importer of LNG in Taiwan. The company controls all aspects of natural gas supply in the country, including exploration and production, imports, domestic pipeline transportation and gas wholesaling. CPC operates two existing LNG import terminals: Yung-An - located in the southwest of Taiwan - and Taichung – located in the north (See Map 7).

Reasons for developing the terminal and use of the gas

Traditionally, Taiwan's domestic natural gas production has been limited, and gas was exclusively sourced from LNG imports. Taiwan's gas and LNG market is mature and LNG imports started LNG in 1990 through the Yung-An terminal. Import capacity was enhanced with the construction of the Taichung terminal in 2009. Currently, Taiwan ranks as the 5th largest LNG importer in the world with Qatar, Malaysia and Indonesia as its main suppliers.

Imported LNG is primarily used for power generation. In 2011, Taiwan Power Company (Taipower) - the state-run company for production and distribution of electric power - was the main user, accounting for 60% of total gas consumption. Independent Power Producers (IPP's) constituted the second biggest user (22%), with residential and industrial users accounting for 11% and 7% respectively. In 2011, gas represented 29.1% of Taiwan's electricity mix, the second biggest source of electricity generation after coal (40%). The development of LNG terminals in Taiwan has come

[153] Lietuvos Energija, UAB group is a state-controlled company group operating in power and heat generation and supply, electricity trade and distribution, trade and supply of natural gas, as well as maintenance and development of electricity sector.

along a structural change in the country's electricity mix: in 1996, natural gas accounted for 2% of electricity generation.

Map 7 Location of Taiwan's LNG regasification terminals

Source: elaborated from 2015-2035 LNG Market Assessment. Outlook for the Kitimat LNG Terminal, prepared for KM LNG Operating General, Poten & Partners October 2010.

Type of terminal and main characteristics

Both terminals are onshore terminals. Yung-An terminal has a tank storage of 0.69 Mcm and a total capacity of unloading 12.64 Bcm/year. Taichung Terminal has a tank capacity of 0.48 Mcm and a capacity of unloading 6.32 Bcm/year.

The LNG facility was not only earmarked to supply to one power plant but instead, CPC developed transmission and distribution systems in western Taiwan that allowed gas from LNG sources to be distributed to scattered residential and industrial users as well as other power generation plants.

Development of the terminal and financing

Both terminals were developed by CPC. Yung-An terminal began operations in 1990 to supply gas to nearby Hsingta Power Plant, but also to other relatively more distant power stations. Taichung Terminal started in 2009, and was created to supply natural gas to the Ta Tan power generation complex. No detailed information on financing of the terminals is publicly available.

Business model

The terminals are owned and managed by CPC. Apart from the original long-term LNG sale and purchase agreements (SPAs) with Indonesia, Malaysia and Qatar, CPC recently (2012) signed four new SPAs for LNG imports with countries including Papua New Guinea, Qatar, and Australia. Mid-term and short-term agreements with Trinidad and Tobago, Egypt, and Nigeria are used to stabilise supply volumes into the country. The business model is therefore a slightly modified version of the integrated value chain approach. Although CPC owns and operates the terminal, it is not the power generation company, but the sole trader of wholesale gas. This in combination with a diversified and mature gas market gives CPC sufficient commercial guarantee to take on the risk of LNG purchases.

In 2012 CPC sold a total of 16.0 Bcm of natural gas, mainly for domestic power generation, co-generation, and industrial users and household consumers. The main buyer of gas was Taipower.

Accessibility to the terminal by third parties

CPC is the sole importer of LNG in Taiwan and the company controls all aspects of natural gas supply in the country, holding a monopoly in the market. Therefore no third party access to the regasification terminal is possible.

Power sector

Electricity generation relies mainly on coal (40.3%), natural gas (29.1%) and nuclear power (19.0%). Its relatively isolated geographic location means that Taiwan lacks interconnections with other regions and as a result the country is self-reliant on power supply.

The electricity market opened up with the entrance of independent power producers (IPPs) in 1995. Nevertheless, Taiwan Power Company (Taipower), the only state-owned integrated utility, holds a high market share and great influence over electricity prices.

Energy pricing has traditionally been subject to government intervention, leading to below cost pricing of electricity and petroleum products.

Summary of key points

- Terminal promoted, developed and owned by CPC, holding the public monopoly for LNG imports in Taiwan.
- The business model is a slightly modified version of the integrated value chain approach. Although CPC owns and operates the terminal, it is not the power generation company, but the sole trader of wholesale gas. This in combination with a diversified and mature gas market gives CPC sufficient commercial guarantee to take on the risk of LNG purchases.
- Imported LNG is primarily used for power generation. Taiwan Power Company - the state-run company for production and distribution of electric power - was the main user, accounting for 60% of total gas consumption.
- The development of LNG terminals in Taiwan has come along a structural change in the country's electricity mix. There are limited opportunities for

electricity trade due to lack of power grid interconnections with other areas.

A8.9 Uruguay

Currently, Uruguay does not have any LNG regasification terminals. *GNL del Plata* is a planned offshore LNG gas regasification terminal that will be built in a location approximately 4 km west of Montevideo's port (See Map 8). The commercial operation of the terminal is expected to begin in 2015. Construction works of some parts of the terminal have already started.

Map 8 Location of GNL del Plata regasification terminal project

Source: adapted from Google Maps and Inter-American Development Bank.

Reasons for developing the terminal and use of the gas

Traditionally, the main components of Uruguay's energy supply have been fuel oil and hydropower. In 2001 to 2006, oil imports accounted for 56% of the primary energy mix, followed by hydropower (20%), biomass (17%), electricity imports (3%) and natural gas (2%)[154].

In 2008, the Government of Uruguay approved the Energy Policy to 2030, a strategic plan which aims to diversify Uruguay's energy supply. Increasing the share of both renewables and natural gas in the country's energy mix constitutes one of the key pillars of this long term strategy. As natural gas supply to Uruguay was limited to imports from Argentina by pipeline – its sole supplier-, Uruguay decided to favour LNG imports as an alternative by promoting the development of *GNL del Plata*.

The imported gas will be primarily used for power generation. *GNL del Plata* will have the capacity to meet Uruguay's short and medium term natural gas demand for thermoelectric generation, as well as its residential and industrial demand. In 2012, gas amounted to 1% of total energy consumption in the country. Some estimates suggest that natural gas could reach 5.9% of Uruguay's total energy consumption in 2030.

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[154] All natural gas is imported through pipeline from Argentina. In 2012, imports amounted to 0.06 Bcm.

In addition, *GNL del Plata* will allow Uruguay to export natural gas to Argentina through the *Cruz del Sur* pipeline. Lastly, in case there are potential electricity surpluses, they may also be exported to neighbouring countries. Argentina and Uruguay have electricity trade relations. Exchanges take place through the Salto Grande interconnection. Exports from Uruguay have nevertheless been minor in the past.

Type of terminal and main characteristics

GNL del Plata is an offshore LNG regasification terminal which includes an onshore and an offshore component. The main components are: (i) the regasification terminal, which includes a breakwater embedded in the river floor, and a Floating Storage and Regasification Unit (FSRU) that will be attached to the principal pier´s mooring system; (ii) an access channel; and (iii) a natural gas pipeline, composed of a subsea pipeline, a terrestrial pipeline, and surface installations to send the gas to the national grid.

Once in operation, *GNL del Plata* will have a regasification capacity of 10 Mcm per day (3.7 Bcm per year) of natural gas, with the option to expand the capacity to 15 Mcm per day (5.5 Bcm per year).

Development of the terminal and financing

At the beginning, Argentina was involved in the *GNL del Plata* project. In 2007, Uruguay and Argentina signed an 'Energy Cooperation Agreement', aiming to analyse the construction of a regasification terminal in Uruguay, which would respond to the expected increase in natural gas demand in both countries. In 2010, they signed a new agreement to jointly develop the regasification terminal. However, as new shale gas reserves were discovered in the *Vaca Muerta* field in Argentina, Argentina decided to withdraw from the project.

Currently, the project is being promoted solely by the Government of Uruguay through *Gas Sayago*, a joint venture owned by *Administración Nacional de Usinas y Trasmisiones Eléctricas* (UTE), the state owned power company, and *Administración Nacional de Combustibles, Alcohol y Portland* (ANCAP), a state owned oil, alcohol and cement company.

In August 2012, an international bidding process for the design, construction and operation of the regasification terminal was organized. Twelve consortia presented their technical and financial credentials and four groups were qualified to continue in the process[155]. In May 2013, GDF was selected as the winner of the process by a committee composed by the UTE, ANCAP, and the National Directorate for Energy[156].

The project involves private financing from *GDF Suez* on a build, own, operate and transfer (BOOT) basis. The BOOT contracts lasts for 15 years and was signed between *GDF Suez* and *Gas Sayago*. The construction and operation of the terminal will be ultimately financed by the Uruguayan State, which will pay monthly fees to GDF Suez over the duration of the 15 year contract and to which GDF Suez will transfer the

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[155] FCC-Enagás (Spain), GDFSuez (France-Belgium), Hoegh-Belfi (Norway-Chile) and Samsung, Itochu, Kogas and NYK (Korea-Japan).

[156] The National Directorate for Energy is a Directorate within the Ministry of Industry, Energy and Mining.

terminal to Uruguay at the end of the contract. GDF Suez will receive a monthly fee of US$ 14 million a month. Payments will be made by UTE and ANCAP through Gas Sayago. In principle, the fees should cover all the investment and operating costs.

The Inter-American Development Bank (IDB) financing is likely to be used by Uruguay[157] The IDB is currently assessing a US$ 200 million loan application for Uruguay's Gas Sayago offshore GNL del Plata LNG regasification project.

Business model

GNL del Plata will provide regasification services to *Gas Sayago*. UTE and ANCAP, the state companies who own *Gas Sayago* will purchase the LNG and will guarantee payments made by *Gas Sayago* to GDF Suez. The business therefore functions like a tolling arrangement model, where the regasification terminal operator and owner is excluded from the LNG and gas trade. As noted above, the terminal will operate under a BOOT contract. Once the contract ends, the terminal will be transferred to the Uruguayan State.

Accessibility to the terminal by third parties

Since the terminal's entire capacity[158] will be reserved by the off-taker *Gas Sayago*, it is unlikely that open access to third party (demand side) users will be granted or promoted.

Power sector

Electricity generation relies heavily on hydropower (51% of total electricity generation in 2012), oil derivatives (35%), and biomass (12%) Uruguay has electricity interconnections both with Argentina and Brazil.

The state owned company UTE is a dominant actor in terms of generation, transmission and distribution. There is a competitive generation regime, although independent power producers (IPP's) have a relatively low market share (7% of total power installed in 2010) and the majority of installed power corresponds to state-owned UTE and the binational company (owned by Argentina and Uruguay) *Salto Grande*. IPP's rely basically on bio-mass to generate electricity.

Summary of key points

- BOOT structure with private sector involvement in the construction and operation of the terminal. LNG and gas trade risk borne by public power utility and shielded from regasification terminal operator.
- LNG terminal used for power generation with the objective to diversify gas supply sources.

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[157] Currently, IDB financing is being considered for some parts of the terminal, although not for the FSRU. IDB does not exclude participating in the FSRU's financing in the future.

[158] The terminal will be capable of receiving LNG carriers up to 218,000 cubic meters.

- o Regional trade possibilities in gas (via pipeline) to Argentina as well as electricity (via existing transmission line); however no formalised regional cooperation agreements regarding gas imported through the *GNL del Plata* regasification terminal.

- o Taking into consideration Argentina's original participation in the project and subsequent withdrawal, this project highlights the difficulties and uncertainties surrounding the development of *regional* regasification terminals.

A8.10 Brief case studies – 6 countries

A8.10.1 China

- o The Chinese gas market is currently characterised by an oligopolistic structure in production and transportation, which sells at regulated prices either to bulk customers or regional monopolies at the city gate, which then on-sell gas to end users at prices that are also regulated.

- o There are 6 existing onshore terminals, and 8 (onshore) planned ones (by 2015). Of the 14 terminals, 8 are/will be owned and operated by CNOOC[159]. 3 by CNPC[160], through its listed arm, PetroChina and 1 terminal will be owned and operated by private firm Sinopec[161].

- o There is no mandated access to LNG and limited scope for the development of competition and gas trading. An exception is the (temporary) introduction of LNG trading in December 2010 by the Shanghai Petroleum Exchange (SPEX) and again in the summer of 2012. The former was launched to address a tight supply situation at the time, while the most recent attempt aims to secure gas volumes for gas-fired plants during the peak electricity summer period.

- o LNG import prices are oil-linked and determined by bilateral commercial negotiations between importers (primarily CNOOC) and suppliers. The resale price of LNG is not directly regulated. Importers are required to negotiate the sale of regasified LNG at the wholesale level ie with distribution companies or directly to large industry and power companies.

- o The overall contractual terms require NDRC[162] approval prior to importers obtaining the necessary permits for importing LNG and operating the regasification terminals. LNG importers are required to negotiate the sale of regasified LNG (inclusive of terminal charges) with distribution companies or directly to large industry and power companies. Although these prices are not formally regulated, overall contractual terms require

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[159] China National Offshore Oil Corporation, state-owned.

[160] China National Petroleum Corporation, state-owned

[161] Sinopec is also a significant player in the Chinese gas transmission sector.

[162] National Development and Reform Commission

NDRC approval prior to importers obtaining the necessary permits for importing LNG and operating LNG terminals

A8.10.2 Greece

- The Revithoussa LNG terminal (onshore), the only one in Greece, is able to provide balancing and TPA services (although there is currently only one user).
- The terminal is an example of a lightly-used LNG terminal (25% in 2011) which offers wider benefits in terms of security of supply and as a means of developing future competition, and which has been deliberately developed on this basis.
- The terminal is owned by DEPA[163] and operated by DESFA, which is the fully-owned subsidiary of DEPA.
- Until recently, LNG imports were made entirely under a long-term contract between DEPA and Algeria's Sonatrach. In 2010, the terminal saw the first import by a third party, Mytilineos, which was partly used for its own generation and partly resold to DEPA. Further third party imports have taken place since.[164]
- Capacity at the terminal is fully open to third parties and is allocated on a first-come-first-served basis. Third parties using the terminal also need to book capacity on the national gas transmission system which can be difficult to obtain.
- The need for the terminal is justified on the basis of:
  - Providing storage facilities. The Greek gas system lacks any storage, except linepack, other than that provided by the terminal's tanks.
  - Security of supply. The terminal offers an alternative to reliance on Russian gas imports (which represented the entirety of supply prior to its commissioning).
  - Developing competition. The terminal provides a convenient entry point for new shippers and suppliers, as the growth in third party use shows.

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163 Dimosia Epichirisi Paroxis Aeriou (DEPA) is the Greek public corporation responsible for gas infrastructure.

164 Despite its low level of use, denial of access is still reported as occurring due to a lack of storage capacity.

A8.10.3 Japan

- Japan is the largest importer of gas (in the form of LNG). There are a large number of LNG importers, specifically 7 power companies, 8 gas companies and several industrial importers.

- There are 32 LNG facilities in Japan, mostly adjacent to individual power plants. Some LNG terminals are owned individually by power utilities and gas suppliers while others are owned in co-operation through joint ventures.

- Electricity companies importing gas for power generation and some large industrial users, import gas for their own purposes and independently from the city gas industry. Electricity utilities also supply LNG to other new entrants to the gas market. At the same time, gas companies have entered into the electricity market.

- Japanese LNG buyers are gas and power companies carrying out business in an integrated manner, from procurement and imports to transmission, distribution, downstream gas and power supply and marketing. As a result, the Japanese gas market is highly fragmented with regional monopolies and limited competition. Consequently, the few gas trading companies in the country only trade in LNG cargoes, rather than actual pipeline gas deliveries.

- There is no mandatory functional unbundling of LNG infrastructure. However, gas trading guidelines stipulate that it is 'desirable' that business operators that own or manage LNG terminals create manuals for negotiations about the use of LNG terminals by third-party companies so as to clarify the preconditions and rules for such negotiations from the viewpoint of ensuring fair and effective competition.

- Some LNG terminal operators have developed access guidelines, but in practice it has generally proven difficult to establish TPA at LNG terminals. This is because LNG regasification terminals are generally designed to match an importer's specific supply portfolio (secured under long term contract) within the terminal's hinterland. The lack of network interconnection between regions further constrains the ability and the incentive to secure TPA and increase competition.

- The LNG terminals in Japan have either been developed as merchant operations acting as both importer and marketer or for own gas use by power utilities. Under both types of arrangement, the LNG owners and operators effectively pay for their own services through the margin achieved between the cost of gas and the sales price (either as gas or electricity) into their local market.

- The majority of the LNG is bought by power producers under long-term purchase contracts. However, since 2011, power producers have more increased LNG purchases through spot contracts, in order to meet the increasing gas demand. Consequently, gas suppliers are having to offer more flexible terms and conditions. [165]

- In general, LNG prices in Japan are oil-linked. However, many gas sale and purchase agreements include price re-opening clauses to be activated responding to changing market environments. The question is how to argue effectively that the current situation represents changes in market environments that justify renegotiation of pricing terms in existing contracts.

- New purchasing arrangements are being discussed by Japanese importers:[166]

  - **Liquefaction tolling arrangements**

  - **Equity participation with product lifting**: "The idea to have Japanese importers be involved in LNG production projects (importers make equity investments in supply projects] and gain the Japanese government-backed financial support to the projects is based on expectations that an importer's proactive involvement could lead to active influence toward lowering procurement prices."

  - **Aggregating procurement activities between buyers**: with the objective of improving the country's bargaining position in the global LNG market.[167]

  - **Pipeline imports**

A8.10.4 Singapore

- ***Separation of terminal ownership and use***: SLNG[168] is developing the LNG terminal (onshore)[169] with, initially, only a single private company being contracted to purchase and supply LNG. This is on an aggregator basis with the company being free to determine how best to source LNG to meet its contractual supply commitments.

- A competitive tendering process was conducted to select an LNG aggregator, which was won by BG Group. BG is responsible for marketing LNG to customers and supplying their requirements from its own gas portfolio. BG holds a monopoly for the initial capacity of the LNG terminal.

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165 http://www.gastechnology.org/Training/Documents/LNG17-proceedings/3-3-Hiroshi_Hashimoto.pdf

166 http://www.gastechnology.org/Training/Documents/LNG17-proceedings/3-3-Hiroshi_Hashimoto.pdf

167 http://eneken.ieej.or.jp/data/4436.pdf

168 ***Singapore LNG Corporation (SLNG)*** is a fully state-owned company, owned by its regulator, EMA.

169 The terminal was originally to be developed by a private company but the preferred bidder was unable to obtain the necessary financing.

- The existing aggregator's contract is exclusive until the LNG market reaches a minimum size, which is now close to being achieved. Discussion is underway as to whether, once this occurs, other suppliers will also be able to use the terminal which would introduce TPA as well.

- Given the planned expansion of the terminal's capacity, EMA consulted on options for the next market tranche during 2012, but has issued no conclusions to date. The options consulted on were:[170]

  - ***Regulated sole provider (BG + 1).*** A new monopoly importer would be appointed for the incremental LNG capacity. The importer's procurement strategy, LNG sales terms and prices would be regulated.

  - ***Government-appointed multiple aggregators (BG + 3).*** Up to three new aggregators would be selected through a competitive tendering process and be awarded franchises covering a specific amount of LNG, in a similar manner to BG's existing contract.

  - ***Market-driven aggregation***. Open competition between LNG importers would be permitted, subject to entry criteria such as a minimum throughput volume or deliveries per year to ensure efficient terminal use.

- Currently, BG has contracted with SLNG for the use of the terminal and is responsible for scheduling LNG deliveries and sending-out gas on behalf of its customers. In scheduling deliveries, customers are given priority according to the size of their contracts.

A8.10.5 South Korea

- LNG is purchased primarily through long-term supply contracts, with spot cargoes complementing this supply to correct market imbalances and meet peak seasonal demand.

- South Korea has four LNG regasification facilities. Pohang Iron and Steel Corporation (POSCO) and Mitsubishi Japan jointly own the only private regasification facility in Korea, located on the southern coast in Gwangyang. This last terminal currently has four customers who import LNG for own use.

- In addition to operating three of the four LNG receiving terminals, KOGAS owns and operates the entire national pipeline network, and sells regasified LNG to 14 power generation companies and private gas distribution companies.

- Recently, an open access policy has been put in place to give direct importers improved access to the transportation network and LNG

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[170] http://www.ema.gov.sg/media/com_consultations/attachments/4f755f26e9d75-Post-3_Mtpa_Consultation_Paper_FINAL.pdf

facilities. However, companies are only permitted to negotiate importing gas directly for their own use and are prohibited from reselling gas.

- Most LNG imports into Korea are delivered according to long-term contracts, usually 20 to 25 years in duration. Until recently, long term supply of LNG to Korea was organised on a take-or-pay basis. Korea is active in the spot LNG market because of its very seasonal demand for gas.

- Companies wishing to import LNG directly are only permitted to do so for their own use and are prohibited from reselling their gas. To facilitate direct imports the government has introduced a TPA regime on a negotiated basis, despite earlier intentions for a regulated regime. In practice, however, obtaining access has been difficult and, indeed, POSCO decided to construct its own LNG terminal because it was unable to negotiate access to KOGAS' LNG terminals and pipelines.

A8.10.6 Vietnam

- The Electricity Regulatory Authority of Vietnam (ERAV) regulates the electricity industry as it moves toward a market structure. There is no equivalent body for the regulation of the gas industry.

- LNG import infrastructure was introduced in light of the projected supply gap, as an investment by Vietnamese authorities.

- Offshore gas transportation infrastructure is owned either by PVN[171] exclusively or in partnership with international oil companies who operate the upstream field. Onshore infrastructure is owned by PVN and its operation is by a subsidiary of PVN. A similar arrangement is planned for Vietnam's LNG terminals.

- ***Thi Vai LNG terminal*** (onshore) — developed by PVN, who will be the gas purchaser and supplier. Customers for LNG supplied from the terminal will be independent power plants (IPPs) and industrial customers in surrounding estates.

- ***Son My LNG terminal*** (onshore) — PVN will be responsible for developing the terminal (by 2019/20) and purchasing LNG for supply to the BOT and other customers.

- The costs of LNG terminals and other infrastructure are expected to be separately identified and charged rather than being bundled into final gas sales prices. This would allow for the introduction of Third Party Access (TPA) in the future. It may also facilitate the development of uncontracted

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[171] ***PetroVietnam (PVN) is the state-owned company*** that carries out petroleum activities. It comprises four main business activities (oil and gas exploration and production; oil refinery; processing, transportation and distribution of natural gas and its products; 10% of installed generation capacity) undertaken by 4 fully-owned subsidiaries.

LNG import capacity and storage as a means of enhancing supply security and the development of LNG terminals on a 'tolling' basis.